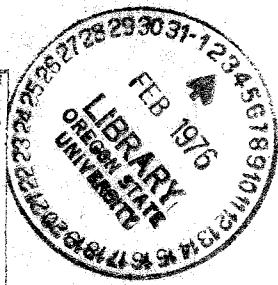


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Finishing with Wood and Bark Residues COMPACT

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Forest Research Laboratory
Oregon State University

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BOILERS FIRED WITH WOOD AND BARK RESIDUES

David C. Junge, Ph.D.
Research Associate
Department of Mechanical Engineering
and Research Coordinator
Office of Energy Research and Development
Oregon State University

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Forest Research Laboratory
School of Forestry
Oregon State University
Corvallis, Oregon 97331

in cooperation with

Plywood Research Foundation
1119 A Street
Tacoma, Washington 98401

FOREWORD

This book is not written as a "how-to" book. Rather, it is written to increase the understanding of systems and processes in operating boilers with wood and bark fuels. Emphasis is on the importance of completing the combustion reaction to minimize pollutant emissions.

The material presented grew out of a series of lecture notes. It encompasses the author's personal experience in the field, information found in a variety of publications, and considerable information from on-the-job operators, powerhouse superintendents, and engineers. Although the primary objective was to write a book that would be useful to operators, experience has shown that the information contained also may be of value to managers and engineers concerned with powerhouse operations.

The operation of boilers fired with wood and bark residues can have several goals. Included are the need to generate low-cost steam on a reliable basis that meets stringent emission standards, the desire to obtain high thermal efficiency, and the goal of burning large volumes of waste materials to minimize difficulties in solid-waste disposal.

To meet these objectives, both the system and the operator must function properly. Sufficient equipment must be available to prepare and transport fuel, complete the combustion reaction, generate high-quality steam in response to demand, and clean the exhaust gas stream to meet emission standards. Not only does this require sufficient equipment, it requires that the equipment be well maintained. Plugged, broken, dirty, uncalibrated, or unlubricated equipment prevents the system from doing its job.

Operator skills are equally important. Even the best equipped and maintained systems will not function optimally if the operators are uninformed or misinformed. The purpose of this book is to upgrade the skills of operators of hogged fuel boilers. Subject matter was selected in combustion systems, characteristics of wood- and bark-residue fuels, principles of combustion, factors affecting combustion of hogged fuel, monitoring equipment, combustion control equipment, pollution control devices, measurement of pollutant emissions, and regulations pertaining to emissions from boilers fired with hogged fuel. Emphasis is placed on the importance of completing the combustion reaction as a means of minimizing pollutant emissions.

ACKNOWLEDGEMENT

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1. COMBUSTION SYSTEMS FOR WOOD- AND BARK-FIRED BOILERS

Wood and bark residues can be burned with ease and little or no equipment. This is demonstrated by the classic campfire. You need only start a small fire with dry scraps or twigs and pile the wood properly to enjoy a cheery blaze.

Utilizing wood fuel in this manner is enjoyable, but has drawbacks. First, most of the heat escapes with the exhaust gases. Second, campfires smoke.

To take full advantage of the heating value of wood and bark fuel and yet control the smoke, a complex system for combustion and heat exchange is necessary. These systems, referred to as "boilers," have many components, which include systems to prepare, store, transport, and feed the fuel; systems to heat, transport, and control the flow of air for combustion; a furnace for combustion; a heat exchanger system to transfer available heat from the combustion process to heat energy in steam; control devices to limit emissions of air pollutants; a feed-water treatment system to control foaming, minimize scale formation and sedimentation, and provide a continuous flow of deaerated water to the steam generating system; and systems to monitor and control interrelated processes.

There are many variations in equipment used on boilers. One typical arrangement is shown schematically in Figure 1. Important variations are discussed.

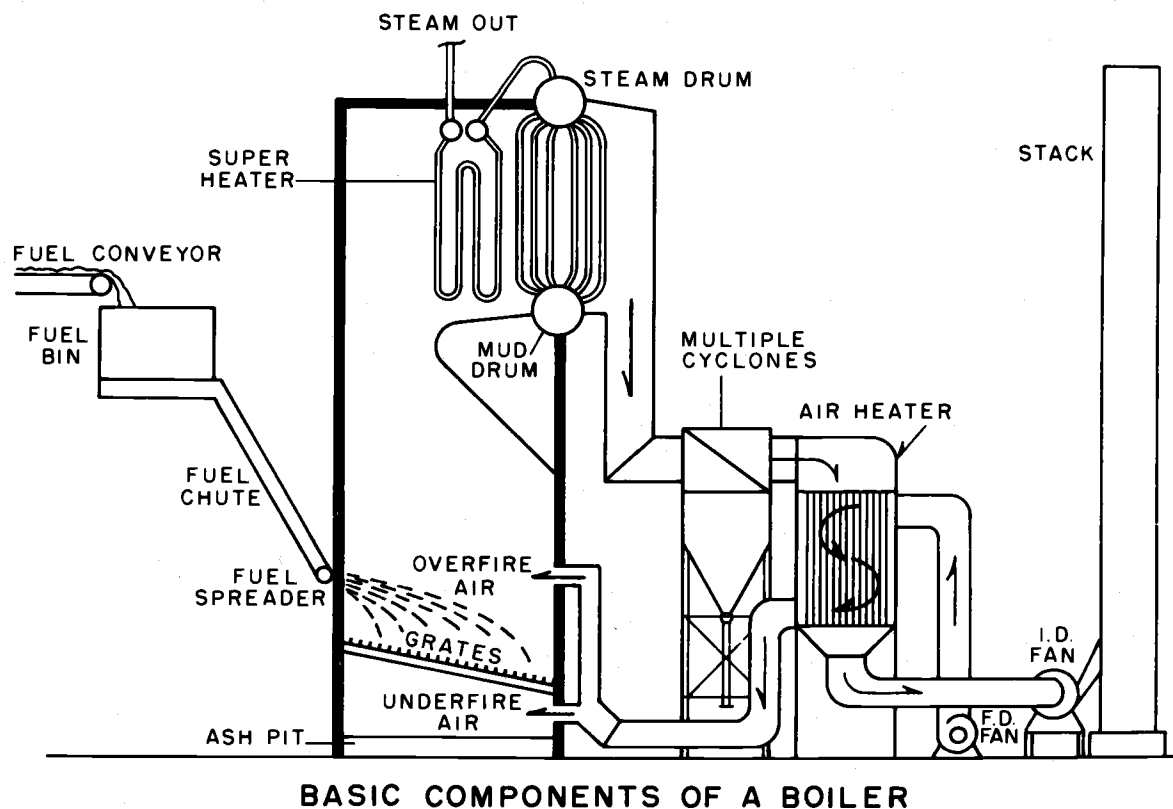


Figure 1. Typical basic components of a boiler.

Furnace Designs

Three basic classes of furnace design are commonly used for wood firing: Dutch ovens, spreader stokers, and suspension burners.

Dutch Ovens

The Dutch oven design was the standard up until the late 1940's and early 1950's (Figure 2). It is primarily a large, rectangular box, lined on the sides and top with firebrick (refractory). Heat is stored in the refractory and radiated to the conical fuel pile in the center of the furnace. This aids in driving moisture from the fuel and evaporating the organic materials. The refractory may be water cooled to minimize the damage to the furnace from high temperatures.

The fuel pile rests on a grate. Underfire air is fed through the grate. Overfire air is fed in around the sides of the fuel pile. By design, incomplete combustion is intended to occur in the Dutch oven or primary furnace. Combustion products pass between bridge wall and drop-nose arch into the secondary furnace chamber, where combustion is completed before gases enter the heat exchange section.

This furnace design has a large mass of refractory, which helps to maintain uniform temperatures in the furnace region. This aids in stabilizing combustion rates, but results in slow response to fluctuating demands for steam. The system works well, if it is not fired at high combustion rates and if the steam load is fairly constant. With this design, however, the underfire airflow rate is dependent upon height and density of the fuel pile on the grate. When the fuel pile is wet and deep, the underfire airflow is low. Thus, the fire may be deficient in oxygen. As the fuel dries and the pile burns down, the flow rate increases as the pressure drop through the fuel pile decreases. This brings about an excess of air in the furnace. For fluctuating steam loads, the result is continuous change from insufficient air to excess air. This feature, coupled with slow response, high cost of construction, and high costs of refractory maintenance, resulted in phasing out Dutch oven designs.

A variation of the Dutch oven design is the fuel cell. Fuel cells usually incorporate a primary and a secondary combustion chamber (Figure 3). The primary combustion chamber is a vertical, refractory-lined cylinder with a grate at the bot-

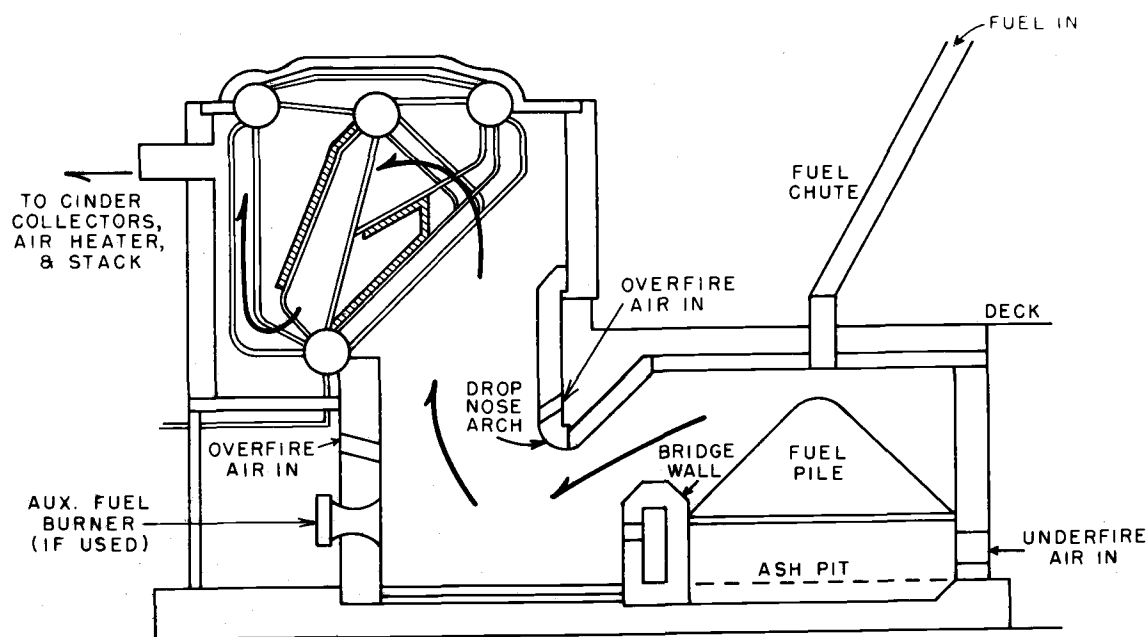


Figure 2. Dutch oven furnace and boiler.

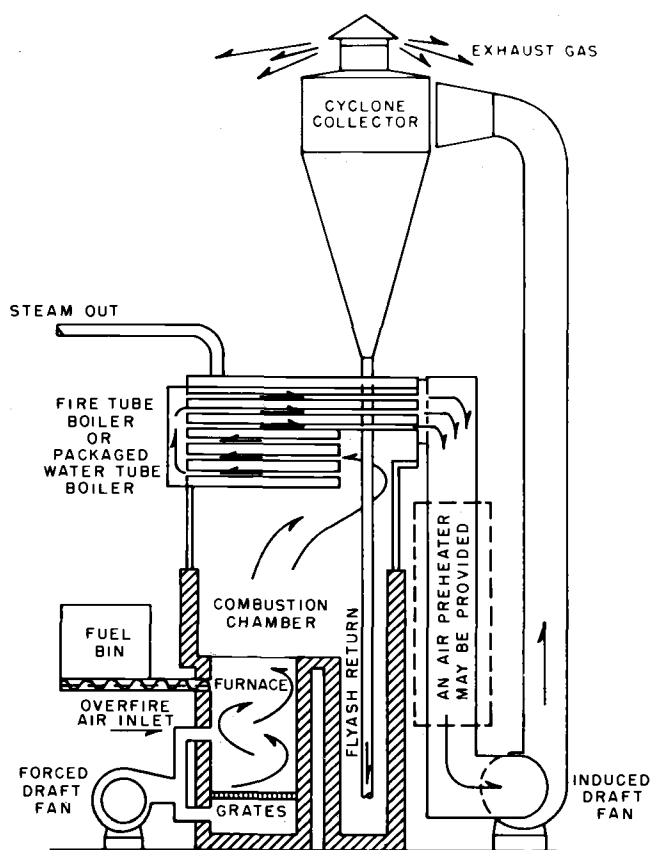


Figure 3. Fuel cell furnace system.

tom. Fuel is fed into the cell and drops to the grate or is fed from an undergrate stoker. Air is fed through the grate, and the combustion is partially completed in the cell. Heat is radiated to the fuel pile from the hot refractory. Combustion is completed in the secondary combustion chamber.

Spreader Stokers

In spreader-stoker furnaces (Figure 4), fuel is spread pneumatically or mechanically across the furnace. Part of it burns in suspension, but large pieces fall on a grate. The feed system is designed to spread an even, thin bed of fuel on the grates. The flame over the grates radiates heat back to the fuel to aid combustion. Underfire air can be controlled, because the pressure drop through the fuel mat is fairly constant.

Spreader-stoker furnace walls normally are lined with heat exchange tubes (water walls). As there is little refractory, construction and maintenance costs are low. For a given steam-generation capacity, spreader stokers are substantially smaller than Dutch ovens. Also, they can respond to load variations quickly and with less upset in the combustion process. With little or no refractory to reflect heat back to the fuel, heated combustion air is normally used.

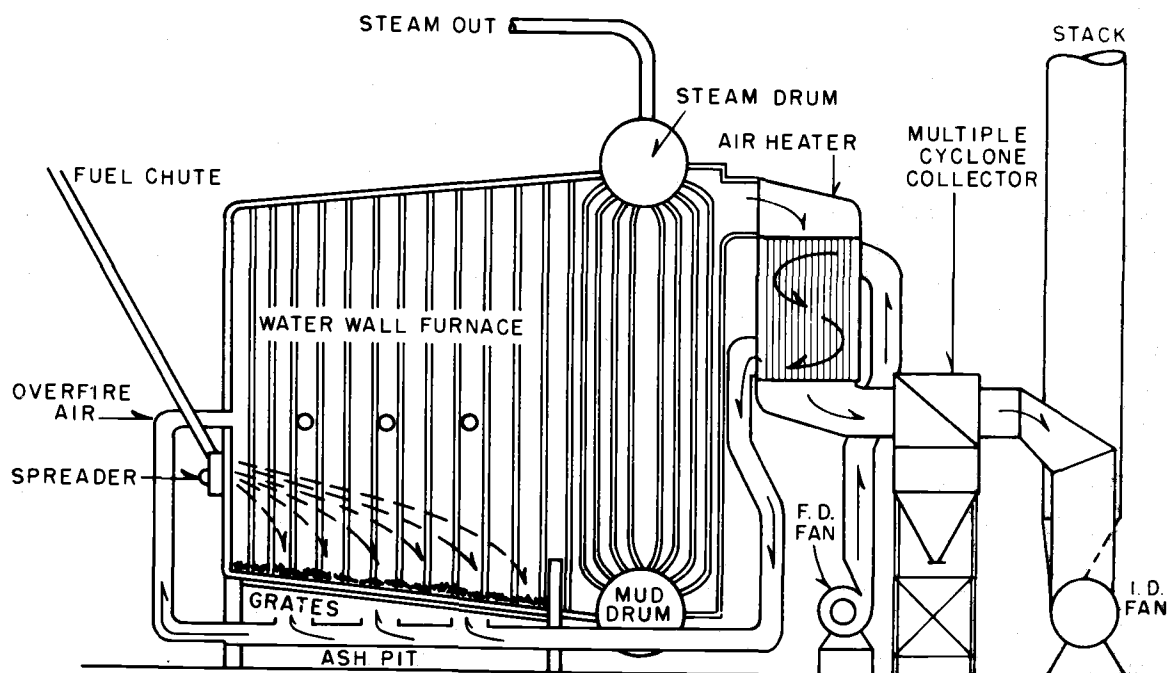


Figure 4. Small spreader-stoker furnace.

Suspension Burning Systems

Fuel in small sizes can be burned in suspension, that is, supported by air rather than by fixed metal grates. Sanderdust usually is burned in this manner. With adequate reduction in size, wood and bark residues also can be burned in suspension. The advantages of suspension burning include low capital costs for combustion equipment because grates are not required, and ease of operation, as grate cleaning is not necessary. The ash goes into suspension as particulate matter in the exhaust stream or falls to the furnace bottom for removal, and rapid changes in rate of combustion are possible.

Suspension burning has disadvantages, however. Because most of the ash escapes with the exhaust gases, control of fly ash may be difficult.¹ Temperature control in the combustion chamber is critical. If the ash-fusion temperature is exceeded, the ash may form large pieces, which can plug or damage the system. Fuel preparation must be extensive to assure fuel size small enough for suspension burning. Moisture content also must be controlled within reasonable limits. This can be costly for systems burning wood and bark fuels. For sanderdust fuel, the processing already is done. Residence time is critical (as in any combustion system). The nature of suspension burning incorporates short residence. At high combustion rates, it may be insufficient for the process to go to completion.

Suspension burning systems range from simple sanderdust burners mounted in an existing furnace to especially designed furnaces, coupled to extensive systems for fuel preparation. Some systems incorporate cyclones in the suspension process. Recent developments in combustion systems use fluidized beds as suspension systems. These offer great potential for control of the combustion process as well as control of emissions. Only a few fluidized beds are used currently, but they are expected to become more common during the next decade, especially for low-capacity units.

¹ Some suspension units are designed to "slag" or melt the ash in the combustion chamber, thus reducing the amount of ash entrained in the exhaust-gas stream.

Variations in Grate Designs

Within the categories of Dutch ovens and spreader stokers, the grate systems may vary substantially. They may be categorized as fixed or dumping grates; air-cooled or water-cooled grates; flat or inclined grates; stationary grates, continuously moving chain grates, reciprocating grates; or grates with large area for gas passage, such as "herringbone" rather than pinhole designs. Design of a particular grate system takes into account such factors as fuel size, moisture content, available heat, maximum rate of steam generation of the boiler, and acceptable level of maintenance. Many of the differences, however, reflect the product line of particular manufacturers.

Fire-Tube and Water-Tube Heat Exchangers

In boilers, the purpose of a heat exchanger is to transfer heat energy released by the combustion process to heat energy delivered in steam. This is done two ways. In the water tube boiler, the most commonly used, water is put into tubes and hot combustion gases pass around the outside of the tubes (Figure 2). In the fire tube boiler, hot gases pass through the tubes and water circulates around the outside (Figure 3). With this design, hot gases can travel through the tubes in turbulent flow patterns, which increases the rate of heat exchange to the water and makes the design very efficient. The design is pressure limited because of high mechanical stresses placed on the drum by its inherent features. Fire tube boilers are seldom larger than 15,000 pounds per hour (pph) in capacity.

In 1973 in Oregon, there were 56 fire tube and 185 water tube boilers fired with residue wood and bark fuels. Together, they consumed 5 million units (one unit equals 200 cubic feet) of fuel in that year (11).

Size of Boilers

Boilers are measured by their capacity to generate steam. Several measurement systems are used, of which two are particularly important in referring to wood- and bark-fired boilers. The first is boiler horsepower (bhp), which is the rate at

which the boiler can evaporate water at 212 F to saturated steam at 212 F. For example, 1 bhp = 34.5 pounds of water evaporated per hour. A typical boiler might be rated at 700 bhp. It was designed to generate steam at a rate of $34.5 \times 700 = 24,150$ pph at atmospheric pressure. The system rating above atmospheric pressure would be less than 24,150 pph.

A more exact rating system refers to the design steam generation rate at a particular temperature and pressure. For example, a typical boiler might have a capacity of 50,000 pph at 165 pounds per square inch absolute (psia) at 366 F.

The advantage of specifying temperature and pressure is that it tells you how much energy is available in the steam. Reference to a steam table provides information on the energy in terms of British thermal units (Btu).

Wood- and bark-fired boilers have a wide range in capacity. The smallest units are hand fired and produce less than 1,000 pph of low-pressure steam. At the other end of the scale, boilers are operating with capacities of 450,000 pph. New boilers are designed as large as 800,000 pph. Most commonly, industrial wood- and bark-fired boilers range from 20,000 to 150,000 pph.

2. CHARACTERISTICS OF FUELS FROM WOOD AND BARK RESIDUES

Wood and bark prepared for firing a boiler are commonly referred to as hogged fuel. The term stems from the machine used to reduce the size of residues. The machine is called a hog.

Hogged fuel is measured commonly in quantities of 200 cubic feet, called "units." In any given unit, characteristics of the fuel may vary substantially. A typical unit of fuel, however, may have the following characteristics (3): total weight = 3,650 pounds, dry weight = 2,190 pounds, water by weight = 40 percent, heating value per dry pound = 9,840 Btu, heating value per unit = 21,200,220 Btu, and ash content = 1.88 percent.

Hogged fuel can be classified or characterized by species, size, moisture content, ultimate analyses, proximate analyses, and heating value. The influence of these parameters is discussed in Chapter 4, and their control is examined in Chapter 6.

Table 1. Approximate Range in Size and Moisture Content of Typical Components of Hogged Fuel (14).

Component	Size range	Moisture content
	In.	%
Bark	1/32-4	25-75
Coarse wood residues	1/32-4	30-60
Planer shavings	1/32-1/2	16-40 ²
Sawdust	1/32-3/8	25-40
Sanderdust	2 μ ¹ -1/32	2-8
Reject "Mat Furnish"	10 μ ¹ -1/4	4-8

¹Small end of the range is measured in microns (One micron = 1/1,000,000 meter).

²From kiln dried to green.

Species

Many species of wood are available for hogged fuel. Some commonly used species in the Pacific Northwest include Douglas fir, true firs, alder, ponderosa pine, western hemlock, spruces, larch, cedars, and redwood. The differences between species that affect their efficiency as hogged fuel are found in heating values and in material handling.

Cedar bark is infamous as fuel because of problems with hogging and transporting. The bark is long and "stringy" and difficult to reduce in size in a hog. It tends to plug feeder systems, wrap up in conveyors, and present difficult handling problems. By comparison, most other commonly used species are less difficult to handle.

Size

The size of hogged fuel depends on the material that makes up the fuel. A typical sample of hogged fuel might include a combination of bark, coarse wood residues (slabs, trimmings, and endpieces), planer shavings, sawdust, sanderdust, and reject "mat furnish." Each of these component parts has recognizable size characteristics (Table 1).

Moisture Content

There are two ways to describe the moisture content of fuel; the wet or "as is" basis, and the dry basis. The wet basis is more commonly used. For wet-basis determinations, the weight of moisture in fuel is divided by the total weight of fuel plus moisture, and the answer is expressed as a

percentage. Therefore, moisture content (wet basis) = (weight of moisture x 100)/(weight of dry fuel + weight of moisture).

The relation between moisture contents (MC) expressed on a wet and a dry basis is found easily from the following equations:

$$\text{MC (wet)} = 100 \times \text{MC (dry)} / [100 + \text{MC (dry)}], \text{ and}$$

$$\text{MC (dry)} = 100 \times \text{MC (wet)} / [100 - \text{MC (wet)}],$$

where moisture content is expressed as a percentage on either a wet or dry basis. The wet basis will be used in this work.

Moisture content is significant for two reasons. First, it varies over a wide range of values and, therefore, makes control of the combustion process difficult. For example, consider MC of the different components of hogged fuel. Bark, coarse wood residue, and sawdust normally have a moisture range from 30 to 65 percent. The average value is around 45 percent. This is dependent, however, upon the time of year, the type of wood (species), and the process used at a particular mill. On the other hand, kiln-dried planer shavings, sanderdust, and some rejected mat-furnish materials usually have low MC from 4 to 16 percent. Table 1 summarizes typical MC for the normal components of hogged fuel.

The second significant feature of moisture content is that it has negative heating value; that is, heat is needed to evaporate it.

Ultimate Analyses

Ultimate analyses are used to determine the chemical composition of fuels. The primary components of hogged fuel include those shown in Table 2. Ultimate analyses point out three significant features of hogged fuel. First, there is only a small variation from sample to sample. This is important in calculating and controlling excess air for combustion.

Second, hogged fuel has a high oxygen content. This is significant because less oxygen has to be supplied from air to complete the combustion process.

Third, the sulfur content of hogged fuel is so low that sulfur dioxide from combustion of hogged fuel does not present a risk of air pollution. Combustion of sulfur-bearing coals or oil results in significant emissions of sulfur dioxide.

Proximate Analyses

Proximate analyses of fuels are used to determine the percentage of volatile material, fixed carbon, and ash.

Some typical proximate analyses of wood fuels are shown in Table 3. Note the consistent difference in volatile content of bark compared to that of sawdust, regardless of species except for cedar. In general, volatile content of wood is 10 percent higher than that of bark.

The ash content of wood residues is generally low, but still significant where large quantities are

Table 2. Typical Ultimate Analyses Data for Moisture-Free Samples of Hogged Fuel Bark.

Component	Douglas fir (14)	Western hemlock (14)	Avg of 22 samples ¹
	%	%	%
Hydrogen	6.2	5.8	6.1
Carbon	53.0	51.2	51.6
Oxygen	39.3	39.2	41.6
Nitrogen	0.0	0.1	0.1
Ash (inorganics)	1.5	3.7	0.6

¹These samples were collected and analyzed by Weyerhaeuser Company. They were random samples of hogged fuel taken from various mill sites.

Table 3. Typical Proximate Analyses of Moisture-Free Wood Fuels (8).

Species	Volatile matter	Charcoal	Ash
	%	%	%
BARK			
Hemlock	74.3	24.0	1.7
Douglas fir, old growth	70.6	27.2	2.2
Douglas fir, young growth	73.0	25.8	1.2
Grand fir	74.9	22.6	2.5
White fir	73.4	24.0	2.6
Ponderosa pine	73.4	25.9	0.7
Alder	74.3	23.3	2.4
Redwood	71.3	27.9	0.8
Cedar bark	86.7	13.1	0.2
SAWDUST			
Hemlock	84.8	15.0	0.2
Douglas fir	86.2	13.7	0.1
White fir	84.4	15.1	0.5
Ponderosa pine	87.0	12.8	0.2
Redwood	83.5	16.1	0.4
Cedar	77.0	21.0	2.0

burned. The ash content of bark usually is greater than that of wood. Handling and harvesting of logs frequently causes dirt and sand to cling to the bark. Saltwater storage and transport of logs also can add to the ash content of fuel by depositing sea salt in the wood or bark.

Heating Value

The heating value of hogged fuel is dependent upon two components of fuel, fiber and resin (4). Wood fiber has a heat value of about 8,300 Btu per pound. Resin has a heating value of 16,900 Btu per pound. Woods with more resin, therefore, have higher heating values than those with low resin contents.

Bark generally has more resin than is in wood. Softwood bark generally has more resin than

hardwood bark. Some typical heating values are shown in Table 4.

Table 4. Typical Heating Values in Btu's Per Pound for Moisture-Free Bark and Wood (8).

Species	Heating value	
	Wood	Bark
Douglas fir	9,200	10,100
Douglas fir	8,800	10,100
Western hemlock	8,500	9,800
Ponderosa pine	9,100	---
Western redcedar	9,700	8,700
Red alder	8,000	8,410

3. PRINCIPLES OF COMBUSTION

When wood burns, it undergoes a complex process called combustion that includes both physical and chemical reactions. These will be examined as we define the characteristics of combustion.

Characteristics of Combustion

Combustion is both an **oxidation** and a **reduction** process in which the fuel is oxidized by oxygen from the air and the oxygen in the air is reduced by the constituents of the fuel. We recognize that to burn hogged fuel, oxygen from the air is necessary.

The concentration of oxygen available for combustion is important in controlling the rate of burning. If pure oxygen is fed into a furnace, the material will be consumed much more rapidly than with normal air. This seldom concerns the operation of hogged-fuel boilers, except in those few installations where primary or secondary air is recirculated from a combustion-exhaust system. Then oxygen concentration is reduced, which slows the rate of combustion or the rate at which the wood burns.

Combustion is an **exothermic** process that emits or releases heat. The amount of heat emitted as a fuel is burned can be determined precisely. For example, heat released from combustion of Douglas-fir bark (Table 4) is about 10,100 Btu per pound of dry material.

Combustion is a **rapid** process. Oxidation of materials can occur over a wide range of rates. At one extreme is the oxidation of paint on your automobile. Normally, this is a slow process that occurs over many months. Comparatively speaking, oxidation in the combustion of hogged fuel is rapid. Depending upon the size of the furnace, many tons of fuel can be consumed in an hour.

Combustion occurs in the **gaseous** phase. Matter can exist as a solid, a liquid, or a gas. For most fuels, combustion can occur only when they are in the gaseous form. The important exception to this is carbon, which can burn in the solid phase.

In combustion, fuels are heated to a temperature high enough to drive off the water in the fuel as water vapor, to decompose the fuel, and to evaporate the volatile component of the fuel. As a gas, fuel can mix thoroughly with gaseous molecules of oxygen in the air. As each molecule of fuel

contacts the appropriate number of molecules of oxygen, a chemical reaction can occur between fuel and oxygen. But in the burning of charcoal briquets, oxygen can reach the surface of the fuel and cause it to glow as combustion occurs.

Combustion is a complex of both physical and chemical reactions. Steps in the burning of hogged fuel are:

Dehydration, a physical process, in which fuel is heated to the point where the water evaporates; **evaporation**, a physical process, in which volatile components of the wood are heated, usually between 200 F and 1,100 F, until they change from the solid into the gaseous phase; **pyrolysis**, a chemical decomposition of the original molecules into other molecular species because of high temperature; **mixing** of fuel molecules with oxygen molecules, a physical process that occurs as soon as the fuel is evaporated and comes into contact with the combustion air; and **oxidation and reduction**, a process of chemical reaction in which original reactants disappear to form new chemical substances and heat and light are emitted.

Light, which usually is **emitted** in the combustion process, is dependent upon the type of fuel that is used. Most fuels will burn with visible flame. A hydrogen flame is not easily visible, however. A flame from wood fuels is always apparent during combustion.

Combustion is a **free radical** reaction. In the two processes, pyrolysis and oxidation-reduction, the molecules of fuel are thought to break apart to form independent, charged ions, referred to as "free radicals." Although this characteristic is significant in the control of some combustion processes, it is not important to combustion of wood and bark residues.

A summary statement might be that combustion is a complex physical-chemical reaction that occurs primarily in the gaseous phase.

Chemistry of the Combustion Process

Although combustion is a complex physical and chemical process, it can be viewed as two simple reactions for the purpose of combustion calculations. First, carbon (C) combines with oxygen O_2 to form carbon dioxide (CO_2):



Second, hydrogen (H) combines with O_2 to form water (H_2O):



In this chapter, we will consider these basic chemical reactions and demonstrate how much oxygen is required to bring the reactions to completion. In doing this, we will introduce the concept of excess air and discuss its measurement.

Atoms and Molecules

All things in the world are made up of atoms and molecules. Atoms are basic forms of all substances. If we reduce elements such as carbon, hydrogen, lead, gold, or sodium down to their smallest units, we find atoms.

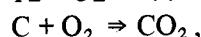
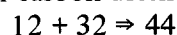
Molecules consist of one or more atoms. Some molecules consist of the same kind of atoms, some of different kinds of atoms. Oxygen, as we know it in air, is in a molecular form of two atoms of oxygen, expressed symbolically as O_2 . Carbon dioxide molecules, CO_2 , have one atom of carbon and two atoms of oxygen.

An important characteristic of atoms is that they have weight, referred to as atomic weight. Carbon atoms always have the same relative weight, which equals 12. The atomic weights of molecules and other atoms that are important in the combustion of hogged fuel are listed in Table 5. Materials such as hydrogen, oxygen, and nitro-

gen normally are found in nature as two atoms that form a molecule of the substance.

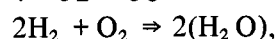
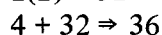
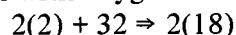
The concept of a "pound mole" is helpful in quantifying chemical reactions. A pound mole of a substance is the same as the molecular weight of that substance, expressed in pounds. For example, a pound mole of carbon is 12 pounds of carbon. A pound mole of oxygen is 32 pounds of oxygen. A pound mole of hydrogen is 2 pounds of hydrogen.

Pound moles have two important features. First, when chemicals undergo chemical reactions, the proportions of materials in the reaction usually are expressed simply in terms of pound moles. For example, when carbon combines with oxygen to form carbon dioxide,



12 pounds of carbon combine with 32 pounds of oxygen to form 44 pounds of carbon dioxide. In terms of pound moles, 1 pound mole of carbon combines with 1 pound mole of oxygen to give 1 pound mole of carbon dioxide.

As a second example, when hydrogen combines with oxygen to form water (H_2O),



4 pounds of hydrogen combine with 32 pounds of oxygen to form 36 pounds of water. As pound moles, two pound moles of hydrogen plus 1 pound mole of oxygen give 2 pound moles of water. To express the amounts of materials in a reaction by the simple numbers of pound moles is helpful.

A second important feature of pound moles is that for gases, a pound mole always takes up the same volume under standard conditions of temper-

Table 5. Atomic and Molecular Weights of Typical Elements in the Combustion of Hogged Fuel.

Element	Atom symbol	Atomic weight	Molecule symbol	Molecular weight
Carbon	C	12	C	12
Hydrogen	H	1	H_2	2
Oxygen	O	16	O_2	32
Nitrogen	N	14	N_2	28

ature and pressure. One pound mole of oxygen occupies a volume of 359 standard cubic feet (SCF). One pound mole of hydrogen also occupies 359 cubic feet. Similarly, one pound mole of nitrogen (N) (28 actual pounds) takes up 359 cubic feet under standard conditions of temperature and pressure, defined as 32 F and 29.92 inches of mercury (or 14.7 pounds per square inch absolute) in this instance. This information helps to determine the volume of oxygen required to burn a given weight of hogged fuel. It also helps in determining the volume of air required to obtain oxygen for combustion.

Combustion of Wood

Let us look at the combustion of hogged fuel from a chemical-analysis viewpoint. Under the section in Chapter 2 on ultimate analyses of hogged fuel, we found little variation in the chemical composition of samples of hogged fuel. Table 2 lists data from typical analyses by weight as hydrogen, 6.1; carbon, 51.6; oxygen, 41.6; nitrogen, 0.1; and ash, 0.6 percent.

To relate this information to a practical example, consider that you have 100 pounds of dry hogged fuel with these chemical proportions. Water in hogged fuel does not undergo any chemical change in the combustion process. It simply becomes water vapor. Now, we can look at the fuel in terms of the pounds of different chemical substances in it. For example, 100 pounds of dry hogged fuel equals 51.6 pounds of carbon, 6.1 pounds of hydrogen, 41.6 pounds of oxygen, 0.1 pound of nitrogen, and 0.6 pound of ash.

Next, we convert these pound measurements of the chemical constituents into pound moles of the different parts of the hogged fuel. For example, 1 pound mole of carbon weighs 12 pounds. The 100-pound sample of hogged fuel contains 51.6 pounds of carbon which, at 12 pounds per pound mole, equal 4.3 pound moles. The 6.1 pounds of hydrogen, at 2 pounds per pound mole, equal 3.05 pound moles. And the 41.6 pounds of oxygen, at 32 pounds per pound mole, equal 1.3 pound moles.

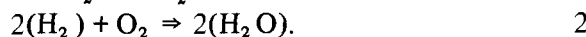
As nitrogen and ash do not participate in the combustion process to any great extent, they will

not be considered here. A summary of the pound moles of material found in 100 pounds of dry hogged fuel is shown in Table 6.

Table 6. Partial Summary of the Amount of Elements Found in 100 Pounds of Dry Hogged Fuel.

Element	Amount	
	<i>Pounds</i>	<i>Pound moles</i>
Carbon	51.6	4.3
Hydrogen	6.1	3.0
Oxygen	41.6	1.3

Two basic reactions occur in the combustion of hogged fuel.



In the first reaction, 1 pound mole of carbon combines with 1 pound mole of oxygen to form 1 pound mole of carbon dioxide. In our example of 100 pounds of hogged fuel, there are 4.3 pound moles of carbon. Therefore, to burn this to completion would require 4.3 pound moles of oxygen.

In the second reaction, 1 pound mole of oxygen is required to burn the 2 pound moles of hydrogen, as seen in equation 2. Therefore, to burn the 3 pound moles of hydrogen in 100 pounds of hogged fuel will require 1.5 pound moles of oxygen.

To burn 4.3 pound moles of carbon requires 4.3 pound moles of oxygen.

To burn 3.0 pound moles of hydrogen requires 1.5 pound moles of oxygen.

Total oxygen required is 5.8 pound moles.

A 100-pound sample of hogged fuel contains 1.3 pound moles of oxygen as part of the molecular structure of the fuel (Table 6). This oxygen is available for participation in the combustion process.

Total oxygen required to burn fuel is 5.8 pound moles.

Oxygen available from the fuel itself is 1.3 pound moles.

Oxygen that must be supplied from air is 4.5 pound moles.

We can readily convert this amount back into terms that are easier to visualize. Recall that 1 pound mole of any gas takes up exactly 359 cubic feet under standard conditions of temperature and pressure. Thus, 4.5 pound moles of oxygen would occupy 1,616 standard cubic feet ($359 \times 4.5 = 1,616$). As oxygen is roughly 21 percent of the volume of air, the total volume of air required for combustion of 100 pounds of hogged fuel is

$$1,616 \times 100/21 = 7,695 \text{ SCF of air.}$$

This is equal to 617 pounds of air required per 100 pounds of fuel.

Excess Air

We have seen the exact amount of air that is required to burn 100 pounds of hogged fuel. In an actual situation, however, some excess air is required for two reasons. First, for combustion to occur, each molecule of gaseous fuel must come into physical contact with one or more molecules of oxygen. To insure this, a few extra molecules of oxygen must be supplied, thus increasing the probability of contact of the molecules. Second, in some furnace designs, excess air is necessary to assist in drying the wet fuel enough for combustion to occur and to properly disperse the fuel on the grates.

Excess air normally is expressed as a percentage of the amount that must be supplied to meet exactly the requirements for combustion. In the example of burning 100 pounds of hogged fuel, we found that 7,695 SCF of air were required. This can be a basis for determining excess air. For example, to calculate the air requirement at 25

percent excess air, we add on 25 percent of 7,695 SCF, or

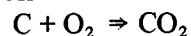
$$(1 + 0.25) \times 7,695 = 9,619 \text{ SCF.}$$

In the same manner, we can determine the air requirement under conditions of 50, 100, and 150 percent excess air (Table 7).

The effects of excess air on combustion will be discussed later. For the present, we must be aware of the magnitude of the airflow for different percentages of excess air. Each 100 pounds of dry hogged fuel burned requires more than 1,200 pounds of air at 100 percent excess air. Currently, many hogged fuel boilers operate in the range of 150 percent excess air and are using over 1,500 pounds of air per 100 pounds of hogged fuel burned.

Primary Products of Combustion

Referring back to Equation 1, we found that carbon in fuel combines with oxygen to form carbon dioxide.



1

One pound mole of carbon dioxide is formed for each pound mole of carbon and oxygen, and one hundred pounds of hogged fuel contain 4.3 pound-moles of carbon. Therefore, the combustion products will include 4.3 pound moles of carbon dioxide.

Now, consider the components of the combustion products caused by excess air. If the process included no excess air, no oxygen would be in the flue gases. If, however, excess air is provided, the flue gases will contain the excess oxygen that was not used in the combustion process. For

Table 7. Summary of the Combustion Air Requirements to Burn 100 Pounds of Dry Hogged Fuel with Various Percentages of Excess Air.

Excess air	Multiplying factor	Volume of air	Weight of air
%		SCF ¹	Pounds
0	1	7,695	617
25	1.25	9,619	771
50	1.50	11,543	926
100	2.00	15,390	1,234
150	2.50	19,238	1,543

¹SCF: standard cubic feet.

example, if 25 percent excess air is added to the basic air requirement of 7,695 SCF, it is increased by 1,924 SCF of air. This makes a total of 9,619 SCF (Table 7). When the additional 1,924 SCF are added, 21 percent of it is oxygen. Therefore, $0.21 \times 1,924 = 404$ SCF of oxygen added, but not used in combustion. In terms of pound moles, this is equivalent to

$$404/359 = 1.13 \text{ pound moles.}$$

Therefore, the flue gases for the condition of 25 percent excess air will contain 1.13 pound moles of oxygen per 100 pounds of fuel burned.

The same approach can be used to determine the oxygen content of flue gases for other percentages of excess air (Table 8).

The last component of the flue gases that will be considered is the nitrogen content. Recall that roughly 79 percent of air is nitrogen. This does not undergo any significant chemical reactions in the combustion of hogged fuel. Therefore, nitrogen that enters the process will leave the process as nitrogen.

As with oxygen, the amount of nitrogen entering the process is partially dependent upon the amount of excess air introduced. For the conditions of no excess air, 7,695 SCF of air were required to burn 100 pounds of hogged fuel. Seventy-nine percent of this amount is nitrogen, or

$$0.79 \times 7,695 = 6,079 \text{ SCF.}$$

In pound moles, this represents

$$6,079 \text{ SCF}/359 \text{ SCF per pound mole} = 16.9 \text{ pound moles of nitrogen.}$$

With 25 percent excess air, 9,619 SCF of air was required (Table 7). Seventy-nine percent of this, or

$$0.79 \times 9,619 = 7,599 \text{ SCF,}$$

is nitrogen. In pound moles, this represents

$$7,599 \text{ SCF}/359 \text{ SCF per pound mole} = 21.2 \text{ pound moles of nitrogen.}$$

Table 9 summarizes the pound moles of nitrogen for various amounts of excess air used to burn 100 pounds of hogged fuel.

With the information in Tables 8 and 9, we now can analyze the major constituents of dry flue gases in the combustion of hogged fuel. With no excess air, we find the following combustion products:

Carbon dioxide	= 4.3 pound moles,
Oxygen	= 0 pound moles (Table 7),
Nitrogen	= 16.9 pound moles (Table 8), and
Total products	= 21.2 pound moles.

In percentages:

Carbon dioxide	= $4.3/21.2 \times 100$ = 20.3 percent of total dry flue gas,
Oxygen	= $0/21.2 \times 100$ = 0 percent of total dry flue gas,
Nitrogen	= $16.9/21.2 \times 100$ = 79.7 percent of total dry flue gas.

With no excess air, the combustion gases would have 20.3 percent carbon dioxide. This can be measured directly with an Orsat Flue Gas Analyzer.

Table 8. Summary of Oxygen Contents of Flue Gases for Various Percentages of Excess Air to Burn 100 Pounds of Dry Hogged Fuel.

Excess air	Volume of air	Air in excess of base	Oxygen in excess of base	Oxygen in flue gas
%	SCF ¹	SCF ²	SCF ²	Pound moles
0	7,695	0	0	0
25	9,619	1,924	404	1.13
50	11,543	3,848	808	2.25
100	15,390	7,695	1,616	4.50
150	19,238	11,543	2,424	6.75

¹SCF: standard cubic feet.

²Surplus over base requirement.

Table 9. Summary of the Nitrogen Content of Flue Gases for Various Percentages of Excess Air to Burn 100 Pounds of Dry Hogged Fuel.

Excess air	Total air	Nitrogen	Nitrogen
%	SCF ¹	SCF ¹	Pound moles
0	7,695	6,079	16.9
25	9,619	7,599	21.2
50	11,543	9,119	25.4
100	15,390	12,158	33.9
150	19,238	15,198	42.3

¹Standard cubic feet.

With 25 percent of excess air, we find that

Carbon dioxide = 4.3 pound moles,
 Oxygen = 1.13 pound moles (Table 7),
 Nitrogen = 21.2 pound moles (Table 8), and the
 Total = 26.63 pound moles.

In percentages:

Carbon dioxide = $4.3/26.63 \times 100$
 = 16.1 percent of total flue gas,
 Oxygen = $1.13/26.63 \times 100$
 = 4.2 percent of total flue gas, and
 Nitrogen = $21.2/26.63 \times 100$
 = 79.6 percent of total flue gas.

In this example, the combustion gases would indicate 16.1 percent carbon dioxide. By going through these calculations for each percentage of excess air, we can develop the values in Table 10.

The values of carbon dioxide and oxygen shown in Table 10 can be plotted against the percentage of excess air (Figure 5). This plot and data from a flue gas analysis for either carbon dioxide or oxygen allow you to read the percentage of excess air immediately. Data on both gases are not necessary, but may help as a check on accuracy of the flue gas analysis.

The water-vapor content of the flue gases is not considered in the analysis because, in most flue gas analyzers, the gas sample is cooled before actual analysis for constituents, which condenses the water vapor and removes it from the sample.

Thus, the analysis is made on only the nonwater constituents of the gas. Data in Table 10 and Figure 6 are calculated on a dry basis.

The actual water-vapor content, measured in flue gases from hogged fuel boilers, ranges from about 6 to 24 percent by volume. For hogged fuel whose average moisture content is from 45 to 50 percent by weight, the water-vapor content of the flue gas will be about 16 percent by volume under stack conditions. This value varies with moisture content in the fuel, relative humidity of the air, and percentage excess air. If a wet scrubber is installed to control particulate emissions from the

Table 10. Composition of Dry Combustion Gases¹ for Various Percentages of Excess Air.

Excess air	Carbon dioxide	Oxygen	Nitrogen
%	%	%	%
0	20.3	0	79.7
25	16.1	4.2	79.6
50	13.5	7.0	79.5
100	10.1	10.5	79.4
150	8.1	12.7	79.3

¹For combustion of wood and bark, the theoretical sum of carbon dioxide and oxygen should be 20-21% of the dry combustion gases.

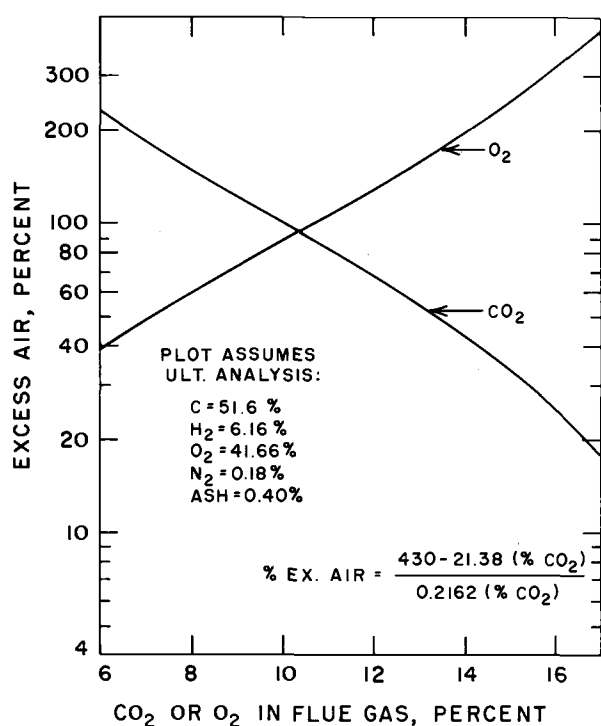


Figure 5. Relation of excess air to percentage of oxygen and carbon dioxide in flue gases.

boiler, water-vapor content in the gas, downstream from the scrubber, will increase.

Other Products of Combustion

The foregoing discussion deals only with the primary constituents of flue gases (carbon dioxide, oxygen, nitrogen, and water vapor). These usually make up 98-99 percent of the total material emitted from the combustion process. Other materials are emitted, however (Table 11), which can be categorized as gaseous or particulate. The term "gaseous" is self explanatory. The term "particulate" is somewhat misleading. The Federal Government and most state regulatory agencies define particulate as any material that exists either in the liquid or solid state under conditions of 29.92 inches of mercury (standard atmospheric pressure) and 70 F. With this definition, some materials that exist as gases at the higher stack temperatures (from 400 to 750 F) may condense to form liquids

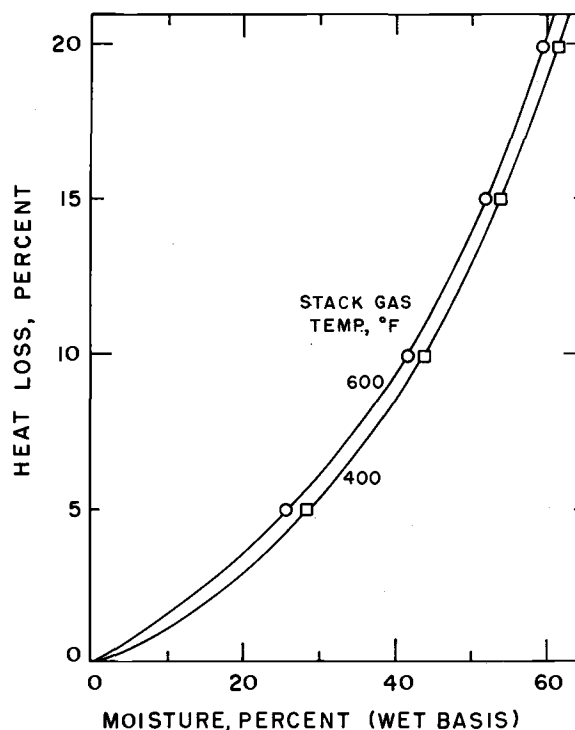


Figure 6. Relation of heat loss to moisture content of Douglas-fir bark.

or solids at lower temperatures. This becomes important with regard to air-pollution emissions, because most boilers have limitations on the concentrations or amounts of particulate material that can be emitted to the atmosphere. Measurement and control methods for particulate emissions are discussed in chapters 5 through 8.

Summary of Reactants and Products of Combustion

Table 12 summarizes the data concerning the amount of air used in the combustion of 100 pounds of dry hogged fuel. It also lists the volumes of the gaseous products of combustion for various amounts of excess air. Note that under standard conditions of temperature and pressure, there is little difference in the volumes of gases that enter and leave the process. At higher stack temperatures, however, the exhaust gases expand and become substantially greater in volume.

Table 11. Summary of Materials Normally Found in Flue Gases from Combustion of Hogged Fuel.

Gases	Particulate material
Nitrogen Carbon dioxide Oxygen Water vapor Carbon monoxide Unburned hydrocarbons ¹ Sulfur dioxide Oxides of nitrogen (NO ₁ NO ₂) Inert gases	Inorganic flyash Fixed carbon Traces of metals and salts

¹High-molecular-weight hydrocarbons may be considered as particulate matter if they can exist as liquids or solids at ambient pressures and temperatures.

Table 12. Air Requirements and Products of Combustion Formed in Burning 100 Pounds of Dry Hogged Fuel with Various Amounts of Excess Air.

Excess air	Total air input	Weight air input	Volume of combustion products	
			Dry basis	Actual basis ²
%	SCF ¹	Pounds	SCF ¹	SCF ¹
0	7,695	617	7,611	19,521
25	9,619	711	9,560	24,520
50	11,543	926	11,470	29,419
100	15,390	1,234	15,329	39,317
150	19,238	1,543	19,153	49,125

¹Standard cubic feet.

²At stack conditions assumed to be 600 F and 16% moisture content.

The information in Table 12 was developed from the average ultimate analysis of 22 samples of hogged fuel. It may differ slightly for fuels whose ultimate analysis is not the same as that indicated in Table 2. It differs substantially for the combus-

tion of coal, oil, gas, or other fossil fuels.

An important feature of Table 12 is that it indicates the influence of excess air on gas volumes. A detailed discussion of the effects of excess air is provided in Chapter 4.

4. FACTORS AFFECTING THE COMBUSTION OF HOGGED FUEL

We can categorize the factors affecting complete combustion into three groups: Fuel related, air related, and others. Many of these factors are interrelated.

Fuel-Related Factors

Some of the characteristics of hogged fuel, such as size, moisture content, ultimate analysis, proximate analysis, and heating value, were discussed in Chapter 2. Each of these factors influences the combustion process.

Size

The combustion process is a gaseous-phase reaction (Chapter 3). About 75-85 percent of wood fuels is volatile and must burn in the gaseous state. This requires proper conditions for evaporation of the fuel. The size of fuel particles directly affects their ability to evaporate. The smaller the pieces, the more rapidly their volatile components will vaporize and burn. Large pieces have reduced surface area available for evaporation to occur. Furthermore, large pieces of wood tend to insulate their interior parts, so more time is required for the volatile material to become sufficiently hot to vaporize.

The amount of surface area available for evaporation is represented by the ratio of the surface area to volume. Table 13 shows the

approximate ratio of surface area to volume for each major component of hogged fuel.

Moisture Content

Moisture content of fuel directly affects the rate at which fuel can evaporate to the gaseous state. Recall the first step in the combustion process—evaporation of water from the fuel. If the moisture content is high, this process takes a long time and requires a significant amount of energy. For dry wood fuels, evaporation of volatile material takes place immediately, so the combustion process is rapid.

Table 13 lists typical moisture contents for the major components of hogged fuel and the combined relative effect of fuel size and moisture content on the rate of combustion. The last column of Table 13 is a relative scale only. It should not be interpreted to mean that dry sanderdust will burn exactly 100 times faster than wet bark. It does indicate, however, that the actual rate at which sanderdust burns is considerably greater than the rate for wet bark.

Time variations in moisture content may make control of the combustion process difficult.

Table 13. Typical Moisture Contents, Relative Ratios of Surface Area to Volume, and Their Combined Relative Effect on the Rate of Combustion of Wood and Bark Residues.

Residue	Typical moisture content	Relative ratio, surface to volume	Relative effect on rate of combustion
<i>Percent</i>			
Bark	45	1	2
Coarsewood	45	1	2
Planer shavings, kiln-dry	16	5	30
Planer shavings, green	40	5	12
Sawdust	35	6	17
Sanderdust	5	10	200
Reject mat furnish	6	8	130

For example, if the forced- and induced-draft systems are adjusted for good combustion of moderately wet fuel (that is, 45 percent MC) and suddenly a load of dry fuel is sent to the combustion chamber, the rate of combustion increases rapidly. In most boilers, the result is an immediate deficiency of oxygen and generation of unburned carbon particles that cause a black exhaust plume. The reverse situation also can occur. If dry fuel is burned with proper amounts of excess air, and the moisture content suddenly increases to a high level, the rate of combustion will decrease rapidly. Under these circumstances, the excess air may exceed reasonable limits until adjustments in the fuel-air ratio can be made.

As noted earlier, moisture content of fuel is significant because it has a negative heating value; that is, heat is needed to evaporate it. Figure 6 shows the heat loss from a range of fuel moisture contents for Douglas-fir bark. About 13 percent of the total heat in the fuel is required for moisture evaporation at 50 percent moisture content; about 26 percent of the fuel heat is needed at a fuel moisture content of 67 percent.

Not only does increasing the moisture content of fuel increase heat losses and, thereby, reduce overall efficiency, but it also retards combustion, lowers flame temperatures, and reduces the rates of steam generation. When the fuel moisture content reaches a range of 64-70 percent, a stable fire cannot be maintained unless auxiliary fuel is added to help drive off the water. In addition, water in the fuel evaporates to roughly 5,700 times its liquid volume in the furnace. The effect is to increase the gas velocity through the combustion zone, which reduces residence time for combustion, increases particle carryover into the heat exchanger section, and increases the size requirements of gas-cleaning equipment on the boiler. Clearly, an advantage can be gained by limiting the moisture content of hogged fuel. In recognition of this, several plants in the Northwest are installing fuel-drying systems as part of their emission control packages.

These variations in moisture content and size bring up an important feature of feeder systems for hogged fuel. Most fuel-feed systems are controlled on a bulk-volume basis. That is, they are designed to vary only the volumetric flow rate of the fuel.

The relation between the volume of the fuel and its heat content is less constant for hogged fuel than for other fuels. Therefore, attempting to control the combustion process through controlling airflow rate and bulk-feed rate is difficult. A more ideal system would be to measure and control heat flow into the furnace along with airflow into the furnace. Then, when a slug load of planer shavings comes to the furnace, the system could detect its proportionately high heat content and control the rate of fuel feed accordingly. At the same time, corrections could be made to the airflow to maintain a reasonable range of excess air for combustion. Unfortunately, instantaneous, continuous Btu analyzers are not now available for hogged fuel analyses. Therefore, the next best solution is to mix the fuel thoroughly so as to stabilize, as much as possible, the size and moisture content of the fuel.

Ultimate Analysis

The data obtained from an ultimate analysis of a fuel sample determine the amount of air required to burn the fuel completely. In Chapter 2, the ultimate analysis data were used to calculate that stoichiometric combustion of 100 pounds of hogged fuel requires 617 pounds of air. Also, the ultimate analysis data made it possible to determine the composition of the products of combustion for different amounts of excess air. Thus, by measuring the percentage of carbon dioxide or oxygen in the dry flue gas, it is possible to determine the percentage of excess air directly.

There is substantial difference in the composition of various fuels, such as natural gas, coal, oil, and wood. Therefore, for each of these fuels the stoichiometric ratios of air to fuel will vary substantially. With knowledge of the ultimate analysis of a fuel, we can make combustion calculations for that fuel and, thereby, determine the relations between flue-gas composition and percentage of excess air. This is one of several critical parameters in controlling the combustion process.

Proximate Analysis

Proximate analysis provides information on percentages of volatile material, fixed carbon, and ash in the fuel sample. The percentage of volatile

material (the part of the fuel that vaporizes to form a gas when it is heated to a high temperature) has an important bearing on combustion of the fuel. Except for carbon, all fuels commonly used in boilers must evaporate before they can burn. When they are in the gaseous state, they can mix with oxygen from the air and go through the process of combustion. Carbon can burn in the solid state, as is seen in the combustion of charcoal briquets.

By knowing the percentage of volatile material in a fuel sample, we can estimate the rate of combustion for the fuel. Fuels high in fixed carbon will burn at a slow rate. Therefore, they will require longer residence time in the furnace for complete combustion than fuels with a high percentage of volatile material. Roughly, from 75 to 85 percent of hogged fuel is considered to be volatile (Table 3).

The ash content of fuels as determined by proximate analysis is significant for several reasons. First, ash does not burn. It plugs the air passages on grates and in the heat exchange sections. The ash that does not stay in the boiler is carried out by the exhaust gases and acts as an air pollutant. As an example of the quantities, consider a boiler that burns 9 units of hogged fuel per hour to make 100,000 pounds per hour of steam. The ash going into the boiler amounts to roughly 9,000 pounds per day if the ash content is 2 percent.

Second, ash can damage the boiler physically. Large quantities of sand and other abrasive material will erode boiler tubes and mechanical collectors. High content of sea salt may cause corrosion in a boiler if condensation occurs in the heat exchangers or breachings.

Knowledge of the ash content of hogged fuel is important in designing mechanical collection equipment. From an operational standpoint, the ash content directly affects the frequency with which grates must be cleaned and soot blown off tubes, and the amount of ash and dirt buildup in the boiler.

Heating Value

The heating value of fuel directly affects the rate at which fuel is fed into a furnace. For example, a boiler generating 100,000 pounds per hour of steam may have the following equivalent fuel feed rates per minute:

570 pounds of hogged fuel at 40 percent moisture content and 5,000 Btu per pound,

310 pounds of dry hogged fuel with 9,000 Btu per pound, or

150 pounds of No. 6 fuel oil with 18,000 Btu per pound.

Obviously, the rate of fuel feed affects the operating cost of a boiler. Knowledge of the heating value of fuels, however, is generally not an important factor in operating a hogged fuel boiler. First, measuring Btu content on a continuous basis is difficult. Second, if it could be measured, the values obtained would not influence the settings of the combustion controls on the boiler. Third, the moisture content of the fuel is not taken into account in the values shown in Table 4. Thus, the values do not reflect the available Btu content for generating steam in the boiler. The primary benefit of knowing heating value of the fuel is in making engineering calculations for boiler design and efficiency.

In addition to fuel related factors, such as size, moisture content, ultimate analysis, proximate analysis, and heating value, six other factors affect the combustion of hogged fuel. These include the method of feeding the fuel, the distribution of fuel in the furnace, variations in rates of fuel feed, the depth of fuel pile in the furnace, auxiliary fuel usage, and separate firing practices. Each is discussed in detail.

Method of Feeding Fuel

The method of feeding fuel to a boiler furnace is dependent upon the furnace design. For Dutch ovens, the fuel is dropped through a chute on top of a pile. Several piles may be used for one boiler. For spreader-stoker furnace designs, the fuel is spread across a grate with a mechanical or pneumatic spreader. The desired result is to lay a thin, uniform mat of hogged fuel across the entire area of the grates (Figures 2 and 4).

These two systems differ substantially. With the Dutch oven, the fuel reaches the top of the pile in a "stream" and cascades down the sides. Little combustion of the fuel occurs until it has settled on the sides of the pile. There, it receives radiant heat from the refractory lining of the oven. This heat input, coupled with convectional heat transfer from the hot gases around the pile, provides energy

to evaporate the water in the fuel and raise the temperature for combustion to occur. Gases evolved from the pile are rich in carbon monoxide. As these pass between the drop-nose arch and the bridge wall, the overfire air supplies sufficient oxygen to complete the combustion of carbon monoxide to carbon dioxide.

In a spreader-stoker design, the fuel is spread across the grate of the furnace so that it must fall through the flames of the burning material on the grates. Small, dry particles of fuel, such as sander-dust and planer shavings, will heat quickly and burn in suspension before they arrive at the grate. Larger, moist fuel parts, such as bark and coarse white wood, will fall to the grate and burn at that location until they become small enough and light enough that the air from under the grates can carry them into suspension. The combustion will be completed for these articles in suspension (provided that the necessary time, temperature, and turbulence are maintained). The spreader-stoker design does not use large amounts of refractory to radiate heat back to the burning fuel pile. Heat is radiated from the flame zone above the grates back to the fuel on the grates. This aids in the initial combustion. Heat also is transmitted to the fuel through turbulent flow of hot combustion gases within the furnace and from heated underfire air. Combustion must be completed in the furnace chamber.

The method of fuel feed is tied closely to the particular design of furnace, and feeding methods are not easily interchangeable. The furnace design and the methods of fuel feed associated with a particular design do influence the process of combustion.

Distribution of Fuel in the Furnace

Furnaces are designed for uniform combustion of fuel across the furnace. Fuel on the left-hand side of the furnace should be subject to the same conditions of available air, temperature, turbulence, and gas velocity as fuel on the right-hand side. If the fuel feeding system allows for uneven distribution of the fuel, the combustion system will be unbalanced. The right-hand side may have too much air, too low gas velocity, too high temperature, or too much or too little of

another parameter of combustion. The need for uniformity applies to fore and aft distribution of fuel, as well as side to side. The primary concern is that fuel be placed evenly in the combustion zone in all types of furnaces.

Variations in Fuel Feed Rates

In almost all boilers, swings occur in the steam demand under normal operation. In some instances, these range from 40 to 125 percent of the boiler rating over periods as short as a few minutes, although most units do not undergo such violent changes in load. In responding to load variations, the fuel feed rate is increased or decreased. Decreasing feed rate usually has no adverse effect on the combustion reaction. The fire burns to a lower level, and steam production drops off.

With increased steam demand, substantial problems may occur. Consider a furnace that is operating at 75 percent of full load. Suddenly, the load increases to 100 percent. As the steam demand increases, the fuel feed rate increases. The furnace receives hogged fuel with moisture from 45 to 50 percent. This increase in the rate of wet fuel going to the furnace may tend to lower the temperature in the combustion zone. As the temperature drops off, the combustion rate drops off. To compensate for this, more air is added, usually as underfire air, to help dry the fuel and increase the rate of combustion, which increases the percentage of excess air. This tends to reduce combustion efficiency and frequently results in sending substantial amounts of unburned material out of the furnace. Gradually, the wet fuel dries, the temperature in the combustion zone increases, the rate of combustion increases, and the steam output from the boiler increases.

The degree to which the upset in combustion occurs is dependent upon several factors:

- Rate of combustion initially,
- change in fuel feed to meet the new load,
- design and size of the furnace,
- moisture content of the fuel,
- size of the fuel,
- temperature of underfire and overfire air,
- amount of excess air, and
- other related combustion parameters.

The factor that triggered the upset was the increase in fuel feed rate. If feed rate is increased drastically over a short time, substantial upsets can be expected with normal hogged fuel. If the feed rate is increased gradually, less disturbance will occur to the combustion process. The most dramatic example of this upset condition can be seen in furnaces that are batch fed from a hopper. To maintain stable combustion conditions is virtually impossible when a ton or more of wet, cold, hogged fuel is dropped into a furnace.

Depth of Fuel Pile in the Furnace

The depth of fuel pile has two major effects on the combustion process. First, the amount of underfire airflow depends on the depth of the fuel pile. As most hogged fuel boilers are not equipped to vary air pressure, when the pile height increases, the airflow rate decreases. A decrease in underfire airflow may raise the overfire airflow if the air duct system is not equipped with individual damper controls.

The reverse situation also occurs. When height of the fuel pile decreases, the underfire air has less resistance to flow as it passes through the pile. Flow rate, therefore, increases in the underfire air and may decrease on overfire air. This applies to Dutch oven and spreader-stoker designs, although the responses to pile depth would not be equal.

The second effect of varied fuel pile height is changes in radiated heat transfer to the fuel and is applicable to Dutch ovens only. In Dutch ovens, the closer the fuel is to the hot refractory lining, the faster the volatile portion of the fuel receives radiated heat and evaporates to the gaseous phase. Thus, raising the pile height can increase the rate of combustion in a Dutch oven. There is an upper limit, however. As the surface of the fuel pile approaches the top of the Dutch oven, the volume of gas in the oven decreases. This reduces residence time and increases gas velocities. The resulting incomplete combustion of fuel will lower the temperature in the furnace and slow the rate of combustion.

Separate Firing Practices

In hogged fuel boilers, the various fuel components, such as bark, planer shavings, and sander-

dust, can be mixed together and fed to the furnace as a mixture, or they can be fed separately. Two fuel components that usually are put into the furnace through separate systems are sanderdust and cinders.

Sanderdust firing. Sanderdust particles are small and low in moisture content. These characteristics result in extremely rapid combustion if the fuel is properly suspended and other conditions are favorable. Rapid combustion means that the available oxygen will be consumed at a high rate. If the oxygen supply is limited, the sanderdust as well as the other fuel may be "starved" for oxygen. In this instance, unburned particles will leave the furnace as dense, black smoke. To avoid this circumstance, sanderdust can be injected separately with its own controlled air supply.

Separate firing of sanderdust offers several advantages over mixing it with other components of hogged fuel. A well-designed system can limit dust problems in handling and storage, provide a proper balance of air and fuel, provide air at the correct place and, in general, improve combustion conditions. Further, sanderdust firing systems can be responsive to changes in boiler load. They can be used to release heat energy quickly to compensate for rapid swings in load. If sanderdust is mixed with other hogged fuel, the response to load swings is less rapid. Furthermore, sanderdust fired in a mixture with hogged fuel frequently is not well mixed. The result is spasmodically high rates of combustion when the sanderdust is a high percentage of a mixture and high rates of excess air when sanderdust flow rates are reduced. Design criteria for sanderdust firing systems are discussed in Chapter 6.

Cinder reinjection. Cinders collected in control devices, such as cyclones or multiple cyclones, also exhibit properties that make them difficult to transport, store, and burn. Discussions of these properties may provide insight regarding their effect on the combustion reaction.

Cinders are a combination of fixed carbon, inorganic fly ash, and larger particles of inorganic, incombustible material such as sand and clay. The percentage of this material that is capable of burning, that is, the fixed carbon, is dependent upon combustion conditions in the furnace. If

conditions are good, perhaps only from 10 to 15 percent of the cinders will be combustible. If combustion conditions are poor, then as much as 90 percent of the cinders may be fixed carbon.

The rate of combustion of fixed carbon is substantially lower than the rate of combustion for the volatile materials in wood fuels. As wood undergoes combustion, the volatile materials evaporate to the gaseous phase and burn. In the gaseous phase, they burn more rapidly than carbon in the solid phase. For example, consider how long charcoal briquets burn compared to blocks of wood cut to the same size. This difference is important for hogged fuel furnaces because, when cinders are reinjected, they require longer residence time to reach complete end products of combustion. If residence time at high temperature is not sufficient, unburned cinders will leave the furnace again as potential air pollutants.

The carbon portion of cinders is not mechanically strong. It crushes easily to a fine powder with low density. This usually occurs in rotary screen systems that remove sand and heavier particles. The resultant form of the carbon makes it difficult to handle because of the dust. It also presents problems when reinjected into the furnace. The small, light particles of carbon can be suspended in the turbulent airflow of the furnace and carried out of the combustion zone quickly—frequently before the combustion reaction has had time to go to completion.

Consider two extreme situations where cinder reinjection might be employed. First, consider a furnace in which combustion of the fuel is good and only 15 percent of the cinders is carbon (Figure 7). Separation of this material in a screening system probably will meet with only limited success because the carbon particles are expected to be small. Much of the inorganic fly ash will be of about the same size and density. Thus, the screened material that is to be reinjected probably will be only 50 percent combustible at most. Because of its combustion characteristics and size, when it is reinjected, only 50 percent of the combustible portion likely will burn. The rest will be carried out of the furnace as “new cinders.”

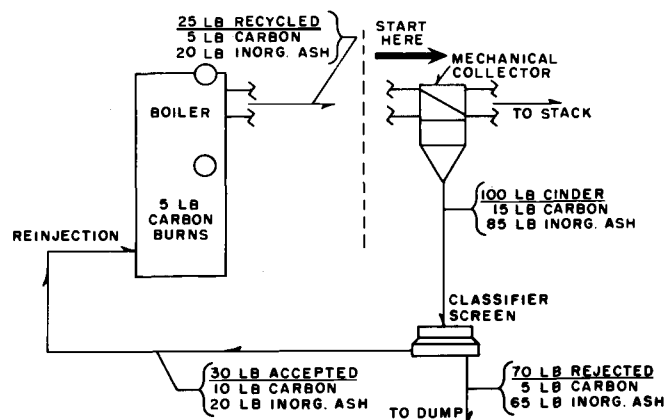


Figure 7. Flow path of 100 pounds of cinders high in inorganic ash, screened and reinjected, with good combustion. Note the small amount of carbon burned and the recirculation of inorganic ash.

Thus, for every 100 pounds of cinders that are initially collected:

Only 15 pounds will burn,

the reinjected portion after screening likely will consist of 10 pounds of carbon and 20 pounds of incombustible material, and

after reinjection, only 5 pounds of the carbon will burn, but the remainder, plus the 20 pounds of incombustible material, will be recycled through the system.

Operating a system like this is difficult to justify when you consider the increased rate of particulate emission from the stack and the erosion of the boiler tubes and the cinder collection system from continually recycled inorganic material.

Now consider the opposite extreme. Assume that you are operating a furnace in which combustion conditions are poor. Cinders collected in the multiple cyclones are 90-percent carbon and large (Figure 8). After screening, the reinjected material is 95-percent carbon and reduced in size. When reinjected into a poor combustion situation, perhaps from 20 to 30 percent of the carbon burns. The remainder is recycled through the system. Being reduced in size, a substantial portion will not be caught in the collectors, but will go out of the stack as air pollutants.

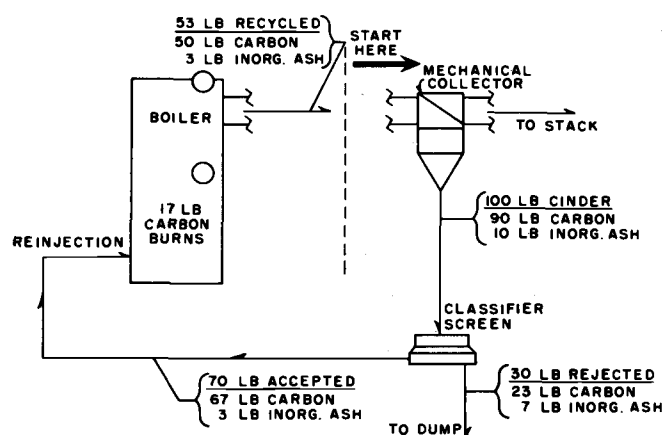


Figure 8. Flow path of 100 pounds of cinders high in carbon, screened and reinjected, with poor conditions for combustion. Note that, although some recycled carbon is burned, much escapes out of the stack.

Two basic things are wrong with this system. First is the attempt to burn, in an already poor combustion situation, a material that does not burn well. Second is the amount of inorganic, incombustible material, which is the same as in the first example of good combustion. As in the first example, this material is recycled through the system, which results in erosion and increased loading to the atmosphere. Again, operating under these conditions is difficult to justify.

This raises an important question: Why reinject cinders at all? The answer is that reinjection helps to solve a serious problem of solid waste. For example, a boiler that is designed for a capacity of 100,000 pounds per hour on hogged fuel probably will emit from 800 to 900 pounds of cinders per hour. Of these, maybe from 300 to 400 pounds per hour are combustible. Reinjection reduces the solid-waste problem in two ways. First, it results in some reduction in the volume of the combustible portion of the ash. Second, it gets rid of the remainder of the ash by emitting it to the atmosphere as particulate matter. Thus, it solves a solid-waste problem by creating an air-emission problem.

If cinders are not reinjected, what can be done with them? Alternatives include use as

landfill, raw material for charcoal briquets, filler material for concrete blocks and roadways, and as a soil conditioner.

Auxiliary Fuel Usage

Auxiliary fuels frequently are used in hogged fuel boilers. When the hogged fuel is very wet and will not support combustion, other fuel sources can provide the heat required to evaporate moisture from the wood. In some installations, available hogged fuel is not sufficient to generate the steam required. A third reason for using auxiliary fuel is that higher rates of steam generation can be achieved for a given size boiler through the use of fuels with higher Btu content. Fourth, auxiliary fuels can be used effectively to handle rapid swings in load.

Auxiliary fuels such as coal and oil have two major effects on the combustion reaction in a hogged fuel boiler. The first deals with the sulfur content of these fuels. Both coal and oil contain small percentages of sulfur. This material oxidizes in the combustion process to form sulfur dioxide—an air pollutant. Regulatory agencies have established limits on the percentage of sulfur allowable in these fuels. For most areas, the limit after July 1974, is 1.75 percent for bunker-grade oils and 1 percent for coal (5).

In addition to being an air pollutant, sulfur dioxide can cause significant damage to the boiler components if it is allowed to condense. Air preheaters are particularly susceptible to this condensation-corrosion problem.

The second major effect of auxiliary fuels in hogged fuel boilers relates to ash content. This is not serious in the use of natural gas because its ash content is negligible. On the other hand, the ash content of coal can range from 6 to 30 percent (1). Ash content of residual oil should be less than 0.5 percent (1), but has been measured in excess of 10 percent.² If coal with an ash content of 6 percent is used, its ash content per ton is three times that of hogged fuel. Thus, loading to the collectors may

²Personal communication with Prof. A. Hughes, Dept. of Mechanical Engineering, Oregon State University, Corvallis.

well exceed the design capacity of the collectors, if it is used extensively. Furthermore, size, density, and other characteristics of coal flyash may differ from that of wood.

Use of auxiliary fuel of any type requires that both fuel flow and airflow be controlled within reasonable limits for proper combustion throughout the full range of operation.

Thus, there are many fuel-related factors that exert a significant effect on the combustion reaction in hogged fuel boilers. Included in these are considerations of species, size, moisture content, ultimate analyses, proximate analyses, heating value, method of feeding fuel, distribution of fuel in the furnace, variations in fuel feed rates, depth of fuel pile, separate firing practices, and auxiliary fuel usage.

Air-Related Factors

We now will consider air-related factors that affect the combustion reaction. Included will be percentage of excess air, air temperature, ratio of overfire to underfire air, turbulence of air, amount of air compared to size of furnace, and flow relations between induced-draft systems and forced-draft systems.

Percentage of Excess Air

As noted previously, excess air is required for complete combustion of hogged fuel. Each molecule of fuel in the gaseous state must come into contact with one or more molecules of oxygen. Only then can the chemical reactions occur to complete the combustion process. By supplying excess air, the probability of this occurring increases.

There is a limit to how much excess air can be added and still help the combustion reaction. Several factors are influential.

When air is brought into the combustion chamber, it is well below flame temperatures. During combustion, it must be heated from its input temperature to combustion temperatures, an increase of up to 1,800 F. This requires heat energy that comes from the combustion. As the amount of air is increased, more energy is taken from the combustion process to heat incoming air.

This lowers the temperature in the combustion zone, which slows the rate of the reaction. If the fuel fails to burn completely because of slow reaction rate, air pollutants will be generated.

As the energy requirement to heat incoming air increases with the amount of excess air, thermal efficiency of the combustion system goes down. The result is that more fuel is required to produce a given amount of steam (Figure 9).

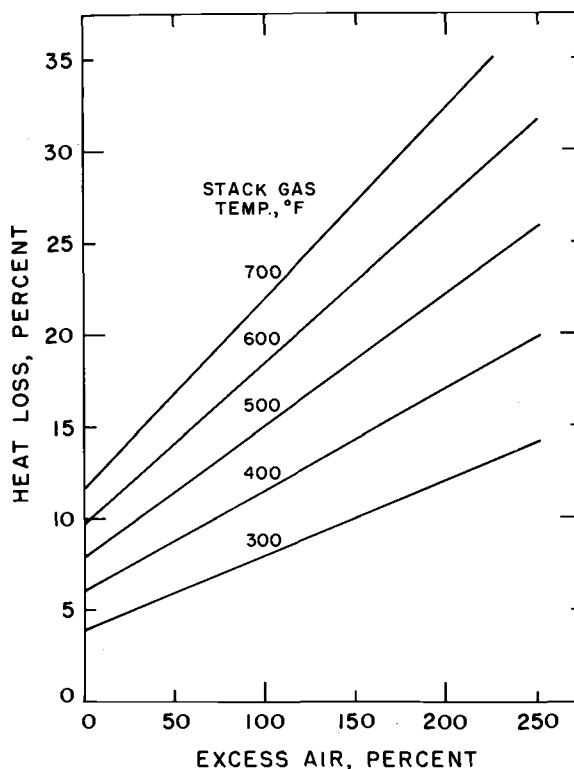


Figure 9. Relation of excess air to heat loss at five temperatures of stack gases.

Furnaces are fixed in volume, that is, they have a certain height, width, and depth, which do not change. As airflow into a furnace increases, the velocity of gases passing through the furnace increases. Furnaces are designed for a reasonable range of gas velocities based on an assumed upper limit of excess air, usually 50 percent. If more than 50 percent excess air is used, gas velocities in the

furnaces may be so high (particularly at high rates of steam generation) that they will carry fuel out of the combustion zone. If this occurs and the unburned fuel enters the heat exchange tubes of the boiler, gas temperatures will drop quickly below those necessary for the combustion reaction to go to completion. Thus, air pollutants will be formed.

An interrelated effect of high gas velocities because of excess air is to reduce the residence time of fuel in the combustion zone. The combustion reaction takes time to go to completion. If large amounts of excess air result in high gas velocities, they also result in short residence time of volatile gases and fly carbon in the combustion zone. Again, this means that the process may be stopped before combustion is completed (by low temperatures in the heat exchange zone) and unburned organic materials will go out the stack as air pollutants.

The gas flow rate into and out of a furnace has a linear increase proportional to increased excess air (Table 12). At 100 percent excess air, roughly twice as much gas passes through the furnace as at 0 percent excess air. Pressure drop through the system increases as well as mass flow. Movement of this gas requires forced-draft and induced-draft fans, which in turn require power. The cost of energy to run these fans is significant. For example, a 100,000-pounds-per-hour hogged fuel boiler using 100 percent excess air requires 50 horsepower more than for the same boiler using 50 percent excess air. Over a year's time, this will cost \$3,125 for power at 10 mills per kwh.

The size of forced-draft and induced-draft systems, which include motors, fans, ducts, and dampers, is based on the steam generation rate of the boiler and some reasonable, maximum value of excess air; for example, 50 percent. If more than 50 percent excess air is used, then one or more of the system components will be an improper size. This can result in loss of control of the systems because of being outside their design ranges; improper balance between forced-draft and induced-draft systems, which can cause pressurizing of the furnace or excessive furnace draft; and inability of the air systems to respond to load changes or variations in the fuel.

The size of the particulate-collection systems also is based on the maximum steam generation rate and some reasonable value of excess air. As in the instance of forced-draft and induced-draft systems, pollution control equipment will not function at its best if gas flow rates deviate from design conditions. Too much excess air will result in lower collection efficiency for most pollution control systems.

In summary, some excess air is necessary to bring about proper combustion. Too much excess air can be detrimental to a combustion system because it:

- Cools the combustion reaction and slows down the rate of reaction.

- Reduces thermal efficiency.

- Increases gas velocities in the furnace and transports the fuel out of the furnace before it burns completely.

- Reduces residence time in the furnace so that fuels cannot burn completely.

- Requires extra power in the fan system, which can be a significant cost factor.

- Can unbalance an air system, which results in loss of combustion control, improper pressure conditions in the boiler furnace, and inability of the system to respond to load variation.

- Causes improper operation of collection equipment if the gas flow exceeds design conditions, which can occur with large percentages of excess air.

How much excess air should be used? According to most designers and manufacturers of hogged fuel boilers, from 25 to 50 percent is the optimum range. In actual practice, most hogged fuel boilers are operated at from 100 percent to 150 percent excess air and are not operating at the best conditions. Most of these units would operate better for combustion efficiency at lower levels of excess air.

As a matter of practicality, the best level of excess air will vary from boiler to boiler. Generally, if the level is from 40 to 75 percent, the unit probably is functioning reasonably well. This corresponds to carbon dioxide levels in the exhaust gases of 14.3 to 11.0 percent. We should recognize that, because of the variations in furnace design,

fuel moisture content, steam generation rate, and other factors that affect the combustion process, optimum conditions for excess air cannot always be maintained. Equally, we should be aware of the negative effects of too much excess air.

Air Temperature

The temperature of air entering the combustion zone has a significant effect on combustion. Preheating this air has the following advantages: It increases ability of the air to remove moisture from wet fuel; it increases the furnace temperature, which increases the rate of combustion and reduces formation of air pollutants; it increases overall efficiency of the system by utilizing heat energy that otherwise would be lost up the exhaust stack; and it increases the steam generation capacity.

Ratio of Overfire to Underfire Air

In most hogged fuel boilers, the incoming air for combustion is split into two ducts. One brings the air in under the fuel pile or grates. The other brings air in over the fuel pile. In many spreader-stoker designs, part of the overfire air is used to pneumatically spread the fuel across the grates.

The percentage of total combustion air going to the underfire and overfire air ducts influences the combustion process. The ratio of the two flows is, therefore, one of the parameters of concern. The best ratio for good combustion varies from boiler to boiler. It is also dependent upon the characteristics of the fuel, such as moisture content and size.

In theory, boilers should function best with 75 percent overfire air and 25 percent underfire air. This idea is based on proximate analyses of hogged fuel. Roughly 75 percent of the fuel is volatile organic material (Table 3). As it goes through the steps of combustion, it will pyrolyze to the gaseous state. The combustible gases will rise above the solid hogged fuel, mix with air, and burn. Thus, 75 percent of the air, in theory, should be supplied above the pile. The remaining 25 percent of the fuel, the fixed carbon, will remain on the fuel pile or grate system. Combustion air to meet its needs (25 percent of the total) should be supplied from underfire air.

Unfortunately, this theoretical approach does not account for many design parameters that affect the combustion process. Perhaps the main variable to be considered is the furnace design, such as Dutch oven or spreader stoker). Another important variable is fuel moisture content, as more moist fuel requires more underfire air. Taken together, the result is that many systems operate best with 75 percent underfire air and 25 overfire air.

Turbulence of Air

For complete combustion, one or more molecules of oxygen must come into direct physical contact with each molecule of gaseous fuel at a temperature adequate to insure ignition and with sufficient residence time to complete the reaction. Adequate mixing of the gaseous fuel and oxygen is brought about by turbulent gas flow in the furnace. The primary purpose of overfire air jets or nozzles is to accomplish this. Generally, the more turbulence in the furnace, the higher the probability of completing the combustion reaction. If the gas flow pattern is smooth or laminar, little mixing occurs.

For safety, mixing is important to avoid dead spaces or quiescent zones where fuel vapors can accumulate and reach high concentrations. This can result in puffing or small explosions in the combustion zone.

Flow Relations Between Forced-Draft and Induced-Draft Systems

Forced-draft air systems bring combustion air to the furnace. Complete systems include facilities to deliver preheated air under automatically controlled flow conditions throughout the full range of boiler operations. Induced-draft air systems draw the combustion products out of the boiler under controlled flow rates and remove entrained air pollutants. Such equipment as multiple cyclones and scrubbers generally are considered part of the induced-draft system because of their physical location and effect on pressure drops and flow rates in that system.

Forced-draft and induced-draft systems play important roles that affect the combustion reaction. Their operation directly affects most of the

related combustion parameters, such as percentage of excess air, turbulence, and air temperature. Furthermore, the balance between flows in these two systems determines the pressure in the furnace. In most hogged fuel boilers, particularly older installations, a slight negative pressure is maintained in the furnace and heat exchange sections to minimize puffing and to keep fuel and combustion products in the furnace.

Not all hogged fuel boiler installations operating today are equipped with balanced, automated, forced-draft and induced-draft systems. Many have no forced-draft system at all. Others use natural draft from smoke stacks rather than a controlled induced-draft fan system. Such installations do not have good control of the combustion process throughout the full range of operation. Incomplete combustion may occur at regular intervals with resultant emissions of smoke, cinders, underburned hydrocarbons, and other air pollutants.

Other Factors

To maintain good combustion conditions and good heat transfer, soot and ash deposits from the furnace and heat exchanger tubes must be removed. Failure to remove such materials results in partial blocking of the gas passages. If the grates are plugged, insufficient air for combustion will occur in localized parts of the furnaces. This brings about loss of steam generating capacity, loss of efficiency, and increased pollutant emissions. Similarly, if the tube passages are plugged, capacity and efficiency are reduced.

Most plants have regular schedules for soot blowing and grate cleaning. The frequency depends on content of fuel ash; combustion efficiency;

furnace design; average rate of steam generation; plant steam demand schedule; local regulations on air pollution; and operator's initiative.

How well the job is done depends both on the operator and the equipment he controls. The important point is, a clean boiler is more efficient and pollutes less than one fouled with ash and soot.

The operator has some control over the cleanliness of a boiler, but he has less control over other factors that significantly affect the combustion reaction. These include basic design, maintenance, steam generation rate, and water level.

Dutch ovens and spreader stokers use different approaches to fuel combustion. As such, their differences in basic design influence the combustion reaction.

As with all production equipment, boiler components require maintenance to function well. Poor maintenance results in lower boiler efficiency and higher emission rates for air pollutants. It may result also in safety hazards, unwanted downtime, and significant equipment damage.

Boilers are designed to produce steam within a range of rates. If actual loads are either too low or too high, combustion conditions will be upset by equipment limitations. In many installations, the maximum steaming rate is not determined by the boiler capacity, but by emission levels from the system.

Many operators have reported that variations in water level in the steam drum affect the combustion rate. Field experience indicates that a responsive, automatic, liquid-level control system on the feed-water system at the steam drum is helpful in controlling furnace temperatures. This is particularly true for water walled, spreader-stoker systems.

5. MONITORING EQUIPMENT

Monitoring equipment is used to measure and indicate the important parameters in boiler operation. It is distinguished from control equipment, which controls the combustion variables. Examples of monitoring equipment include meters to read temperature, pressure, and flow rates of steam produced. Some monitoring systems are limited to providing data for the operator's information. Others use the information as a signal to operate a control system. For example, steam flow meters simply record the flow rate of steam produced. Steam pressure, however, is indicated on a gauge for the operator's information and also used as a control signal to increase or decrease fuel flow.

For common monitoring systems to monitor pressure, temperature, and flow, many good references are available (1, 3).

Fuel Monitors

Most hogged fuel boilers do not have equipment to measure variables of hogged fuel such as moisture content and size. There are systems, however, that can provide useful information for operators.

Metal detectors have the obvious advantage of limiting damage to equipment because of tramp metal in the fuel system. They can be used to shut off conveyors, sound alarms, or perform similar functions.

Fuel weighing systems provide data concerning fuel flow rates that have two uses. It is helpful in accounting for total fuel usage, and can be used to signal the operator when no fuel is being carried by the conveyor system. Weight data are limited in value because weight of fuel varies directly with moisture content, and moisture content can vary over a wide range in hogged fuel.

Television scanners can monitor most fuel handling systems, including conveyors, hogs, storage bins or piles, feed systems, and screens. Each component of the system can plug or fail to function, with the result that the fuel supply to the boiler stops. By locating closed-circuit television scanners at critical points in the system, any disruption can be spotted quickly by the operator, and corrective action can be undertaken to minimize changes in fuel flow to the boiler. Scanners can be installed with several cameras and only one video screen. Using the selector switch, the operator can check the system at any one of several points.

Fuel feed monitors are helpful in the common situation where hogged fuel boilers are equipped with more than one feed point. The operator can have an easily visible means of determining whether or not fuel is flowing freely through each feeder. Feed monitors are found in a wide variety of types, from plexiglass panels in the system, to mechanical linkages that move as long as fuel is being fed. The rate of feed seldom is measured.

Fuel moisture meters could be helpful. Spot checks occasionally are made on fuel moisture content. Few plants do it regularly, however, and the data are not used to control the combustion process. Efforts are under way to develop reliable systems for continuously measuring fuel moisture. This type of information is useful in determining when to use auxiliary fuel, but it is not necessary to the operation. Where fuel drying and sizing are part of the operation, moisture measurement can be a valuable control monitor for the fuel preparation system.

Air Monitors

The comments on air monitoring equipment are limited to combustion air input systems and air measurements in the induced-draft system. Exhaust gas monitoring equipment is discussed separately.

Even though temperatures and flow rates of combustion air are critical parameters in the combustion process, few boilers are equipped with monitors to measure and indicate gas temperatures or flow rates, for several reasons.

First, seldom does a need exist to know what the air temperatures are. If the boiler has an air preheater, it is used to maximum capacity. If it has no air heater, knowing the air temperature does not provide information to assist the operator in his duties.

Second, total airflows have a direct bearing on the percentage of excess air. This parameter can be determined accurately from analyses of the exhaust gases. Therefore, measurements of input airflows are redundant.

Third, the cost of installing equipment for continuous monitoring of airflow has prohibited its use. Continuous measurements of gas flows to underfire and overfire air systems would be helpful to the operator. It would tell him to correct the flows for optimum combustion conditions. The economic returns of such equipment, however, are difficult to identify. Therefore, few boilers are equipped with monitors for input airflow.

Air pressure monitors are common on boilers. Draft gauges on control panels indicate positive and negative pressure conditions at various points in the combustion and heat exchange systems. Data from these instruments are used by the operator to determine when plugging occurs because of ash building up in the system. They also are useful in setting airflows to maintain proper pressure conditions in the furnace.

Exhaust Gas Monitoring

Flue gases can be monitored continuously to determine parameters such as temperature, percent carbon dioxide or oxygen, and opacity or optical density.

Temperature

Measurement of flue gas temperature can provide helpful information to an operator, but its use is limited. This parameter is dependent upon so many variables that fluctuations are difficult to relate to specific variables. For example, changes in air heater performance, steam generation rate, fuel moisture content, fuel heating value, and percent excess air all affect exhaust gas temperatures.

Because of installation costs and limitations on value of the data, many boilers are not equipped for continuous monitoring of stack temperature.

Percent Carbon Dioxide or Oxygen

Of all continuous monitors available to the boiler operator, those used to analyze flue gas for carbon dioxide or oxygen are the most valuable indicators of combustion conditions. As noted in discussion of the effects of excess air, the balance between fuel and air supply is critical to proper combustion. Continuous measurement of combustion products can inform the operator of any upsets in the balance of these variables. The operator then can adjust conditions to maximize boiler efficiency and minimize air pollutant emissions. Without data from flue gas analyses, the operator can only guess at the percentage of excess air being used in the system.

Continuous gas analyzers are costly to install (for example, \$2,000-\$5,000 per installation). They also require reasonable maintenance and calibration to function properly. They are easily justified, however, because of fuel savings and reduction of air pollutant emissions.

One difficulty should be noted regarding continuous flue gas monitors. Most commercial units are fairly delicate instruments. The output signal is based upon a small voltage generated by the instrument in response to the concentration of the gas being analyzed. If the instrument is not grounded properly, a false reading may occur because of an electro-chemical reaction within the instrument. This is a common problem, but one that is easy to correct.

The best alternative to continuous flue gas analyzers is use of grab-sample analyzers. Two types are commonly employed: the Orsat analyzer and Fyrite gas analyzers. Each is adequate for measurements to within about 0.2 percent. The cost is moderate, and the instruments are well designed for field use. Orsat analyzers require more skill to operate than do the Fyrite units, but they may have a slight advantage in increased accuracy. Both units require regular replacement of chemicals. Either one is adequate for taking spot checks

on flue gas constituents. Sample time from start to finish may be 10-15 minutes. Therefore, if combustion conditions vary substantially over short intervals, this type of analysis may not be suitable.

The importance of flue gas analyses cannot be overstressed. Every operator should have these data at his disposal at all times. Without them, he cannot properly control the combustion process.

Opacity

Most regulatory agencies have implemented standards regarding opacity limitations. The standards specify that emissions may not exceed an opacity limit (usually 20 or 40 percent) (5) for more than 3 minutes out of any hour. Commercial opacity monitors are available and commonly are used. Their use, however, is limited to providing information to the operators. In most states, charts from opacity monitors are not acceptable to regulatory agencies as proof that the emissions are in compliance. Opacity monitors are useful as warning devices to signal an operator of a combustion upset that results in particle emissions. They do not respond to gaseous pollutants.

Opacity monitors are installed in the exit-gas duct system, usually downstream from devices for emission control (for example, multiple cyclones). This location may be in the breeching or in an exhaust stack. The systems commonly have a light source, a photoelectric cell, an amplifier, and a recorder (Figure 10) (6). Light from the source travels through the exhaust gas stream. Particles in the gas stream will absorb or scatter the light and reduce the signal at the photoelectric cell. This approach to monitoring has several inherent difficulties.

First, the amount of light absorption and scattering depends on the distance that the light beam travels in the gas stream. Opacity regulations refer specifically to opacity at the discharge point from the stack. If the distance across the top of the stack is exactly the same as the distance from the monitor light source to the photocell, the monitor can record accurately the opacity at the top of the stack. But if the distances are not equal, the monitor is not measuring the opacity at the top of

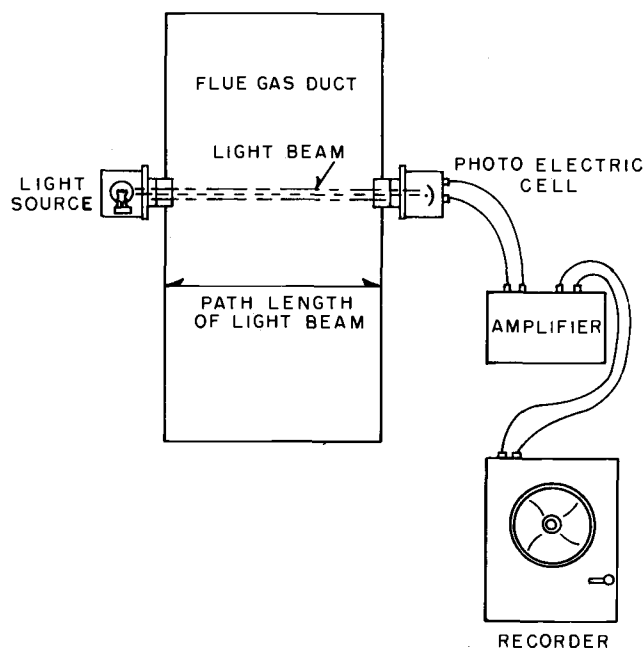


Figure 10. A common arrangement of instruments to monitor opacity of exit flue gases.

the stack. Substantial errors can occur because of differences in geometry.

Second, being mounted in the boiler breeching, the monitors may be subject to high temperature and vibration. These factors may result in limited bulb life and need for frequent maintenance and recalibration of the monitors.

Third, particulate emissions from the furnace tend to coat the protective lenses on the optical system. This coating results in false readings of opacity. Lenses must be cleaned frequently to keep the instruments functional. The more expensive commercial models are equipped with continuous purge systems to avoid this problem.

Fourth, opacity is dependent upon many factors, such as gas temperature (density), size of particulate matter, concentration of particulate matter, relative humidity, and length of light path. Should any of these parameters vary between the monitoring location and the discharge point of the stack, the opacity monitor would not reflect opacity at the stack discharge point.

Note that opacity is strongly dependent upon size of the particles in the gas stream. Large particles do not scatter or absorb light to the same degree as small particles. For example, in a heavy rain you may be able to see clearly for $\frac{1}{2}$ mile. But if rain droplets are reduced in size to fog, visibility can drop to only a few feet. Because opacity is dependent upon particle size, measurements of opacity cannot be used as measurements of particle concentration. Attempts to show relations between concentrations of flue gas particles and opacity have not been highly successful.

The cost of opacity monitors ranges widely. The least expensive units can be installed for less than \$500. At the other end of the scale, the investment can exceed \$6,500. For \$6,500, however, the operator benefits from automatic recalibration at regular intervals, continuous purge systems to keep the lenses clean, automatic correction for geometric differences between the actual monitoring location and the stack outlet, low maintenance, and high reliability in the system.

Opacity and Optical Density

Some commercial monitors measure optical density rather than opacity. To avoid confusion over terms, understanding the relation between these terms may be helpful.

Opacity is measured on a scale from 0 to 100 percent. At 0-percent opacity, the light beam is not scattered or absorbed. It passes through the gas stream and reaches the photoelectric cell at full intensity. As the concentration of particles in the gas stream increases, scattering and absorption of the light beam increase. At 100-percent opacity, no light is received at the photoelectric cell from the light source.

Optical density has a scale from 0 to infinity. It is defined as:

Optical density = $\log_{10} [(1/100 - \text{percent opacity})]$. (Figure 11)

Zero percent opacity corresponds to zero optical density. One hundred percent opacity

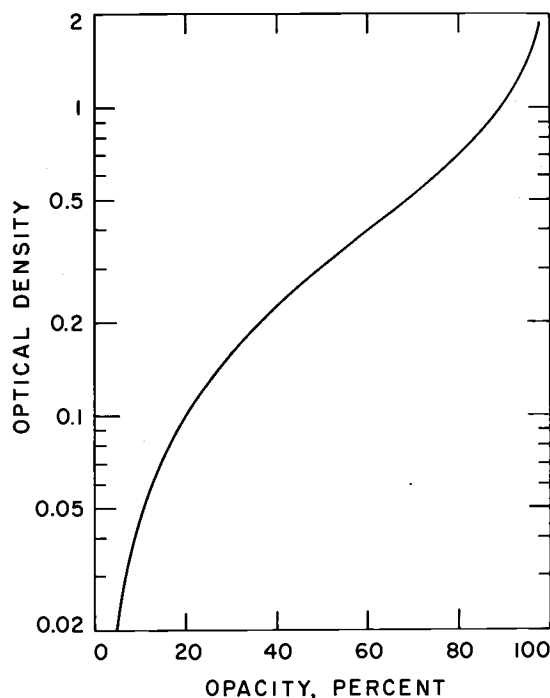


Figure 11. Relation of opacity to optical density.

corresponds to infinite optical density. The term "absorbance" is used interchangeably with optical density.

TV Stack Monitors

Closed-circuit television systems have been installed in many plants to visually monitor stack emissions. They aid the operators by providing a continuous display of stack visibility. Although this is useful during daylight, it is of little value at night unless the plume from the stack is well lighted. The advantage of this system is that it allows the operator to see stack emissions without leaving the boiler control panel. The main disadvantage is that the operator must constantly observe the monitor to detect upsets. This disadvantage can be overcome by use of an opacity monitor with appropriate time delay and visual or audible alarm.

6. COMBUSTION CONTROL SYSTEMS

Control of the combustion process requires control of variables that affect the process (Table 14). Not all of the variables can be controlled. For example, in most plants, tree species of the fuel cannot be controlled. Some important variables, however, can be controlled.

Generally, control systems have two goals: control of the variables within specific range limits (for example, control of excess air in a range from 40 to 75 percent); and maintenance of uniform levels of each variable (for example, keeping the fuel well mixed so that the average fuel size and moisture level stay constant).

Table 14. Factors Affecting the Combustion Reaction in Boiler Installations Fired by Hogged Fuel.

Identification	Reference page
FUEL-RELATED FACTORS	
Species	9
Size	10
Moisture content	11
Ultimate analyses	14
Proximate analyses	15
Heating value	16
Method of feeding fuel	36
Distribution of fuel in furnace	37
Variations in fuel feed rates	38
Depth of fuel pile in furnace	39
Separate firing practices	40
Auxiliary fuel usage	44
AIR-RELATED FACTORS	
Percent excess air	47
Air temperature	51
Ratio of overfire air to underfire air	51
Turbulence of air	53
Flow relation between forced-draft and induced-draft systems	53
OTHER FACTORS	
Cleanliness of the combustion system	54
Basic furnace design	55
Maintenance of components	55
Steam generation rate	55
Steam drum water level	56

Fuel-Related Combustion Controls

Fuel Size Control

Four systems can be used to control fuel size: screening fuel to separate the oversize pieces;

hogging the large pieces to reduce their size; mixing the fuel in the storage and transport systems to maintain uniform size; and maintaining separate facilities for storage, transport, and feeding of sanderdust.

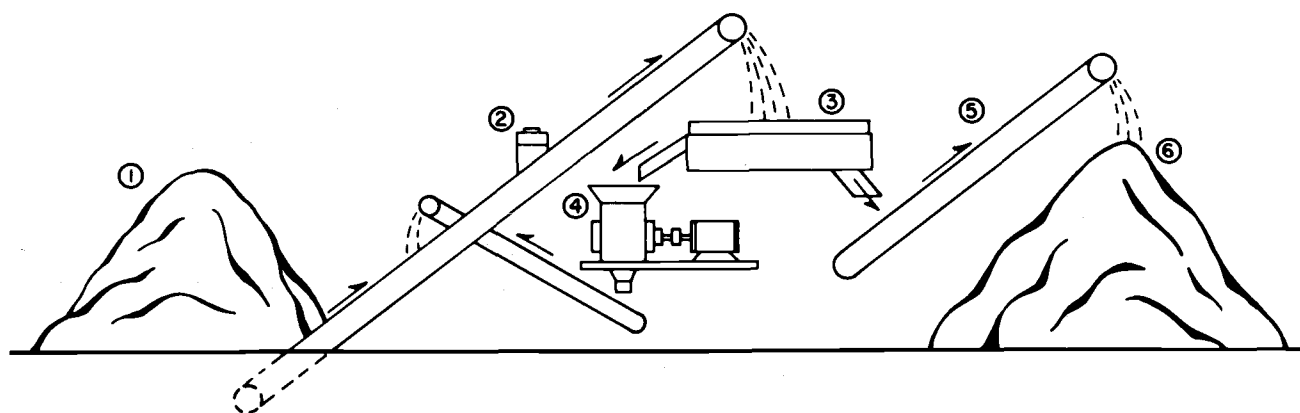


Figure 12. System for preparing hogged fuel.

1. Pile of rough fuel.
2. Metal detector.
3. Separating screen.
4. Hog for pieces too large to pass through the separating screen, with conveyor to recirculate hogged pieces.
5. Conveyor for material that passes through the separator screen.
6. Storage for hogged fuel.

Screening and hogging operations generally are combined (Figure 12). In Figure 12, note the metal detector ahead of the screen. This protects the hog and the rest of the combustion system from tramp metal.

Hogs are usually hammer type, as they have fewer maintenance problems than knife hogs. Power requirements range from 25 to 1,500 horsepower. Power requirements increase with the rate of material flow and with size reduction requirements.

Separation of sanderdust and other fine material that is produced by specific process operations serves two purposes. Small, dry particles create severe dust problems, unless storage and transport facilities are designed for dust control. By separating this material and handling it in a controlled system, the dust problem and explosion potential can be substantially limited. Also, small dry particles burn rapidly and, therefore, consume oxygen rapidly. If sanderdust is fired in a separate burner, the proper air-to-fuel ratio can be maintained for good combustion. If sanderdust is mixed with hogged fuel, proper air-to-fuel ratios are difficult to maintain.

Fuel Moisture Content Control

As with size, fuel moisture can be controlled with several methods:

Vibrate "loose" water off the fuel on a shaker screen.

Press water out mechanically.

Drive off moisture by heating the fuel in fuel dryers.

Cover the fuel storage pile to keep rain water out.

Control the processes that generate the fuel to limit water addition to the fuel.

Mix the fuel so that moisture content is uniform over time.

Each of these control methods is self explanatory, and each has limitations. Vibrating off water may be effective when the moisture content exceeds 55 percent. If the process that generates the wood adds large quantities of moisture (for example, hydraulic barking), this can be an inexpensive and low-maintenance approach to control of surface moisture.

Presses also are limited in the amount of moisture they can remove. For most hogged fuel, pressing can lower moisture levels to 50-55 per-

cent. Heating the fuel can reduce moisture content. Moisture level maintained in a range from 25 to 35 percent is usually adequate for good combustion. At levels below 20 percent, significant dust problems can occur with "fines."

Heating-type dryers have the potential for generating pollutants of three types: if the wood fuel is overheated (above 300 F) the volatile organic material will evaporate and go out of the dryer with the exhaust gas stream, which may condense in the atmosphere to form a visible plume; dry "fines" may create a dust pollutant problem; and, if the dryer is fired by a separate combustion system, products from the combustion process may become pollutant emissions.

Covered fuel storage will keep rain out of the fuel, and this can be a significant benefit in wet climates. The disadvantages lie in cost of the structure and access to the fuel in event of a fire in the pile. If fuel is put through a drying system, particularly one that reduces moisture levels to less than 45 percent, covered storage of the dried fuel may be desirable.

Control of water additions to fuel in production processes is usually difficult. For example, hydraulic barking cannot be replaced by mechanical barkers at most plants. There is a trend, however, toward dry-deck log storage and sorting rather than ponding. This reduces moisture levels in wood residues. By careful inspection of the processes that generate wood residues, it may be possible to locate other sources of water addition and to reduce these sources.

Adequate fuel mixing can be accomplished by spreading fuel across the face of a pile and removing the fuel from a central pickup point. As noted previously, mixing brings about uniformity in both size and moisture content. This adds to the stability of the combustion process.

Maintaining Fuel Heating Value

Experience has shown that Btu content of hogged fuel can be reduced substantially by storing it for long periods at high moisture levels. According to one study, Douglas-fir hogged fuel lost 7 percent of its initial heating value over 10 months (7). As a rule of thumb, hogged fuel should not remain in a pile in excess of 3-4 months.

A first-in—first-out system for fuel storage is effective in limiting storage time. For most plant sites, this requires addition of, or changes to, conveyor systems. Figure 13 illustrates one such scheme for fuel storage.

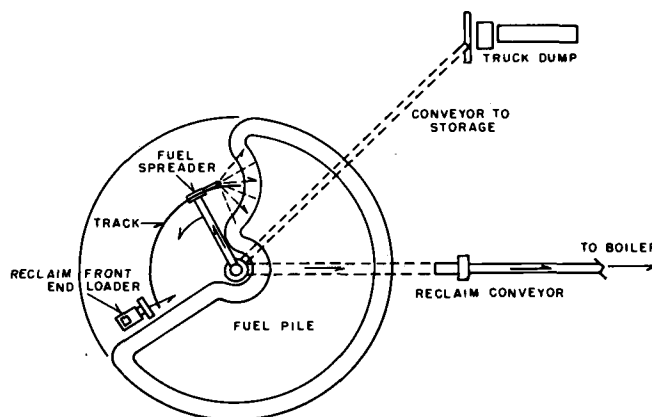


Figure 13. System to limit fuel-storage time by insuring that fuel first into storage will be first out to be burned. (Radar Pneumatics Company, Portland, Oregon.)

Control of Fuel Distribution in the Furnace.

The methods applied to control fuel distribution in the furnace are, of course, dependent upon the basic furnace design. In Dutch ovens with center feed chutes, little can be done to alter the placement of fuel over the grates. Ideally, the pile should be set squarely in the center of the refractory and symmetrically about the underfire air feed system. If the fuel chute is off center and piles fuel in a corner or to one side of the oven, combustion will not proceed uniformly in the pile. Corrections for better distribution of fuel in Dutch ovens are usually expensive and must be made with a cold furnace.

For spreader stokers, most systems have manual adjustments for fuel distribution. Mechanical spreaders can be slowed or increased in speed. Baffle plates often are provided to control the angle at which fuel is injected into the furnace. Other adjustments are sometimes available to set the width of the fuel path. These same variables are often available on pneumatic spreader systems. The most important control, however, is the operator. By inspecting the fuel pile through inspection and cleanout ports, he can determine the uniformity of

fuel distribution in the furnace and can make any required adjustments to correct difficulties. This should be done regularly. No automatic systems are available to replace operator skills in this area.

Controlling Variations in Fuel Feed Rates

For combustion control, the ideal situation is to have steam generation rate and fuel feed rate always constant. The worst condition is to have fuel fed on a batch basis to a furnace with a highly fluctuating demand for steam.

Fortunately, few furnaces are batch fed today. The fuel flow usually is controlled by a hopper fed screw or similar device. Direct current drives are common where the control signal comes indirectly through a transducer for steam header pressure. Great ingenuity has been shown in boiler plants to provide uniform fuel feed to the furnaces.

Process operations in the plant control steam demand and, therefore, fuel flow rate. Better control of process operations often can help to eliminate wide fluctuations in steam demand. This requires understanding of the problems and cooperation on the part of plant supervisors and production personnel.

Fuel Pile Height Controls

Over the past 60-70 years, there has been little or no fixed control of the depth of fuel piles, either in Dutch ovens or in spreader stokers. Each operator runs the furnace the way he thinks is best. Only recently was any effort exerted to control the depth of the fuel piles by automatic means. This technology has been applied to Dutch ovens with moderate success.

The approach is simple. A temperature sensing probe is inserted from the top into the pile. As the pile burns down, the probe is exposed to higher rate of heat input. When more fuel is added, it covers the probe and thereby insulates it from the flame temperatures. By measuring the probe temperature, a direct measure of the pile height is obtained. The temperature can be used as a control signal to the feed system. Thus, the height of the pile can be controlled automatically.

Several commercial models are available. These are divided into two classes: those that sense the temperature with a thermocouple and those that use continuous water flow through the probe

and then measure the temperature of the water. Each system appears to work well with little or no maintenance difficulties. The water system has a disadvantage in that, even though the flow rate is low, the total volume of water that is used can be large over a year. This is extremely important in light of the strict standards for water discharge that are facing industry.

The alternative to automatic control of fuel pile height is manual control by the boiler operator. This requires continued surveillance of the furnace condition, particularly during load swings, and constant adjustment to maintain optimum conditions. For most installations, this is not optimal. The operator attempts to maintain the fuel pile at a reasonable working height with limited instrumentation and considerable guesswork.

Sanderdust Firing

Most difficulties experienced with sanderdust firing are related to the small size of the particles and their low moisture content. Taking these into consideration, one can develop design criteria for systems to fire this material that allow advantageous use of sanderdust. A well-designed system would reasonably control dust, avoid plugging, provide variable control of feed rate, ensure good particle suspension, locate the particles in the flame, and maintain a pilot light.

Dust control. Any system for transporting, storing, and feeding must be designed to minimize dust emissions. This is important to meet regulations for air pollution control as well as for control of fire or explosions.

Nonplugging. As with any system for feeding, storing, or transporting fuel, efforts must be made to avoid plugging the system. This generally does not present special problems with sanderdust, unless the material is wetted to limit dust. Dry sanderdust will flow easily and seems to respond well to the use of vibrators where necessary. Bridging can be a problem, but it is easily avoided through proper design of the system.

Controlled variable feed rate. Control of the feed rate of sanderdust is as important as with any other fuel. Special attention is needed to insure constant, nonplugging feed to maintain steady combustion. Control of combustion air for the fuel

is equally important. The small size and dry nature of sanderdust result in very rapid combustion. Sufficient air must be supplied at the right place to completely burn this material. Large quantities of excess air must be avoided, however, as they, too, can upset the combustion process. A well-designed system incorporates variable airflows that correspond to requirements for the full range of sanderdust feed rates.

Good particle suspension. The firing system should separate individual particles of sanderdust as they are injected into the furnace. This is necessary to mix particles with combustion air. Separation usually is accomplished with swirling vanes or a cyclonic type of feeding system.

Location in the flame zone. To complete the combustion reaction, sanderdust particles must be exposed to high temperature long enough to burn completely. This occurs if they are injected directly into the flame in the furnace. If, however, they enter the furnace at a point where they are not exposed to flame temperatures long enough, combustion will not be completed.

Pilot light requirements. Many boiler installations incorporate a pilot light system for sanderdust burning. For safety, this is desirable. For combustion, pilot lights probably do not add significantly to the process. Their prime function is to avoid an explosive situation in the furnace under fluctuating conditions.

Difficulties experienced with sanderdust firing usually can be traced to failure to recognize the unique properties of this fuel and to provide adequately for them.

Cinder Reinjection

Attempts to improve combustion conditions through cinder reinjection may have negative results. As noted previously, carbon particles do not burn rapidly. They are generated in an atmosphere of incomplete combustion. To send a low-grade fuel back into a furnace with poor combustion does not improve combustion conditions. Some procedures, however, are helpful in limiting the negative effects of cinder reinjection.

Classifying the cinders is probably the most beneficial. This process separates the combustible material from the noncombustible, inorganic constituents. Typical classifier installations have rotat-

ing or vibrating screens that separate particles by size. Small particles are considered to be high in noncombustible material. Large particles are high in carbon and are returned to the furnace.

A particular advantage of classifying cinders is that the process removes abrasive material from the fuel. If the noncombustible silicates and metallic oxides are cycled around the system, from the furnace through the heat exchangers and multiple cyclones, severe erosion can occur. This causes high maintenance, particularly to collectors and heat exchanger tubes. Classifying limits this problem.

Although not commonly done for boilers fired with hogged fuel, crushing carbon particles before reinjecting them has an advantage. The purpose is to gain the maximum possible ratio of surface area to volume so that the material will burn rapidly. Note that this procedure is commonly used in large, coal-fired power plants where the coal is pulverized to fine powder before injection. Large carbon particles have low density and will be suspended in the exhaust gases. As they burn slowly, they may not be in the flame long enough to burn completely in the furnace. Small particles, however, may be in the flame long enough to burn completely.

Providing a proper cinder injector is as important to combustion as designing a proper oil or sanderdust burner. If the carbon particles are pulverized, they must be properly suspended and provided with an appropriate fuel-to-air ratio at the place where combustion occurs. A well-designed system should include storage bins and feeders that can assure a continuous and controlled flow of this fuel. Proper turbulence should be available for good mixing during combustion.

Control of the Combustion Process With Auxiliary Fuels

When auxiliary fuels are used in conjunction with hogged fuel, the combustion process becomes more complicated. Two areas are of particular concern: ash buildup and availability and control of combustion air.

Auxiliary fuels used are predominately residual fuel oils. Natural gas and coal, however, are used also. The recent shortage of fossil fuels in general has resulted in plants receiving residual fuels with high ash contents, up to 10 percent. This

can contribute about $2\frac{1}{2}$ times the amount of ash per Btu of heat input as normal hogged fuel. Plants that fire a combination of hogged fuel, residual oil, and sanderdust may experience heavy deposits of slag on heat exchange tubes. These deposits contain high concentrations of calcium sulfide (calcium from ash in the fuel and sulfur from the auxiliary fuel oil). The high furnace temperatures associated with use of auxiliary fuel oil may contribute to formation of this slag on superheater tubes. Lowering the maximum steam generation rates may help to alleviate this problem, as it would result in lowered furnace temperatures. Use of fuels with lower ash content also would help, if such fuels were available and economically attractive.

When auxiliary fuels are used, they are fed through especially designed burners that should provide adequate primary and secondary air for the particular fuel being fired. Combustion air required for hogged fuel should not be used to burn auxiliary fuel. Conversely, auxiliary fuel burners should not be used to supply air for burning hogged fuel. Air should be provided at the point where combustion is occurring and with sufficient turbulence for good mixing.

In Chapter 3, combustion calculations were made for hogged fuel with a particular ultimate analysis. Residual fuels will have completely different ultimate analyses, with generally higher carbon contents and lower oxygen contents. Combustion products as measured in the flue gas will be, therefore, substantially different for oil than those for hogged fuel. As the carbon dioxide or oxygen content of the flue gas is used normally to determine the percentage of excess air in the combustion process, care must be exercised to avoid misinterpretation of the data when auxiliary fuels are used. For example, 12 percent carbon dioxide is equivalent to 50 percent excess air for oil-fired plants. For hogged fuel, 12 percent carbon dioxide is equivalent to 70 percent excess air. Furthermore, as flue gases from combustion of hogged fuel will mix rapidly with gases from auxiliary fuel, it is difficult to determine through flue gas analysis which fuel has an excess or a deficiency of air.

Air-Related Combustion Controls

Air-related combustion controls are concerned with percentage of excess air, air temperature, ratio of overfire to underfire air, air turbulence, flow relations between forced-draft and induced-draft fan systems, and maintenance of boiler components.

Percentage of Excess Air

The first step in controlling excess air is to monitor the products of combustion (carbon dioxide and/or oxygen). The data can be used to adjust excess air levels to provide optimum conditions for combustion. Without instruments to monitor the flue gas constituents, excess air can be controlled only by guesswork. Note that it is necessary to measure either carbon dioxide or oxygen, but measuring both is unnecessary.

The signal from a flue gas analyzer can be used as a control signal fed directly to controls for the forced-draft and induced-draft dampers (Figure 14). As an alternative, the signal may be read by the operator, who then makes manual adjustments to the airflow controls. The type of airflow adjustment depends upon the design of the boiler (that is, Dutch oven, spreader stoker, or other) and the equipment available to regulate the combustion process. Obviously, the process cannot be controlled without adequate fans, dampers, and positioners, and sufficient instrumentation to provide status data to the operator.

Regulating the percentage of excess air is simple. As the level of carbon dioxide drops, the rates of overfire and underfire airflow are reduced. (Note that this is dependent on the design of the furnace and the firing equipment available). For many hogged-fuel furnaces, the desired set point for carbon dioxide is about 13.5 percent (or 50 percent, excess air). When levels of carbon dioxide go above the set point, the airflow rates should be increased.

The concept of controlling percentage of excess air is simple to grasp. Accomplishing this task continuously for a given boiler installation is generally not so simple. Typically, a boiler has continued variations in steam generation rate, fuel

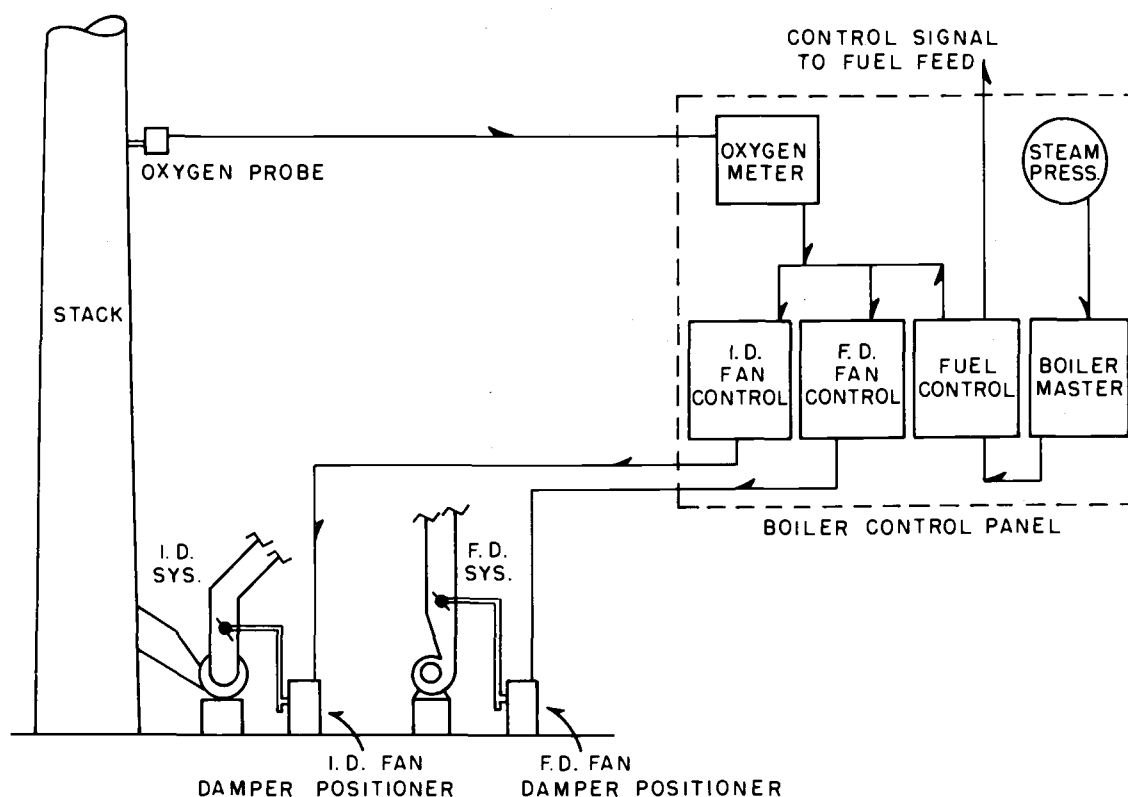


Figure 14. A flue-gas analyzer used to control dampers for induced-draft (I.D.) and forced-draft (F.D.) fan systems (13).

moisture content, fuel size, fuel heating value, amount of ash buildup on grates and in heat exchangers, and other variables that affect combustion.

These variables complicate the control of excess air on an automatic, continuous basis. A skilled operator, however, using information provided by continuous flue-gas analysis, can make appropriate corrections to the system and maintain reasonable combustion conditions. Two things are necessary, data on flue-gas constituents, and sufficient boiler controls to allow the operator to make the required corrections.

Air Temperature Control

In most plants, the boiler operator has no means of regulating air temperature directly. If a preheater is part of the system, it normally is used to its full capacity. If there is no preheater, the furnace must function on colder air.

Although the boiler operator usually does not have control over temperature of the forced-draft air system, he does have control over other air inputs to the furnace. With few exceptions, hogged-fuel boiler furnaces are operated at a slightly negative pressure. Therefore, if any openings are in the furnace, cold ambient air will be pulled in. Such openings usually are found as:

- inspection ports,
- cleanout doors,
- cracks in the casing,
- cracks in the refractory,
- fuel chutes,
- and poor seals around sources of cold air, such as doors, drums, pipes, and sootblowers.

By closing sources of cold air to the furnace, the operator can gain additional control of the combustion process. Not only does he increase combustion-zone temperatures, he can avoid local

"cold spots" that add to maintenance problems, and he is better able to control excess air. Note that infiltration (leakage) air has all of the detrimental characteristics of cold, excess air, but provides none of the benefits of excess air.

Controlling the Ratio of Overfire to Underfire Air

Control of this variable must be accomplished with properly installed fans, air ducts, and dampers. The design is dependent upon the type of furnace. Spreader-stoker furnaces and suspension systems require different ratios of airflow distribution than do Dutch ovens.

The operator is concerned with several operational problems regarding the distribution of air in the forced draft system. For wet fuel, adequate underfire air must be provided to help drive off the moisture from the wood. For pneumatic-spreader systems, sufficient overfire air must be provided to distribute the fuel. As ash or fuel builds up on the grates, underfire airflow will be reduced. This is caused by lessened pressure across the grates and ash. Reduction of underfire airflow also may mean a proportionate increase in overfire airflow, depending on the fan system used. Overfire air must create maximum turbulence without disturbing ash or fuel on the grates. Furthermore, the overfire air must be arranged to avoid impingement directly on hot refractory or metal surfaces to limit damage resulting from condensation, thermal stresses, and thermal shock.

Few hogged fuel boilers are equipped with a forced-draft air system that has capability to continuously balance the flows between overfire and underfire air. For most plants, primary control is in keeping the grates sufficiently clear of heavy ash buildup. The goal is to limit the pressure drop across the grates to reasonable levels. This will assure the flow of underfire air. Sealing leaks in the furnace and air systems also will assist in obtaining a proper balance. Deliberate design of high-pressure drop (from 2 inches to 3 inches of water) across spreader-stoker grates can aid in insuring good distribution of undergrate air even when fuel distribution on the grate is not ideal.

Control of Air Turbulence

Turbulent patterns of gas flow are brought about by position, direction, velocity, and mass-

flow rates of gases entering the furnace. High turbulence is obtained when the gases are sent into the furnace in swirling patterns from high-velocity nozzles. The position and the direction of the nozzles have strong influence on the flow pattern. These inlet nozzles usually are fixed, so operators have little or no control on the degree of turbulence in the furnace. Minor changes can be made to the turbulent-flow patterns by varying the ratio of overfire to underfire air. For most hogged fuel boilers, however, control of this variable in the combustion reaction is left to engineers and designers of boilers. Turbulence in existing boilers frequently can be improved by addition of properly located, high-velocity air nozzles.

Control of Flow Relations Between Forced-Draft and Induced-Draft Fan Systems

Forced- and induced-draft fan systems should be operated so as to provide a proper amount of excess air for good combustion. For most boilers fired with hogged fuel, an appropriate range would be from 40 percent to 75 percent excess air. Second, a slightly negative pressure in the furnace is desirable to keep the products of combustion in the furnace. This is particularly true of old furnaces that have many leakage points. Under such circumstances, excessive negative furnace draft adds undesirable infiltration air. On new furnaces with completely sealed exterior casings, to maintain negative furnace draft is not necessary. Third, these fan systems should maintain an adequate amount of turbulence in the combustion zone. Last, they should provide sufficient air to distribute fuel properly in spreader-stoker furnaces with pneumatic spreaders. Each of the criteria should be met throughout the full range of steam generating rates for the boiler. Further, the forced-draft and induced-draft systems must be able to respond to load variations rapidly.

If the criteria for these systems are to be met, the fan systems must be equipped with calibrated, automatic controls. An operator cannot make manual adjustments to control airflow dampers with the speed or accuracy that is required to maintain proper air balances throughout the full range of operating loads. The controls should be properly maintained. Regularly scheduled cleaning, lubricating, and calibration should be done by a

competent instrument technician. Operators should be intimately familiar with the capabilities of the control systems at their disposal and make full use of them.

Maintenance of Boiler Components

The foregoing discussion should make the reader aware that controlling the combustion process requires a substantial amount of complicated equipment. To gain high efficiency and low levels of air pollution requires:

Fuel sizing, drying, mixing, storage, and feeding equipment with special provisions for firing sanderdust, cinders, and auxiliary fuel.

A grate system with provisions for ash removal.

An air system with forced-draft and induced-draft fans, dampers, damper positioners, and controls.

An air-preheater system.

Devices to reduce air pollution by removing particles in the flue gas.

Monitoring equipment to provide information for control of excess air.

A heat exchanger system, equipped with soot blowers to avoid ash buildup in the gas passage.

Maintenance of these components is an important factor in achieving high efficiency and low emission levels. Without proper maintenance, the various parts of the system soon will fail to perform their intended functions.

Most maintenance needs are obvious. For example, sliding surfaces need regular lubrication. Without it, they eventually will stop sliding or be severely damaged. Other maintenance needs are not so obvious. For boilers fired with hogged fuels, two are of particular concern: boiler control systems and leakage of air into the system.

Boiler control systems. Most boiler control systems have pneumatic controls that are operated with compressed air and have low airflow rates. Maintenance problems arise because of contamination of the compressed air. Lubricating oil and condensed water collect in the air lines and are extremely effective in plugging lines and coating controls with a gummy, sticky surface. As an indication of the magnitude of the problem, a control panel, with air flowing at 1 cubic foot per minute through control lines, uses over 500,000 cubic feet of air a year. If an aftercooler is used on the compressor to remove 90 percent of the entrained water, the control panel may still have 5 gallons of water condensing in the lines each year. Mixed with cylinder lubricating oil, this forms a coating that can make a control system inoperative in from 1 to 2 years.

Two corrective measures are recommended. First, install a refrigerating and filtering system to remove the impurities. Second, provide cleaning and recalibration of the boiler controls regularly by a competent instrument technician. Major cleaning and recalibrating should be done at least every 2 years. This service is available from reputable contractors, if not readily available "in house."

Leakage of air into the system. Control of airflows throughout the boiler system is critical in maintaining good combustion. Any uncontrolled airflow into the process results in some loss of control of the process. As most furnaces and emission control devices are operated under slightly negative pressures, any opening in the system results in airflows into the system. Typical openings are open inspection ports, cracks in the furnace casing or setting, open cleanout doors, openings around soot blowers, cracks in the breaching and fan casings, and fuel chutes that allow passage of large airflows. These varied, uncontrolled sources of air should be sealed tightly.

7. POLLUTION CONTROL DEVICES

Air pollutants are classed either as gaseous pollutants or particulate pollutants. The combustion process generates both. Gaseous pollutants include carbon monoxide (CO), sulfur dioxide (SO₂), oxides of nitrogen (NO_x), and unburned hydrocarbon gases (HC).

Particulate pollutants are defined as any material that exists in the liquid or solid state under standard conditions of temperature and pressure and is emitted to the atmosphere by the process. Uncombined water is excluded from the definition because it is not generally considered an air contaminant. The definition, however, does include flyash, unburned carbon, condensed droplets of liquid hydrocarbons, and metallic salts. All of these materials are products of the combustion of hogged fuel.

Emissions of gaseous pollutants from boilers fired with hogged fuel are minimal and not of great concern, especially from well operated units. Regulations pertaining to these are discussed in Chapter 8. Pollution control devices generally are not installed on hogged fuel boilers to control gaseous combustion products.

Emissions of particulate pollutants can be substantial. Any major upset in stable combustion can generate large amounts of carbon and unburned hydrocarbons. Devices are installed on most boilers to capture these pollutants. The control devices generally fall into one of four categories: cyclone separators, scrubbers, baghouse filters, and electrostatic precipitators. Each of these will be discussed in detail.

Of the four categories, the cyclone and multiple cyclone devices are the most popular. They are the least expensive, require the smallest amount of physical room, have few moving parts to wear out, and, if properly designed and maintained, can be reasonably efficient. But, unless the combustion process is well controlled throughout the full firing range of a particular boiler so that resulting emissions are low, these control devices cannot guarantee to bring boilers into compliance with stringent emission regulations.

The recent trend in emission control devices is toward use of scrubbers in combination with cyclonic-type collectors. Many plants have somewhat antiquated boiler equipment, uncontrolled fuel moisture and size, or inadequate combustion controls. Faced with stringent emission regulations, this system seems to be least expensive in guaranteeing compliance. Baghouses and electrostatic precipitators generally are not considered practicable at this time and are used only rarely.

Meeting stringent air-pollution standards generally requires the use of one or more types of control devices. These varied devices do have limitations, however. If the combustion process is poorly controlled and generates excessive amounts of particulate material, the pollution control devices may be inadequate to keep the boiler within compliance. Combustion control is as important in meeting emission standards as are pollution control devices.

Particle Characteristics

The effectiveness of pollution control devices depends to a large extent on characteristics of the particles they are trying to capture. Therefore, we should understand some of these characteristics when discussing control devices.

Size

Size seems to be a simple concept. When we want to know the size of something we generally measure it with a scale. In measuring small particles, the scale is in microns, which are units of length equal to 1/1,000,000 meter. A period from

a typewriter is about 850 microns in diameter. A typical particle of flyash might be 15 microns.

Flyash particles from a boiler may range from less than 1 micron to more than 100 microns. To determine particle size, many particles are measured and the results are averaged. Particle size may be stated as an average or mean size, or size may be expressed in terms of weight fractions with assumed shape and density.

Density

Density refers to how much a substance weighs per unit of volume. Water has a density of 62.4 pounds per cubic foot, but the density of air

is roughly 0.08 pound per cubic foot. Density of particles is important, because it affects the collection efficiency of pollution control devices. Low-density particles are more difficult to collect than high-density ones.

Settling Velocity

The maximum speed that a particle can attain when it is falling through quiet air is its settling velocity. Large, dense particles, such as bricks, can achieve a high velocity. Cigarette smoke, on the other hand, contains very small particles and is not dense. This combination gives the appearance that smoke particles do not settle at all. Actually, they do settle, but very slowly. Particles that settle at less than 1 centimeter per second are considered to be aerosols.

Resistivity

Resistivity of particles is related to their ability to carry electron charges. It is only of concern in the use of electrostatic precipitators as pollution control devices. Some particles can accept electron charges, others cannot. Hogged fuel flyash has only limited capability to accept electron charges because of its resistivity character.

Adhesive Character

Some particles are naturally sticky. Under proper conditions of temperature and moisture, they will adhere to themselves and to other surfaces. Such particles may be easy to separate from an airstream, but difficult to remove from the control device. Most emissions from hogged fuel boilers present no such problems. Only high levels of unburned hydrocarbons present problems that are apt to be severe.

Particle Strength

A major difficulty with fixed carbon particles is that they break easily into smaller particles. Mechanical processes where rubbing, abrasion, vibration, or crushing occurs can have a major effect on the size of carbon particles. This is of concern in control devices of systems for collecting and handling carbon.

Particle characteristics of size, density, settling velocity, resistivity, adhesive character, and

strength all have a bearing on the selection of appropriate particle-collection equipment. This will become apparent in discussion of the various control devices.

Cyclone Separators

The most common particle-control device in use is the cyclone separator, which cyclonically separates particles from exhaust gases. As shown in Figure 15, the particle laden gas enters the top of the cyclone. The tangential inlet (or inlet guide vanes) spins the gas stream in a helical path down the inside. The particles in the gas stream are forced to deviate from a straight pathway as they rotate about the cyclone axis. Their resistance to

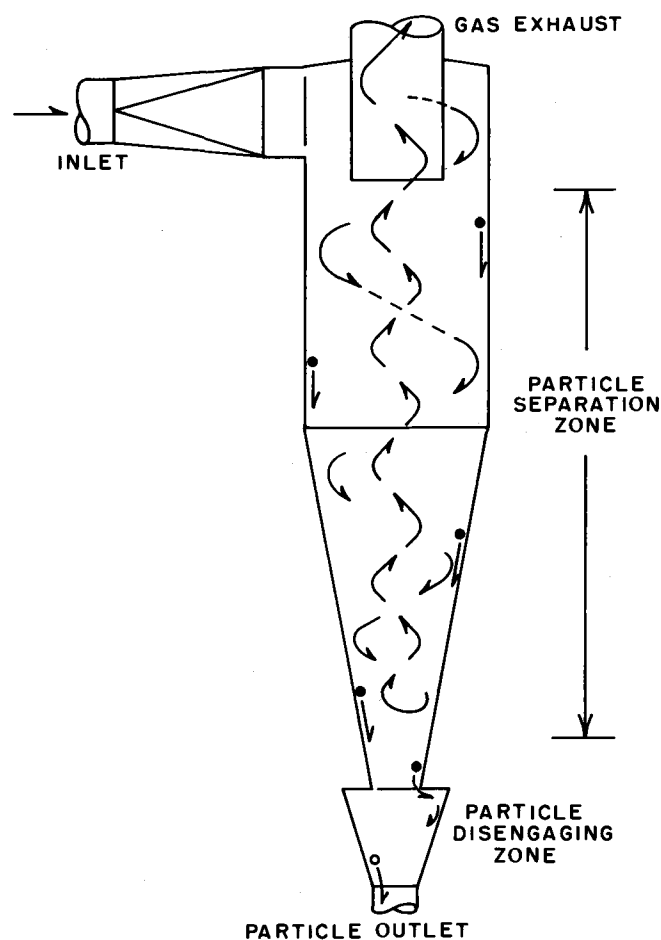


Figure 15. Cyclone collector for particles in flue gases (9).

change in direction causes the particles to migrate toward the cyclone walls. As they reach the walls, gravity and the downward motion of the gas stream carry them to the bottom. The gas stream changes direction as it approaches the bottom and goes toward the discharge in a return vortex.

Many factors affect cyclone efficiency. Six important ones are discussed here.

Diameter of cyclone. As cyclone diameter increases, particles must travel further through the air stream to reach the wall. Therefore, increasing diameter reduces collection efficiency.

Length of cyclone. As cyclone length increases, the gas has a longer residence time. Longer residence time means more time for the particles to move through the gas to the wall. Thus, increasing the length of the cyclone increases efficiency.

Particle disengaging zone. When particles reach the bottom of the cyclone, they drop out under the force of gravity. If a bin or collection chamber is at the bottom, the return vortex may dip into the bin and reentrain particles in the exit gas stream. To prevent this occurrence, some cyclones are equipped with disengaging zones at the outlet. As particles reach the bottom of the first cone, they drop into a second one. Their helical path sends them to the periphery of the second cone, away from the return vortex. This reduces the chance of reentrainment and increases cyclone efficiency.

Flow rates of the gas stream. Cyclones are designed to operate within a range of gas flow rates. If the gas flow rate is too low, the particles will not experience sufficient centrifugal force to separate them from the carrier gas. If, on the other hand, flow rates are too high, then energy is wasted in a drop in pressure across the unit, and the high flow rates may disrupt the return vortex configuration. This will reduce efficiency also. Manufacturers' design criteria should be followed to see that the cyclones are used within the specified range of gaseous flow rates.

Push- or pull-through systems. Cyclones can be operated either as push-through systems or, under vacuum conditions, as pull-through systems. Theoretically, there is little difference in efficiency. In practice, however, push-through systems are usually more efficient, because pull-through

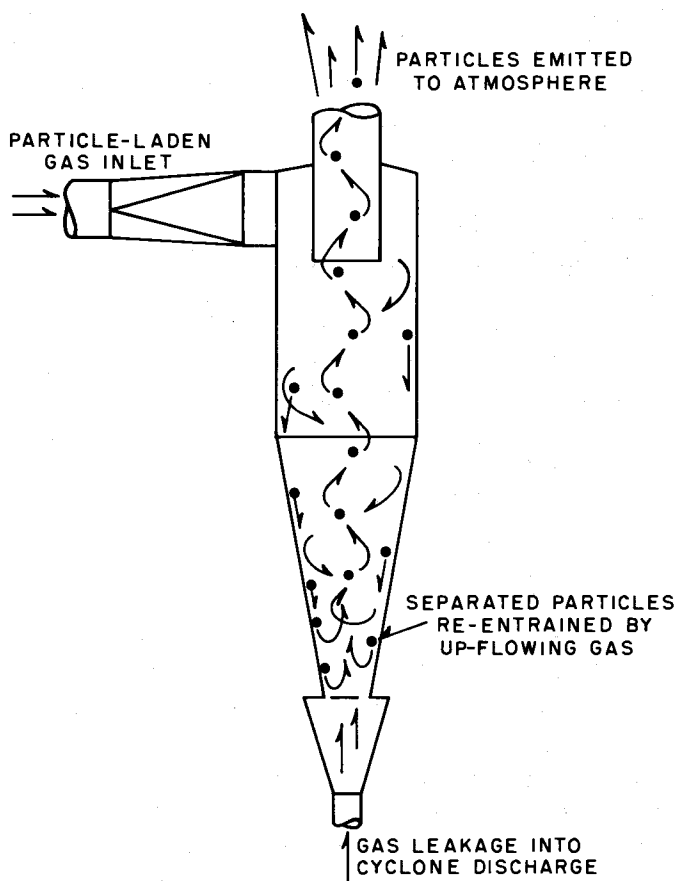


Figure 16. In pull-through cyclones, leakage through vacuum seals at the discharge point for particles will lead to their re-entrainment (9).

systems must have vacuum seals on the bottom of the cyclone where the particles are discharged. If leakage occurs on these seals, air will leak into the cyclone at this point and reentrain particles (Figure 16). Because leakage is likely to occur at some point on a pull-through system, such systems tend to be generally less efficient than push-through systems. On hogged fuel boilers, push-through systems subject the induced-draft fan to extensive abrasion from particles in the flue gas. Therefore, pull-through systems normally are used.

Particle characteristics. As noted previously, size and density of particles control their settling velocity. Particles that can settle rapidly out of an air stream are easily captured in a cyclone separator. They can cross airstream lines and reach the cyclone walls during the residence time of gas in

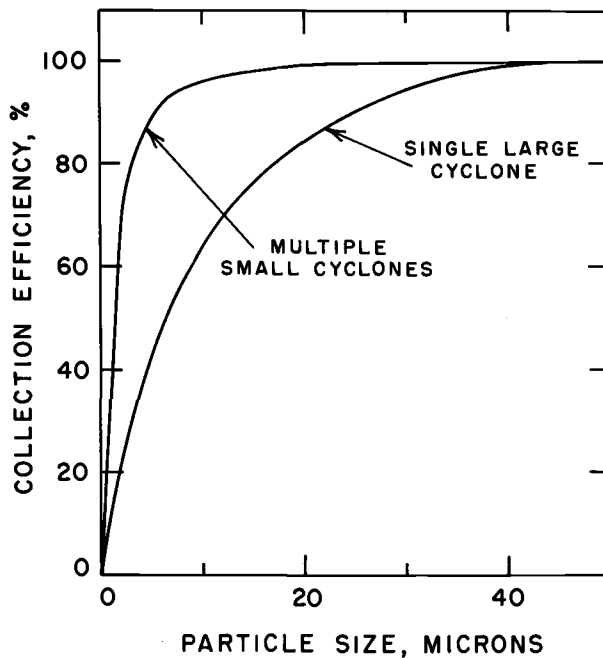


Figure 17. Relation of particle size to collection efficiency of cyclones (9).

the cyclone. On the other hand, small particles with low settling velocities may not be able to reach the cyclone walls in the brief time that the gas is in the cyclone. Figure 17 illustrates a typical curve of cyclone efficiency for various particle sizes. Note that for a typical cyclone, particles whose diameters exceed 40 microns have a 99 percent probability of being captured. Particles whose diameters are less than 10 microns have only a 64 percent probability of being captured. If this particular cyclone were used to separate sanderdust from an airstream and the mean size of the sanderdust was 7 microns, the cyclone efficiency would be about 53 percent.

Plugging. Pneumatic transport systems are designed to handle a continuous flow of material without plugging. Because of mechanical difficulties, however, most cyclones will plug on occasion. Whenever this occurs, the full concentration of incoming particulate matter is exhausted from the cyclone, usually to the atmosphere.

Although other factors can affect the collection efficiency of cyclones, these seven factors are the most significant and deserving of attention.

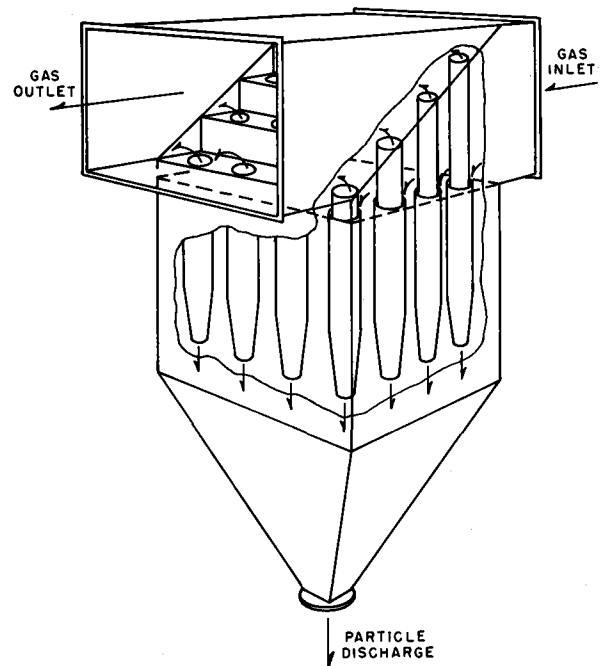


Figure 18. Simplified diagram of a multiple cyclone.

Multiple Cyclones

Multiple cyclones are particle collection systems that have more than one cyclone, ducted in a parallel-flow arrangement. Usually, the term is applied to systems that contain from 50 to 250 small-diameter cyclones, enclosed in a single box. A typical multiple-cyclone installation is pictured in Figure 18. The inlet gas stream is ducted to a manifold cyclone inlet. The gas stream entering any individual cyclone is directed into a helical path through inlet guide vanes at the top of the cyclone. This path provides the centrifugal force to separate the particles from the gas stream. As with conventional large cyclones, the gas stream moves downward and then reverses its direction and exits the cyclone in a return vortex. Particles that are removed from the gas stream drop out of the bottom into a hopper or bin.

The purpose of using a multiple-cyclone system rather than one or two large cyclones is that multiple cyclones have much smaller diameters on each individual cyclone. This increases the efficiency of particle collection, particularly with

small particles. Many small cyclones are required to handle a large gas flow because of the flow limitations of each small unit. Figure 17 illustrates a typical collection-efficiency curve for multiple cyclones compared to standard large cyclones.

The factors that affect efficiency of a multiple-cyclone installation are much the same as those that affect efficiency on large single units. There are other considerations, however.

Most multiple-cyclone installations on hogged fuel boilers are installed upstream from the induced-draft fan. This is done so that air entering the fan will be clean, thereby limiting erosion on the fan. This means, however, that most of the multiple-cyclone installations are operated under vacuum conditions. Therefore, any leakage in the bin or collection hopper at the bottom of the cyclones will result in reentrainment of the particles and lower collection efficiency. Particular attention should be paid to sealing inspection ports.

Leakage into a collection hopper not only reduces efficiency, it also increases the danger from fires in the hopper. The gas stream in multiple cyclones is usually oxygen deficient, because it has just come from a furnace and combustion process. The hot bits of unburned carbon usually will burn rapidly, if subjected to a stream of fresh air from a leak in the hopper.

Removal of material from the hopper must be able to keep up with the rate of input. If not, the hopper will plug and eventually the individual cyclones also. Most hoppers have inspection ports or other means of noting when the system plugs. Individual cyclones also can plug, especially if they are of small diameter.

A great disadvantage in the design of multiple cyclones is that they are encased in a metal box that prevents regular, visual inspection of each of the cyclones inside. Because the material that they remove from the exhaust gases contains small amounts of ash and sand, abrasive damage to individual cyclones is a common problem. Multiple cyclones can be eroded completely without operators being aware of their condition. To keep them in good working condition, a regular, visual inspection of each cyclone is recommended. This is, of course, difficult to do when the boiler must be

kept in service continuously with minimum shut-down time.

Uneven gas distribution to multiple cyclones can decrease their efficiency. Substantial variations in inlet pressures from one point in the multiple-cyclone box to another will result in improper flow patterns of the flue gases. Flue gases will flow out of the bottom of a few individual cyclones, into the hopper, and back up through the bottom outlets of other cyclones, with substantial reentrainment resulting.

Scrubbers

As noted previously, small particles with low settling velocities are difficult to capture in cyclone separators. Large particles can be captured with relative ease. One approach to particle control is to trap small particles on the surface of large particles, such as liquid droplets, and then collect the large particles. This is done in devices referred to as scrubbers, or "wet scrubbers," as most scrubbers use a liquid to capture the particles.

The design of scrubbers seeks to optimize three parameters: surface area of the liquid, contact between particles and liquid, and collection of the liquid.

Surface area of the liquid exposed to the particles can be maximized by spray showers (Figure 19), venturi scrubbers (Figure 20), and other systems that convert the liquid into small droplets. (Note: a gallon of water sprayed into droplets the size of a period has a surface area of about 300 square feet.) Alternative means of increasing the liquid surface area include water-curtain scrubbers and foam scrubbers.

The particles may be brought into contact with the exposed surface of the liquid as an integral feature of the scrubber. For example, in venturi scrubbers, the area just downstream from the throat of the nozzle is extremely turbulent. The turbulence increases the probability of contact of individual particles with liquid droplets. As another example, in spray-nozzle systems, increasing the pressure drop across the nozzles increases the velocity of droplets formed by the nozzles. The high-velocity droplets will impact upon particles carried in the gas stream. Some scrubbers use

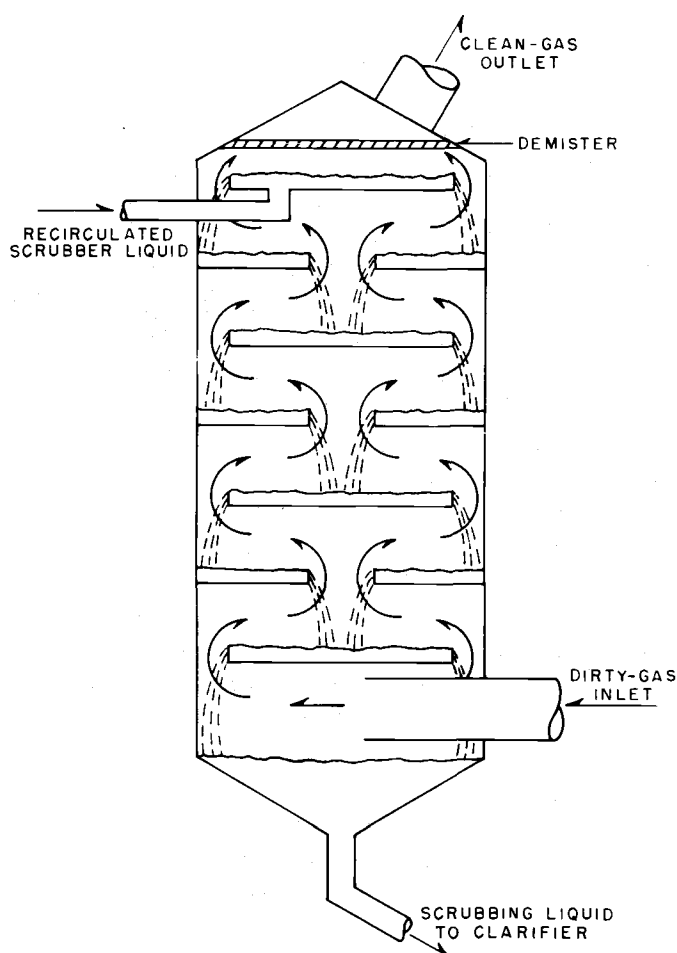


Figure 19. A cascading shower scrubber for increasing the efficiency of removing small particles from gases.

mechanical fans to aid in bringing the liquid into contact with particles in the gas stream.

Collecting the liquid in the most efficient manner is not difficult to accomplish because of the size of the liquid droplets. A properly designed cyclone system works well in conjunction with venturi scrubbers and spray-shower systems. Enclosed liquid-curtain scrubbers keep all of the liquid in the system, except for the portion that may go off as a vapor in the exit gas stream.

The liquid used in wet scrubbers is usually water. When the systems are applied to hogged fuel boilers, the resulting liquid will become basic, with a pH in the range 7.5-10. Evaporation of the scrubbing liquid will take place because of the heat

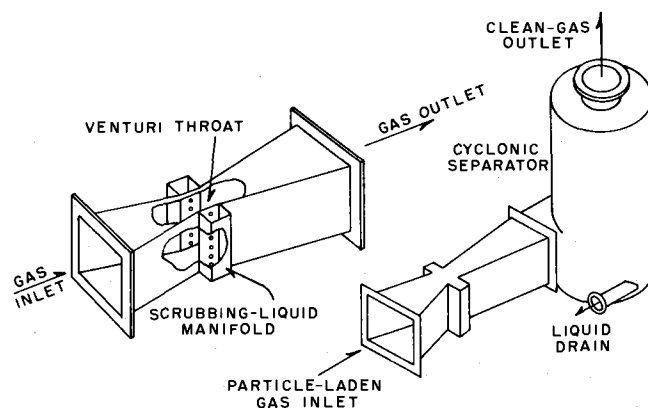


Figure 20. A venturi scrubber system in which turbulence downstream from throat increases the contact of particles and liquid droplets (10).

input of the incoming flue gas. The plume leaving a particular scrubber may be, but is not necessarily, saturated with water vapor. Water vapor in the exit gas will condense when it comes into contact with cool, ambient air. It forms tiny droplets that make the plume visible to the public. The visible plume from wet scrubber systems is a serious detriment because of the adverse public reaction regarding visible emissions.

Wet scrubber systems generally are divided into three classes, based upon the energy input to the system (Table 15). As expected, the collection efficiency of small particles generally increases with higher energy input to the system. The energy input may be in the form of a drop in pressure across liquid spray nozzles, venturi sections, collection cyclones, or other devices.

Collection efficiencies for wet scrubbers extend over a wide range. For use on boilers fired

Table 15. Three Classes of Wet Scrubbers, Based on Energy Requirements.

Description	Pressure drop across the system
	<i>In. water</i>
Low	0-10
Medium	10-30
High	30-100

with hogged fuel, systems usually are designed to operate with overall collection efficiency ranging from 95 to 98 percent, expressed as a percentage by weight. Collection efficiencies will be higher for large particles and lower for small particles.

An advantage of wet scrubber installations for boilers is that they are not subject to fire damage. If hot sparks carry over to a wet scrubber, the liquid will quench the fire quickly. The obvious disadvantage of such systems is that they generate problems of water pollution. Once the particles are trapped in the scrubbing liquid, they must be removed and the liquid recirculated. Field experience indicates that the solid particles will settle out of the water in a reasonably brief time (for example, 30 minutes). Thus, clarifiers work well to settle the particulate, but they are expensive to construct. Solids disposal from the clarifiers is an associated problem. For example, a boiler with a capacity of 100,000 pounds per hour, using hogged fuel, may generate from 8 to 10 tons per day of solids in the exhaust gas stream. If this is collected a wet scrubber, the solids from the clarifier will be in the form of a slurry that is messy to handle and difficult to dispose of. It is extremely important in designing a wet scrubbing system to make adequate provisions for collection and disposal of the solids.

Baghouse Filters

Baghouse filters are not used extensively on boilers fired with hogged fuel, largely because of fire hazard.

Baghouse filters are containers filled with cylindrical bags made of cloth. The particle laden airstream enters the bags from the bottom. As the gas passes through the bags, the particles are trapped on the inside surface. Various systems have been designed to remove trapped particles. These include shaking, reversing the gas flow, impinging a high-velocity jet of air on the outside of the bag at regular intervals, and other techniques. In each system, the goal is to make the trapped particles fall out of the bag into a collection hopper.

Baghouse filters have the advantages of being extremely efficient even for fine (sub-micron) particles. Their collection efficiencies commonly

are greater than 99 percent. They do not require a great deal of energy to operate. Pressure drops are normally less than 10 inches of water. They do not add liquid, so there is no visible plume and no water cleanup problem.

The disadvantages may outweigh the advantages. The bags are temperature limited. The upper limit of temperature is considered to be 600 F for most commercially available material. A small fire in the ash collection hopper, or a glowing ember in the flue gas, would cause extensive damage to a baghouse. If used downstream from an efficient multiple-cyclone collector, however, the combustible content of the material captured in a baghouse generally will be too low to support combustion in the baghouse. This potential for fire damage is the most critical disadvantage.

Baghouse life is limited by wear on the bags. The constant flexing or shaking action to remove collected particles shortens normal bag life to 18-24 months. This results in high maintenance costs.

Baghouses are generally large structures. Many plants do not have adequate room to locate this type of pollution control device.

Baghouses have high initial capital cost compared to alternative devices.

Baghouses must be fully insulated to avoid condensation inside the bags or on cool surfaces. This is particularly important where sulfur-bearing auxiliary fuels are used.

Electrostatic Precipitators

Electrostatic precipitators have been used widely to control particle emissions from combustion sources. They are rarely used on boilers fired with hogged fuel, however.

In operation, a negatively charged electrode runs parallel to a positively charged (grounded) plate (Figure 21). A large, direct-current voltage (that is, from 30,000 to 90,000 volts) is applied between the wire electrode and the plate. This brings about a flow of electrons through the gas from the wire to the plate. Particles entrained in the gas stream are bombarded by electrons traveling toward the positive plate. As electrons gather

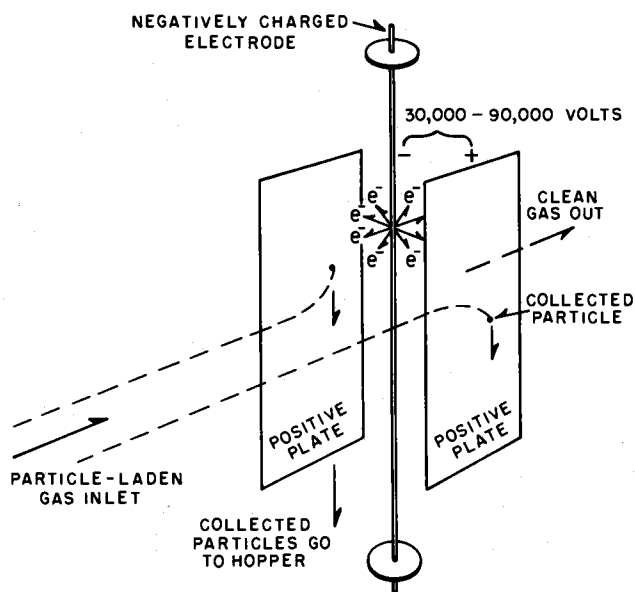


Figure 21. In an electrostatic precipitator, particles gain electrons from a negatively charged electrode, are attracted to positively charged plates, then shaken into a hopper.

on the individual particles, the particles take on a net negative charge. This net charge pulls the particles toward the plate, where they are collected.

Shaking or rapping devices are installed on the plates to dislodge the collected particles. They fall into a collection hopper below the plates.

Many factors affect collection efficiency in these units. One of the important factors is resistivity of the particles. If they have low electrical resistivity, such as that of carbon, they give up the negative charge to the positive plate and assume a positive charge. As like charges are repelled, carbon particles are pushed away from the plate and are reentrained in the gas stream. This substantially lowers collection efficiency.

On the other hand, if particles have high electrical resistivity, they will be unable to give up their negative electric charge. As the particles build up on the collecting plate, they can form an insulating barrier and even set up a net negative charge. Again, this reduces precipitator efficiency.

The emissions of flyash and unburned carbon from boilers fired with hogged fuel have low electrical resistivity. Electrostatic precipitators therefore have low collection efficiency. The efficiency can be increased by conditioning the particles with injection of a material that will alter resistivity to a more appropriate operating range. Sulfuric acid mist is used in some instances to accomplish this. Such solutions, however, present problems of corrosion to the equipment and increased potential for environmental pollution.

Electrostatic precipitators are large pieces of equipment and are costly to install. The combined factors of high capital cost and potential for low efficiency have resulted in limited use of these devices to control emissions from boilers fired with hogged fuel.

8. MEASUREMENT OF AIR-POLLUTANT EMISSIONS

Several different measurements can be made of air pollutant emissions from boilers fired with hogged fuel. For example, standard procedures have been developed to determine opacity, concentration of particular matter in grains per standard cubic foot (gr/SCF), mass-emission rate in pounds of particulate per hour, particle size distribution, and concentration of various pollutant gases such as carbon monoxide, nitrogen compounds, and sulfur dioxide.

These measurements are discussed individually in the next several sections, except for gaseous pollutants, which are not of primary concern when burning hogged fuel, as noted in Chapter 7.

Opacity Measurement

The discussion in Chapter 5 deals with instruments that can monitor opacity. This can be done automatically and continuously with commercially available equipment. Most regulatory agencies, however, will not accept the chart records from such equipment as proof of compliance with opacity regulations. They require that the opacity be determined visually by a trained and certified person.

Two scales of measurement are commonly used. The Ringelmann Smoke Scale for use on black smoke emissions and the Opacity Scale for use on emissions of other colors. The relation of these two scales is as follows:

Ringelmann scale	Opacity scale
No.	%
0	0
½	10
1	20
1½	30
2	40
2½	50
3	60
3½	70
4	80
4½	90
5	100

Certification schools for smoke and opacity readings have been set up across the country. Classes are held throughout the year to meet the demand. In general, the classes consist of two separate sessions. The first is to learn the theory and limitations of the technique. The second is to gain field experience in actually reading plumes. Examinations are held at the end of each session to determine degree of competence. Recertification

of ability in smoke and opacity reading is required at intervals ranging from 6 months to 1 year. For information on such schools, contact the state regulatory agency.

Concentration of Particulate Matter and Mass-Emission Rate

Measurement of the concentration of particulate matter is complex. There are no commercially available instruments that can do this continuously. It must be done on a "grab sample," in which a representative sample of the boiler emission is collected from the flue gas. The sample is analyzed by a procedure established by the U.S. Environmental Protection Agency (E.P.A.).

The specific procedure requires a minimum of \$4,000 in equipment to gather the sample. In addition, a substantial amount of laboratory equipment is required for the analyses. The process of sampling and analysis for a single complete E.P.A. test on a boiler at one operating level costs about \$2,000. A complete series of tests may cost as much as \$25,000. This complex process requires skilled technicians and engineers. It is much more than simply sticking a probe into an exhaust stack and reading a number.

Of particular concern in the procedure is the sampling location. The E.P.A. has recommended that sources be sampled at a location at least eight diameters downstream and two diameters upstream from the nearest source of disturbance to the airstream (5). This includes such parts as valves, bends, elbows, expansion joints, and tees. For many boiler installations, the recommended sampling location may be 100 feet up the smokestack. The cost of installing a sampling platform large enough to accommodate technicians and sampling

equipment on a smokestack may run into thousands of dollars. Such platforms should include adequate safety railings, toe railings, wind screens, and electric service outlets. They also should be equipped with some means of supporting a block-and-tackle hoist for raising and lowering the equipment.

There is a tendency to construct such platforms as temporary arrangements. Due consideration should be given to the fact that for each boiler test, several technicians will have to work about 2 days on the platform. The effects of exposure to heat, cold, wind, high elevation, and exhaustion demand that every safety precaution be provided.

The specified procedure is published in the Federal Register of December 23, 1971 (5). The same procedure is used to determine the mass-emission rate.

Particle Size Measurement

The procedure used to determine particle size has two steps. The first is to collect a representative sample of the particles and the second is to

analyze the sample. Like measurements of particle concentration, particle size measurement requires sophisticated equipment for collection and analysis, as well as skilled technical approaches.

Representative sampling for particulate matter can be achieved only if the particulate matter enters the sampling system at the same velocity as the airstream in which it is entrained. This is called isokinetic sampling.

Analysis of the collected samples usually is done with a microscope under laboratory conditions. A minimum of 100 particles should be measured to determine the size distribution of particles in each sample. Size is reported in terms of the percentage of particles smaller than a given size.

For particles collected in impactation systems, analyses for size and weight distribution may be carried out by weighing the samples of particles collected in each section of the impactor. This also allows a determination of mean size and size distribution of the particles, based on the weight distribution of the sample.

9. REGULATIONS PERTAINING TO EMISSIONS FROM BOILERS FIRED WITH HOGGED FUEL

Emission regulations are enforced by three levels of governmental agencies: the U.S. Environmental Protection Agency, state regulatory agencies, and local or regional agencies. Their enforcement programs are based on a permit system, which requires that any piece of equipment or process that generates or emits pollutant materials to the atmosphere must have a permit to operate. To obtain such a permit, one must demonstrate that the pollutant emissions will be lower than the maximum values established by the agencies. Further, before new equipment can be installed, the agencies must be satisfied that emissions from the equipment or process will not exceed the established standards. Some agencies' regulations include requirements that "best available technology" or "best available practical technology" be employed to control emissions. Some agencies also require that new installations include "advances in the art" of control of emissions. Interpretation of these requirements is frequently a controversial matter.

Actual emission standards vary somewhat from agency to agency. Most agencies have set standards regarding opacity, concentration of particulate matter, size of particulate matter, nuisance resulting from emissions of particulate matter, and emissions of sulfur dioxide. Some agencies have set standards on the mass of particulate that can be emitted, based on either an hourly rate or the rate of heat input to the boiler.

Opacity Standards

Opacity standards generally are based on location of the installation and its age. For example, if a boiler is located in an area of high population density, the regulation may specify that opacity of the plume from the stack may not exceed 20 percent for more than 3 minutes of any hour. A boiler located in a more remote area may be subject to a limitation of 40 percent opacity.

In general, boilers that were installed and operating before 1970 and are located in areas of low population density are subject to the limitation of 40-percent opacity. New installations are subject to the 20-percent-opacity limitation for most agencies. Standards for Oregon and Washington are indicated in Table 16. Readers should obtain copies of current regulations that apply to their specific jurisdiction.

Concentration of Particulate Matter

Regulations affecting allowable concentrations of particulate matter often are stated in terms of maximum grains per standard dry cubic foot of exhaust gas corrected to 12 percent carbon dioxide. This needs some explanation.

A grain is 1/7,000 pound. Most emission regulations have set either 0.10 or 0.20 grain per standard dry cubic foot (SDCF) as the maximum limit.

The term "standard dry cubic foot" is often confusing, because no agreement exists as to how standard conditions are defined. Most agencies agree that standard pressure equals 1 atmosphere, or 29.92 inches of mercury. Standard temperature is not agreed upon, however. It is variously stated as 32 F, 60 F, 68 F, 70 F, 0 C, or 20 C. The majority of the agencies accept 68 F or 20 C, which are equivalent.

The correction to 12 percent carbon dioxide is a linear correction to the measured concentration of particulate matter. It is made so that individual plants will not attempt to meet standards by diluting the emissions with clean air. For example, suppose boiler emissions were subject to a limitation of 0.10 gr per SDCF, and test showed a concentration of 0.15 gr per SDCF. One means of lowering the measured value is to add clean air at the base of the exhaust stack. By blowing in air at a rate equal to the rate of exhaust gas flow from the boiler, the concentration of particulate matter would drop to 0.075 gr per SDCF. At the same time, levels of carbon dioxide from the boiler would be diluted. By enforcing a correction to 12 percent carbon dioxide, the agencies assure that exhaust air is not diluted to meet emission standards.

The standards themselves are generally set at either 0.10 or 0.20 gr per SDCF. As with opacity

Table 16. Summary of Opacity Regulations in Oregon and Washington¹.

Agency	Existing sources		New sources
	Before 7-75	After 7-75	
	%	%	%
OREGON			
Oregon D.E.Q. ²	40	40	20
Lane Regional A.P.A.	40	40	20
Mid-Willamette Valley A.P.A.	40	40	20
WASHINGTON			
Washington D.O.E. ³	40	20	20
N.W. Washington A.P.A.	40	40	20
Olympic A.P.A.	40	20	20
Puget Sound A.P.A.	40	20	20
S.W. Washington A.P.A.	40	20	20
Spokane County A.P.A.	40	40	40
Tri-County A.P.A.	40	40	20
Yakima County A.P.A.	40	20	20

¹Personal communication from M. Cory, Boise Cascade Corporation, Boise, Idaho. Mr. Cory contacted each agency listed and compiled their regulations.

²Special control areas restrict existing sources to 20%.

³May require a restriction to 20% opacity and 0.10 gr per standard cubic foot in sensitive areas.

standards, the level is based on location of the facility and on its age. Grain loading standards for Oregon and Washington are shown in Table 17.

Mass-Emission Rates

As an alternative to establishing limits on concentrations of particles in flue gases, some agencies have set limits on the pounds of material that may be emitted per hour or per million Btu's of heat input to the boiler. In general, the maximum values allowable vary with the size of the boiler. Larger boilers have the more stringent standards. For specific values applied to local plants, contact the regulatory agency that has jurisdiction over the particular plant in question.

Size of Particulate Matter

Some, but not all, agencies have established limits on the maximum size of particles that may be emitted by boilers. The limitation usually is set

at 250 microns. Its purpose is to avoid spreading large pieces of unburned carbon, which act as a soiling nuisance. Consideration now is being given to establishing regulations on the maximum concentration of smaller particles (that is, less than 10 microns). This is a result of studies indicating that smaller particles present the greatest hazard to human health.

Nuisance Regulations

Most agencies have a general regulation that pertains to nuisance emissions. The usual statement is to the effect that no process or operation shall emit materials that are a nuisance to the surrounding property or community. Such regulations are not directed specifically toward boilers fired with hogged fuel. They are referred to occasionally, however, if flyash or unburned carbon from a stack becomes a public nuisance.

Table 17. Summary of Particulate Concentration Standards in Oregon and Washington.¹

Agency	Existing sources		New sources
	Before 7-75	After 7-75	
	Gr ²	Gr ²	Gr ²
OREGON			
Oregon D.E.Q.	0.2	0.2	0.1
Lane Regional A.P.A.	0.2	0.2	0.1
Mid-Willamette Valley A.P.A.	0.2	0.2	0.1
WASHINGTON			
Washington D.O.E.	0.2	0.2	0.2
N.W. Washington A.P.A.	0.2	0.2	0.1
Olympic A.P.A.	0.2	0.1	0.1
Puget Sound A.P.A.	0.2	0.2	0.1
S.W. Washington A.P.A. ³	0.2	0.2	0.2
Spokane County A.P.A.	0.1	0.1	0.1
Tri-County A.P.A.	0.2	0.2	0.1
Yakima County A.P.A.	0.2	0.1	0.1

¹Personal communication with M. Cory, Boise Cascade Corporation, Boise, Idaho. Mr. Cory contacted each agency listed and compiled their regulations.

²Grains per standard cubic foot.

³After 1975, best available control technology is required on all boilers. The regulation is only a guide to allowable emission levels.

Emission of Sulfur Dioxide

Hogged fuel contains low levels of sulfur. A typical analysis may show 0.080 percent by weight (2). Auxiliary fuel may be sulfur bearing, however,

and most agencies have placed limits on the allowable sulfur content of boiler fuels. Typical values are shown in Table 18.

Table 18. Regulations of the State of Oregon Pertaining to Allowable Sulfur Content in Auxiliary Fuels (12).

Fuel type	Maximum allowable sulfur
	%
Residual oil	2.5 before 7-74
Residual oil	1.75 after 7-74
No. 1 Dist. oil	0.3
No. 2 Dist. oil	0.5
Coal	1.0

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