THE STEAM BOILER

By E. M. Powell

1. SELECTION OF EQUIPMENT

The modern steam boiler is only one part of the carefully integrated steam-generating unit, defined as a unit to which water, fuel, and air are supplied and in which steam is generated. It consists of a boiler with fuel-burning equipment and, typically, water-cooled furnace, superheater, reheater, economizer, and air heater, or combinations of these. The component parts are so interrelated that it is impracticable to discuss the steam boiler alone. This article will deal, therefore, with selection and performance of a steam-generating unit, with particular emphasis on the boiler itself.

For maximum overall reliability and operating economy each component must be correctly proportioned and related to the others. To produce a coordinated unit requires, first, a background of experience covering each element of the design and its functional relation to other elements; second, a wide variety of designs to choose from in order that the exact type and size best suited to the particular needs of any plant may be recommended and furnished.

Many pitfalls in the selection of steam-plant equipment can be avoided through the employment of competent and reliable consulting-engineering organizations with broad experience in power-plant work and the ability to integrate manufacturers' designs with the remainder of the plant.

FACTORS INFLUENCING SELECTION. Factors which exert the greatest influence on selection of fuel-burning and steam-generating equipment are fuel characteristics, capacity and steam conditions, space conditions, cost, and individual preference.

FUEL CHARACTERISTICS. Before attempting even a preliminary selection of equipment, complete information should be available as to fuels on which designs and predicted performance are to be based. This information should be established by a comprehensive survey of the market, to determine which fuel, available in quantities sufficient to guarantee a reliable source of supply, offers the greatest economic value over a long-range program. It usually is desirable to establish a secondary fuel supply for emergency use when the supply of primary fuel is interrupted or changes in price make the secondary fuel economically more attractive.

If possible, the equipment should be selected so that the performance with the secondary fuel will be equivalent to that with the primary fuel. However, if the reserve of primary fuel is ample to insure that any interruption in supply would be only temporary, and if the price differential between primary and secondary fuels is fairly stable, it may be better economy to design for maximum efficiency with the primary fuel and accept some compromise in performance and maintenance costs with the secondary fuel.

Fuels available to the average plant, in order of importance, are coal, fuel oil, and natural gas. (See Section 2.) Neither cost nor heating value is a true index of their economic value. These are only two of many factors in the overall cost per thousand pounds of steam generated.

Other factors to be considered are the efficiencies and operating costs obtained with different fuels. Natural gas, piped directly from the supply mains to the burners, incurs practically no operating costs; no refuse results from its use. The cost of burning fuel oil usually is low, consisting of storage, pumping, heating, atomization, and maintenance of equipment. Although the ash content is low, heating surfaces must be cleaned. Depending on the sulfur content, there may also be corrosion in air heater, economizer, fan and breeching connections. The cost of cleaning and maintaining such equipment must be charged to burning oil.

The cost of burning coal should include maintenance of equipment, handling charges from car to storage to steam-generating unit, cost of cleaning heating surfaces, and ash handling. The average cost of burning coal in the United States, exclusive of fixed charges, is about 5% of its cost, for fuel oil approximately 1.5% of the equivalent coal cost, and for natural gas 0.5%.

The type of fuel-burning equipment depends on burning characteristics of the fuel and the capacity for which the unit is designed. For example, stokers usually are the more
<table>
<thead>
<tr>
<th>Type of Fuel-burning Equipment</th>
<th>Approximate Continuous Combustion Rate, pounds per sq ft per hr (dry basis)</th>
<th>Range in Maximum Continuous Furnace Liberation Rates, Btu per cu ft per hr</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Anthracite</td>
<td>Bituminous Coal</td>
</tr>
<tr>
<td>Pulverized coal</td>
<td></td>
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<tr>
<td>Single-retort stoker</td>
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<td>Multiple-retort stoker</td>
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<tr>
<td>Spreader stoker</td>
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<tr>
<td>Chain-grate stoker</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Traveling-grate stoker</td>
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<td>45</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stationary grate</td>
<td>20</td>
<td>20</td>
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<tr>
<td>Special furnaces</td>
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</table>
Economical selection for comparatively low capacity units and pulverized coal for high capacities. A more complete discussion of fuel-burning equipment is found on p. 7-04. Table 1 illustrates the adaptability of different firing methods to various commonly used fuels and required stoker and furnace sizes. All coals, including anthracite, have been burned successfully in pulverized form, except coke breeze.

The range of capacities for which each type of fuel-burning equipment is particularly suitable and most commonly used is shown in Table 2.

**Table 2. Fuel-burning Equipment Selection Check List—Capacity Basis**

(Combustion Engineering)

<table>
<thead>
<tr>
<th>Fuel-burning Equipment</th>
<th>Continuous Capacity Range, pounds of steam per hour</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>1000 to 15,000</td>
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<tr>
<td></td>
<td>15,000 to 150,000</td>
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<tr>
<td></td>
<td>35,000 to 200,000</td>
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<tr>
<td></td>
<td>150,000 to 1,000,000</td>
</tr>
<tr>
<td>Pulverized coal</td>
<td>...</td>
</tr>
<tr>
<td>Single-retort stoker</td>
<td>![checkmark]</td>
</tr>
<tr>
<td>Multiple-retort stoker</td>
<td>![checkmark]</td>
</tr>
<tr>
<td>Spreader stoker, dumping-grate</td>
<td>![checkmark]</td>
</tr>
<tr>
<td>Spreadere stoker, continuous-discharge</td>
<td>![checkmark]</td>
</tr>
<tr>
<td>Chain-grate stoker</td>
<td>![checkmark]</td>
</tr>
<tr>
<td>Traveling-grate stoker</td>
<td>![checkmark]</td>
</tr>
<tr>
<td>Stationary grates</td>
<td>![checkmark]</td>
</tr>
<tr>
<td>Oil burners</td>
<td>![checkmark]</td>
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<tr>
<td>Gas burners</td>
<td>![checkmark]</td>
</tr>
</tbody>
</table>

* Occasionally.
† Rarely exceeding 40,000 lb per hr.
‡ Occasionally for capacities exceeding 200,000 lb per hr.
§ Up to approximately 125,000 lb per hr.

Special refuse or by-product fuels are available from industrial processes such as blast-furnace gas, other gases, paper-mill liquors, bagasse, bark, and wood refuse. Burning characteristics of these fuels and other design considerations given to their use are discussed in Section 2.

**CAPACITY AND STEAM CONDITIONS.** Capacity is one of the most important factors in determining the type of unit to be selected. Table 3 illustrates the capacity ranges for which each of the general types of boilers has been found most adaptable, the

**Table 3. Steam-generating Equipment Selection Check List—Capacity Basis**

(Combustion Engineering)

<table>
<thead>
<tr>
<th>Type</th>
<th>Continuous Output, pounds of steam per hour</th>
<th>Maximum Design Pressure, psig</th>
<th>Maximum Temperature, °F</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1000 to 15,000</td>
<td>15,000 to 150,000</td>
<td>35,000 to 200,000</td>
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<tr>
<td>Firetube boiler</td>
<td>![checkmark]</td>
<td>![checkmark]</td>
<td>![checkmark]</td>
</tr>
<tr>
<td>Three-drum low-head boiler</td>
<td>![checkmark]</td>
<td>![checkmark]</td>
<td>![checkmark]</td>
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<tr>
<td>Two-drum vertical unit-type boiler</td>
<td>![checkmark]</td>
<td>![checkmark]</td>
<td>![checkmark]</td>
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<tr>
<td>Three- or four-drum vertical boiler</td>
<td>![checkmark]</td>
<td>![checkmark]</td>
<td>![checkmark]</td>
</tr>
<tr>
<td>Special utility-type boiler</td>
<td>![checkmark]</td>
<td>![checkmark]</td>
<td>![checkmark]</td>
</tr>
<tr>
<td>Controlled forced-circulation</td>
<td>![checkmark]</td>
<td>![checkmark]</td>
<td>![checkmark]</td>
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</tbody>
</table>

* Up to approximately 225,000 lb per hr on coal, and 300,000 lb per hr on oil and gas.
† Present maximum used. Design and materials available for higher temperature.
‡ Controlled forced-circulation boilers are designed in various types and sizes for the full range in capacities.

Maximum steam pressures for which they are usually designed, and the corresponding maximum steam temperatures. There is also a partial correlation between steam conditions and capacity. Maximum pressures and temperatures seldom prove economical except in the higher capacity ranges. The flow ranges have been selected so that 1000 to
15,000 represents the small heating plant, 15,000 to 35,000 the small industrial, 35,000 to 150,000 most of the industrial plants and some of the smaller utilities, and 150,000 to 1,000,000 nearly all the central-station types. Included in this latter group are some of the large units for industrial plants.

Limitations imposed by steam pressure and temperature are predominantly structural. They affect the weight of steel required, hence the cost; temperature affects the space required by the superheater and adaptability of the boiler to provide that space. Another condition affecting design is feedwater temperature. Boilers without economizers are not affected by variation in feedwater temperature, except as it affects the heat input to a pound of steam. However, in boilers equipped with economizers, boiler and economizer surface must be proportioned to suit the variations in feedwater temperature.

**Heat-recovery Equipment.** The selection of heat-recovery equipment is primarily an economic study based on capitalization of the fuel saving credited to its use. The choice between an air heater and an economizer (see p. 7-30) depends on (1) allowable maximum air temperatures (depends on type of fuel-burning equipment used); (2) boiler pressure and feedwater temperature as affecting allowable absorption in the economizer; (3) arrangement and amount of heating surface required; and (4) temperature of gas at boiler outlet.

Conditions other than economic may make the use of air heaters desirable. With pulverized coal firing, preheated air is necessary for drying coal in the pulverizer, and as an aid to combustion in the furnace. Use of air heaters with stoker-fired units will not yield as much increase in efficiency as with pulverized-coal-fired units, because the preheated-air temperature is normally limited to 300 F, to avoid excessive maintenance of grates. Here economizers provide a better means of increasing the efficiency than air heaters.

In large utility-type designs, heat-recovery equipment almost always includes economizers and air heaters to obtain the highest efficiency which can be justified economically: 88 to 90%. Most of these units are designed for high-pressure operation, and the cost of boiler and economizer surface is high. Since thickness of air-heater parts is not affected by steam pressures, it is usually economical to use a large amount of air-heater surface.

**SPACE CONDITIONS.** In an existing building both shape and volume of the space available have a marked effect on the capacity of the unit which can be installed, heat-recovery equipment possible, type of firing, and possibly the range of fuels which can be fired at a given capacity. For instance, burners firing pulverized coal, oil, or gas require furnaces of such shape as to provide for the proper length of flame travel for complete combustion and to avoid harmful flame impingement. Best operation with a traveling grate stoker will be obtained as its length is increased, whereas the grate length of a spreader stoker is limited by the maximum distance over which it is possible to distribute the fuel uniformly. Coal having low ash-fusion temperatures frequently dictate the use of larger furnaces than are actually required for satisfactory combustion so that sufficient water-cooled surface can be provided. This cools the gases below the temperature at which excessive slag and ash accumulations would occur at the entrance to the first gas passage of the boiler.

**COST.** Extreme care should be exercised in the extent to which first cost is allowed to influence the equipment selected. A complete economic study should be made (see Section 16) considering the load factor of the plant, the cost of fuel, and the efficiency of the plant as a whole, rather than the steam-generating equipment alone.

For instance, a small plant located near an ample supply of low-priced fuel and having a seasonal load of a few months of each year can justify a standard boiler, a stoker, no water-cooling in the furnace or heat-recovery equipment, and will operate with natural draft. On the other hand, a base-load plant, whether industrial or utility, with a load factor approaching 100% and burning a high-priced fuel, can easily justify an efficient fuel-burning system, water-cooled furnace, high steam pressure and temperature, as well as heat-recovery equipment, forced- and induced-draft fans, and control equipment. The value of the fuel burned during the life of such a unit may represent forty times the initial investment. Even a small advantage in reliability, efficiency, or flexibility gives economic
justification for the relatively small additional first cost necessary to provide the better unit.

Too many variables are involved to prepare any accurate cost comparisons that may be applied to specific cases. However, for a given set of steam conditions and firing methods, one large boiler can be constructed at a cost of 15 to 25% less than two boilers having the same combined capacity. A unit designed to operate at steam conditions of 600 psig—750 F will cost between 40 and 50% more than one for 200 psig—500 F.

INDIVIDUAL PREFERENCE. Well-founded individual preference, not personal prejudice, should be considered if it is based on the familiarity of the plant personnel with the operation of a given type of equipment or if the plant itself was designed for a specific type and not suited to others without expensive changes. However, improvements in design and the higher efficiency or capacity that may be obtained within the same space at reduced cost for labor and maintenance should not be overlooked. The types of boilers listed in Table 3 are described briefly below with some of their chief advantages and limitations.

TYPES OF BOILERS. Fire tube boilers are relatively inexpensive compared to the corresponding water tube boilers. Their design and construction, however, are such that there is a definite limitation in the size and pressure for which they can be built. They are seldom used above 150 psig design pressure. One advantage is the large water-storage capacity. Because of this feature, wide and sudden fluctuations in steam demand are met with little change in pressure. There are many types of fire tube boilers in use today with internal or external furnaces, but the most widely used is the horizontal return tubular type illustrated in Fig. 1.

The three-drum low-head boiler, as its name implies, was designed for limited space, especially when headroom is low. Like other water tube boilers, they are seldom designed for pressures below 150 psig. Because of its low overall height, its capacity is limited by the hydraulic head available for maintaining circulation of water and steam through the tubes. Baffles are arranged for natural draft operation with a normal stack height. A typical application of this boiler is shown in Fig. 2.

Two-drum boilers are the simplest of the bent tube types and are available in many designs. Because of the flexibility in their design and increased hydraulic head, they can be used for a wide range of capacities and pressures and are adaptable to any method of firing. A design for a large industrial plant is shown in Fig. 3, fired by a spreader stoker and using high-pressure overfire air to create turbulence in the furnace and shorten the length of flame travel.

Three- or four-drum vertical boilers in industrial and small utility plants have been replaced to a large extent by the less expensive two-drum boiler. Their chief application today is found in the special utility-type class, where they are designed to fit the conditions
of each particular installation. They are described and illustrated at length later in this discussion.

**Sectional-header boilers** were also designed to meet conditions of low headroom, and for that reason are still widely used in the marine field. Their chief advantages are simplicity, excellent performance, and adaptability to construction over a wide range in performance. The desire for higher capacities per foot of furnace width which exceeded the limit of satisfactory water and steam circulation in this type of boiler, together with the development of welding technique, served to accelerate the use of bent-tube designs particularly in the higher pressure and capacity field. A typical unit of this design is shown in Fig. 4.

**WASTE-HEAT BOILERS.** Waste heat, for our purpose, is defined as the sensible heat in noncombustible gas, such as gas leaving furnaces used for processing metals, ores, and other materials. Boilers are usually installed where the waste gases are continuously discharged from a process at a temperature well above that of saturated steam at the required pressure. Gas temperatures above 1000°F usually justify application of waste-heat boilers. High gas temperatures permit efficient heat transfer with low velocities, resulting in low draft losses by permitting natural draft operation. Low gas temperatures (1) require high velocities to obtain efficient heat transfer and (2) necessitate the use of induced-draft fans. One notable low-temperature application is where steam is required in a plant equipped with diesel engines. The exit gas temperatures range from 500 to 800°F, depending on whether the engine is designed for a two-stroke or four-stroke cycle. (See Section 13.)

Forced-circulation boilers are particularly suited to duty with diesel engines, since small tubes and high gas velocities can be used for most efficient heat transfer with the low temperatures involved. They can be of compact design and provide more flexibility of tube arrangement and location since they do not depend on hydraulic head for circulation, as do natural-circulation boilers. The low gas temperature limits the operating pressure to about 200 psig. Such a boiler is illustrated in Fig. 5. This boiler consists of a cylindrical-shaped shell containing heating surface as a number of horizontal pancake coils stacked one above the other. Each coil is a continuous circuit connecting the inlet and outlet headers. An orifice is used in the inlet header for each coil to insure uniform distribution of water. The boiler may be installed either vertically or horizontally and the headers arranged to suit installation requirements.

Boilers used in steel mills containing open-hearth and continuous-heat furnaces can be either water tube or fire tube type. Fire tube boilers are sometimes preferred because of the low infiltration into the setting, thereby minimising the possibility of the explosion of combustible gases.

Water tube boilers are usually preferred with cement and lime kilns, copper and zinc
furnaces, because they are available in large sizes and permit baffling to recover solids suspended in the gas stream if desired. They are more accessible for cleaning and less susceptible to damage by sudden temperature changes than fire tube boilers. A water-cooled furnace can be readily applied to reduce the temperature of gases containing nearly plastic solid matter, thereby reducing slagging difficulties in the convection passes of the boiler.

Vertical bent-tube boilers are preferred to straight-tube boilers when dust-laden gases are present, since they are more flexible in tube arrangement, require less space for tube removal, and are more positive in water and steam circulation. Also, they are more adaptable to the application of superheaters, and the vertical tubes minimize dust accumulation.

Figure 6 shows one of four boilers serving two large reverberatory furnaces in a copper refinery. This design, illustrating all the points enumerated, was developed from experience with heat and chemical recovery from paper-mill liquor where gases contain large quantities of luminous solid matter at a temperature near the plastic point. Boiler tubes are widely spaced, vertical to minimize ash deposit. Soot blowers are provided in the furnace roof and in the boiler as indicated by double circles. The large hopper at the bottom of the furnace and the hopper at the bottom of the boiler passes collect a large percentage of the dust from the gas stream for the recovery value of that dust. Numerous doors are provided for observation and manual cleaning if necessary. This particular boiler was designed for 45,000 lb of steam per hr at 750 psig and 661 F.

FORCED-CIRCULATION BOILERS.
Natural circulation in a boiler may be defined as the movement of water and steam through boiler tubes in conformity with the available head resulting from the difference in density of the circulating fluid in the downcomer and riser circuits. Although natural circulating head may be present also in a forced-circulation boiler, the primary circulating force is supplied by a pump. There have been many different designs employing the forced-circulation principle, most of which can be grouped in four basic types.

(1) The "once-through" type does not require a separating drum. Water is fed into the boiler by the feedwater pump and passes progressively through the various sections of the unit for water heating, evaporating, and superheating. Since all the water is evaporated in one pass through the unit, all the solid matter in the feedwater must be deposited on the heating surface. This presents the serious problem of arranging the zone of deposit in a cool region to avoid overheating the tube metal, and of providing for washing the affected surfaces. Second, the low water-storage capacity makes necessary a sensitive control system for regulating the flow of fuel, air, and water.

(2) The "recirculation" type discharges water and steam into a drum in which the steam is separated from the water. The circulated water and feedwater are taken from the drum and fed to the evaporating circuits through a circulating pump. The concentration of solids in the boiler water may be controlled by blowdown from the drum, in the conventional manner.

(3) In the third type, evaporation takes place entirely in a drum, avoiding the deposit of solids on heating surface. The rate of evaporation is considerably greater than the output of the unit, and a pump is used to force this steam through the superheater. The excess steam is returned to the drum to evaporate feedwater by direct contact. The large volume of steam handled by the pump results in such high power requirements that this type of unit is not economical except at very high pressures.
The fourth basic type avoids one limitation of the once-through type by discharging a mixture of water and steam into a separator, from which the water is removed and passed through heat exchangers for conservation of heat. This type requires no special circulating pump but does require sensitive control equipment.

The recirculation type is most widely used in this country because the methods of control and operation most nearly approach those of the natural-circulation boiler. Its chief advantages are (1) the ability to proportion the water flow to the various circuits in accordance with predetermined requirements; (2) the ability to make use of small-diameter, thin-walled tubes; and (3) the facility with which tubes may be arranged for most efficient utilization of the space available, without regard to natural circulating head.

**TYPICAL CASE OF EQUIPMENT SELECTION.** Additional power generation is required in a large public utility plant. The unit shown in Fig. 7 was designed to meet the steam conditions tabulated below and to burn a good grade of West Virginia bituminous coal with provision for other coals of lower heating value, grindability, and ash-fusion temperature.

**Specifications**

<table>
<thead>
<tr>
<th>Specification</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure at superheater outlet, psig</td>
<td>1.285</td>
</tr>
<tr>
<td>Superheated steam temperature, °F</td>
<td>950</td>
</tr>
<tr>
<td>Continuous capacity, lb per hr</td>
<td>620,000</td>
</tr>
<tr>
<td>Control is to be provided so that a constant steam temperature of 950 °F is maintained from 475,000 lb per hr to 620,000 lb per hr</td>
<td></td>
</tr>
<tr>
<td>Approximate load factor, %</td>
<td>80</td>
</tr>
<tr>
<td>Feedwater temperature, °F</td>
<td>451</td>
</tr>
</tbody>
</table>

**Selection of Equipment.** The first design step in selecting such a unit is the determination of furnace dimensions. The width is set by the maximum evaporation per unit of drum length at which it is possible to operate and yet secure satisfactory steam separation and purification in the drum. Velocity of gas flow at entrance to boiler and superheater as it may affect slag accumulation is also a factor. With this unit, tangential burners are used. Furnace depth and height are proportioned to provide the required volume, as well as necessary height and cross-sectional area for satisfactory burner arrangement for the secondary low-quality fuel.

The furnace walls are fully water cooled to secure a gas temperature at the superheater inlet which is low enough to avoid slag accumulations. This gas temperature, however, must be sufficiently high to provide the required steam temperature at the minimum load for which superheat control is desired. The use of vertically adjustable burners which may direct the fuel and air either upward or downward in the furnace provides a relatively wide range in control of furnace outlet temperature, and thus increases the capacity range over which constant steam temperature is obtainable. In addition, dampers for by-passing a portion of the gas around the superheater surface are used for control of steam temperature beyond the range of burner regulation. In some cases, deaerthers are also included to increase flexibility in control of steam temperature.

A large amount of superheating surface having a high percentage of alloying materials is required for a steam temperature of 950 °F. To produce this steam temperature, the gas-temperature drop through the superheater is approximately 925 °F. As a result, the temperature differential between gas and steam is relatively small. This condition requires use of a counterflow arrangement between steam and gas. Close spacing of the surface and high velocity will produce high heat-transfer rates, but will result in excessive draft loss, tube erosion, and slag accumulations. Operating experience on many installations with high steam temperature at high capacity provides the designer with many data from which he can determine correct spacing of superheater elements and optimum gas velocity.

After establishing superheater design, the next step is to select the air heater and economiser combination, and then fill in with boiler convection surface to secure the desired gas outlet temperature from the unit. On the basis of specified load factor and fuel cost, it is possible to justify an outlet-gas temperature of less than 300 °F. However, 300 °F is usually set as the allowable minimum to avoid corrosion in the air heater. Improvements in air heater cleaning methods, materials, arrangement of surface, and methods for increasing metal temperatures during low load operation, such as recirculating preheated air to the inlet of the air heater, indicate that lower outlet-gas temperatures may be practicable. The outlet-gas temperature and calculated gas and air quantities, having been determined, the maximum practical size of air preheater is selected. Performance calculations then establish gas temperature at air heater inlet, i.e., economizer outlet. The economiser performance is established by limiting the water temperature rise to avoid generating steam under any expected operating condition, and then determining the
corresponding drop in gas temperature. Length of economizer elements is usually equal to the furnace width. The number of tube rows in height and width is adjusted to provide this performance and thus sets the gas temperature at the economizer inlet. This temperature immediately indicates whether additional convection surface is needed between superheater outlet and economizer inlet. Surface of this type is part of the boiler and is generally arranged as a vertical tube bank between upper and lower drum. A minimum amount of this convection surface should be installed, to avoid increasing cost of drums.

The foregoing discussion outlines the fundamental approach to arranging and proportioning the several types of heat-absorbing surfaces of a steam-generating unit. There are a number of other factors which also require careful analysis to provide a well-balanced unit: the number and size of drums required to produce steam of acceptable purity must
be established (for the specified capacity two upper drums are generally provided); arrangement of equipment must fit into space conditions existing at the plant; design of water walls and convection surface must provide for adequate steam and water circulation; and overall draft loss through the unit should be reasonable, to avoid excessive fan power.

The number of pulverizers (see p. 7-82) recommended for these larger units may be two, three, or four, depending on character of operating load and quality of coal. The pulverizers are selected with ample capacity to handle the lowest quality of coal, considering moisture, grindability, and heating value, that may be used.

2. BOILER DESIGN AND HEAT BALANCE

FACTORS OF PERFORMANCE. The term performance refers to the rate of output, efficiency of heat transfer, draft and pressure requirements of the steam-generating unit or any of its component parts.

Output or capacity of steam boilers is expressed in many ways. The term most commonly used is actual evaporation, the pounds of steam generated per hour at the given steam temperature and pressure. This term does not offer an accurate comparison between one unit and another since the heat transferred per pound of steam generated may vary widely, depending on steam pressure, temperature, and feedwater temperature. A more accurate method for comparison is to report output in terms of total heat transferred per hour to the water and steam as it passes through the unit. Turbine steam rates are usually expressed in pounds of steam required per kilowatt-hour generated, which probably accounts for the popularity of the term actual evaporation for rating the boilers supplying the steam.

When the heat-transfer equipment of a steam-generating unit consisted solely of a boiler and was used primarily in conjunction with a steam engine, it was common practice to rate the unit in terms of boiler horsepower. A boiler horsepower was defined as the evaporation of 34.5 lb of water per hour from a temperature of 212 F into dry saturated steam at the same temperature. This is equivalent to 33,475 Btu per hr. It was common practice to rate a boiler on the basis of 10 sq ft of heating surface per boiler horsepower. With improved firing methods it was found that a boiler could develop considerably more than its "rated capacity." The ratio of actual to rated capacity expressed in percentage came to be known as per cent of rating. With the advent of water-cooled furnaces and heat-recovery equipment, less work was required of the boilers for a given total output so that higher capacities could be developed per rated horsepower. Many steam-generating units today, particularly in central stations, contain no boiler heating surface as such. Boiler horsepower and per cent of rating would be meaningless in such cases, and, for that reason, these terms have become obsolete although they are still used occasionally with reference to standardized boilers of low capacity.

The factor of evaporation is the ratio of the heat actually required to heat one pound of feedwater to the final steam conditions, to the heat required to evaporate one pound of water from a temperature of 212 F to dry saturated steam at 212 F. Equivalent evaporation is the product of actual evaporation and the factor of evaporation. This term is seldom used today, although it does represent a true measure of the total heat output.

Efficiency of a steam-generating unit is the ratio of the heat absorbed by water and steam to the heat in the fuel fired. It is a measure of the potential heat energy in the fuel which has been converted and transferred to the steam, in which form it can do useful work.

There are two accepted methods of testing for efficiency, described in detail in the ASME Power Test Code for Stationary Steam Generating Units. (See p. 19-12.) The preferred method involves the direct measurement of input and output. The measurements needed are the quantity and heat value of the fuel, the quantity of steam generated, and the heat absorbed per pound. It is also necessary to obtain sufficient heat loss data to construct a heat balance to permit checking the results. The difficulties in accurately determining fuel and steam quantities and a representative heat content of each is so great with larger units that an alternate method is generally used. In this method, the efficiency is determined by calculating the losses in per cent and subtracting from 100. Minor losses such as sensible heat in the refuse, loss due to moisture in the air, and loss due to unburned hydrocarbons can be calculated from the Test Code or a nominal mutually agreed "unaccounted for" loss assigned to cover these and other unmeasured losses. In this country the higher heating value is used in determining the heat input from the fuel, whereas in Europe the lower heating value is commonly used. The lower heating value equals the higher heating value minus 1020 Btu for each pound of water present as moisture in the fuel or formed by burning the hydrogen in the fuel.
When the boiler and fuel-burning equipment are of different manufacture, the boiler manufacturer can guarantee the overall efficiency based on an assumed CO₂ leaving the unit and an assumed loss due to unburned combustible. The manufacturer of fuel-burning equipment will guarantee to burn the required quantity of fuel so that the combined effect on the efficiency of the steam-generating unit will not be less favorable than that resulting with a given CO₂ in the exit gas and a given heat loss due to unburned carbon.

**BOILER HEAT BALANCE** (see also Combustion, Section 2). The losses usually included in a heat balance are these.

1. **Heat loss due to dry gas** represents the sensible heat in the dry flue gases and is equal to pounds of dry gas per pound as-fired fuel \( \times c_p(t_{exit} - t_{fuel}) \), where \( c_p \) is the specific heat of the gases, taken as 0.24 for approximate calculations. For accurate values see p. 2-10. The heat loss thus calculated is expressed as Btu per pound of "as-fired" fuel. If a complete analysis of the flue gas is available, the weight of dry gas per pound as-fired fuel may be calculated from

\[
\frac{11\text{CO}_2 + 8\text{O}_2 + 7(\text{N}_2 + \text{CO})}{3(\text{CO}_2 + \text{CO})} \times (\text{lb carbon burned per lb as-fired fuel} \times \frac{f/0.5}{\text{lb per lb as-fired fuel}})
\]

where CO₂, O₂, N₂, and CO are the constituents of the dry flue gas expressed in per cent by volume, and S is the pounds of sulfur in the fuel per pound, as-fired.

2. **Heat loss due to moisture** in fuel is due to evaporating moisture in the fuel and superheating it to the temperature of the flue gas. Temperature at which evaporation begins may be quite low, owing to the low partial pressure of the water vapor in the gaseous products of combustion. The heat lost is the difference between the total heat of water vapor at exit temperature and of liquid water at fuel temperature. When the gas temperature leaving the unit is less than 575 F,

\[
\text{Btu loss per lb as-fired fuel} = \text{lb H}_2\text{O per lb as-fired fuel}(1089 - t_{fuel} + 0.47t_{exit})
\]

When \( t_{exit} \) is greater than 575

\[
\text{Heat loss} = \text{lb H}_2\text{O per lb as-fired fuel}(1066 - t_{fuel} + 0.5t_{exit})
\]

3. **Heat loss due to water from combustion of hydrogen** is determined in the same manner as outlined in (2), by calculating the water formed as 9 lb per lb H₂ in the as-fired fuel. If free moisture is included as hydrogen and oxygen, in the ultimate analysis of fuel as fired, the formulas will give the total moisture loss, and calculation of loss due to moisture in fuel outlined under (2) may be omitted.

Moisture in gaseous fuels exists in two separate forms which require different treatment in calculating the heat loss. Washed gas contains entrained water in the form of suspended globules of liquid. In this form it can be treated as described under (3). There is no entrained water in an unwashed gas. Nearly all gaseous fuels contain some water vapor. In natural gases the water vapor is present because of water that has been in contact with the gas in the ground or because of rehydration. In refinery gas, blast-furnace gas, or coke-oven gas, it is present owing to the nature of the process of which they are a product or because of subsequent cleaning operations. This item assumes a real importance with unwashed blast-furnace gas supplied to the burners at high temperature. The moisture in vapor form does not require the heat of vaporization. The heat loss, therefore, represents the difference in sensible heat between the fuel temperature and that of the flue gas according to the following equation:

\[
\text{Btu loss per lb as-fired fuel} = \text{lb H}_2\text{O per lb as-fired fuel} \times 0.47(t_{exit} - t_{fuel})
\]

4. **Heat loss due to moisture in air** is treated in exactly the same manner as the moisture in fuel in vapor form as described under (3).

5. **Heat Loss Due to Carbon Monoxide.** The presence of CO as detected by flue-gas analysis indicates incomplete combustion. It is seldom found with properly operated modern fuel-burning equipment. A small amount represents an appreciable heat loss.

\[
\text{Btu loss per lb as-fired fuel} = \frac{\text{CO}}{\text{CO}_2 + \text{CO}} \times 10,160 \times \text{carbon burned per lb as-fired fuel}
\]

where CO₂ and CO represent percentages by volume of carbon dioxide and carbon monoxide in the dry flue gases and 10,160 is the difference in Btu evolved in burning 1 lb carbon to CO rather than to CO₂.

6. **Heat Loss Due to Combustible in Refuse.** To determine this loss accurately involves measuring separately the weight of refuse in the ash pit, boiler hoppers, and gas stream leaving the unit as well as the heat value of that refuse by calorimeter. The heat loss then becomes the product of pounds of refuse per pound of as-fired fuel and the heat value per pound of refuse. This loss is sometimes approximated by burning out a sample of refuse, determining the loss in weight, and considering that to be carbon with a
heat value of 14,600 Btu per lb. This method should not be used in checking guarantees since the heat value of the combustible may vary as much as 9000 to 14,600 Btu per lb, depending on its composition.

7. **Heat loss due to radiation** includes all the heat lost to the surroundings by either radiation, convection, or conduction, through the setting or the casing of the unit. No satisfactory method has been developed for measuring the loss. However, it is known to vary with the type of setting and particularly the extent of water cooling of the furnace walls and capacity. Accordingly, the American Boiler Manufacturers Association issued Fig. 8, showing the variation for different wall constructions and capacities. It has been adopted by the industry and ASME Test Code.

![Figure 8: Variation in heat loss due to radiation for different wall constructions and capacities.](image)

**HEAT TRANSFER.** The theory of heat transmission is described in detail in Section 3 of this handbook. However, there are so many departures in the operation of a steam-generating unit from the controlled conditions of the laboratory that considerable modification is necessary before laboratory data can be used for design. All three methods of heat transfer—radiation, convection, and conduction—are present in each part of the steam-generating unit. For example, the heat transferred from the furnace gases to the water and steam within a water-wall tube must pass through a series of resistances interposed by the gas film adjacent to the tube, slag on the tube, tube wall, scale deposited on the inside by the water evaporated, and the film of water and steam. Additional resistance may be present between the slag and tube wall or the scale and tube wall, depending on the bond between them.

**Heat transfer through the gas and evaporating films** do not follow the simple equation for conduction. The temperature drop through the other resistances is inversely proportional to the thermal conductivity. For radial heat flow through curved surfaces, the temperature drop can be calculated from this equation:

\[ Δt = \frac{Q}{12k} \times r_2 \times \left( \log \frac{r_3}{r_1} \right) \]

where \( Δt \) = temperature drop across any single resistance, °F; \( Q \) = heat absorption, Btu per hour per square foot of outside tube surface; \( k \) = thermal conductivity, Btu per square foot per hour per °F for 1 foot of thickness; \( r_2 \) = outside radius, inches; \( r_1 \) = inside radius, inches.

The conductivity of scale varies from 0.04 to 2.12, depending on its composition and temperature; steel varies from 21.5 to 30, and steam from 0.036 to 1.009.

The gas film is the dominating resistance to heat transfer with clean surfaces. However, accumulations of ash on the outside surface, or scale on the inside, may become the con-
trolling resistance if allowed to continue unchecked, and will result in loss of efficiency. High metal temperatures and possibly failures will result from scale.

The rate of heat absorption in a given furnace, corresponding to a given rate of heat release, will vary over a wide range within the limits shown approximately in Fig. 9. It is impracticable to present in compact form curves more accurate than these, since the efficiency of heat absorption varies widely with the type of firing, fuel burned, amount and disposition of heating surface, and the cleanliness of that surface. Generally, the rapid combustion of pulverized coal and liquid or gaseous fuels occurs with a relatively short flame, and with a correspondingly high rate of heat absorption, particularly when combustion takes place near the bottom of the furnace. This is found to be especially true with tangential firing.

Heat transfer in tube banks, whether they form a part of the boiler, superheater, economizer, or air heater, differs in two ways from that in furnaces. The rate follows the laws of convection rather than radiation except for the relatively small quantity of non-luminous radiation from the CO₂, SO₂, and water vapor in the gas. The hourly quantity of heat transferred will be in direct proportion to the temperature difference between the hot and cold fluids. One or both of these temperatures will vary as the gas passes over the tube bank.

Fundamental heat-transfer equations (see also Section 3) which apply to most problems of boiler design are:

\[ Q = R \times S \times \Delta t \]

where \( Q \) = heat absorbed, Btu per hour; \( R \) = overall rate of heat transfer, Btu per square foot per hour per °F; \( S \) = heating surface, square feet; and \( \Delta t \) = logarithmic mean temperature difference fluid to fluid, °F.

Also, neglecting leakages and radiation losses, the heat absorbed is equal to the heat given up by the gas or

\[ Q = W \times c_p \times (t_1 - t_2) \]

where \( W \) = weight of gas, pounds per hour; \( c_p \) = mean specific heat of gas at constant pressure, Btu per pound per °F; and \( t_1 - t_2 \) = gas temperature drop, °F.

The overall rate of heat transfer in tube banks of boilers, superheaters, and economizers is dependent on the series of resistances, as in a furnace tube. The resistances through steam, water films, and tube wall are so small, however, that only the resistance of the gas film need be considered, with clean surfaces. In air heaters, the resistance through the air film is of the same order of magnitude as that through the gas film, so that the overall rate is \( 1/R = 1/R_a + 1/R_s \), where \( R \) = overall rate, Btu per square foot per hour per °F; \( R_s \) = thermal conductance through gas film, Btu per square foot per hour per °F; and \( R_a \) = thermal conductance through air film, Btu per square foot per hour per °F.

Whether the gas flows parallel or transverse to the axis of the tubes or through the tubes has a great effect on the rate of heat transfer. The approximate variation is shown in Fig. 10, where the upper limit represents flow across tubes of small diameter and the lower limit represents flow parallel to tubes on relatively wide centers. Pure cross flow or parallel flow are seldom found in boilers. This fact, along with stratification of gases and ineffective surfaces due to structural exigencies and ash accumulations, makes a background of practical and operating experience most important.

The temperature difference which produces the flow of heat depends on whether the temperature of one or both fluids vary, and the relative direction of both fluids passing through or over the heating surface, i.e., whether they flow counter to, parallel to, across one another, or some combination thereof. In any case, the mean temperature difference equals

\[ \Delta t = \frac{\text{Greatest difference} - \text{least difference}}{\log_e \left( \frac{\text{Greatest difference}}{\text{least difference}} \right)} \]
When the temperatures of both fluids vary, the greatest heat transfer with a given heating surface is obtained where they are arranged in counterflow. With the parallel flow arrangement, the highest temperature of the heated fluid can approach, but never reach, the lowest temperature of the heating fluid.

**DRAFT LOSS.** The various items included in the pressure differential across the convection surface of a steam-generating unit are friction due to flow across tubes; loss in head due to turns; friction due to flow through, or parallel to, tubes; and stack effect.

These equations show the mechanics of friction losses:

- Flow across tubes: \( PD = fN\sqrt{H_e} \)
- Turn loss: \( PD = KH_e \)
- Flow along tubes: \( PD = f\left(\frac{L}{D}\right)H_e \)

where \( PD \) = pressure drop, inches of water; \( f \) = friction factor, dimensionless; \( N \) = number of restrictions; \( K \) = constant, depending on type of turn; \( L \) = length of tube, feet; \( D \) = inside or equivalent diameter, feet; \( G \) = mass velocity, pounds per hour per square foot furnace area; \( d \) = density, pounds per cubic foot; and \( H_e \) = velocity head, inches of water = \( 0.0002307\left(G/1000\right)^{2/3}/d \).

Data on the variation of friction factor with tube arrangement are available in the literature on the subject. For flow across tubes, a close approximation is 0.24 when the tubes are in line, and 0.36 for staggered tubes.

Turns in boilers and air heaters are usually of the severest type in that they are generally 180 degrees and very abrupt. The factor \( K \) may be taken as 1.5 when the velocity head corresponds to the average velocity at the turn.

The friction factor for flow along tubes varies, depending on Reynolds' number, tube diameter, and degree of roughness of the surface. A conservative approximation for this type of equipment is 0.02. The diameter to be used for flow through tubes is the actual inside diameter; for flow along a bank of tubes it is the equivalent diameter, four times the free gas-passage area divided by the gas-touched perimeter of the tubes.

Because of the great difference in coefficient of heat transfer between cross and parallel flow, lower velocities are usually used for the former in order to obtain reasonable draft losses. The overall rate of heat transfer Btu per hour per square foot, in the various parts of a typical high-capacity, high-temperature, steam-generating unit, normally falls within the following range: Waterwalls—45,000 to 80,000. Superheater—8000 to 12,000. Boiler—2000 to 5000. Economizer—3000 to 4500. Air heater—500 to 700.

**BOILER CONSTRUCTION**

By J. R. Kruse

**3. SCOPE OF CODES FOR CONSTRUCTION**

There are at least five sets of rules covering construction of steam boilers. Four of them are mainly for marine boilers. The code most widely used for construction of land-plant boilers is the Boiler Construction Code of the American Society of Mechanical Engineers, referred to herein as the Code. Codes for construction of boilers for marine use are U.S. Coast Guard Marine Engineering Regulations and Material Specifications; the American Bureau of Shipping Rules for Building and Classifying Steel Vessels; Boiler Construction Rules and Regulations by Lloyd's Register of Shipping; and Boiler Construction Rules for United States Navy Vessels.

All these rules are, in reality, "Safety Rules," written to provide maximum safety, and yet permit a construction well within practical methods. In the United States, most states have adopted the ASME Code as their safety code. A few have added several minor rules to the Code, for boilers operated in that state. A few others have their own rules, based to a great degree on the ASME Code. There are also a few states that have no rules at all, but it is common practice of boiler manufacturers to build boilers to meet the ASME Code.

All code committees are continually revising their rules to achieve uniformity. The ASME Code Committee is probably the most active; therefore, the other code bodies use ASME as a basis for revisions wherever practical. Many foreign countries are now accepting land-type boilers built to the ASME Code. Some, however, have rules that differ considerably from those of ASME.
Since all codes are continually being revised, it is important that the latest revised rules be followed in the design and construction of boilers. The latest editions or the addenda can be obtained from the following sources:

ASME Codes, from The American Society of Mechanical Engineers, 29 West 39th St., New York, N. Y.
Coast Guard Rules, from The United States Coast Guard, 1300 E St., Washington, D. C.
ABS Rules, from The American Bureau of Shipping, 45 Broad St., New York, N. Y.
Lloyd’s Rules, from Lloyd’s Register of Shipping, 17 Battery Place, New York, N. Y.
Navy Specifications, from the United States Navy, Boiler Section, Washington, D. C.

BOILERS AND UNFIRED PRESSURE VESSELS. Since construction requirements for unfired pressure vessels of the many different types are similar to those for boilers, the construction rules for both are similar in many phases.

The Boiler Code Committee of the American Society of Mechanical Engineers, in cooperation with other association committees, such as the American Society of Testing Materials, the American Welding Society, and the American Petroleum Institute, has prepared a number of different sections of the Code, listed below:

Section I. Rules for Construction of Power Boilers (includes Section VI, Rules for Inspection of Material and Steam Boiler and the Appendix).
Section II. Material Specifications.
Section III. Boilers of Locomotives.
Section IV. Low-pressure Heating Boilers.
Section V. Suggested Rules for Care of Power Boilers.
Section VII. Miniature Boilers.
Section VIII. Unfired Pressure Vessels.
Section IX. Qualification for Welding Procedure and Welding Operator.

An additional Unfired Pressure Vessel Code for Petroleum Liquids and Gases was prepared by a joint committee drawn from the ASME Committee and the American Petroleum Institute Committee. This code is designated as the API-ASME Code.

ENFORCEMENT OF CODE RULES. The enforcement of any code is carried out by duly authorized inspectors of the originating organization. This enforcement applies to construction, erection, and sometimes operation of the boilers. Enforcement of rules for boilers operating in the United States comes under the jurisdiction of the National Board of Boiler and Pressure Vessel Inspectors. This organization works closely with the ASME Boiler Code Committee, on which it has representation. The many boiler insurance carriers’ inspectors hold National Board licenses, obtained only by taking written examinations given by one of the member states. These authorized inspectors are required to make shop and field inspections before certificates necessary for insurance coverage and operation can be issued to the owners.

FACTORS OF SAFETY USED IN VARIOUS CODES. No term has been misused so widely as the so-called factor of safety. Consider three types of vessel, designated as types A, B, and C.

Type A. Steam Boilers or Vessels Pierced with Unreinforced Holes. In these vessels, stress at the edge of holes may be over twice average hoop stress. In applying an initial hydrostatic test of (1 ½ X working pressure) to a drum built with a so-called factor of safety of 5, the steel at the most highly stressed part is so strained as to produce a permanent set and redistribution of forces in the stressed area. The factor is based on ultimate strength, and with a steel in which yield strength is one-half the ultimate strength, yield strength is 2 ½ times average hoop stress at the working pressure. If stress at the sides of tube holes is (2 X average hoop stress), and the hydrostatic test is made at (1 ½ X working pressure), stresses at the sides of tube holes are (3 X average hoop stress) at the working pressure. This would exceed yield strength of the material. If the so-called factor of safety is made less than 5, as is often done, there is a greater yielding of the material on application of the hydrostatic test and a greater redistribution of stresses.

Type B. Vessels Having No Holes or Other Stress Raisers in Their Shells. In these vessels, yield strength is not exceeded until hoop stress, which is uniform from end to end of the cylinder, is exceeded. Such vessels could be operated safely with a much lower so-called factor of safety than those with holes or other stress raisers in the shell. Application of a hydrostatic test of (1 ½ X working pressure) to a vessel of this type, built with a factor of safety of 5, does not exceed the yield strength, as occurs with Type A vessels.

Type C. Penstocks for Boulder Dam. This construction is described by C. M. Day and Peter Bier of the U. S. Bureau of Reclamation in Mechanical Engineering, Aug. 1934. The yield strength of the special steel used in the penstocks is 38,000 psi; hoop stress was limited to 18,000 psi. The article describes tests made by elastic analysis, and by sub-
jecting 1/8 scale models of the penstocks to hydrostatic pressure. The parts were built so that maximum stress at any point would not exceed about 19,000 psi.

Each of the three types of vessels has its own field of application. Type A includes all pressure vessels having unreinforced holes, or in which unreinforced holes, as telltale holes for determining shell thickness, may be drilled after the vessels are in operation. This type is covered by ASME and similar construction codes.

Type B includes vessels constructed under rules of the Interstate Commerce Commission for transporting liquids and gases under pressure. For such vessels, a so-called factor of safety, of, say, 3 1/2 where there is no corrosion, gives as great a degree of safety as some Type A vessels where the factor is 5.

Type C represents the highest type of construction for pressure vessels where walls cannot be made of uniform thickness with no stress raisers. By limiting both hoop and maximum stresses, due to departing from uniform shell thickness, as well as at special branch connections and reinforced openings, no question can arise as to the effect of exceeding yield strength in any part of the structure.

THE ASME CODE FOR LOCOMOTIVE BOILERS specifies:

Factor of safety used in design and construction of new boilers shall be not less than 4.5.

Factor of safety used in determining maximum allowable working pressure calculated on conditions actually obtained in service shall not be less than 4.0.

Maximum allowable working pressure determined by conditions obtained in service shall not exceed that for which boiler was designed.

THE JOINT API-ASME CODE contains provisions for removing vessels from service if the factor of safety becomes lower than certain values. At first glance it would appear that factors of safety given in the API-ASME Code are lower than those given in the Unfired Pressure Vessel Section of the ASME Boiler Code in the ratio of 4 to 5. However, the factor of 4 is a figure below which vessels cannot be operated, whereas the ASME Code refers to initial factor of safety when boilers are built. Another feature in the two codes brings the two factors for stress-relieved unfired pressure vessels nearer together. In the API-ASME Code, tensile strength used in applying the formulas is that for coupons which are tested at the steel mill, after being stress-relieved in the same manner as the vessel will be stress-relieved; whereas in the ASME Code coupons for such vessels are not stress-relieved at the steel mill. In stress relieving the coupons, by holding them at a temperature of 1100 to 1200 F., for 1 hr per inch of thickness of plates, tensile strength may be lowered about 10%. The factor 5 in the ASME Code was considered ample to cover this lowering of the tensile strength; whereas in the API-ASME Code it was embodied in the Code on account of the lower operating factor.

The 1946 ASME Code for boilers and pressure vessels omits the term “Factor of Safety,” in the formula for determining the maximum allowable working pressure. Instead, certain working stresses are allowed on various materials, at various temperatures. In effect this change is equivalent to reducing the so-called factor of safety to nearly 4 for some constructions.

RULES FOR CONSTRUCTION. In designing and fabricating boilers, it is essential that the proper rules be followed. These rules depend on type of service and locality, among other things. The correct rules may be ASME or state rules for a stationary boiler, operating in the United States. For merchant vessels under the United States flag, the rules of the U. S. Coast Guard or the Rules of the American Bureau of Shipping, or both, are applicable. If the boiler is for a Navy vessel of the United States, it may be built to the special Navy Specifications, or, if not a combat vessel, it may be built to either the ASME Rules or the U. S. Coast Guard Rules. If the boiler is for a vessel operating under a foreign flag, the Rules of Lloyd’s Register of Shipping may apply.

These states require all stationary power boilers to be built according to the ASME Code rules: Arkansas, California, Delaware, District of Columbia, Indiana, Iowa, Louisiana, Maine, Maryland, Michigan, Minnesota, Nebraska, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Oregon, Panama Canal Zone, Pennsylvania (a few minor exceptions or additions are required), Rhode Island, Tennessee, Texas, Utah, Vermont, Washington, West Virginia, and Wisconsin. The above states may have their own codes, which are the same as ASME. These states have boiler laws, but do not require that the boilers be built to any specific rules: Colorado, Connecticut, Mississippi, and Montana. These states will accept standard ASME boilers, or boilers stamped by the National Board. Massachusetts has her own boiler codes similar to the ASME Code. Slight differences are found in a few sections. The remaining states do not have boiler laws, but many of the Canadian provinces accept boilers built to the ASME Code rules.

The foregoing data on States Boiler Rules are in accordance with the Sept. 1, 1949, Synopsis of Boiler Laws as published by the National Bureau of Casualty Underwriters, 60 John Street, New York 7, N. Y. This synopsis is brought up to date each year.

All ASME codes are kept up-to-date by issuance of annual code “pink sheet addenda,”
available about August of each year. "Interpretations" of the codes are issued whenever necessary, to clarify the intent of the code.

**PREAMBLE TO THE ASME POWER BOILER CODE.** To have better understanding of just what the Power Boiler Code scope is, the preamble to this code section is quoted.

Preamble

This code covers rules for construction of power boilers to be used in stationary service. **Stationary boilers as herein considered include portable and tractor boilers.**

The Code does not contain rules to cover all details of design and construction. Where complete details are not given, it is intended that the manufacturer, subject to the approval of the authorized inspector, shall provide details of design and construction which will be as safe as otherwise provided by the rules in the Code.

A pressure vessel in which steam is generated by the application of heat resulting from the combustion of fuel (solid, liquid, or gaseous) shall be classed as a fired steam boiler.

An unfired pressure vessel which generates steam for power or heat to be used externally to itself shall be classed as an unfired steam boiler. Such vessels may be constructed under the appropriate classification of Section VIII of the Code and shall be equipped with the safety devices required by Section I of the Code in so far as they are applicable to the service of the particular installation.

The material for forced-circulation boilers and boilers with no fixed steam and water line shall conform to the requirements of the Code. All other requirements shall also be met except where they relate to special features of construction made necessary in boilers of these types, and to accessories that are manifestly not needed or used in connection with such boilers, such as water gages, water columns, and gage cocks.

 Separately fired steam superheaters which are not integral with the boiler or are separated from the boiler by stop valves are considered fired pressure vessels and their construction shall comply with Code requirements, including all piping, valves, and required safety devices, from the inlet flange to the outlet flange. If welding ends are used at the inlet or outlet of the superheater, Code requirements shall begin or end at the weld where flanges, if used, would have been placed. Such attachment welds to external connecting pipes are not within the scope of the Code, if they are not exposed to high-temperature gases.

These rules apply to the boiler proper and pipe connections up to and including the valve or valves as required by the Code. Superheaters, reheaters, economizers, and other pressure parts connected directly to the boiler without intervening valves shall be considered as parts of the boiler and their construction shall conform to the Code rules.

The eleventh edition of this Handbook carried voluminous extracts from the ASME Boiler Construction Code. Since it was published, increase in pressure and temperature has necessitated expansion of the Code's size so that abridgment of its requirements in useful form has become impossible. The reader, to be certain he has the latest information, should consult the latest revision. This is available (ASME Boiler Construction Code [Combined Edition], 1949 Edition) through ASME, 29 W. 39th St., New York, N. Y., for $12.50.

**MOISTURE, SUPERHEATERS, AND REHEATERS**

By P. B. Place and F. I. Epley

4. MOISTURE IN STEAM

By P. B. Place

**CARRYOVER.** Steam may carry various amounts of water and impurities out of the boiler. This contamination of the steam is called carryover.

**Steam quality** is the liquid contamination in the steam, expressed in percentage, by weight, of the mixture. Thus 99.8% quality steam contains 0.2% moisture. Steam quality is determined by calorimetric methods on saturated steam samples.

**Steam purity** is the solids impurity in the steam, expressed in parts per million (ppm) of impurity. Thus a 1 ppm steam contains 1 part by weight of solids contamination per million parts of steam. Steam purity is determined by evaporation, or by conductivity determination, of condensed steam samples of saturated or superheated steam.

If the moisture in the steam is boiler water of known concentration, the following equality exists between steam quality and steam purity:

\[
Ppm \text{ impurity} = \frac{\% \text{ moisture} \times \text{ppm in boiler water}}{100}
\]

\[
\% \text{ moisture} = \frac{\text{ppm impurity} \times 100}{\text{ppm in boiler water}}
\]
STEAM SAMPLING. The objective in steam sampling is to obtain a sample of steam representative of the total steam flow. Usually some form of perforated nozzle is used in the saturated header of the superheater, in the steam circulators between the boiler and superheater, or in a main steam line. Figure 1 shows types of sampling nozzles suitable for use in headers, tubes, and pipes. In pipe and tube nozzles, the sampling holes face upstream and are spaced to sample from equal areas of cross section of the line.

Sampling rates are determined by the relation

\[ f = \frac{a}{A} \times F \]

where \( f \) and \( F \) are sample and steam flow rates and \( a/A \) is the ratio of total sample hole area to pipe area. The total area of sample holes should be less than the cross-section area of the nozzle to insure a small pressure drop and distribution of flow. The number of holes may vary from 4 for pipe diameters up to 6 in., to 8 for pipe diameters over 12 in.

Sampling nozzles should be located after a length of straight pipe equal to at least ten diameters. Locations in order of preference are (1) vertical pipe, downward flow; (2) vertical pipe, upward flow; (3) horizontal pipe, vertical insertion; and (4) horizontal pipe, horizontal insertion. Steam containing less than 1% moisture is more easily and accurately sampled than steam containing higher amounts of moisture.

TYPES OF CARRYOVER. There are three types of carryover: (1) slugs of water, (2) foam, and (3) spray.

Priming. Carryover of type 1, known as priming, may occur under conditions of high water level or severe surging in the boiler drum. Priming is essentially mechanical and usually due to high water level or spouting of submerged risers.

Foamover. Carryover of type 2, known as foamover, occurs when foam accumulates in the boiler drum and is carried out by the steam. Foamover is the most common type of excessive carryover. It is due to foaming of the boiler water and is caused by stabilization of bubble films by impurities in the boiler water. High concentrations, organic matter, oil, and suspended matter are often causes of foaming.

The American Boiler Manufacturers' Association recommends the following boiler-water concentration limits for various operating pressures:

<table>
<thead>
<tr>
<th>Pressure, psi</th>
<th>Concentration, ppm</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 to 300</td>
<td>Not over 3500</td>
</tr>
<tr>
<td>301 to 450</td>
<td>Not over 3000</td>
</tr>
<tr>
<td>451 to 600</td>
<td>Not over 2500</td>
</tr>
<tr>
<td>601 to 750</td>
<td>Not over 2000</td>
</tr>
<tr>
<td>751 to 900</td>
<td>Not over 1500</td>
</tr>
<tr>
<td>901 to 1000</td>
<td>Not over 1250</td>
</tr>
<tr>
<td>1001 to 1500</td>
<td>Not over 1000</td>
</tr>
</tbody>
</table>

These limits are arbitrarily based on average experience. In some cases, excessive foaming may not develop at higher concentrations; in other cases excessive foaming may develop at lower concentrations.

Spray. Carryover of type 3 occurs when spray, mist, or fog, which are degrees of atomization of the boiler water, are steam borne from the drum in much the same manner as dust is carried by air currents. Spray carryover is due to incomplete purification of the steam, leakage in drum baffles, or operation beyond velocity limitations of the purification equipment. The normally small contamination in commercial steam is usually of this type.
STEAM-QUALITY DETERMINATIONS. Steam calorimeters are used to determine the quality of saturated steam, i.e., the amount of moisture in the steam. There are several types of calorimeters, but the most common is the throttling calorimeter.

The throttling calorimeter is a device in which a flowing sample of saturated steam of known temperature and pressure is expanded through an orifice to a lower pressure, usually atmospheric. The passage through the orifice and calorimeter involves no heat loss other than radiation, and since the total heat in the sample is greater than that of saturated steam at lower pressure, the excess heat in the sample is used in superheating the expanded sample and/or evaporating any moisture in the sample. If the temperature and pressure of the steam entering and leaving the calorimeter are known, the amount of moisture in the sample can be determined.

Figure 2 shows a design that can be made of standard pipe fittings and in which both a temperature recording bulb and calibrating thermometer may be used.

The apparatus required for throttling calorimeter test is a suitable means of sampling the steam, the calorimeter, and a means of measuring the pressure and temperature of the inlet and outlet steam. Pressure of inlet steam is usually measured by calibrated steam pressure gage, and inlet-steam temperature may be obtained from steam tables or by thermometer in a suitable well, located upstream of the calorimeter orifice. Outlet-steam pressure is usually checked with a mercury manometer attached to the exhaust chamber of the calorimeter. In most cases, the orifice size and steam flow are adjusted to give atmospheric discharge pressure. Outlet-steam temperature must be carefully measured with a calibrated thermometer or thermocouple. Radiation loss can be reduced by inserting the thermometer or couple in the exhaust steam flow without shielding in a thermometer well.

![Fig. 3. Maximum moisture capacity of throttling calorimeters.](image)

![Fig. 4. Throttling calorimeter outlet temperature for moisture up to 1%. Values shown by 0% moisture curve are theoretical temperatures resulting from throttling dry and saturated steam from the pressures shown by the ordinate to 15 psia. They are useful in establishing the temperature correction. See example.](image)
A minimum steam flow of 250 to 300 lb per hr through the calorimeter is desirable to minimize radiation effects. Different-sized orifices are required for different operating pressures to obtain suitable sampling rates.

Above and below 450 psig, the total heat in saturated steam decreases, and the available heat- and moisture-determining capacity of the calorimeter decreases. The practical range of operation for throttling calorimeters is from 150 to 900 psig, with most satisfactory performance between 350 and 550 psig. Figure 3 shows the maximum moisture content determinable by throttling calorimeter at various operating pressures, and Fig. 4 shows the maximum temperatures at calorimeter outlet for different pressures and moisture contents up to 1%. Steam containing more than 1% moisture is difficult to sample, and determinations of high moisture are subject to errors traceable to sampling difficulties.

Moisture in the steam is calculated from this equation:

\[ m = \frac{H_1 - H_2}{L} \]

where \( m \) = pounds of moisture per pound of steam sample; \( H_1 \) = total heat in saturated steam at inlet temperature and pressure; \( H_2 \) = total heat in superheated steam at exhaust pressure and exhaust temperature (corrected for radiation); and \( L \) = latent heat of evaporation at inlet pressure.

**Example.**

<table>
<thead>
<tr>
<th>Calorimeter inlet pressure</th>
<th>440 psia</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calorimeter back pressure</td>
<td>0.6 in. Hg</td>
</tr>
<tr>
<td>Calorimeter normal temperature</td>
<td>323 F</td>
</tr>
<tr>
<td>Calorimeter outlet temperature</td>
<td>318 F</td>
</tr>
</tbody>
</table>

Pressure correction:

| 0.6 in. Hg = 0.3 psi |
| 14.7 + 0.3 = 15.0 psia |

Temperature correction:

| Theoretical dry steam temperature = 325 F |
| Calorimeter normal temperature = 323 F |
| Temperature correction = - + 2 F |
| Corrected outlet temperature = 320 F |
| Total heat in sample at 440 psia = 1204.6 Btu/lb |
| Total heat at 15 psia and 320 F = 1202.2 Btu/lb |
| Latent heat at 440 psia = 770.0 Btu/lb |
| Moisture in steam = (1204.6 - 1202.2)/770.0 |
| = 0.003 lb per lb steam |
| = 0.3% |
| Steam quality = 99.7% |

The separating calorimeter is a separation device consisting essentially of a perforated cup. Moisture is thrown out and deposited in a separating chamber while the dry steam passes up and out of the separating device through an annular steam jacket around the separating chamber. The dry steam discharges through an orifice. The steam flow may be determined by condensing and weighing, or by calculating the flow by Napier's equation provided the size of the orifice is known (see Sections 1 and 3).

The amount of moisture deposited in the separating chamber can be read directly from a gage glass graduated in 1/100 lb units. Although the accuracy of this type calorimeter is less than that of the throttling type, it has a much wider range. If well insulated, the radiation loss is less than 0.05%.

The universal calorimeter consists of a separating and throttling calorimeter, of high and low range, respectively, in series. If \( Y_1 \) = percentage of moisture, by weight, in steam as determined by the combination calorimeter; \( w_1 \) = weight of moisture collected in separating calorimeter in a given time, pounds; \( w_2 \) = weight of dry steam condensed after passing through the throttling calorimeter, pounds; \( Y_2 \) = proportion, by weight, of moisture in steam discharged from separating portion as determined by throttling calorimeter; then, without radiation losses,

\[ Y_1 = \frac{w_1 + w_2 Y_2}{w_1 + w_2} \times 100 \]

The electric calorimeter is one form of superheating calorimeter. Steam enters the bottom of the calorimeter, passes upwards over heating coils, and thence to atmosphere. To determine moisture content, it is necessary to know the electrical input, temperature of the exhaust steam, and the formulas and constants furnished by the manufacturers of the apparatus.

**STEAM-PURITY DETERMINATIONS.** Evaporation Method. The solids impurity in steam may be determined by evaporation of a known amount of sample under carefully
controlled conditions. A relatively large sample of condensate is evaporated in a light-weight dish by radiant heat. The evaporation is done within a dustproof cabinet through which purified air passes to remove vapors. Automatic adjustment of sample feed to the evaporating dish is usually provided, and, when all the condensate is evaporated, the residual solids are determined by the difference between the final and original weight of the evaporating dish.

**Conductivity Method** (Ref. 1). Carryover of dissolved, ionizing, boiler water salts is usually determined by measuring the *electrical conductivity* of the condensate. The method does not measure suspended matter, organic material, or unionized solids such as silica. The usual unit of measurement is the micromho, which is the reciprocal of the resistance, in millions of ohms, corrected to standard temperature of 77 F.

Equivalent ppm impurity in steam = micromho × 0.6.

Dissolved gases that ionize in solution, such as NH₃ and CO₂, must be eliminated from the sample by a degasification process, or suitable correction made for their presence. Continuous degasification and conductivity recording equipment is available which makes this method practical for continuous measurement of steam impurity of less than 0.5 ppm. Portable test equipment consists of a conductivity dip cell (usually having a cell constant of 0.1), a sample degasifier or chemical means of determining the amount of NH₃ and CO₂ in the sample, and a thermometer for checking condensate temperature. An approximate correction for dissolved gases may be obtained by determining the difference between the conductivity of the condensate before and after boiling (and recoling).

**Example.**

\[
\begin{align*}
\text{Conductivity of condensate sample} & = 4.5 \text{ micromhos} \\
\text{Conductivity after boiling and recoling} & = 1.2 \text{ micromhos} \\
\text{Conductivity correction for gases} & = 3.3 \text{ micromhos} \\
\text{Ppm impurity in steam} & = 1.2 \times 0.6 = 0.7 \text{ ppm}
\end{align*}
\]

**STEAM PURIFICATION** is obtained in boiler drums by means of baffles and devices known collectively as *drum internals*. The process of purification is a stage process that involves (1) primary separation, (2) steam washing, and (3) steam drying.

**Primary separation** of the bulk of the circulating water from the steam is the first step. This stage of purification, always necessary in water tube boilers and when generated steam and circulating water are delivered to a drum as a mixture, involves separation of a relatively large amount of water from the steam; such principles as gravity separation, change in direction, and centrifugal action are utilized. Separation of bulk water is not difficult, and failure of primary separation is usually due to failure to separate that portion of the water that is present in the form of excessive spray and/or foam films. Over 98% of the circulating water should be separated in this primary separation step to avoid possible overloading of the subsequent steps of washing and drying. Primary separation in fire tube boilers occurs below the water level in the drum, and separation equipment is not involved.

**Steam washing** is an optional step in purification, in which the separated steam is washed or rinsed in low concentration feedwater to reduce the concentration of impurities in the final moisture in the steam. Washing is not usually applied to single-drum boilers unless the drum is large enough to accommodate this extra step. Washing is a process of mixing the feedwater with the steam, and the steam is usually passed through the water dispersed as a spray. Current opinion is that steam washing with condensate feedwater reduces volatilized silica carryover in the steam.

**Steam drying** is the final stage of purification in which the residual moisture in separated or washed steam is removed. Drying, a process of removing small amounts of moisture from a relatively large volume of steam, is essentially a filtration process. Dryers have large surface areas on which moisture is deposited as it passes through at relatively low velocity. At low operating pressure, steam velocity through the dryer may be 8 to 10 ft per sec, but at high operating pressure this velocity should be 2 to 3 ft per sec or less. Dryers are designed to separate relatively small amounts of moisture and become overloaded when steam entering the dryer contains more than 5 to 10% moisture. Dry pipes and dynamic dryers, utilizing centrifugal action, reduce moisture in steam to tenths of 1%, but filter-type dryers, utilizing closely spaced screens or bent plates, are required to obtain steam having high purity. (See also Refs. 2 and 3.)

**PERFORMANCE OF DRUM INTERNALS.** Failure to obtain satisfactory steam quality and purity is usually due to one or more of these causes.

1. Excessive foaming of the boiler water, which is a chemical phenomenon and over which drum internals may have little control.
2. Improper installation of internals which may result in leakage of water or impure steam through assembly joints and contamination of the outlet steam.
3. Improper design of internals for the condition involved.
4. Exceeding the design capacity of internals which may be limited by such factors as pressure drop, drainage capacity, or flow velocity.
5. Plugging of internals with chemical sludges, poor distribution of water or steam flow, or chemical or mechanical damage to internals which may result in leakage.

5. SUPERHEATERS

By F. I. Epley

THE SUPERHEATING PROCESS. When water is heated to the boiling point in a closed vessel, the vapor released causes the pressure to rise. As the pressure increases, the boiling temperature also rises. Steam is usually generated in a boiler at constant pressure. During the change of state from a liquid to a vapor at constant pressure, the vapor in contact with the liquid remains at constant temperature until vaporization is complete. When all the water has been transformed into steam, further addition of heat will raise the temperature, causing the steam to be superheated.

Water enters the boiler at some specified pressure and temperature, and heat is added to bring it to the boiling point. Further heating causes evaporation of the water at the saturation temperature corresponding to boiler pressure. The saturated steam is then removed from the saturated liquid, and heat is again added at substantially constant pressure, the only pressure differences being those due to friction in various sections of the boiler.

The properties of steam accepted as a commercial standard are given in *Thermodynamic Properties of Steam*, by Keenan and Keyes, John Wiley and Sons, 1936. (See also Section 4.) A working knowledge of these tables is necessary for quick and accurate solution of thermodynamic problems of the steam boiler.

Saturated steam is delivered to the superheater in an almost-dry state. Steam containing water in any form, either as minute droplets, mist, or fog, or due to entrainment of water in boiling or to partial condensation is called wet steam. The enthalpy of the mixture is less than that of dry saturated steam at the same pressure, because vaporization is incomplete. If the steam contains 3% moisture, the quality is said to be 97%. For modern steam-generating units, the quality of the saturated steam delivered to the superheater is very high, in many boilers over 99.75%.

With saturated steam, the heat available for doing useful work depends entirely on the pressure, whereas with superheated steam additional heat is available as the degree of superheat increases. This additional available energy, obtained through increased expenditure of fuel, yields economic benefits and a net efficiency gain of considerable magnitude.

Because of the increase in thermal efficiency of the heat cycle and the reduced erosion of turbine buckets under the lower moisture conditions, steam superheaters are always used in modern steam power stations. In fact, the ability to obtain relatively high steam temperatures has made it economically possible to design and build high-pressure steam power generating units.

Practical limits of steam temperature and pressure are set by the materials available for superheater construction. Considerable development in the metallurgy of alloy steels has taken place during the last few years, as well as in manufacture of both tubing and finished sections of the superheater. These developments have made possible the design of satisfactory superheaters for high-temperature and high-pressure boiler installations. Improvements in welding and other methods of fabrication have also contributed greatly to the development of such installations.

THE INTEGRAL SUPERHEATER is a bundle of tubes located within the boiler setting, and receiving heat from the same gases that generate steam in the boiler. It may be either of the radiant or convection design, or a combination of both, depending on the manner in which heat is transferred from furnace gases to the steam.

Radiant superheaters absorb heat by direct radiation from the furnace gases, and may be located in one or more furnace walls. Since the furnace temperature and, therefore, the amount of heat available from radiation, does not rise as rapidly as the rate of steam flow, a radiant superheater has a falling characteristic, i.e., the steam temperature drops as the steam output rises. Tubes located in the furnace walls absorb heat at a high rate, and in order to minimize tube failures, high mass flows of steam through the tubes are necessary; this can be achieved only at the expense of pressure drop. The steam-temperature characteristic of a straight radiant superheater is shown as curve A in Fig. 5.

Convection superheaters absorb heat by impingement and flow of hot gases around the
tubes. A true convection superheater has a rising characteristic. Mass flow and temperature of the gas entering the superheater zone, as well as the steam flow from the boiler, increase with an increase in firing rate. These changes in temperature produce a greater mean temperature difference between the gas and steam. This, together with the higher gas mass flow, causes an increased rate of heat absorption, resulting in an increased steam temperature. A convection superheater which is not entirely shielded from the furnace combines to some extent the effects of both radiant and convection heat absorption, resulting in a more nearly constant degree of superheat over the range of outputs. The steam-temperature characteristic of a straight convection superheater is shown as curve $B$ in Fig. 5.

A combination of the rising steam-temperature characteristic of the convection superheater with the falling characteristic of the convection superheater has been used on a few installations to maintain nearly constant steam temperature over a greater range of ratings. The steam-temperature characteristics of such a combination of superheaters is shown as curve $C$ in Fig. 5.

**SUPERHEATERS FOR STRAIGHT-TUBE BOILERS.** For moderate steam temperatures, the superheater can be located above the boiler tube bank. The superheat which can be obtained in such a location is limited principally by the gas temperatures and the available space. Operating conditions and the design of the furnace and boiler also have a great effect.

In general 200°F superheat can be obtained with economical sizes of superheaters in coal-fired boilers without appreciable water-cooled surface in the furnace. With oil and natural gas fuels, the superheat will be about 150°F. A typical “overdeck” superheater installation is shown in Fig. 6.

When furnace walls are covered with generous amounts of water-cooled surface more heat is absorbed from the furnace gases, resulting in lower furnace-gas temperatures and lower gas temperatures throughout the boiler. The gas temperature entering the superheater is reduced to such a degree that considerably more surface is required for the same superheat. Approximately twice as much superheater surface is required in a boiler with full water-cooled surface, as in the same boiler with a refractory furnace.

When the superheat becomes too great, it is necessary to split the boiler tube bank to provide space to install an “interdeck” superheater. In this way the superheater surface can be considerably reduced, owing to the higher gas temperature at this point. The steam...
temperature obtained is greatly increased with such an arrangement, and is sufficient to
cover most needs of the present-day power plant.

**SUPERHEATER FOR SEMIVERTICAL BOILERS.** Superheaters can be installed
in bent-tube boilers in an intertube position, as in Fig. 7. With this arrangement a large

part of the heat is absorbed by direct radiation from the furnace, resulting in a relatively
flat steam temperature characteristic. This type can be installed in most semivertical
boilers, although construction details in some boilers make such a design imprac-
tical.

Most superheaters for semivertical boilers are installed in an interbank location, as shown in Fig. 8, or in an interpass location as shown in Fig. 9. The super-
heat obtained with either arrangement is ample for most requirements except where
the available space is limited.

**SUPERHEATER SURFACE REQUIRED.** The relation between heat ab-
sorbed by steam in the superheater and that given up by gases of combustion, radiation included, is

\[
A UT = W c (t_1 - t_g) \\
A UT = W_1 c_1 (T_1 - T_2)
\]

where \(A\) = area of superheater surface, square feet; \(U\) = conductance, Btu per
hour per square foot per degree mean tem-
perature difference; \(T\) = logarithmic
mean temperature difference between
steam and gases of combustion; \(W, W_1\)
= respectively, weight of gases of com-
bustion and weight of steam passing
through superheater per hour; \(c, c_1\) = re-
spectively, mean specific heat of gases of
combustion and of steam; \(t_1, t_2\) = respec-
tively, gas temperature entering and leaving superheater. °F; and \( T_1 \), \( T_2 \) = respectively, temperature of superheated steam and saturated steam.

Surface required is \( A = H/UT \), where \( H \) = heat to be absorbed by superheater, Btu per hour = \( (h_1 - h_2) \); \( h_1 \), \( h_2 \) = respectively, total heat of superheated and saturated steam, Btu (see Section 4).

\[
T = \frac{\text{(Maximum temperature difference)}}{\log_e \left( \frac{\text{Maximum temperature difference}}{\text{Minimum temperature difference}} \right)}
\]

Conductance \( U \) varies with temperature of gases, gas velocity, steam velocity, tube size and spacing, surface cleanliness, and other variables of minor importance. Approximate values for 2-in. tube elements are

<table>
<thead>
<tr>
<th>Mass flow</th>
<th>2000</th>
<th>3000</th>
<th>4000</th>
</tr>
</thead>
<tbody>
<tr>
<td>( U ), interdeck superheater</td>
<td>7–7.5</td>
<td>8.5–9.5</td>
<td>10–11.5</td>
</tr>
<tr>
<td>( U ), overdeck superheater</td>
<td>6–6.5</td>
<td>7.5–8.5</td>
<td>9–10</td>
</tr>
</tbody>
</table>

Mass flow is defined as pounds of gas or steam per hour per square foot of minimum free flow area.

Temperature drop through the steam film in superheater tubes for various rates of heat absorption and steam mass flows is given in Fig. 10. Temperature drop \( t_d = H/UF \);

**Table 1. Superheater Surface Required for Various Superheats**

<table>
<thead>
<tr>
<th>Interdeck. Entering Gas, 1950 F</th>
<th>Sq ft</th>
<th>Overdeck. Entering Gas, 1300 F</th>
<th>Sq ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Superheat. °F</td>
<td>Parallel Flow</td>
<td>Counterflow</td>
<td>Superheat. °F</td>
</tr>
<tr>
<td>100</td>
<td>1400</td>
<td>1396</td>
<td>100</td>
</tr>
<tr>
<td>200</td>
<td>3032</td>
<td>2962</td>
<td>200</td>
</tr>
<tr>
<td>300</td>
<td>5275</td>
<td>4940</td>
<td></td>
</tr>
<tr>
<td>400</td>
<td>8835</td>
<td>7550</td>
<td></td>
</tr>
</tbody>
</table>

\( UF = 0.95G/1000 \), where \( UF \) = steam film conductance, Btu per hour per square foot of inside tube surface; \( G \) = mass steam flow; other notation as above. The curves are based on a specific heat of steam of 0.55 and a friction factor of 0.004. For any other specific heat or friction factor, temperature drop will vary inversely as the square root.

Table 1 illustrates typical data on superheater design.

**CONTROL OF STEAM TEMPERATURE.**

For steam temperatures of 900 F and higher, it is necessary to use some means of control to hold the steam temperature within safe limits. Occasionally specifications require the designer to incorporate steam-temperature control for installations involving steam temperatures as low as 750 F.

Various means are employed to control steam temperatures. Some of these are described below.

**Control by Firing.** It is practical to control firing of fuel in the furnace so that the heat absorption in the furnace walls can be controlled over a broad range, thereby creating a change in the gas temperature entering the superheater. The normal furnace temperature characteristic falls off more at partial loads than the gas temperature required to maintain constant steam temperature, but with certain types of burners and fuels it is possible to raise the furnace temperatures at partial loads to compensate for this. In this way constant steam temperatures can be maintained over a wide range of output.

![Fig. 10. Effect of steam mass flow and heat absorption on temperature drop through steam film in superheater tubes.](image-url)
**Damper Control.** By-pass dampers for controlling steam temperatures have been widely used in this country. The general design is practically the same in nearly all cases, differing only in details. The principle involved is by-pass of a larger or smaller portion of the gases, only a part of the gases going over the superheater surface. In general the design has given satisfactory operation provided the damper mechanism is constructed to withstand the gas temperatures.

**Desuperheating Control.** Desuperheaters, both of the spray and nonecontact type, have been used for steam-temperature control. The superheater is designed with excess surface so that at partial loads there is sufficient surface to give the required steam temperature. The desuperheater then is used to remove the heat represented by the excess steam temperature.

Desuperheaters can be located either at the superheater outlet or between sections of the superheater. In the former arrangement it is necessary to design the superheater materials to withstand steam temperatures in excess of the final superheated steam temperature. The excess depends on operating conditions but frequently exceeds 100 F for a high-temperature installation.

The desuperheater can be placed between the primary and secondary sections of the superheater. In this way it is possible to design the high-temperature section of the superheater for actual operating conditions existing at the outlet of the superheater, making allowances for only nominal excesses. The low-temperature section would then be uncontrolled, and the materials would be adequate to withstand the highest expected steam temperature.

For nonecontact desuperheaters, the degree of control is less for those located interstage because of the lower temperature difference. However, the use of an interstage desuperheater gives a safer boiler unit than one in which the desuperheater is located beyond the superheater outlet.

When condensate or excellent feedwater is available, spray-type desuperheaters offer a satisfactory and economical means of control of steam temperature. Here too the interstage location of the desuperheater is preferable to a location beyond the superheater outlet. The degree of control is at least equal to any other means used in modern power boilers. With the spray desuperheater impurities may be injected into the superheated steam, and carried over into the turbine. With condensate such carryover usually is negligible. For the usual high-pressure high-temperature installation, each 10 F reduction in steam temperature requires about 0.8% of condensate or total feedwater flow to the boiler or economizer.

**Control by Superheater Design.** By combining radiant and convection surfaces in proper proportions, it is possible to maintain a substantially constant steam temperature over a range of loads. To make full and effective use of this device, it may be necessary to adjust burners or fuel-burning conditions in the most favorable manner.

**EFFECT OF FEEDWATER TEMPERATURE.** For the same fuel-burning rate, superheat increases with decrease in temperature of feedwater. Gas weights and temperatures entering superheater will not change, but steam weight through superheater will be less, since more heat is required to evaporate each pound of water. For the same capacity, the superheat will vary approximately in direct proportion to the heat absorbed per pound of steam in boiler and superheater (and economizer, if any), for a change of not more than 150 F in feed temperature. Excessive superheat may result if it is necessary to supply the boiler with cold feedwater.

**SEPARATELY FIRED SUPERHEATERS.** Where steam is used for process, close temperature control may be imperative. A separately set and separately fired superheater is sometimes employed. Such a unit may be directly fired with coal, oil, gas, or other fuels, and designed for any practical capacity or range of operating conditions. Automatic combustion or fuel control may be applied. Where the installation of integral superheaters is impractical, separately fired superheaters have been used in conjunction with existing power boilers. Separately fired superheaters are also designed for use in testing, to cover a wide range of operating conditions. In special cases, such superheaters have been designed for 1400 F low-pressure operation, but the majority of such installations are designed for 700 F and less.

**THICKNESS OF SUPERHEATER TUBES.** The ASME Code for power boilers prescribes methods of determining the allowable working pressure for superheater tubes. Stresses for the more common materials used in superheaters are given in Fig. 11. Since the maximum allowable stress is dependent on the metal temperature of the superheater tubes, it is necessary to have a means of predicting it. The principal factors entering into calculation of tube-wall temperatures are (1) quantity of heat being transmitted through the tubing, (2) steam velocity on inside tubes, and (3) degree of uniformity of steam temperature delivered from the multiple steam paths of the superheater. For the normal convection designs the difference between average steam temperature leaving the super-
heater and maximum tube temperature is less than 125 °F, for high-temperature, high-pressure installations. For lower temperature installations, this difference may be as low as 75 °F. An average value of 100 °F may be used for the usual convection design of superheater. The effect of mass flow and heat absorption on the temperature drop through the steam film is illustrated in Fig. 10.

Convection superheaters located in moderate gas temperature zones receive a relatively small amount of heat directly from the furnace, hence heat absorption per square foot is low or moderate. On the other hand, radiant superheater surface located in the furnace where temperatures are high has a rate of heat absorption comparable to that obtained in furnace water-cooled surface, hence may have tubing temperatures considerably higher than in convection superheaters. Reduction in tubing temperature results from using high steam velocities to afford the maximum possible cooling effect of the steam, but even with high steam velocities it is not uncommon to have tubing temperatures which exceed steam temperatures by 300 °F or more. For this reason, low steam velocities and low pressure drops are advisable for radiant superheaters.

USE OF ALLOY STEEL IN SUPERHEATERS. Superheaters designed for 800 °F and higher may require use of several grades of alloy steel at various locations in the superheater because of temperature variation. Design pressure has a greater effect on the thickness of tubing required and a lesser effect on the grade of material required. General practice indicates that these materials are satisfactory for the stated metal temperature limits.

<table>
<thead>
<tr>
<th>Material Description</th>
<th>ASME Specification No.</th>
<th>Temperature Limit, °F</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low carbon</td>
<td>SA-17, SA-192</td>
<td>850</td>
</tr>
<tr>
<td>Carbon molybdenum</td>
<td>SA-209</td>
<td>950</td>
</tr>
<tr>
<td>1 to 1/4% Cr, 1/4% Mo</td>
<td>SA-213 T-11</td>
<td>1050</td>
</tr>
<tr>
<td>5% Cr, 1/4% Mo</td>
<td>SA-213 T-16</td>
<td>1100</td>
</tr>
<tr>
<td>18% Cr, 8% Ni</td>
<td>SA-213 TP-321</td>
<td>1300</td>
</tr>
</tbody>
</table>

These data are to be used only as guides to practice. Because of economic and other considerations, the designer may find it satisfactory to deviate from these values.

PRESSURE DROP IN SUPERHEATERS. Ample steam-pressure drop in superheaters is desirable from the standpoint of the superheater designer. The greater the pressure drop and the higher the steam velocity, the more adequate is the protection to the superheater tubes; excessive pressure drop in the superheater, however, results in higher boiler design pressure. Experience indicates that a steam pressure drop through the superheater of 3 to 5% of the boiler design pressure is satisfactory. On large, high-capacity units it may be advantageous to use a higher pressure drop to simplify design.

Pressure drop in superheater tubes can be expressed by

\[ p = \frac{400/V}{D} \times \left( \frac{G}{100,000} \right)^2 \]

where \( p \) = pressure drop, pounds per square inch; \( f \) = friction factor; \( V \) = specific volume of steam, cubic feet per pound; \( D \) = inside diameter of tube, inches; \( G \) = steam mass flow, pounds per hour per square foot of free flow area. Bends will increase \( p \) from 50 to 100%, depending on their number per 100 ft of tube and their radius. Additional pressure drop for each 90-degree bend, expressed in equivalent feet of straight pipe is, approximately,

Radius of bend, tube diameters  1   2   3
Equivalent straight pipe, ft    6.2  4.3  3.3

Pressure drops of 20 to 25 psi per 100 ft of tube are not excessive.
SETTING OF SUPERHEATER SAFETY VALVES. In all superheaters, a certain steam velocity through the tubes is necessary for protection against burning. Superheater safety valves, therefore, should be set to operate at a pressure below that of the boiler (saturated) safety valves, to insure that superheater valves blow first. If safety valves on boiler and superheater are set for the same pressure, boiler safety valves will blow first, and the superheater will have little or no flow of steam, with consequent danger of tube burning.

6. REHEATERS

Within the last few years, attention has again been given to the reheat cycle in steam electric power stations (Refs. 4 and 5). The increase in efficiency of such a cycle has resulted in considerable saving in fuel, even when offset by additional fixed charges. The rise in the fuel price has made use of the reheat cycle attractive, in some applications.

A re heater or resuper heater is simply a second steam super heater located within the boiler setting or separately set and separately fired. The integral design of reheater has been more popular and perhaps more practical. The reheater surface may be either of the convection or radiant design, and important installations have been using both arrangements.

The reheater frequently is used in connection with compound or topping turbines, where it receives steam from the high-pressure section of the turbine at a lower pressure and temperature than the steam entering the high-pressure turbine. In the reheater, this steam is heated again to some specified temperature, usually near the original temperature. However, it does experience a friction pressure loss in the reheater tubes and piping, partially offsetting the intrinsic gain of the thermodynamic cycle. After the reheater, the steam passes to the low or intermediate pressure section of the turbine. (See also Sections 4 and 8.)

REFERENCES


ECONOMIZERS, AIR PREHEATERS, AND WASTE-HEAT UTILIZATION

By W. S. Patterson and H. Karlsson

7. ECONOMIZERS

By W. S. Patterson

Economizers, first used about 1860, antedate air preheaters. At that time fuel was very inefficiently burned, and even though low pressures and low capacities prevailed, a tremendous amount of waste heat was carried away in the flue gases. It was possible to recover economically much of this waste with a relatively inefficient economizer employing large, thick-wall tubes, widely spaced, so as to cause little added draft loss. Later, when use of mechanical stokers made it possible to operate boilers at higher capacities, the flue-gas temperature was high because of the increased capacity, even though combustion of the fuel was more efficiently accomplished. Thus there was a need for economizers even with low-pressure boilers. When both high pressures and high ratings became prevalent, the use of heat-recovery equipment was even more necessary to prevent excessive loss of heat in the flue gas.

In the early days it was not uncommon practice to install one economizer to serve several boilers. Modern practice is to provide an economizer to serve each steam-generating unit.

In their earliest applications, economizers were called upon to heat relatively cold water which was not deaerated and thus carried considerable oxygen. To reduce oxygen corrosion, the economizers were constructed of cast-iron tubes arranged vertically with
the water entering all tubes at the bottom and leaving at the top. The gases were passed through at right angles to the tubes. With this arrangement, it was not possible to take advantage of the countercurrent principle, and the extent of heat recovery was limited. Tubes 4 in. in diameter were frequently used. The generally accepted maximum pressure for cast-iron economizers was 250 psi, and it was necessary to adopt other tube materials when higher pressures were encountered.

STEEL-TUBE ECONOMIZERS. Steel is the most suitable material for high-pressure economizers, except for corrosion resistance. The principal reasons are thinner tubes; smaller diameter; closer spacing; more heating surface in a given space; better heat transmission for a given weight or surface; lower cost; and less radiation loss.

A steel-tube economizer must be supplied with water that has been properly deaerated and heated to above 200°F. The water should first be raised to the boiling point in a well-ventilated open-type deaerating heater. With careful operation this method of treatment reduces the oxygen content to 0.05 ppm or less. In moderate pressure plants, about 400 psi, it is usually economical to heat the feedwater to a temperature between 180 and 220°F by means of bled steam, even when flue-gas economizers are used. With high pressures, such as 1400 psi, bleed heating of the feedwater is carried as high as 400°F. (See Section 8.)

ARRANGEMENTS OF ECONOMIZERS. Steel-tube economizers are arranged in vertical or horizontal banks. The vertical type is known as an integral economizer when it is arranged similar to a bank of boiler tubes and located within the boiler setting.

Integral economizers frequently are provided with two drums. The upper one is divided into two compartments, with feedwater introduced on one side of the partition and discharged from the other side. The water thus makes two passes through the economizer in flowing from one compartment through part of the tube bank to the lower drum and then back through the remainder of the tube bank to the other compartment of the upper drum. If the economizer is vertically baffled for two gas passes, these may be arranged to give countercurrent flow. An efficient arrangement of this type is shown in Fig. 1A. The design shown in Fig. 1B eliminates one of the economizer drums. In this one the feedwater is introduced into the lower drum, makes only one pass through the tube bank, and then is discharged directly to the boiler drum. Cross-flow baffles have been employed in some integral economizers as illustrated in Fig. 1C. Integral economizers have a low water velocity, and hence a low water-side pressure drop. This characteristic is not conducive to good distribution and positive circulation, and accelerates corrosion.

Horizontal-tube Type. Today the most widely used type of economizer employs horizontal steel tubes generally arranged in staggered, closely spaced rows with the gases flowing transverse to the axis of the tubes. The water flows progressively through the tubes, upward or downward from row to row. Upward flow of water is preferred by some engineers, particularly if there is any possibility of steam being generated in the economizer. However, many down-flow applications are in successful use.

Cleaning. At one time it was considered necessary to make all economizer tubes accessible for cleaning. Small junction boxes were used, each serving as a return bend between a pair of straight tubes. The tubes were fastened into the boxes by rolling. A hand-hole fitting was provided for rolling, inspection, and tube cleaning. The pressure drop in these junction boxes was great, and their use has been discarded in favor of flanged return bends, each end of which is bolted to a similar flange attached to a straight tube.
Each straight tube, therefore, is accessible at one end. This type requires doors at one or both ends of the economizer. Illustrated in Fig. 2, this construction is recommended where poor feedwater makes frequent routine inspection or cleaning necessary. The tubes are accessible at one end only. Such construction permits the necessary tube cleaning, and has the advantage of reducing the number of bolted joints.

Fig. 2. Economizer with flanged return bends.

When feedwater is of intermediate quality requiring infrequent inspection and cleaning, the connection between pairs of tubes forming a water-flow circuit is made at one end by the use of a plugged bifurcate, actually an accessible return bend. By removing the plug, a quick access is possible, and the tube cleaner may be inserted in either tube. The opposite end is provided with bends of the same type as that shown in Fig. 2.

The recent adoption of inhibited hydrochloric acid for cleaning internal tube surfaces may lead to the omission of provisions for mechanical tube cleaning where it would otherwise be necessary.

The continuous-tube type, illustrated in Fig. 3, affords no access to the tube interiors, and is recommended only for installations where good feedwater conditions make

Fig. 3. Continuous-loop type economizer.
internal cleaning unnecessary. The inlet header is shown at the bottom, outside of the setting. The outlet header and the tubes for delivering the feedwater to the boiler are shown at the top, inside of the setting. Also illustrated are vertical support rods, located at both sides of the economizer, and used when an economizer is located inside the boiler setting.

The foregoing steel tube economizers employ 2-in. OD tubes spaced on $3\frac{1}{2}$-in. horizontal centers and use 5 $\frac{1}{2}$-in. staggered vertical spacing. Longitudinal continuous fins, 2 in. wide and $\frac{1}{4}$ in. thick, are welded to top and bottom of tubes to increase the amount of effective heating surface provided in a given space. The fins not only increase the heating surface but also strengthen the tubes against bending and lessen the accumulation of ash on top of the tubes.

External Arrangement. Economizers are sometimes located outside the boiler setting as a separately supported and encased unit. Figure 4 illustrates an arrangement supported on outside steel but not entirely separate from the boiler in that one side of the economizer enclosure forms part of the rear boiler wall.

Illustrated in Fig. 5 is an effective arrangement in which the economizer is located within the boiler setting and directly below one of the drums. In this position, it may be supported from the boiler drum by means of alloy beams and hanger rods. Air-cooled and water-cooled hangers have also been used. Water-cooled headers are sometimes used for support beams. Feedwater at the same temperature and pressure as at the economizer inlet may be passed through the headers to cool these support members. The water flow rate is proportioned by the use of orifices in the various parallel circuits. An alternate arrangement is to make the support headers a part of the boiler circulation system.

Soot Blowers. For maximum effectiveness, economizer surface must be kept clean externally as well as internally. Therefore, provision frequently is made for the installation of revolving soot blowers in horizontal rows. Blowers located between supports and end panels are sometimes of the stationary type. Others are of the revolving type, designed for a 360-degree blowing arc. Eight to ten rows of
tubes is the maximum number that can be used, with effective cleaning. Economizers, therefore, are divided into banks of tubes with small blowers located in the space between banks.

ECONOMIZER SELECTION. Draft Loss. The amount of heating surface installed in an economizer depends on gas inlet and outlet temperatures, inlet water temperature, whether or not countercircuit of fluids is employed, and allowable draft loss. Other things being equal, a low draft-loss economizer requires more surface, but in designing a high draft-loss economizer, the gas velocity must be kept below a limit of 6000 to 8000 lb per hr per sq ft of flow area if tube erosion is to be avoided with high-ash coal, depending on the abrasive qualities of the ash. High draft-loss economizers frequently also have a high pressure drop on the water side, generally limited to about 40 psi.

Economizer versus Air-heater Surface. Economizer surface being more expensive than air-heater surface, it is generally more economical to use an air heater of maximum size and an economizer of minimum size when both are required to obtain the desired heat recovery from the flue gases. The exception to this rule is when the unit is stoker-fired, in which case the air-heater size is limited by the air temperature permitted at the stoker grate, and a larger economizer must be used. Stoker-fired installations of moderate efficiency may work out more economically if the air heater is omitted entirely because the gas and air ducts associated with a small air heater have to be charged against the heater and may represent a large percentage of the cost of the air-heater installation.

The proportion of the heat required to generate steam increases for the economizer and decreases for the boiler as critical pressure is approached. In fact many higher pressure units generate 100% of the steam produced in the water walls surrounding the furnace and employ practically no boiler surface beyond the furnace. This practice has not, however, resulted in the use of enormous economizers because high-pressure systems employ several stages of feedwater heating by steam bled from the turbine so that water temperature entering the economizer may be 400 to 500 °F. It is customary to heat the water in the economizer only to within 35 to 40 °F of saturation temperature unless the economizer is designed for steaming under certain conditions of operation.

EXTERNAL CORROSION. The overall heat transfer rate obtained with economizers is of the order of 3000 to 4500 Btu per hr per sq ft. The temperature gradient through the tube wall is therefore very small, and since the conductance at the inside film is very high, the outside surface temperature of the tubes is just a few degrees higher than the water temperature. The gas in contact with the tubes is therefore cooled practically to water temperature. The dew point of flue gas is difficult to determine if sulfur is present in the fuel. With no sulfur present, it would normally be about 120 °F, but with a small amount of SO2 and water vapor both present, the dew point may be increased to more than 300 °F. Consequently some external corrosion may be expected when the entering temperature of the water is lower than the dew point of the gas.

8. AIR PREHEATERS

By Hilmer Karlsson

Air preheaters in the power plant add heat to the combustion air by extraction of heat from the flue gases leaving the boiler. Their use permits high heat recovery, elimination of economizers, and use of turbine stage heating of feedwater. Preheated air increases furnace capacities, tends to stabilize the flame, and improves combustion. Air preheaters have been more widely used in the last decade because of the advancement in pulverized fuel firing and the successful application of water-cooled furnace construction.

Air preheaters on the boiler permit operation at low gas-exit temperatures. Owing to the relatively low cost of air-preheater surface, the present trend is toward higher recoveries in the air heater, thus reducing the amount of pressurized surface required in the boiler.

Air preheaters are of two basic types, recuperative and regenerative. The recuperative type is the conventional heat exchanger, with steady, continuous flow of both air and flue gases, each always on the same side of the heat exchange surface. In the regenerative type the two fluids also are separated by the heat-transfer surface, one fluid flowing on one side and the other on the opposite side. However, in the regenerative type (which can be divided into intermittent and continuous types) the heating surface is alternately exposed to one fluid and then the other. The checker work used in the steel industry with open-hearth furnaces is an example of the intermittent regenerative type. The best-known of the continuous regenerative types is the Ljungstrom.

TYPES OF AIR HEATERS. Plate-type Heaters. A typical unit of the plate type, illustrated in Fig. 6, is composed of welded envelopes, each envelope being complete with
air inlet and outlet, air-side spacers, and gas-side spacers. The air passes through the envelopes. When stacked side by side in the casing, the gas passages are formed by the spaces between the adjacent envelopes. The width between envelopes or the gas passages varies from $\frac{1}{2}$ to $1\frac{1}{4}$ in., closer spacing being used for clean gases and wider for gases containing solids in various degrees and of different types. Air spacing is usually smaller than gas spacing, but ordinarily neither is less than $\frac{1}{2}$ in. This type of unit is generally of the same width as the economizer or boiler preceding it.

**Tubular Air Preheater.** A tubular air preheater (Fig. 7) consists of a tube bank with the tubes fastened into a stationary tube sheet at the top of the unit and a floating tube sheet at the bottom to provide for difference in expansion due to temperature differences between tubes and casing. The unit is further provided with baffles to direct the fluid over the outside of the tube surface. In the illustration shown, the flue gases are passed through the tubes while the air is passed outside. This is the arrangement most commonly used although there are several applications where the gases are taken outside the tubes and the air inside. The tubes can be either vertical as illustrated or horizontal. Furthermore, the unit may be built in one section as shown or in two sections. The latter type of construction is now advocated where low exit-gas temperatures prevail with fuels high in ash, sulfur, and moisture. In some instances, the tubular air heater is also separated in two units with a relatively small unit located ahead of the economizer, where an economizer is used, for preheating the primary air on pulverized coal-fired units. The large section is located after the economizer for preheating of the secondary air. The unit illustrated shows a cold-air by-pass for the purpose of controlling the temperature of the tubes at the cold end of the unit. In other makes, a certain amount of metal-temperature control is accomplished by reduction of air mass flow in relationship to gas mass flow at the cold end of the unit, thus maintaining metal temperature of the tubes at this point closer to the gas temperature. Tubes are usually $1\frac{1}{2}$ to $2\frac{1}{2}$ in. OD. The 2 in. and $2\frac{1}{2}$ in. OD tubes are the most popular sizes.

**Regenerative-type Air Preheaters (Ljungstrom).** This type of air preheater, illustrated in Fig. 8, has a slowly moving rotor containing the heating surface. Each revolution produces a complete cycle of exchange in which heat from the hot gases is absorbed by the heating surface in the rotor and given up as rotation moves it into the path of the combustion air.

As shown in Fig. 8, the heating surface, made up of specially formed sheets, provides a multiplicity of small channels for gas and air flow, respectively, usually made in two
layers. With the shallow layer at the cold end, replacement cost is low for the part of the surface that is sometimes subjected to corrosive attack. The casing is divided into three sections; the middle section encloses the rotor, and the two end sections contain partitions for separation of gas and air flow, respectively, as well as connections for gas and air entering and leaving the unit. This type of air preheater is built for vertical flow as illustrated and also for horizontal flow of gas and air, respectively.

**Fig. 7. Tubular air preheater.** (Courtesy of Babcock and Wilcox Company)

**Fig. 8. Regenerative-type air preheater.** (Courtesy of Air Preheater Corp.)

**SELECTION OF AIR PREHEATER.** Many factors must be considered in the selection of an air preheater. The major economic factors are fuel cost, fan power, maintenance expense, and cost of installation. The engineering factors are space available, type of fuel, and desired temperature of the exit gas and preheated air, respectively. Generally it will be found that for low capacities and low recoveries the recuperative type of unit is most economical whereas for large capacities and high recoveries, the regenerative type usually shows economic advantages. A detailed study is required to determine the type of unit to use.

The recuperative type of air preheater is stationary and considered airtight; the regenerative type of unit employs moving parts and has a certain amount of air leakage. Experience, however, has proved that the maintenance cost of the moving parts is within acceptable limits and that the loss due to air leakage is compensated for by the feasibility of operating this type of unit at lower exit-gas temperatures.

**PRACTICE. Fuel Saving.** Preheated air gives a substantial fuel saving. For each 100°F drop in temperature of the stack gases, the efficiency of the steam-generating unit is increased 2.25 to 2.6%, as contrasted with 2% increase in efficiency for each 100°F rise in temperature of the air used for combustion. This gain in fuel saving is shown graphically in Fig. 9.

**Fig. 9. Fuel saving with preheated air.** (Courtesy of Babcock and Wilcox Co.)
Air Temperatures. These temperatures of combustion air indicate present-day practice: pulverized coal firing, pulverized lignite firing, and oil and gas firing, 700 F; underfeed chain grate and spreader stoker coal firing, 350 F.

Although higher air temperatures are occasionally used for combustion air, especially in industrial applications where temperatures up to 1000 and 1200 F are not uncommon, these values have been found economical for most applications in power-plant practice. In burning coals of high moisture content and lignite fuels in pulverized form, it is necessary, for proper drying of the fuel, to use high primary-air temperatures; these requirements are illustrated in Fig. 10.

Gas-inlet Temperatures. Air preheaters used with steam-generating boilers are usually designed for maximum gas-inlet temperatures of 850 to 900 F, permitting open-hearth steel construction to be used throughout except for the cold end of the unit, where special corrosion-resistant materials may be employed. Air preheaters for industrial application are operated with gas-inlet temperatures up to 1600 F. It is necessary to construct such units from heat-resistant alloys. It is customary to vary the type of alloy used, in accordance with the requirements (temperature) existing in various parts of the unit, so as to obtain the most economical design.

Gas-outlet Temperatures. The permissible gas-outlet temperature depends on the characteristics of the fuel used as well as on the type of fuel-burning equipment. In order to avoid excessive maintenance cost of the cold-end portion of the heating surface in an air preheater, operating conditions should be such that corrosive attack by acid-forming constituents of the gases and by the entrained solids is held within reasonable limits. Up to the present time, it has been practice to limit the temperature of the gases leaving air preheaters to values arrived at by experience, which vary with the sulfur content of the fuel and the firing method. Minimum metal temperatures are illustrated by Figs. 11 and 12. The curves of Fig. 11 show the limitation in metal temperature usually applied to
bituminous coal of various sulfur contents when fired on stokers and in pulverized form; the curves of Fig. 12 show corresponding values for fuel oil.

Usually an air preheater is selected to operate with the gas-outlet temperatures given in Figs. 11 and 12 at normal load, to avoid undue maintenance from corrosion and deposits. This practice necessitates providing means at part-load operating conditions (where cold gas temperatures are encountered) for maintaining the gas outlet temperature at or above its permissible minimum value. One of the most common methods for both the recuperative and the regenerative types of air preheater is illustrated in Fig. 7. It by-passes part of the cold air around the air preheater during part-load operation so as to maintain the desired gas-exit temperature. This method of operation permits the metal temperature of the surface to approach more nearly the temperature of the gases leaving the unit. The second method increases the temperature of the air entering the air preheater above the ambient, either by passing the air from the forced draft fan over heating coils or by recirculating preheated air to the inlet of the forced draft fan. In the recuperative-type air preheater, this method is purely a means of increasing the metal temperature at the cold end of the unit. In the regenerative-type air preheaters, these methods, in addition, serve to reduce the relative humidity of the air entering the preheater, and thus to obtain a drying action on the air side of the unit and to elevate metal temperatures.

Heat-transfer Rates. Overall heat-transmission coefficients for air preheaters usually range from 2 1/2 to 5 1/2-Btu per hr per square foot per degree Fahrenheit mean temperature difference. The lower values apply to low mass velocities, and the higher values to preheaters where the allowable pressure drop permits operating at higher mass velocities.

Pressure Drop. Air preheaters are usually selected for an air-side pressure drop up to 6 in. water, gage, and a gas-side pressure drop up to 4 in. water, gage. Where the cost of fan power is high, it is economical to select the air preheater for lower resistances. An air heater is usually selected with higher pressure drop on the air side because the forced draft fan handles air at atmospheric temperatures whereas the induced draft fan used to overcome the pressure drop on the gas side handles gases of 250 to 400 F, thus requiring more power per pound of air handled, for the same pressure drop.

Corrosion and Deposits. Knowledge of the factors causing corrosion of air preheater materials is too limited to permit exact evaluation of their effects. It is known, however, that the humidity of the gas stream, sulfur content of the fuel, composition of the ash, and firing methods used, all have a definite bearing on the problem. Empirical curves, based on experience, have been formulated for the minimum preheater metal temperature permissible with various fuels and methods of firing, as shown by Figs. 11 and 12. These curves are useful for guidance only; it still is necessary to determine the safe or economical temperature at which to operate for any given condition on the basis of actual experience.

Sulfur in the fuel is first oxidized to sulfur dioxide and then partially oxidized to sulfur trioxide. Sulfur trioxide in the presence of water vapor produces sulfurous acid. Sulfuric acid of low concentration, in the presence of ferric sulfate, rapidly attacks steel. Ferric and aluminum sulfates, usually present in the deposits on the heating surface, have a high affinity for moisture; thus increased moisture content of the gas stream results in increased rate of corrosion, as does increased sulfur content of the fuel. Moisture in the gas stream may originate from the fuel, soot blower, economizer leaks, quenching-water in ash pits, or from steam lances used in the furnace.

A comprehensive study of corrosion has been published in Bulletin 228, of the University of Illinois Engineering Experiment Station.

Cleaning. Deposits forming on the surface at the cold end of the air preheater may be either of the bonded type or of a more powdery structure. They vary in nature with the type of fuel, firing conditions, etc.

Since air preheaters depend on clean heating surface for maximum efficiency, and since removal of deposits retards corrosion, surfaces of air preheaters working under conditions where deposits occur must be cleaned periodically. Deposits on the heating surface in recuperative-type units affect both heat transmission and pressure drop; in regenerative types, pressure drop only is affected.

In recuperative-type units, deposits are removed by air or steam, or by water washing, cleaning being performed either during operation or during outages, depending on the equipment used. With the Ljungstrom air preheater, steam, air, or water may be used for cleaning during operation, because this type of unit is equipped with manually or power-operated cleaning devices using any of these cleaning mediums. Where the deposits are of a powdery structure, blowing with steam or air is sufficient; where the deposits are bonded, water is necessary for cleaning.

In some cases, alkaliized water has been used successfully for washing down the heating
surface of air heaters, increasing its life, even under severe corrosive conditions. Coating the surface with lime water after removal of the deposit by washing has also been reported to be successful.

9. WASTE-HEAT UTILIZATION

By W. S. Patterson

GENERAL. All fuel-fired furnaces used in industrial processes, including steel-heating furnaces, cement kilns, lime kilns, and zinc and copper furnaces, can justify heat-recovery equipment if they are designed for continuous operation. In all these furnaces solid materials are introduced into the furnace and heated by burning of fuel. Therefore, several methods of recovery of waste heat are available: (1) preheating cold material with the flue gas; (2) preheating combustion air; (3) steam generation in waste-heat boilers; (4) steam superheating; and (5) water heating.

In oil stills, sulfur-burning furnaces, incinerators, diesel engines, and gas turbines, gas leaves at such a high temperature that heat-recovery equipment can be justified economically for heating combustion air or feedwater or for generation of steam. The first gas turbine put into service by a public utility in this country exhausts to a recuperator for heating feedwater for the boilers. Other gas-turbine applications have made use of air preheaters to recover exhaust heat, and in some instances waste-heat boilers may prove economical.

Paper Pulp Industry. Here the black liquor from the digesters contains not only a large amount of combustible matter but also valuable chemicals. In the sulfate process the make-up chemical is sodium sulfate; in the soda process the make-up is sodium carbonate. These are known as alkaline processes. Within the last twenty years great improvements have been made in equipment for recovering waste heat and chemicals from the liquor. In the sulfite process the liquor is acid. In a few sulfite mills by-products are obtained from the waste liquids, but generally they are discharged into streams, causing pollution. However, within the next few years several commercial waste-heat and chemical-recovery systems may be placed in operation in sulfite mills.

Successful, completely integrated chemical-recovery units comprising water-cooled furnace, liquor sprays, boiler, superheater, evaporators, chemical feeding and mixing equipment, fans, air, and gas systems, dissolving tanks, liquor pumps, controls, and instruments have been applied in sulfate mills. Units of this design have also been used in soda mills; they may also soon be applied in sulfite mills, with the omission or modification of the direct-contact cascade evaporators. In these units recovery of chemicals is the primary object; resulting heat recovery and steam generation are secondary objectives. However, the boiler is no longer referred to as a “waste-heat” type because steam is generated and superheated in an efficient manner, and the quantity is as important to the mill operation as that obtained from coal or oil-fired boilers, particularly since the steam generated by the recovery unit represents a large saving in expensive fuel that would otherwise have to be burned in other boilers.

Sewage-treatment plants are sometimes designed to utilize the heating value of sewage to supply heat for processing the sewage and for generation of steam. The primary object is to do it in an economical manner, which may involve burning the dried product if its value as fertilizer is less than its value as fuel. With such an arrangement the dried sewage

<table>
<thead>
<tr>
<th>Type of Primary Furnace</th>
<th>Temperature, °F</th>
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</thead>
<tbody>
<tr>
<td>Nickel-refining furnace</td>
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</tr>
<tr>
<td>Refractory coke oven</td>
<td>1950–2300</td>
</tr>
<tr>
<td>Zinc-refining furnace</td>
<td>1400–2000</td>
</tr>
<tr>
<td>Heating furnace</td>
<td>1700–1900 *</td>
</tr>
<tr>
<td>Copper reverberatory furnace</td>
<td>1650–2000</td>
</tr>
<tr>
<td>Copper-refining furnace</td>
<td>1450 †</td>
</tr>
<tr>
<td>Cement kiln (dry process)</td>
<td>1150–1350</td>
</tr>
<tr>
<td>Cement kiln (wet process)</td>
<td>800–1100</td>
</tr>
<tr>
<td>Open-hearth steel furnace (producer-gas-fired)</td>
<td>1200–1300</td>
</tr>
<tr>
<td>Open-hearth steel furnace (oil, tar, or natural gas)</td>
<td>800–1100</td>
</tr>
<tr>
<td>Gas burners</td>
<td>1050–1150</td>
</tr>
<tr>
<td>Oil stoves</td>
<td>900–1000</td>
</tr>
<tr>
<td>Glass tanks</td>
<td>800–1000</td>
</tr>
</tbody>
</table>

* During operating periods. With furnace kept hot but heating no material, average temperature 1000–1100 F.
† Average over 36-hr cycle; range 500 to 2100 F.
is delivered to a storage bin and sacked as fertilizer or discharged to the furnace, burned in suspension, and the generated heat used in the drying process. Units having a water-cooled furnace and integral boiler for steam generation have been in successful operation for many years. Flash drying and incineration systems have been widely accepted and serve communities ranging in size from 6000 to 3,600,000 population. They are not limited to sewage sludge but have also been used in drying and burning the residue from the production of furfural (cotton-seed hulls, rice hulls, and corn cobs) and, at the same time, in producing all the steam necessary to support operation of the process.

**STEAM SUPERHEATERS AND WATER HEATERS.** Superheaters are sometimes used in conjunction with waste-heat boilers, even when the boiler is of the fire tube type, in which case the superheater is generally located in the gas inlet duct. Economizers are also sometimes used with waste-heat boilers. However, when the temperature of the waste gas is too low for steam generation, it may prove economical to recover the heat by means of water heaters which supply feedwater to other boilers, or hot water for space heating.

**AIR HEATERS (RECUPERATORS AND REGENERATORS).** Air heaters for industrial furnaces and kilns are referred to as recuperators or regenerators, depending on the principle of operation. Sometimes both the air and the gas fuel are preheated. The installation of a recuperator on a continuous steel heating furnace will return between 100 and 200% on the investment, even though the furnace is assumed to be in use during only one-third of the available time, and the calculation is predicated on a recuperator life of only three years.

Recuperators for high temperatures are of two types: metallic and refractory. Refractory types may be so large that excavation and water proofing of the recuperator pit may cost more than the recuperator itself. For many applications, the gas inlet end of metallic recuperators is made of high-temperature heat-resisting metal. There must be a positive flow of the cooler fluid at all times, and the entering gas must be below the maximum temperature for which the apparatus was designed. A refractory chamber, enclosing a metallic recuperator in contact with hot gas flowing through it, will be heated to the gas temperature, but the air flow will keep the metal surfaces at a lower temperature. If the flow of gas and air are stopped simultaneously, the metallic surface may be damaged by heat radiated to it by hot refractories.

In a metallic recuperator handling very hot gas, the metal separating the air and gas streams will generally have a temperature closer to that of the gas. Cast iron and mild steel are unsuitable if the temperature at any time exceeds 900 to 1000 F. For higher temperatures carbonized steel or nickel-chrome alloy steel must be used. Plate- and tubular-type recuperators of these materials are employed in the steel industry. Silicon carbide tubes have also been used. One comparatively new design of recuperator has cast sections of chrome-nickel alloy steel with extended surface on both the gas and the air sides.

Plate-type air heaters have been used as recuperators in conjunction with kilns for the manufacture of bricks, pottery, porcelain, plate glass, malleable castings, and cement. In most installations the gas temperature is 750 to 850 F, and the preheated air is used for combustion of the fuel. Special designs have been developed for entering gas temperatures exceeding 1000 F.

Regenerators used with steel-heating furnaces are of the refractory type. They handle gas up to 2300 F and preheat air up to about 1900 F. The hot-furnace gas is first passed over the refractory checkerwork in a recuperator unit, for a time, to heat it. Then the air is passed through to absorb stored heat. Two or more recuperator units are used to provide continuous cooling of gases and heating of air. Fluid flow is alternated on a schedule to maintain optimum operating economy.

The Ljungstrom regenerative preheater (see p. 7-35) is available in several standard designs for use with installations where gas-inlet temperatures are as high as 1800 F. Typical industrial-furnace applications are oil stills, sewage-disposal plants, metallurgical furnaces, car-thawing sheds, separately-fired superheaters, and numerous other processes.

**Preheaters in the Oil-refining Industry.** The advantages of preheaters designed for high temperatures with oil stills are covered by Mr. O. F. Campbell and T. B. Kimball in Regenerative-type Air-preheaters for Refinery Use, presented at the American Petroleum Institute meeting, 1941. The economy of eliminating the convection bank of a cracking-still furnace and substituting for it an air heater depends on the cost of the convection bank, the cost of air heater and fans, the cost of power to drive the fans, and fuel price. In a conventional cracking still, wherein flue-gas temperatures may exceed 1400 F when the gas leaves the radiant section, the installation of a convection bank, supplemented by an air heater, may prove more economical than the installation of a high-temperature air heater requiring costly alloys in its fabrication. Many cracking stills installed at the present time can justify, from a fuel-saving standpoint, the installation of an air heater.
PUMPING AND HEATING OF FEEDWATER

By A. J. Stepanoff, J. S. Daugherty, and G. D. Dodd

10. THE INJECTOR

Revised and rewritten by A. J. Stepanoff

Principle of Operation of the Injector. The simplest form of single-tube injector is shown in Fig. 1. Entering steam, in passing through the nozzle, acquires high velocity and is condensed by water in the combining tube, creating a vacuum into which water flows through the water-supply pipe. The high-velocity steam entering through the nozzle, comprising a mixture of condensed steam and water, flows into the delivery tube. There the energy of steam expanding from boiler pressure to a partial vacuum produced by condensation is sufficient to create pressure in the water as much as 50 to 80 psi in excess of the boiler pressure, for the range of pressures in which the injector is used. This excess pressure forces the water into the boiler.

Positive and Automatic Injectors. Positive-type injectors have hand-controlled overflow valves, which are closed after operation has started and water appears in the overflow. The advantages of this type of injector are its ability to lift water to a greater height, to start with a lower steam temperature, and to discharge against a higher back pressure. In automatic injectors, opening and closing of the overflow are entirely automatic. This type is preferred for stationary work because of its restarting features.

THE INJECTOR AS A BOILER FEEDER is efficient and convenient. It has no moving parts, is compact, delivers hot water to the boiler without preheating, and has no exhaust steam to be disposed of. When used to feed water to a boiler, its thermal efficiency is 100%, since all heat rejected passes into the water and is carried into the boiler. The loss of work in the injector due to friction reappears as heat which is carried into the boiler. Heat converted into useful work in the injector reappears in the boiler as heat. Although the injector has perfect efficiency as a boiler feeder, it is not the most economical means of feeding because of its inability to handle hot water, thereby excluding utilization of other sources of waste heat for boiler-feed heating. It also is difficult to maintain continuous flow with the injector at low capacity because of the necessity of starting and stopping under such conditions.

The injector has been widely used on locomotives but has been displaced in certain cases by direct-acting feed pumps, especially when feedwater heaters are used. It is limited in stationary work to small or single boilers or as a reserve feeder. The injector used as a pump has an efficiency of approximately 1 to 2%. The weight of feedwater handled per pound of steam usually decreases as steam pressure increases, and varies between approximately 21 lb at 20 psig pressure and 10 lb at 100 psig pressure. The maximum temperature of feedwater which can be handled averages 120 to 140°F at sea level, and lower at higher altitudes.

Table 1. Test of Sellers Injector

(From Practice and Theory of the Injector, by S. L. Kneass)

<table>
<thead>
<tr>
<th>Mean steam pressure, psig</th>
<th>30</th>
<th>60</th>
<th>121</th>
<th>150</th>
<th>200</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature of supply water, °F</td>
<td>67</td>
<td>67</td>
<td>54</td>
<td>54</td>
<td>50</td>
</tr>
<tr>
<td>Maximum capacity:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gallons water handled per hour</td>
<td>1912</td>
<td>2535</td>
<td>3517</td>
<td>3765</td>
<td>4005</td>
</tr>
<tr>
<td>Temperature of delivered water, °F</td>
<td>113</td>
<td>125</td>
<td>134</td>
<td>135</td>
<td>154</td>
</tr>
<tr>
<td>Weight of delivered water per pound of steam used, lb</td>
<td>25.9</td>
<td>19.1</td>
<td>13.6</td>
<td>12.6</td>
<td>10.3</td>
</tr>
<tr>
<td>Minimum capacity:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gallons water handled per hour</td>
<td>765</td>
<td>937</td>
<td>1290</td>
<td>1432</td>
<td>1732</td>
</tr>
<tr>
<td>Temperature of delivered water, °F</td>
<td>171</td>
<td>212</td>
<td>238</td>
<td>250</td>
<td>263</td>
</tr>
<tr>
<td>Ratio of minimum to maximum capacity</td>
<td>0.4</td>
<td>0.37</td>
<td>0.37</td>
<td>0.38</td>
<td>0.41</td>
</tr>
</tbody>
</table>
11. BOILER-FEED PUMPS

Except for very small capacities, centrifugal pumps are used for boiler-feed service almost universally. Their advantages—small size, high speed, and continuous steady flow—make them particularly suited for this service. To save space and weight in marine service, design speeds were gradually brought up to 7500 rpm. For stationary plants 3600 rpm is more common, but a trend to higher speeds is evident. Application of centrifugal pumps to boiler-feed service presented a number of problems not encountered in any other field of application involving high-pressure and high-temperature pumps.

REQUIREMENT OF A STABLE HEAD-CAPACITY CHARACTERISTIC

See Section 5.

THE NET POSITIVE SUCTION HEAD (NPSH) REQUIREMENTS are in excess of those given by the cavitation constant (see Section 5) to prevent vapor binding resulting from a sudden reduction of electric load or sudden increase in pump capacity. The Hydraulic Institute Standards Chart R-24 gives NPSH recommendations in terms of pump capacity and speed for water at 212°F (see Fig. 2). The additional suction head required for water of higher temperature is also given in the Hydraulic Institute Standards Chart R-26 (see Fig. 3).

MINIMUM FLOW. To protect boiler-feed pumps from overheating (vapor binding and scoring may follow) when the capacity is reduced below a safe limit, provision is made to by-pass 5 to 10% of the normal capacity back to the feedwater heater. Such by-passes may be operated manually or automatically, or left open continuously. The leak-off from the balancing devices can be used as a portion of the by-passed capacity. In every case the leak-off is piped to the heater storage space rather than to the pump suction.

SELECTION OF MATERIALS is governed by pressure, temperature, and water treatment. For discharge pressures below 1000 psi cast-iron casings are generally used. Rotors are bronze-fitted for temperatures up to 250°F, and stainless-fitted above 250°F. For pressures above 1000 psi, pump casings are made of steel, stainless-fitted. Figure 4 shows material selection based on the pH value of the boiler feedwater. When feedwater is pure condensate, the pH value does not
accurately describe the corrosiveness of water, and corrosion-resistant materials (stainless steel) should be used.

**Reciprocating Pumps** of the direct-acting duplex type are used for small capacities and moderate pressures. They use approximately 5% of the boiler steam, but if the exhaust is used to heat the feedwater the net heat consumption is less than 0.1%. For small capacities and high pressures, triplex power pumps are used. Special types with adjustable plunger stroke have been developed for boiler-feed service, permitting capacity regulation from zero to the rated capacity (see Section 5).

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**12. OPEN FEEDWATER HEATERS**

*Revised by J. S. Daugherty*

**Types of Heaters.** While any device used to heat feedwater, prior to admitting this water to the boiler, may be called a feedwater heater, the term generally is applied to equipment using steam for heating. This equipment comprises two general classes: (1) open, or direct-contact, heaters, in which the steam comes directly in contact with the water. Tray-type heaters and jet heaters form the two main subdivisions of this class. (2) Closed heaters, in which the heat from the steam is transmitted through tubular metallic walls to the feedwater. Either open or closed heaters can utilize the exhaust from engines or pumps, or be used as stage heaters supplied with steam extracted from bleeder turbines.

**Savings Accomplished by Feedwater Heaters.** Feedwater heaters, either open or closed, conserve the heat in pump or engine exhaust, high-pressure trap discharges, etc., which otherwise would be wasted. There is, roughly, a saving of 1% for every 10°F that the feedwater is heated by waste heat. The saving effected by a heater using waste heat may be determined from the formula \((h_2 - h_1)/(H - h_1)\), where \(h_1, h_2 = \text{Btu per pound of feedwater entering and leaving heater, respectively;}\); \(H = \text{Btu per pound of steam at boiler pressure.}\)

**Removal of Gases from Feedwater.** Of equal importance with the fuel saving effected by the open heater is its ability to liberate and remove dissolved gases from feedwater. Gases cannot stay in solution when the water is heated to the boiling point. The extent to which oxygen can be expelled by heating water in standard open heaters at atmospheric pressure is shown by Fig. 5.

**The Tray-Type Deaerating Feedwater Heater** (Fig. 6) has been developed from the older open heater. It is designed to accomplish practically complete removal of dissolved gases, of which oxygen is the most objectionable. This is effected by heating the water exactly to the saturated steam temperature, spreading it in thin sheets over successive layers of air-separating trays, agitating it thoroughly so that the gases may be brought to the surface and liberated, and sweeping the liberated gases away with the steam vented to the vent condenser.
ATOMIZING-TYPE DEAERATOR. In the atomizing-type deaerator the incoming water is first heated to practically saturated steam temperature by being sprayed in direct contact with steam. After this initial heating, the water contacts a high-velocity steam jet which finely divides or atomizes it and scrubs away the noncondensable gases. The high-velocity steam jet is established by causing the incoming steam to pass through an opening or orifice. This process divides the water so finely that it provides tremendous contact surface between the steam and water permitting the oxygen to be removed in a fraction of a second.

Water Flow. Figure 7 illustrates the flow of water and steam. The water first passes through the vent condenser and then enters the preheating chamber, where it is sprayed into an atmosphere of steam. This spraying is accomplished by spring-loaded valves which distribute the water, evenly divided into small particles, causing it to be heated within 2 to 3 degrees of the steam temperature, and separating over 95% of the oxygen initially present in the raw water. This preheated water is then directed to the atomizer, and falls on the high-velocity steam jet, which divides it into infinitesimal particles or a heavy mist. The division of the water is so thorough that it is atom-
CLOSED FEEDWATER HEATERS

ized, and from this process the deaerator obtains its name. Leaving the atomizer, the deaerated water falls to the storage section, and is available for use in boiler feed or process.

Steam Flow. The steam first enters the equipment through the atomizer at a high velocity. After thoroughly atomizing the preheated water, the steam flows to the preheating section, where practically all of it is condensed. A small amount (1 to 2%) passes to the vent condenser with entrained oxygen and carbon dioxide. There the steam is condensed, and the noncondensable gases are liberated to the atmosphere. The condensed steam contains some oxygen and some carbon dioxide that go back into solution in the vent condenser. This condensate is drained to the preheating section so that it can be thoroughly deaerated by by-passing over the atomizer.

CONSTRUCTION OF OPEN HEATERS. When used for low pressures, open heaters usually are constructed of cast iron. When supplied with superheated steam or used with steam extracted from bleeder turbines, the shells of tray-type or jet-type heaters are rolled plate, either riveted or welded.

PROPORTIONS OF OPEN-TYPE FEEDWATER HEATERS. The importance of the jet-type open feedwater heater is due to its ability to heat large quantities of water in a relatively small space. One large manufacturer offers a line of standard jet heaters with outlet capacities ranging from 100,000 lb per hr to 1,000,000 lb per hr in which the internal volume may be approximated from the formula,

\[ V = \frac{W}{10,000} \]

where \( V \) = internal volume, cubic feet; and \( W \) = outlet capacity, pounds per hour. The proportions of tray-type open heaters are governed primarily by the particular conditions of operation, and no general rule for proportions is available. An approximation of the size of the heater may be made by allowing at least 1 sq ft, in plan, of tray stock for each 15,000 lb per hr capacity. Vertical units vary in height from about 4 ft for small capacities to 10 ft for larger capacities. About half the height is used for water distribution and the tray stack.

Water storage capacity may be combined with open heaters. Where the feedwater is primarily all make-up and the load fluctuations are not severe, approximately 2 min boiler supply has been found sufficient. When the feedwater is condensate, with but a small amount of make-up, it often is the practice to incorporate condensate surge space in the heater storage compartment. The capacity for condensate surge varies from 5 to 30 min supply for the boiler.

The location of an open feedwater heater in relation to the boiler-feed pump is important. It must be at such an elevation above the pump inlet that the pump will receive only vapor-free liquid. The elevation will depend on temperature and pressure of water leaving the heater. See Figs. 2 and 3, and Section 5.

13. CLOSED FEEDWATER HEATERS

By G. D. Dodd

GENERAL. In closed or tubular-type feedwater heaters water flows through the tubes while the heating medium, generally steam, surrounds the tubes, the whole being enclosed by an outer shell. The water ordinarily passes through several tubes in parallel, and sometimes through groups of parallel tubes in alternate directions. This requires a header to introduce the water into the first group of tubes, called the first pass; the water flows back to the header through a group known as the second pass, and so on, for any desired number of passes.

Some designs use a header, known as the return header, at the end remote from the inlet header. Others dispense with the return header, bending the tubes into a U shape to return the flow. When a return header is enclosed in the outer shell surrounded by steam, providing for expansion independently of the shell, it is known as a floating header. Other designs have the return header fixed to the shell, providing for no expansion. Where both headers are fixed an unequal number of passes may be used, and water may enter the tube bundle and be withdrawn from opposite ends.

Common applications of closed heaters include the heating of water for domestic, industrial, or power-plant purposes. Only types used primarily with the regenerative feedwater heating cycle are discussed herein. Heaters in this classification may be installed on either or both sides of the boiler-feed pump. Those on the suction side of the pump are built for relatively low pressures in the tube and header assembly; those on the discharge of the pump are built for relatively high pressures.
Low-pressure heaters are built for tube-side pressures up to 400 psig; high-pressure heaters are built for pressures up to 3500 psig. In present-day practice shells are built for pressures of 50 psig to 900 psig.

**HEATER PROPORTIONS.** The required area or surface of tubes in a feedwater heater is determined by the equation

$$S = \frac{Q \times R \times C}{U \times LMTD}$$  \hspace{1cm} (1)

where $Q$ = pounds of feedwater per hour; $R$ = water temperature rise, °F; $C$ = average specific heat of the feedwater; $U$ = conductivity in Btu per square foot of heating surface per °F per hour; and $LMTD$ = logarithmic mean temperature difference.

Two phrases frequently are encountered in discussion of normal heater calculations. The **Initial terminal difference** is the difference between inlet water temperature and the saturation temperature of steam at the heater shell pressure. The **(Final) terminal difference** is the difference in temperature between the outlet water and the saturation temperature of steam at the heater shell pressure. This is sometimes called the **approach**.

Equations for logarithmic mean temperature differences are found in Section 3.

---

**Fig. 8. Heat transfer rates for feedwater heaters.** (Courtesy of Foster Wheeler Corp.)

**Heat Transfer Coefficient.** Figure 8 gives values of $U$ used for commercial work. Determine the water-flow area through any group of tubes, calculate the velocity (in terms of cold water), determine the average film temperature, and read the $U$ value from the proper curve. Table 2 gives correction factors for tube gage and conductivity.

**Table 2. Multipliers of Basic Heat-transfer Rates for Various Tube Materials and Gages**

For tube OD 5/8 to 1 in. inc.

(Courtesy of Foster Wheeler Corporation)

<table>
<thead>
<tr>
<th>Gage</th>
<th>Arsenical copper</th>
<th>Admiralty</th>
<th>80–20 Cu-Ni</th>
<th>70–30 Cu-Ni</th>
<th>Monel</th>
<th>18–8 Stainless Steel</th>
<th>Low-carbon Steel *</th>
</tr>
</thead>
<tbody>
<tr>
<td>18</td>
<td>1.00</td>
<td>1.00</td>
<td>.95</td>
<td>.92</td>
<td>.89</td>
<td>.85</td>
<td>.52</td>
</tr>
<tr>
<td>17</td>
<td>1.00</td>
<td>1.00</td>
<td>.91</td>
<td>.87</td>
<td>.85</td>
<td>.80</td>
<td>.51</td>
</tr>
<tr>
<td>16</td>
<td>1.00</td>
<td>1.00</td>
<td>.88</td>
<td>.84</td>
<td>.82</td>
<td>.77</td>
<td>.50</td>
</tr>
<tr>
<td>15</td>
<td>1.00</td>
<td>0.99</td>
<td>.86</td>
<td>.82</td>
<td>.79</td>
<td>.74</td>
<td>.49</td>
</tr>
<tr>
<td>14</td>
<td>1.00</td>
<td>0.96</td>
<td>.82</td>
<td>.77</td>
<td>.75</td>
<td>.70</td>
<td>.48</td>
</tr>
<tr>
<td>13</td>
<td>0.98</td>
<td>0.93</td>
<td>.78</td>
<td>.73</td>
<td>.70</td>
<td>.65</td>
<td>.47</td>
</tr>
<tr>
<td>12</td>
<td>0.95</td>
<td>0.90</td>
<td>.73</td>
<td>.68</td>
<td>.65</td>
<td>.60</td>
<td>.45</td>
</tr>
<tr>
<td>11</td>
<td>0.92</td>
<td>0.87</td>
<td>.70</td>
<td>.65</td>
<td>.62</td>
<td>.57</td>
<td>.44</td>
</tr>
<tr>
<td>10</td>
<td>0.89</td>
<td>0.83</td>
<td>.66</td>
<td>.60</td>
<td>.56</td>
<td>.52</td>
<td>.42</td>
</tr>
<tr>
<td>9</td>
<td>0.85</td>
<td>0.80</td>
<td>.62</td>
<td>.56</td>
<td>.54</td>
<td>.48</td>
<td>.41</td>
</tr>
</tbody>
</table>

* Factors for low-carbon steel include additional fouling resistance of 0.001.
Friction loss may be found from Fig. 9. The pressure drop per foot found from the chart is inserted in eq. 2, to find the total pressure drop.

$$\Delta p = \frac{(L' + 5.5d)pN}{d^{1.24}}$$  \hspace{2cm} (2)

where $L'$ = length of tubes, feet; $d$ = inside diameter of tubes, inches; $N$ = number of passes through tubes; $p$ = wall friction loss, pounds per square inch per foot of travel in 1 in. diameter tubes; and $\Delta p$ = pressure drop (total) in pounds per square inch.

Pressure drop for water flowing through smooth seamless drawn tubes, psi = \( \frac{(L' + 5.5d)pN}{d^{1.24}} \)

Average water temp. °F
and specific gravity
\[ \begin{array}{c|c|c}
50 F & 1.00 \\
100 F & 0.99 \\
\end{array} \]

Water velocity, ft/sec based on specific gravity average water temperature

HEATER CONSTRUCTION. Typical construction of low- and high-pressure heaters is shown in Figs. 10 to 13 inclusive.

Figure 10 illustrates shell constructions. The lower one, with removable cover, is adaptable for use with floating header heaters; the upper one, with integrally welded head, is used with U-bend types of heater. These shells are useful for both high and low pressure. Figure 11 is an exploded view of a low-pressure header assembly. Figure 12 illustrates the shear-block type Lockheed high-pressure closure in exploded view. A modified type is shown in Fig. 13.

Lockhead Design. Headers, also known as waterboxes or channels, are generally of forged carbon or low-alloy.
steel, machined as shown, with integral tube sheets. The Lockheed header provides a separate means for supporting head-pressure load and gasket-compression load. The isolated gasket load is carried by a set of bolts compressing the diaphragm gasket between the waterbox channel and a flexible diaphragm. The diaphragm is a disk of heavy flange rim section with a thin flexible center portion. The pressure load is transmitted through the flexible center of the diaphragm to a heavy pressure cover, held in position by a set of shear blocks or a separate set of bolts, as in Figs. 12 and 13. The initial application of pressure or variations thereof will cause movement or change of shape of pressure parts. The flexible section of the diaphragm compensates for this with negligible effect on the row of bolts clamping the diaphragm gasket to its seat. This insures an independently secured tight seal against the pressure, since the seal is entirely separate from the strength member supporting the head load.

**DRAIN-COOLER SECTIONS.** The method of determination of the heating surface described above applies to a simple condensing type of feedwater heater. Use of a drain-cooler section improves the economy of the power plant. In a simple condensing heater the condensed steam is withdrawn at the saturated steam temperature and normally passes through a regulated orifice to the shell of the next-lower heater. This results in flashing of condensate into steam at the lower pressure. This steam is then condensed in the heater shell and reduces the extraction from this (lower) bleed point of the turbine, thus improving the economy.

By using surface segregated from the condensing surface in the higher-stage heater, keeping this surface flooded at all times, and passing the condensed steam over it, the condensed steam can be cooled to a temperature approaching that of the inlet water to the heater. When these drains are rejected to the next-lower heater relatively little flashing occurs, and more steam is extracted from the next-lower stage of the turbine, resulting in additional power. This additional surface, known as a drain-cooler section, is shown in Fig. 14. Depending on the size of the turbine, the load factor, the price of coal, and other considerations it is possible to justify economically the value of drain-cooler sections in one or more heaters. (See *Steam Turbines and Their Cycles*, by J. Kenneth Salisbury, John Wiley and Sons, 1950.)

**DESUPERHEATING ZONE.** Another refinement, in use for many years, is the desuperheating zone. It involves introducing (superheated) steam close to the outlet of the tube bundle system, where the water is at maximum temperature, leaving the condensing zone. This surface, enclosed so that the steam passes over the surface before delivery into the condensing section of the heater, is used where bled steam from the turbine contains a relatively large amount of superheat. The usable heat contained in the superheat depends on the temperature rise through the heater and the heat
of superheat contained in the bled steam. Superheated steam is cooled in passing through this zone, which adds heat to the water after it has left the condensing zone and provides an additional 3 to 15 degrees rise in the feedwater temperature leaving the heater. In a normal condensing heater, after approaching within 4 or 5°F of the saturation temperature, the cost of surface for each additional degree rise becomes uneconomical. By the introduction of a desuperheat zone considerably greater rise can be secured economically. The cost of surface to achieve this rise may be balanced against the value of the fuel saved, and thus proportioned to give maximum return on the investment.

Figure 14 illustrates a high-pressure heater incorporating a desuperheating zone, a drain-cooling section, and the normal condensing section.

**PHYSICAL ARRANGEMENT AND OPERATION.** The heaters described may be built either for horizontal or for vertical mounting. Where large high-pressure heaters are encountered the vertical arrangement is better because of the very heavy tube bundles. Heaters may be arranged with the inlet and outlet header at the top or the bottom, as desired. This freedom of arrangement applies to floating-header heaters as well as U-bend types. When a U-bend type is used with a cooler section, however, a very expensive construction is required to seal the wrapper plate of the cooler section to the tubes when the U section is at the top and the water header is at the bottom.

When horizontal installations with very heavy tube bundles are used it is desirable to withdraw the shell from the bundle, providing rollers for the shell. The bundle may be withdrawn from a fixed shell if internal rollers are used, but this requires a larger and more expensive shell.

**Priming of Drain-cooler Sections.** When drain-cooler sections are used with low-pressure heaters and vertical installations the pressure differential between the two stages may not be sufficient to prime the drain-cooler section. Thus unless the turbine is to be run constantly at very high loads, low-pressure heaters with integral drain-cooler sections should be of the horizontal type.

**Cascading.** When drains are cascaded consecutively from a high-pressure heater through a group of four or five others it often will be found that the drain-cooler section in the lowest heater is larger than the condensing portion of that heater. In such a situation a separate drain cooler is indicated.

**Strength of Wrapper Plate.** Drain-cooler sections and their wrapper plates must be structurally well built and, particularly with horizontal heaters, spaced from the condensing sections so that level control is possible, keeping the wrapper plate of the cooler section submerged at all times. Intermittent uncovering of the wrapper plate and pocketing of steam within it may result in condensation of the pocketed steam and collapse of the wrapper-plate assembly. Care should be taken in introducing drains from a heater containing no drain-cooler section into a heater containing one. These drains should never be introduced into the drain-cooler section of the next-lower heater since a pressure may be developed which will rupture the wrapper plate.

**Floating-head versus U-bend Type.** Selection of a floating-head heater versus a U-bend heater is entirely a matter of preference. The modern regenerative feed cycle
contains very pure, clean water. U tubes can be cleaned chemically when used with clean water. In the past U tubes were seldom used because of the cleaning problem and because tube metal quality had not been developed as it is today. A U-bend type of heater consists of bends of varying radii nested together. If a considerable number of tube failures occurs, it is necessary to retube the entire heater since the inner tubes cannot be removed without removing most of the outer tubes.

Proper venting of closed heaters is particularly important since closed heaters use different relative locations of steam inlets and vents. The steam should be led across baffle plates from the steam inlet in a continuous unidirectional flow to the vents. The vents should be placed as close to the tube sheets as possible, to scavenge properly stagnant gases from points adjacent to baffle or support plates and tube sheets, where they come in contact with tubes. Otherwise condensation in the presence of stagnant gases at these points will corrode the tubes at their outer periphery.

CHEMISTRY OF BOILER FEEDWATER

By Frederick G. Straub and Others

14. COMPOSITION AND ANALYSIS OF FEEDWATER

IMPURITIES IN FEEDWATER. Natural feedwater supplies contain solids and dissolved gases which may promote these conditions in boilers: (1) incrustation or scale; (2) foaming, priming, and solids in steam; (3) corrosion; and (4) caustic embrittlement. To avoid these troubles, it is necessary to study each water supply individually and determine its individual characteristics and how it best may be treated.

Because of the high solids content, sea water and certain other bodies of water are unfit for use in boilers. Rainwater becomes contaminated in falling through the atmosphere, and always contains dissolved gases, including oxygen and carbon dioxide. Carbon dioxide forms a mild acid which greatly increases the solvent action of the water. Thus, with carboonic acid present, it can dissolve considerable amounts of materials such as calcium and magnesium salts from the ground through which the water passes.

CLASSES OF IMPURITIES. Table 1 is a partial list of impurities found in boiler feedwater, their effect in the boiler, and the usual method of treatment. The solubilities are listed to show constituents which may be present in water, and whether they can be expected to precipitate under boiler operating conditions. Increase of temperature increases the solubility of some solids and precipitates others. Regardless of whether solubility increases or decreases with temperature, concentration of solids in the boiler water increases with continued evaporation. Table 2 gives the solubility of substances listed in Table 1. As solubilities vary with temperature and authorities differ on the values for some constituents, it is not possible to estimate all solubilities under boiler conditions. The important feature is the probable effect of these constituents in the boiler. (See next to last column, Table 1.)

The impurities may be roughly classified under these headings.

Dissolved Gases. Inert gases, as nitrogen and the hydrocarbons. Corrosive or active gases, as oxygen, carbon dioxide, and hydrogen sulfide.

Dissolved Solids. Slightly soluble solids include most calcium and magnesium compounds. Also oil and silica.

Highly soluble solids include all soluble salts, as sodium chloride, sodium sulfate, sodium carbonate, sodium nitrate, and certain sodium silicates. Also sodium hydroxide, sodium phosphate, the acids, and certain organic compounds.

Suspended solids include the common clays and silts, organic and inorganic matter, found principally in rivers and streams, and all other insoluble matter.

Insoluble liquids, oils, greases, soaps, etc., have a deleterious effect on boiler water.

SPECIFICATIONS FOR BOILER WATER AND FEEDWATER. The following specifications are practicable with present feedwater treatment methods and equipment.

Feedwater. Dissolved Oxygen. Preferably zero and not over 0.05 cc per liter for boilers; zero where steel tube economizers are used. pH Value. Not less than 7. Excess alkalinity other than required for treatment or protection of feed lines, or to neutralize acids, should be reduced to a minimum. Hardness. Preferably zero. Not over 26 parts per million in terms of calcium carbonate. Chloride. Lowest practical minimum is desired. When due to condenser or other leakage not over 6 parts per million in terms of chlorine. Oil. None. Total Solids. Reduce to minimum. Suspended Solids. None. Organic Matter. Not more than 5 parts per million.

(Continued on p. 7-52)
### Table 1. Usual Impurities of Boiler Feedwater

<table>
<thead>
<tr>
<th>Impurity</th>
<th>Formula</th>
<th>Molecular Weight</th>
<th>Equivalent Weight</th>
<th>Solubility*</th>
<th>Probable Effect in Boiler</th>
<th>Methods of Treatment and Removal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calcium bicarbonate</td>
<td>Ca(HCO₃)₂</td>
<td>162.10</td>
<td>81.05</td>
<td>Moderate</td>
<td>Scale and sludge.</td>
<td>In external treatment of calcium and magnesium compounds, lime and soda softeners plus coagulation and filtration give partial removal. Zeolite softeners and evaporators give more complete removal, the former replacing calcium and magnesium with sodium. Corrosive compounds require alkali treatment.</td>
</tr>
<tr>
<td>Calcium carbonate</td>
<td>CaCO₃</td>
<td>100.08</td>
<td>50.04</td>
<td>Slight</td>
<td>Scale and sludge.</td>
<td></td>
</tr>
<tr>
<td>Calcium hydroxide</td>
<td>Ca(OH)₂</td>
<td>74.10</td>
<td>37.05</td>
<td>Slight</td>
<td>Scale and sludge.</td>
<td></td>
</tr>
<tr>
<td>Calcium sulfate</td>
<td>CaSO₄</td>
<td>136.14</td>
<td>68.07</td>
<td>Moderate</td>
<td>Hard Scale</td>
<td></td>
</tr>
<tr>
<td>Calcium silicate</td>
<td>Variable</td>
<td>110.99</td>
<td>55.50</td>
<td>Very soluble</td>
<td>Corrosive, Scale and sludge</td>
<td></td>
</tr>
<tr>
<td>Calcium chloride</td>
<td>CaCl₂</td>
<td>110.99</td>
<td>55.50</td>
<td>Very soluble</td>
<td>Corrosive, Scale and sludge</td>
<td></td>
</tr>
<tr>
<td>Calcium nitrate</td>
<td>Ca(NO₃)₂</td>
<td>164.10</td>
<td>82.05</td>
<td>Very soluble</td>
<td>Deposits, Lignates CO₂</td>
<td>In internal treatment, calcium and magnesium are precipitated as hydroxide and carbonates by sodium hydroxide and sodium carbonate. Calcium and sometimes part of the magnesium are changed to calcium and magnesium phosphates by treatment with sodium phosphates. Sodium hydroxide is preferred reagent for internal treatment of magnesium compounds. Calcium hydroxide is preferred for external treatment.</td>
</tr>
<tr>
<td>Magnesium bicarbonate</td>
<td>Mg(HCO₃)₂</td>
<td>146.34</td>
<td>73.17</td>
<td>Moderate</td>
<td>Deposits, Lignates CO₂</td>
<td></td>
</tr>
<tr>
<td>Magnesium carbonate</td>
<td>MgCO₃</td>
<td>84.32</td>
<td>42.16</td>
<td>Slight</td>
<td>Deposits, Lignates CO₂</td>
<td></td>
</tr>
<tr>
<td>Magnesium hydroxide</td>
<td>Mg(OH)₂</td>
<td>58.34</td>
<td>29.17</td>
<td>Very slight</td>
<td>Deposits</td>
<td></td>
</tr>
<tr>
<td>Magnesium sulfate</td>
<td>MgSO₄</td>
<td>120.38</td>
<td>60.17</td>
<td>Very soluble</td>
<td>Corrosive, deposits</td>
<td></td>
</tr>
<tr>
<td>Magnesium silicate</td>
<td>Variable</td>
<td>95.73</td>
<td>47.62</td>
<td>Very soluble</td>
<td>Corrosive, deposits</td>
<td></td>
</tr>
<tr>
<td>Magnesium chloride</td>
<td>MgCl₂</td>
<td>148.34</td>
<td>74.17</td>
<td>Very soluble</td>
<td>Corrosive, deposits</td>
<td></td>
</tr>
<tr>
<td>Sodium carbonate</td>
<td>NaHCO₃</td>
<td>84.00</td>
<td>42.00</td>
<td>Very soluble</td>
<td>Increases alkalin</td>
<td>Excess sodium alkalin may be reduced by boiler blowdown. It sometimes is neutralised with sulfuric acid externally. Phosphoric acid and amin phosphates are also used. Evaporation is best practical means of removing sodium compounds from feedwater. Boiler blowdown used for internal reduction of soluble solids.</td>
</tr>
<tr>
<td>Sodium carbonate</td>
<td>Na₂CO₃</td>
<td>106.00</td>
<td>53.00</td>
<td>Very soluble</td>
<td>Increases alkalin</td>
<td></td>
</tr>
<tr>
<td>Sodium hydroxide</td>
<td>NaOH</td>
<td>40.00</td>
<td>40.00</td>
<td>Very soluble</td>
<td>Increases alkalin</td>
<td></td>
</tr>
<tr>
<td>Sodium sulfate</td>
<td>Na₂SO₄</td>
<td>142.05</td>
<td>71.03</td>
<td>Very soluble</td>
<td>Inhibitor for calcium carbondioxide</td>
<td></td>
</tr>
<tr>
<td>Sodium silicate</td>
<td>Variable</td>
<td>58.45</td>
<td>58.45</td>
<td>Very soluble</td>
<td>Increases alkalin</td>
<td></td>
</tr>
<tr>
<td>Sodium chloride</td>
<td>NaCl</td>
<td>58.45</td>
<td>58.45</td>
<td>Very soluble</td>
<td>Increases soluble</td>
<td></td>
</tr>
<tr>
<td>Sodium nitrate</td>
<td>NaNO₃</td>
<td>85.01</td>
<td>85.01</td>
<td>Very soluble</td>
<td>Increases soluble</td>
<td></td>
</tr>
<tr>
<td>Iron oxide</td>
<td>Fe₂O₃</td>
<td>159.68</td>
<td>26.61</td>
<td>Slight</td>
<td>Deposits, Encourages corrosion</td>
<td></td>
</tr>
<tr>
<td>Alumina</td>
<td>Al₂O₃</td>
<td>101.94</td>
<td>16.99</td>
<td>Slight</td>
<td>May add to deposits</td>
<td></td>
</tr>
<tr>
<td>Silica</td>
<td>SiO₂</td>
<td>60.06</td>
<td>30.03</td>
<td>Slight</td>
<td>Hard scale, acts as binder for deposits</td>
<td></td>
</tr>
<tr>
<td>Dissolved oxygen</td>
<td>O₂</td>
<td>32.00</td>
<td>16.00</td>
<td>Slight</td>
<td>Corrosive</td>
<td></td>
</tr>
<tr>
<td>Carboxylic acid or dissolved CO₂</td>
<td>H₂CO₃</td>
<td>62.02</td>
<td>31.01</td>
<td>Very soluble</td>
<td>Retards hydrolysis of carbonates. Reduces alkalinity</td>
<td></td>
</tr>
<tr>
<td>Hydrogen sulfide</td>
<td>H₂S</td>
<td>34.08</td>
<td>17.04</td>
<td>Very soluble</td>
<td>Corrosive</td>
<td></td>
</tr>
<tr>
<td>Oil and grease</td>
<td></td>
<td></td>
<td></td>
<td>Very soluble</td>
<td>Corrosive, deposits, foaming and priming</td>
<td></td>
</tr>
<tr>
<td>Organic matter</td>
<td></td>
<td></td>
<td></td>
<td>Very soluble</td>
<td>Corrosive, deposits, foaming and priming</td>
<td></td>
</tr>
</tbody>
</table>

* See Table 2.
### Table 2. Solubility of Impurities in Boiler Feedwater

<table>
<thead>
<tr>
<th>Substance</th>
<th>Formula</th>
<th>0 C</th>
<th>100 C</th>
<th>Authority</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calcium bicarbonate</td>
<td>Ca(CHCOO)₂</td>
<td>Soluble</td>
<td>Decomposes</td>
<td>Landolt-Börnstein</td>
</tr>
<tr>
<td>Calcium carbonate</td>
<td>CaCO₃</td>
<td>0.0013 (16 C)</td>
<td>0.002</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Calcium hydroxide</td>
<td>Ca(OH)₂</td>
<td>0.1771</td>
<td>0.0667</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Calcium sulfite</td>
<td>CaS₂O₄</td>
<td>0.1759</td>
<td>0.1688</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Calcium silicate</td>
<td>CaSiO₃</td>
<td>0.0095 (17 C)</td>
<td></td>
<td>Seidell</td>
</tr>
<tr>
<td>Calcium chloride</td>
<td>CaCl₂</td>
<td>59.378</td>
<td>157.600</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Calcium nitrate</td>
<td>Ca(NO₃)₂</td>
<td>102.061</td>
<td>362.630</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Magnesium bicarbonate</td>
<td>Mg(CHCOO)₂</td>
<td>Soluble</td>
<td>Decomposes</td>
<td></td>
</tr>
<tr>
<td>Magnesium carbonate</td>
<td>MgCO₃</td>
<td>0.0106 (cold)</td>
<td></td>
<td>Handbook of Chem. and Physics—Hodgman–Lange</td>
</tr>
<tr>
<td>Magnesium hydroxide</td>
<td>Mg(OH)₂</td>
<td>0.0008</td>
<td></td>
<td>Seidell</td>
</tr>
<tr>
<td>Magnesium sulfate</td>
<td>MgSO₄</td>
<td>26.725 (1.8 C)</td>
<td>71.027</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Magnesium silicate</td>
<td>Mg₃SiO₅</td>
<td>*</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Magnesium chloride</td>
<td>MgCl₂</td>
<td>52.380</td>
<td>72.284</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Magnesium nitrate</td>
<td>Mg(NO₃)₂</td>
<td>66.455</td>
<td>137.211 (90 C)</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Sodium bicarbonate</td>
<td>NaHCO₃</td>
<td>6.888</td>
<td>16.465 (60 C)</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Sodium carbonate</td>
<td>Na₂CO₃</td>
<td>6.996</td>
<td>45.153</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Sodium hydroxide</td>
<td>NaOH</td>
<td>42.005</td>
<td>336.642</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Sodium sulfate</td>
<td>Na₂SO₄</td>
<td>4.838</td>
<td>42.192</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Sodium silicate</td>
<td>Na₃SiO₅</td>
<td>*</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sodium chloride</td>
<td>NaCl</td>
<td>35.658</td>
<td>39.165</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Sodium nitrate</td>
<td>NaNO₃</td>
<td>73.274</td>
<td>175.450</td>
<td>Inter. Crit. Tables</td>
</tr>
<tr>
<td>Iron oxide</td>
<td>Fe₂O₃</td>
<td>Insoluble</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Alumina</td>
<td>Al₂O₃</td>
<td>Insoluble</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Silica</td>
<td>SiO₂</td>
<td>Insoluble</td>
<td></td>
<td>Handbook of Chem. and Physics—Hodgman–Lange</td>
</tr>
<tr>
<td>Oxygen</td>
<td>O₂</td>
<td>0.0066 ‡</td>
<td>0.0</td>
<td></td>
</tr>
<tr>
<td>Carbon dioxide</td>
<td>CO₂</td>
<td>0.3346 ‡</td>
<td>0.0576 (60 C)</td>
<td></td>
</tr>
<tr>
<td>Hydrogen sulfide</td>
<td>H₂S₂</td>
<td>0.7066 ‡</td>
<td>0.0</td>
<td></td>
</tr>
</tbody>
</table>

* The formulas and solubilities of the silicates are extremely variable, ranging from very high solubilities (especially sodium) to slight solubility.
† Per 100 cc solution.
‡ Pressure, 760 mm.

**Boiler Water. Sodium Phosphate.** With residual hardness in the make-up, 50 to 100 parts per million expressed as disodium phosphate. **Alkalinity.** Between 100 to 250 parts per million depending on silicates which also are present. The higher alkalinity is preferred when silicate concentration is 100 to 200 parts per million. **Chlorides.** Not over 500 parts per million expressed as chlorine. Preferably as low as possible. **pH Value.** Not less than 10.5, preferably 11.0. **Oil.** None. **Total Solids.** Not over 1700 parts per million.

**ANALYSES.** In examining raw water supplies to determine their suitability for feedwater and proper methods for purification, a complete analysis is preferred. When the purification plant has been standardized, control tests may be applied to feed and boiler water to maintain desired conditions. These usually consist of tests for alkalinity or acidity; pH value; hardness; chloride; sodium sulfate; dissolved oxygen; dissolved solids; turbidity.

**Alkalinity or acidity** is measured quantitatively by a titration method, using a standard acid or alkali in a burette and flask containing sample and color indicator. If indicator shows an alkaline reaction, sample is titrated with the standard acid until a certain color end point is reached. If indicator shows an acid reaction, it is titrated with the standard alkali to a predetermined end point. Alkalinity or acidity is then calculated in parts per million or grains per gallon of the predominating alkali or acid.

**pH value** (hydrogen-ion concentration) is determined to measure the degree of acidity or alkalinity of a sample. In the colorimetric method (generally used) a measured amount of a chosen indicator is added to a measured volume of sample in a test tube or small cell. The color of the tube is compared to sets of color standards which represent the result for different pH values. A useful universal indicator that can be used for both titration work and approximate pH value can be obtained from such laboratory supply houses as Palo-Myers, Inc., New York.

**EXPLANATION OF pH VALUE.** All aqueous solutions contain hydrogen (H) and hydroxyl (OH) ions. The product of their concentrations is equal to a constant value which at room temperature is approximately $1 \times 10^{-14}$. Neutral water contains an equal number
of hydrogen and hydroxyl ions. The hydrogen-ion concentration is, therefore, $1 \times 10^{-7}$ gram of ionized hydrogen per liter.

When acid is added, the hydrogen-ion concentration increases with corresponding decrease in hydroxyl-ion concentration. When an alkali is added, the hydroxyl-ion concentration increases, and the hydrogen-ion concentration decreases. Since all acids and alkali do not ionize alike, the quantity of acid or alkali does not give a direct measure of hydrogen-ion concentration. Strong acids, as hydrochloric, and strong alkalis, as sodium hydroxide, are much more effective in changing hydrogen-ion concentration than relatively weak materials, as carbonic acid and sodium carbonate.

For convenience, only the hydrogen-ion concentration is recorded, whether the solution is acid or alkaline. Hydroxyl-ion concentration may be found by dividing hydrogen-ion concentration into $1 \times 10^{-7}$. Thus, if hydrogen-ion concentration is $1 \times 10^{-8}$, the hydroxyl ion is $1 \times 10^{-14}$. Hydrogen-ion concentration is expressed in terms of pH value, equivalent to log (1/H-ion concentration), that is, to the negative exponent. Thus if hydrogen-ion concentration is $1 \times 10^{-8}$, pH value is 9. The lower the hydrogen-ion concentration, the higher the pH value. In neutral water pH = 7; in water that is relatively ten times as alkaline, pH = 8. If pH = 6, the water is relatively ten times as acid as at pH = 7. Table 3 shows hydrogen-ion concentration, its equivalent pH value, and corresponding color of the universal indicator. Table 4 lists several indicators, their solution concentrations, and the color change for the pH range to which they apply.

### Table 3. Hydrogen-ion Concentration as Shown by Color Indicators

<table>
<thead>
<tr>
<th>Hydrogen-ion Concentration, Gram-moles per Liter</th>
<th>pH</th>
<th>Color of Universal Indicator</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.0</td>
<td>$10^{-0}$</td>
<td>0</td>
</tr>
<tr>
<td>0.1</td>
<td>$10^{-1}$</td>
<td>1</td>
</tr>
<tr>
<td>0.01</td>
<td>$10^{-2}$</td>
<td>2</td>
</tr>
<tr>
<td>0.001</td>
<td>$10^{-3}$</td>
<td>3 Acid range</td>
</tr>
<tr>
<td>0.000, 1</td>
<td>$10^{-4}$</td>
<td>4</td>
</tr>
<tr>
<td>0.000, 01</td>
<td>$10^{-5}$</td>
<td>5</td>
</tr>
<tr>
<td>0.000, 001</td>
<td>$10^{-6}$</td>
<td>6</td>
</tr>
<tr>
<td>0.000, 000, 1</td>
<td>$10^{-7}$</td>
<td>7 Neutral</td>
</tr>
<tr>
<td>0.000, 000, 01</td>
<td>$10^{-8}$</td>
<td>8 Blue</td>
</tr>
<tr>
<td>0.000, 000, 001</td>
<td>$10^{-9}$</td>
<td>9 Blue-violet</td>
</tr>
<tr>
<td>0.000, 000, 000, 1</td>
<td>$10^{-10}$</td>
<td>10 Purple</td>
</tr>
<tr>
<td>0.000, 000, 000, 01</td>
<td>$10^{-11}$</td>
<td>11 Alkaline</td>
</tr>
<tr>
<td>0.000, 000, 000, 001</td>
<td>$10^{-12}$</td>
<td>12</td>
</tr>
<tr>
<td>0.000, 000, 000, 000, 1</td>
<td>$10^{-13}$</td>
<td>13</td>
</tr>
<tr>
<td>0.000, 000, 000, 000, 01</td>
<td>$10^{-14}$</td>
<td>14</td>
</tr>
</tbody>
</table>

*For hydrogen ion 1 gram-mole = 1 gram, but for hydroxyl ion 1 gram-mole = 17 grams.*

### Table 4. Colorimetric Indicator Solutions

<table>
<thead>
<tr>
<th>Indicator</th>
<th>Concentration</th>
<th>pH Range</th>
<th>Color Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meta cresol purple</td>
<td>.04%</td>
<td>1.2–2.8</td>
<td>Red-yellow</td>
</tr>
<tr>
<td>Bromophenol blue</td>
<td>.04</td>
<td>3.0–4.6</td>
<td>Yellow-blue</td>
</tr>
<tr>
<td>Methyl red</td>
<td>.02</td>
<td>4.4–6.0</td>
<td>Red-yellow</td>
</tr>
<tr>
<td>Bromocresol green</td>
<td>.04</td>
<td>4.0–5.6</td>
<td>Yellow-blue</td>
</tr>
<tr>
<td>Bromocresol purple</td>
<td>.04</td>
<td>5.2–6.8</td>
<td>Yellow-purple</td>
</tr>
<tr>
<td>Bromothymol blue</td>
<td>.04</td>
<td>6.0–7.6</td>
<td>Yellow-blue</td>
</tr>
<tr>
<td>Phenol red</td>
<td>.02</td>
<td>6.8–8.4</td>
<td>Yellow-red</td>
</tr>
<tr>
<td>Cresol red</td>
<td>.02</td>
<td>7.2–8.8</td>
<td>Yellow-red</td>
</tr>
<tr>
<td>Thymol blue</td>
<td>.04</td>
<td>8.0–9.6</td>
<td>Yellow-blue</td>
</tr>
<tr>
<td>Phthaline red</td>
<td>...</td>
<td>8.6–10.2</td>
<td>Yellow-red</td>
</tr>
<tr>
<td>Tolyl red</td>
<td>...</td>
<td>10.0–11.6</td>
<td>Red-yellow</td>
</tr>
<tr>
<td>Parasol orange</td>
<td>...</td>
<td>11.0–12.6</td>
<td>Yellow-orange</td>
</tr>
<tr>
<td>Acyl blue</td>
<td>...</td>
<td>12.0–13.6</td>
<td>Red-blue</td>
</tr>
</tbody>
</table>
This method of measuring acidity or alkalinity is useful in controlling corrosion and certain chemical reactions in treatment of feed and boiler water. For feedwater pH should be at least 7, and for boiler water at least 10.5. Figure 1 shows the relation between pH and solubility of iron in deaerated water.

**HARDNESS.** For control purposes, total hardness is determined by adding standard soap solution to a bottle containing a measured amount of sample, shaking the bottle vigorously between additions of soap solution, the bottle lying on its side, until an unbroken lather is maintained for 5 min on the water surface. Volume of soap solution used is referred to a chart or multiplied by a factor. The result is expressed in parts per million, grains per gallon, or equivalent calcium carbonate.

Actually, hardness consists of such materials as calcium and magnesium carbonate and bicarbonates, calcium and magnesium sulfates, and calcium and magnesium chlorides. These materials can be precipitated by boiling, and are known as temporary hardness. For example, the bicarbonates of calcium and magnesium are changed to carbonates, which are much less soluble. The remaining hardness is known as permanent hardness.

Chloride concentration is determined by titrating a measured volume of sample with standard silver nitrate solution, potassium chromate being used as an indicator. The end point is indicated by a red coloration. The result is expressed in parts per million, grains per gallon of chlorine, or equivalent sodium chloride.

**Equivalent sodium sulfate** determination is useful in boiler-water analyses. In control work, benzidine sulfate titration or the turbidity method is used. The titration consists of adding an excess of benzidine sulfate to a measured sample of water. After standing, to allow complete precipitation of sulfate as benzidine sulfate, filter and wash precipitate. Titrate the precipitate with a standard sodium hydroxide solution, with phenolphthalein as the indicator.

The turbidity method consists of adding hydrochloric acid and barium chloride to a measured sample of water, causing a white precipitate of barium sulfate to form. The sample is stirred to keep precipitate in suspension, and the mixture slowly poured into a graduated tube with a small light below it. When sufficient mixture has been added to just obscure the light filament, when looking down the tube, height of liquid is read, and equivalent sodium sulfate in parts per million or grains per gallon is estimated or read from the graduated tube.

**Dissolved oxygen** is an important test in controlling deaeration of feedwater. It involves sampling water through a cooling coil to reduce temperature to below 70°F, flowing water from the coil through a glass-stoppered sample bottle to wash out any air not in the sample. The sample is then fixed with three reagents, usually manganous sulfate, alkaline potassium iodide, and sulfuric acid. A measured volume of the sample is titrated with a standard sodium thiosulfate solution, with starch as an indicator. If dissolved oxygen is absent there will be no blue coloration when the indicator is added. Result is expressed in cc per liter or parts per million of dissolved oxygen.

**Dissolved solids** may be estimated in several ways. In the laboratory they are determined by evaporating a measured volume of sample and weighing the dried residue. For boiler water, hydrometer, densimeter, and conductivity tests are used, suitable calibrations being made for the type of water.

**Turbidity** tests are made by several methods, depending on the amount of suspended solids. For certain boiler waters containing considerable suspended matter, some type of turbidimeter may be used to regulate blowdown for suspended solids. The sulfate meter is operated by pouring liquid containing suspended matter into a tall glass cylinder until a light filament under the cylinder is no longer visible. Height of liquid in the cylinder is then read. Another method, for waters containing less suspended matter, involves the immersion of a graduated rod holding a wire at the end into the sample until the wire no longer can be seen. (See Refs. 1, 2, and 3.)

**15. FEEDWATER TREATMENT**

**CAUSES OF SCALE FORMATION.** Hard scale and incrustations of softer deposits result from the presence or formation of insoluble solids in feed and boiler water. Certain slightly soluble solids, when treated with water-softening chemicals, or heated and concentrated in the boiler water, become less soluble and precipitate. The most objectionable are calcium sulfate and silice, which have a strong tendency to crystallize and precipitate, forming hard scale which is difficult to remove. Both may act as a cement for other insoluble matter and hasten the formation of a heavy scale, which, because of its poor heat conductivity, will cause overheating and failures of boiler tubes. Calcium sulfate, and, to a slightly less extent, silica, tend to form scale on the hottest tubes. Calcium carbonate
is more likely to precipitate in the boiler water than on the tubes. Its deposits tend to be greater in the cooler parts of the boiler. With external heating of feedwater containing calcium bicarbonate, the less soluble calcium carbonate often is formed and deposited in heaters and pipe lines. With this chemical present, the same result may be obtained by continuous addition of caustic soda to feedwater. Calcium phosphate tends to deposit in feed lines when sodium phosphate is used as a treating agent. Tannates have been used to delay precipitation of calcium compounds in the feed system. In general, calcium phosphate does not give serious trouble in boiler water, but periodic cleaning is advisable.

For explanation of the process of scale formation, see Ref. 4.

COAGULATION, SEDIMENTATION, AND FILTRATION may be used alone or in conjunction with lime-soda or other treatments. The removal of suspended matter is an important part of the treating system. Coagulation and sedimentation are carried on in large basins, or in tanks, depending on quantity of water to be handled. Usual coagulants are iron sulfate (eopperas), aluminum sulfate, sodium aluminate, and lime. Cold-water filtration is carried on usually with gravity or pressure-type sand filters. In hot-water filtration, less soluble materials, as calcite or magnetite, should be used to avoid formation of calcium silicate, which may result in hard, dense scale. Sand filters usually are designed for a capacity of 2 to 4 gal of water per minute per square foot of cross-sectional area.

LIME-SODA TREATMENT is applied in several ways, with considerable variation in design of equipment. The principal differences are in the temperature of water, cycle of operation (whether continuous or intermittent flow), and method of applying and agitating chemicals. Hot-process equipment usually consists of chemical mixing tanks, chemical proportioner (which introduces chemicals in proportion to flow of water), a deaerating-type heater, placed above a reaction and settling tank, and a filter to remove unsettled suspended matter. The cycle usually is continuous. Water flows through the heater into the top of the reaction and settling tank, where chemicals are introduced and thence to the bottom of the tank, where suspended matter settles and is blown out. The water then rises through a central duct and is discharged through the side of the tank, at a point below the water level. Treated water finally passes through a closed or pressure-type filter. Retention time of water in the tank is preferably not less than one hour. Figs. 2 and 3 show two types of hot lime-soda water softeners.

In the cold process, equipment may be the same as in the hot process without the heater. Usually, it is desirable to have a longer reaction and settling time, and several treating tanks are provided. In these, water is treated, agitated, settled, and finally drawn off from the top to the filters. Each tank is treated in rotation. The cycle is so timed that treated water always flows from one tank to the filters while water in the others is being treated or settling. Filters frequently are of the open gravity type. Depending on analysis of raw water and excess of treating chemicals used, effluent water from a cold-process softener may have a hardness of 2 to 5 grains per gal, or from the hot-process softener a hardness of 1 to 3 grains per gal.

The chemicals used in these treatments are one or more coagulants (iron sulfate, aluminum sulfate, sodium aluminate), calcium hydroxide, and sodium carbonate. Coagulants are added either before or after lime and sodium carbonate, depending on the ease of coagulating suspended matter. Both iron sulfate and aluminum sulfate create acidity when added to neutral water, which must be corrected by alkaline chemicals. Sodium aluminate gives an alkaline reaction and, besides being a coagulant for suspended matter, it has water-softening properties similar to that of sodium carbonate.

Calcium hydroxide or hydrated lime combines with excess carbon dioxide, and reacts with calcium and magnesium bicarbonates to form less soluble calcium carbonate and magnesium hydroxide. Also when sodium carbonate is present, sodium hydroxide is formed. These reactions for lime are:

\[
2\text{Ca(OH)}_2 + \text{Mg(HCO}_3\text{)}_2 = 2\text{CaCO}_3 + \text{Mg(OH)}_2 + 2\text{H}_2\text{O}
\]

\[
\text{Ca(OH)}_2 + \text{Ca(II)}(\text{HCO}_3)_2 = 2\text{CaCO}_3 + 2\text{H}_2\text{O}
\]

\[
\text{Ca(OH)}_2 + \text{H}_2\text{CO}_3 = \text{CaCO}_3 + 2\text{H}_2\text{O}
\]

\[
\text{Ca(OH)}_2 + \text{Na}_2\text{CO}_3 = \text{CaCO}_3 + 2\text{NaOH}
\]

The principal use of sodium carbonate is to react with calcium sulfate to form a less objectionable scale-forming compound. The treatment is also effective in changing acid-
FIG. 2. Hot lime soda water softener. (Permutit Co.)

FIG. 3. Hot lime-soda deaerating feedwater heater and softener (Cochrane Corp.)
forming salts to neutral salts. The resulting magnesium hydroxide and calcium carbonate are largely precipitated in the softerner. The principal reactions are:

\[
\begin{align*}
\text{CaSO}_4 + \text{Na}_2\text{CO}_3 & \rightleftharpoons \text{Na}_2\text{SO}_4 + \text{CaCO}_3 \\
\text{CaCl}_2 + \text{Na}_2\text{CO}_3 & \rightleftharpoons 2\text{NaCl} + \text{CaCO}_3 \\
\text{MgSO}_4 + \text{Na}_2\text{CO}_3 + \text{Ca(OH)}_2 & \rightleftharpoons \text{Mg(OH)}_2 + \text{CaCO}_3 + \text{Na}_2\text{SO}_4 \\
\text{MgCl}_2 + \text{Na}_2\text{CO}_3 + \text{Ca(OH)}_2 & \rightleftharpoons \text{Mg(OH)}_2 + \text{CaCO}_3 + 2\text{NaCl}
\end{align*}
\]

Note: Sodium hydroxide may be substituted for sodium carbonate and calcium hydroxide in the last two equations.

The amounts and kinds of coagulants added are regulated mainly by coagulation tests. Lime and sodium carbonate additions are regulated by chemical analysis and control tests. The control tests usually made are soap hardness and alkalinity.

After a complete analysis of raw water, theoretically required amounts of lime (calcium hydroxide) and soda (sodium carbonate) may be calculated from the reacting molecular weights of the compounds shown in the foregoing equations. Actually some excess of treating agent is desirable and, owing to impurities, an allowance of 5 to 10% should be made for lime and of 1 to 2% for sodium carbonate.

EVAPORATION of make-up water is especially useful in power plants where the percentage make-up is small and a minimum quantity of boiler deposit is desirable. This process produces purer water than any other process now available. The amount of make-up water which can be so prepared is limited only by economic considerations. See Section 3 for a discussion of evaporators. Condensate from low-pressure boilers sometimes is used to supply make-up water for high-pressure boilers in which no appreciable quantity of scale can be tolerated. To assist continuous operation, feedwater to evaporators may be pretreated in the same manner as for boilers. In other cases it is preferred to crack scale from the evaporator tubes by the introduction of cold water when the scale is brittle. As with boilers, total solids in the water in the evaporator must be regulated to inhibit carrying undesirable quantities of solids into the steam.

INTERNAL WATER TREATMENT consists mainly of maintaining desirable concentrations of chemicals in the boiler water. Chemicals to be added and concentrations to be maintained vary with the nature of feedwater and results of operation. The usual agents for inhibiting scale formation are sodium carbonate, sodium phosphate, and sodium aluminate. Sodium hydroxide, tannates, and various prepared boiler compounds are used on occasion, or for some specific need. In general, prepared compounds are viewed with disfavor from both practical and economic standpoints.

Sodium carbonate is used to promote a desirable alkalinity and to inhibit formation of calcium sulfate scale. It also may retard formation of silica scale. In boilers, it hydrolyzes to form sodium hydroxide and CO\textsubscript{2} gas, the latter passing off with the steam. The extent of this reaction depends mainly on the amount of carbonate in the feedwater but, in general, 70 to 90% of the sodium carbonate becomes sodium hydroxide.

Experiments indicate that under favorable conditions 2 to 3 grains of sodium carbonate in boiler water will inhibit calcium sulfate scale. The final concentration should be regulated by results of practical experience.

Sodium phosphate is used principally to precipitate (as tricalcium phosphate) calcium entering with the feedwater. This finely divided material has considerably less tendency to form objectionable deposits than the calcium compounds that otherwise would be present. A similar reaction may occur with magnesium, but in practice sufficient alkalinity usually is present to precipitate magnesium as magnesium hydroxide. The common forms of sodium phosphate are trisodium phosphate, Na\textsubscript{3}PO\textsubscript{4}; disodium phosphate, Na\textsubscript{2}HPO\textsubscript{4}; monosodium phosphate, NaH\textsubscript{2}PO\textsubscript{4}; sodium metaphosphate, (NaPO\textsubscript{3})\textsubscript{2}.

The less-alkaline phosphates, as monosodium phosphate, are used when there is excess alkalinity in feedwater or when calcium is present largely as calcium carbonate. Total al-
kalinity and total solids in boiler water thus are more easily controlled. Typical reactions of triodium phosphate are:

\[
\begin{array}{cccc}
\text{Soluble Impurity} & \text{Treating Agent} & \text{Insoluble Product} & \text{Soluble Product} \\
3\text{CaCO}_3 & + & 2\text{Na}_3\text{PO}_4 & = \text{Ca}_3(\text{PO}_4)_2 + 3\text{Na}_2\text{CO}_3 \\
\text{Calcium carbonate} & \text{Triodium phosphate} & \text{Calcium phosphate} & \text{Sodium carbonate} \\
3\text{CaSO}_4 & + & 2\text{Na}_3\text{PO}_4 & = \text{Ca}_3(\text{PO}_4)_2 + 2\text{Na}_2\text{SO}_4 \\
\text{Calcium sulfate} & \text{Triodium phosphate} & \text{Calcium phosphate} & \text{Sodium sulfate}
\end{array}
\]

Calcium phosphate thus formed has considerable tendency to adhere to feed lines. It generally is safer to add the phosphates direct to the boiler, or in intermittent doses, so that a minimum of precipitate is formed external to the boiler.

Provided there is sufficient alkalinity in the boiler water, the less-alkaline phosphates give the same type of reaction as above. The following is an example:

\[
\begin{array}{cccc}
\text{3CaCO}_3 & + & 2\text{NaH}_2\text{PO}_4 & + 4\text{NaOH} = \text{Ca}_3(\text{PO}_4)_2 + 3\text{Na}_2\text{CO}_3 + 4\text{H}_2\text{O} \\
\text{Calcium carbonate} & \text{Monosodium phosphate} & \text{Calcium phosphate} & \text{Sodium bicarbonate}
\end{array}
\]

Only a small amount of phosphate need be maintained in boiler water to inhibit scale. Phosphates, unlike sodium carbonate, do not lose efficiency by hydrolysis in boiler water. As with other forms of internal treatment it is important that boilers and other equipment in feedwater and steam systems be inspected and cleaned periodically.

**SODIUM ALUMINATE** usually is given the formula Na₂Al₂O₄, but in liquid form may contain a higher ratio of sodium to alumina. While generally recommended as a coagulant for external treatment, it also is used as a substitute or aid to sodium carbonate and sodium phosphate in internal treatments. It has many of the qualities of sodium carbonate. In addition it tends to make calcium and magnesium precipitates less adherent than if precipitated alone. Under certain conditions it will reduce silica concentration of boiler water, and form calcium or magnesium aluminum silicates, which are not generally adherent. However, under certain adverse conditions adherent silicates have formed, and the manufacturer of the material should be consulted.

For further information, see publications of the National Aluminate Corporation, Chicago.

16. ION EXCHANGE SOFTENERS *

**SODIUM CYCLE EXCHANGERS.** An ion exchange softener operates without precipitation, but exchanges the ions in the water for ions that are usually more desirable than the original ions. Early ion exchangers were called zeolites. They occurred in natural deposits such as the New Jersey Greensands, and some were made synthetically. They are compounds of alumina and silica, called *aluminate silicates*. These silicates have low solubility in water and possess the property of so-called base exchange. The sodium of the zeolite is replaceable by other metal (positive) ions when in contact with their solutions. The reaction becomes reversible when the concentration of sodium ion is increased. Thus a solution of calcium or magnesium salt, when passed through a sodium zeolite bed, will exchange the calcium and magnesium for the sodium in the zeolite and the water will be soft until the sodium in the zeolite is used up. The sodium is replaced by so-called regeneration with a soluble sodium salt, usually sodium chloride, and rinsing out of the released calcium and magnesium chloride. The operation of this process is illustrated as follows:

\[
\begin{array}{cccc}
\text{Calcium} & \text{or} & \text{magnesium} & \\
\text{Bicarbonate,} & \text{chloride} & \text{or} & \text{sulfate} \\
\text{chloride} & + & \text{sodium zeolite} & \\
\text{Sodium} & \text{bicarbonate,} & \text{chloride,} & \text{or} \\
\text{chloride} & \text{or} & \text{sulfate} & \text{zeolite} \\
\text{Calcium} & \text{or} & \text{magnesium} & \\
\text{zeolite} & + & \text{NaCl} = \text{Sodium zeolite} + & \text{calcium} \\
\text{Sodium} & \text{or} & \text{magnesium} & \\
\text{or} & \text{calcium} & \text{or} & \text{magnesium}
\end{array}
\]

The calcium and magnesium content of the softened water is usually of a low value commonly referred to as zero hardness. The degree of residual hardness is governed by many factors and, if properly controlled, may be reduced to an extremely low value. In normal operation, the residual hardness runs less than three or four parts per million.

* Articles 16–19 inclusive contributed by Frederick G. Straub, Research Professor of Chemical Engineering, University of Illinois.
ION EXCHANGE SOFTENERS

The hardness which zeolite removes from a water depends on many factors, such as type of zeolite, rate of water flow, amount of salt used for regeneration, and chemical content of the water being treated. There are two main types of zeolites available, natural and synthetic. The natural zeolites, of the nonporous type, usually have a lower capacity for hardness removal. This capacity is expressed in terms of equivalent calcium carbonate removed per cubic foot of zeolite. It is about 2500 to 5000 grains of calcium carbonate per cubic foot for the nonporous types and increases to about 10,000 grains per cubic foot in the porous zeolites.

The zeolites may be used either in gravity or pressure-flow units. The water to be softened is passed at a suitable velocity through the unit holding the zeolite material until the bed becomes exhausted (the available sodium used). The bed is then backwashed with hard water to remove any suspended material that may have collected on the bed and to retard packing of the bed. This is accomplished by reversing the flow through the zeolite bed. A solution of the desired amount of salt or brine then is passed through the bed in the normal direction. Hard water then is passed through the bed to rinse out the calcium and magnesium chloride released from the zeolite and any excess sodium chloride. When the hardness reaches the desired value the unit is available for use.

Synthetic zeolites in general are not as stable as natural zeolites with waters of low hardness, low silica, or a pH value less than about 6.8. However, even natural zeolites should not be used for low or high pH waters. When waters have a pH below 6.8 or above 8.5, the pH should be adjusted before passing through the zeolite. Likewise, high temperature cannot be tolerated; consequently only waters with normal temperature may be softened by zeolites.

Waters of high hardness, around 30 grains per gallon (5000 ppm) are difficult to soften as are waters having high chlorides.

The exchange of two sodium ions (mol. wt. 2 × 23 or 46) for one calcium (mol. wt. 40) or one magnesium (mol. wt. 24) causes an increase in the total solids of the softened water. Thus a zeolite-softened water has an increase in total solids as compared to a decrease with the normal lime-softening process. In addition to a slight increase in total solids, the conversion to the sodium salts may bring about high alkalinity in evaporators or boilers. If the bicarbonate hardness predominates, the softened water will have the sodium bicarbonate predominating over the sodium chloride and sulfate.

The presence of high sodium alkalinity in many zeolite-softened waters is one of the disadvantages of this type of softening for boiler or evaporator make-up waters. To eliminate this difficulty, the waters often have been pretreated in cold-process lime-softeners or after-treated with sulfuric acid.

Pretreatment with cold-process lime-softening reduces the bicarbonates to a lower value so that the subsequent treatment with the zeolite softener gives a water lower in sodium alkalinity and lower total solids than if it is zeolite softened without pretreatment. However, the higher pH value of the lime-softened water will act to disintegrate the zeolite material and will also precipitate calcium carbonate in the softener due to after-precipitation in the cold lime-softened water. To prevent this trouble, the lime-softened water is acidified by means of sulfuric, phosphoric, or carbonic acid to about pH 8 before it is passed through the zeolite bed.

After-treatment with sulfuric acid of zeolite-softened water is simpler than pretreatment with lime; however, it does not reduce the total solids, but increases them. This increase is due to the reaction between the sulfuric acid and the equivalent amount of sodium carbonate; the sulfate ion (mol. wt. 96) replaces a carbonate ion (mol. wt. 60) with an increase in dissolved solids. In many instances this increase in dissolved solids is not detrimental to the operation, and its disadvantage is more than equalized by lowering of the alkalinity. Care must be taken in handling the acid so as to prevent acidity in the treated water, and to allow for release of the carbon dioxide formed. The carbon dioxide or carbonic acid tends to lower the pH of the treated water and may cause corrosion. Usually this carbon dioxide is removed by blowing air through the acid-treated water. The remaining sodium bicarbonate is slightly broken down to some sodium carbonate by passage of air through the solution with a subsequent increase in pH value.

This process is illustrated by the following reactions:

(1) \[ 2\text{NaHCO}_3 + \text{air} = \text{Na}_2\text{CO}_3 + \text{H}_2\text{O} + \text{CO}_2 \]

(2) \[ 2\text{NaHCO}_3 + \text{H}_2\text{SO}_4 = \text{Na}_2\text{SO}_4 + 2\text{H}_2\text{CO}_3 \]

(3) \[ \text{H}_2\text{CO}_3 = \text{CO}_2 + \text{H}_2\text{O} \]

If zeolite-softened water (having a pH of about 7) is treated by bubbling air through it or spraying the water through air, reaction 1 proceeds, to a small extent, to the right. The solution of sodium bicarbonate has a pH of about 7. As sodium carbonate is formed by removal of carbon dioxide, however, the pH increases because sodium carbonate is a salt of a strong base (NaOH) and a weak acid (H\text{CO}_3), so that the resulting solution is
alkaline in nature (high pH). The amount of carbonate formed and the resulting pH depend on the amount of air used, the carbon dioxide in the air, the amount of bicarbonate present, and the temperature.

When sulfuric acid is added to a zeolite-softened water, the solution becomes acid (pH below 7) before a sufficient amount of sulfuric acid has been added to neutralize completely the sodium bicarbonate. The acidity is caused by the formation of carbonic acid, which tends to decrease the pH value of the solution. If air is blown through the solution, the carbonic acid breaks down to water and carbon dioxide, and the carbon dioxide is removed. If sufficient air is passed through the residual, bicarbonate forms some carbonate (reaction 1) with a slight increase in pH. This increase in the pH of a zeolite-softened water takes place during deaeration in the regular plant deaerator. The bicarbonate tends to form the carbonate as the carbon dioxide is released during deaeration.

Newer materials have been developed which operate on the same principle as the zeolite softener but have eliminated many of the undesirable features of this type of softening. These materials are nonsiliceous and are not attacked by acids or mild alkali. They will normally operate in a pH range between 2 and 9. Since they are nonsiliceous, they do not pick up silica when low-silica waters are softened.

These newer organic materials are of two types; one is the sulfonylated-coal type, the other a resinous type. The sulfonylated-coal type is often referred to as a cationic exchanger; the other is called the resinous cation exchanger. The term cation is used since the positive ions or cations are exchanged.

When operating on the sodium cycle (regeneration with salt) these units operate in a manner similar to the older siliceous zeolites. They usually have a much higher exchange capacity than the natural zeolites, and are of about the same capacity as the older synthetic zeolites. However, some of the newer products may have a capacity as great as 35,000 grains of calcium carbonate per cubic foot. Their ability to work over a wider pH range, coupled with their freedom from silica contamination, makes them quite desirable for boiler make-up water softening. However, when operating with salt as a regenerating material, they still deliver the same type of softened water as the older zeolite softener. Since they are stable at low pH values, they are suitable for removal of all the positive cations, if properly regenerated. This type of operation is discussed in the next article.

### 17. HYDROGEN-CYCLE CATION EXCHANGERS

Since the nonsiliceous type of exchange material is stable at low pH values, it is possible to regenerate it with an acid such as sulfuric or hydrochloric. When so regenerated, it is free from sodium, calcium, or magnesium with the hydrogen ion replacing the sodium ion in the material. When acid-regenerated, it is said to be operating on the hydrogen or acid cycle. If regenerated with acid, and water is passed through, the sodium, calcium, and magnesium are all retained on the bed with the release of the corresponding acid. Thus the bicarbonates will form carbonic acid; the sulfates, sulfuric acid; and the chlorides, hydrochloric acid. All the cations are exchanged for hydrogen as shown

\[
\begin{align*}
\text{Ca(HCO}_3\text{)}_2 & \quad \text{H}_2\text{CO}_3 & \quad \text{Ca} \\
\text{Mg(Cl)}_2 & + \text{H}_2 \text{exchange bed} = \text{HCl} & + \text{Mg exchange bed} \\
\text{Mg(SO}_4\text{)}_2 & \quad \text{H}_2\text{SO}_4 & \quad \text{Na} \\
\text{NH}_4 & \quad \text{NH}_4
\end{align*}
\]

When all the hydrogen in the bed is used up, the exchange reaction stops. It may then be regenerated with sulfuric or hydrochloric acid, usually the former, and the softening cycle repeated.

Since the calcium, magnesium, sodium, and ammonium are all converted to the hydrogen equivalent, there is a reduction of solids. If all these positive ions were present as the bicarbonate, the resulting product would contain nothing but carbonic acid. If air were passed through the effluent, the carbon dioxide could be reduced to a low value and the resulting product would be almost pure water.

### 18. COMBINATION HYDROGEN- AND SODIUM-CYCLE CATION EXCHANGERS

In normal water supplies both chlorides and sulfates are present along with the bicarbonates. In order to control the residual alkalinity, it is possible to split the water flow so that part goes through the hydrogen unit and the rest goes through a sodium unit.
The effluents from the two units are then mixed in such proportions that the alkalinity of that from the sodium unit neutralizes the acidity of that from the acid unit, and the mixed water is degassed to remove the carbon dioxide. Since the chloride, sulfate, and silica pass through both units, the reduction in solids is only the amount of the calcium, magnesium, sodium, and ammonium removed in the hydrogen unit. The amount of excess sodium-softerned water added above that necessary to neutralize the acidity determines the residual alkalinity of the treated water. This may be controlled at any desired value by varying the ratio of the waters passed through the hydrogen and sodium units. When a low residual alkalinity is desired, the presence of the small amount (3 to 5 ppm) of free carbon dioxide left after air degassing is sufficient to give a low pH (below 7) which makes the water quite corrosive, since it is saturated with air. If this water is to be heated before being deaerated, care must be taken to use acid-resistant materials. Of course the hydrogen unit and all its equipment must be of acid-resistant material. In some cases, the effluent from the softener is passed through an acid-resistant vacuum degasser to remove the carbon dioxide and then neutralized with sodium hydroxide. In others, the softened water is passed through a regular deaerating heater.

It is possible to control the amount of acid used in the unit so that it is sufficient to react with a definite portion of the water to be softened, and then to add a brine (salt solution) to regenerate the rest of the bed. Under proper control, water of the desired alkalinity may be obtained from one unit.

In general, the unit working on the hydrogen cycle has less capacity than the sodium unit. Usually the hydrogen cycle has an exchange capacity around 60 to 75% of that of a unit operated on the sodium cycle. The unit is backwashed and then regenerated, usually with dilute sulfuric acid. Care must be taken to keep the sulfuric acid concentration below 2%. If the acid strength is high and a high-hardness water is being softened, it is possible to precipitate calcium sulfate on the mineral bed and retard softening. Hydrochloric acid can be used to prevent precipitation, but sulfuric acid is more desirable from first cost and handling standpoints.

These types of softener may be operated to give residual hardness below 0.20 ppm if all operating conditions are properly controlled.

19. DEMINERALIZATION TREATMENT

It is possible to pass water through a combination of exchange materials and anion-adsorbent materials and, with suitable additional treatment, to obtain a water practically free of dissolved salts. This is commonly referred to as demineralization treatment. The first stage of the softening involves passing the water through a cation exchanger operating on the hydrogen cycle. This converts all negative ions to their acid form and removes all the positive ions (cations). The water is then passed through a second unit operating as an anion (negative ion) adsorber. This unit is regenerated with an alkaline material such as sodium hydroxide or sodium carbonate. The acids are adsorbed on the alkaline bed. The carbon dioxide passes through, along with the inactive silica, and the carbon dioxide is removed by air degassing, leaving a water practically free of all the original dissolved materials except silica. The anion adsorbers have capacities of 10 to 20 thousand grains of equivalent calcium carbonate per cubic foot of material. The alkaline bed cannot be backwashed or rinsed with raw hard water. Usually the effluent from the cation exchanger is used to prevent the precipitation of hardness in the anion adsorber. An excess of the theoretical amount of acid, as well as soda-ash to react with the dissolved materials in the water to be treated, is necessary. Since sulfuric acid and soda-ash are relatively expensive as compared to lime or salt, this method of treatment is more expensive than the older methods of softening. However, often, as in boiler-feed make-up for high-pressure boilers, the reduction in blowdown by the reduction of dissolved solids in the softened water may more than balance this increased cost. If the silica in the raw water is appreciable, it soon builds up in the boiler until the blowdown is regulated by the silica content, and the advantage of the demineralization is no longer evident. In order to adapt this method to treatment, several modifications have been tried. The first method involves changing the silica from an almost chemically inert form to an active or more highly ionized form so that it will be retained on the adsorbing bed. This is accomplished by having an excess of fluoride in the water above that necessary to form a fluosilicate. Thus, if hydrofluoric acid is present, it reacts as follows to form fluosilicic acid:

\[6HF + SiO_2 = H_2SiF_6\]

Thus six molecules of fluoride react with one of silica. The fluosilicic acid is adsorbed in the anion-removal bed.
There are several methods of introducing the hydrofluoric acid into the water. Hydrofluoric acid could be added to the effluent from the hydrogen cation exchanger, but the difficulty in handling hydrofluoric acid restricts the use of this method. In a second method, fluoride (as sodium fluoride) is added to the water ahead of the hydrogen cation exchanger. The sodium fluoride is converted to hydrofluoric acid in the cation exchanger. The hydrofluoric acid reacts with the silica to form the fluosilicic acid, which in turn is adsorbed on the anion removal bed. Calcium fluoride may also be added to the hydrogen cation exchanger to form hydrofluoric acid. It is necessary to modify the operation when the fluoride treatment is used so as to rinse the anion unit with excess acid from the cation unit to flush out the fluosilicic acid before regenerating with soda-ash. If the unit is regenerated directly with soda-ash, the silica precipitates in the anion adsorbing bed.

It is claimed that this process reduces the silica below 0.5 ppm and keeps the fluoride in the effluent below 0.5 ppm. Since the cost of the fluoride is rather high, it may be advantageous to use a silica reduction process in connection with lime treatment ahead of the demineralization treatment.

Another method being used is to demineralize and de-gas the water and then to pass it through a second anion alkaline-type adsorber that removes the silica in the water, which at that stage is free of all minerals except silica. This treatment gives a treated water with silica below 0.5 ppm.

20. EFFECTS OF IMPURE FEEDWATER

CORROSION. Corrosion in boilers or feedwater equipment may be explained by the electrochemical theory. (See Ref. 5.)

The principal accelerators of corrosion in boilers are (1) dissolved oxygen; (2) acids; (3) surface deposits, especially those that are electrowegetive to steel; (4) unlike metal couples, as brass and steel; and (5) electrolytes, as strong salt solutions. There are four common methods of preventing corrosion. (1) Removal of dissolved gases in feedwater, especially dissolved oxygen and carbon dioxide. This can be done by deaerating processes. (2) Neutralization of acids and maintenance of desirable alkalinity and hydrogen-ion concentration (pH value) in feed and boiler water. (See p. 7-52.) (3) Periodic mechanical cleaning. Protective paints may be applied if desired. (4) Avoidance of excessive salt concentrations.

HIGH-TEMPERATURE CORROSION. At higher temperatures, especially above 950 F, steam may react with iron according to the equation

\[ 3\text{Fe} + 4\text{H}_2\text{O} \rightarrow \text{Fe}_3\text{O}_4 + 4\text{H}_2 \]

Iron Steam Black magnetic Hydrogen oxide

At temperatures up to 950 F this corrosion reaction is slow. Above this temperature the rate is accelerated, and alloys like the Cr-Ni alloy KA2 are recommended. These materials form a protective oxide film on the metal surface, whereas steel does not.

CORROSION FATIGUE. Under certain conditions of corrosion and stress, metals may corrode in the form of deep sharp pits, which later develop into fissures or cracks. If the action is not stopped, the parts attacked eventually will fail. The action may be produced by subjecting metal to ordinary corrosive conditions while under stress, which may be intermittent in nature. Microscopic examination shows the action to occur in a characteristic manner, producing cracks that are transcrystalline and in a nearly straight line. The products of corrosion fill the crack, and the metal shows little or no elongation or distortion.

CAUSTIC EMBRITTLEMENT. With certain types of feedwater, cracks of a peculiar form may appear in the boiler plate, particularly at the riveted seams below the water line. These cracks are intercrystalline and do not follow the lines of the maximum stress, as they sometimes occur past each other and around parts or islands of the plate. This action has been termed caustic embrittlement, as it occurs where concentrated sodium hydroxide (caustic soda) is present in the water in the boiler in the absence of other elements.

Embrittlement is inhibited when a certain ratio of sodium sulfate to sodium carbonate is maintained in the feedwater. This has led to ratios (given in Table 5) of sodium sulfate.

<table>
<thead>
<tr>
<th>Table 5. Recommended Ratios of Sodium Sulfate to Total Sodium Hydroxide</th>
</tr>
</thead>
<tbody>
<tr>
<td>Working pressure of boiler, psig</td>
</tr>
<tr>
<td>Sodium sulfate</td>
</tr>
<tr>
<td>Total sodium hydroxide and carbonate alkalinity as equivalent sodium carbonate</td>
</tr>
</tbody>
</table>
to total sodium hydroxide and sodium carbonate alkalinity, calculated to equivalent sodium carbonate, being recommended for different working pressures.

Embrittlement is caused by concentration of caustic soda at joints and through the effect of the stress in the metal at the joints. The trouble experienced with caustic embrittlement was a factor that led to the use of fusion-welded drums. (See Ref. 6.)

**FOAMING AND PRIMING.** Foaming may be described as the formation of a large amount of foam in the boiler, due to failure of steam bubbles to coalesce and break. It is accompanied by considerable increase in moisture content of the steam generated by the boiler.

Priming is characterized by large amounts of water passing out of the boiler with the steam, usually in intermittent slugs which endanger steam lines, turbines, and engines. It may occur simultaneously with foaming. High water levels in boilers promote priming.

Foaming and priming generally are caused by high concentration of dissolved and suspended solids, possibly accompanied by oil and soaps in boiler water, and sudden changes in boiler capacity. These conditions may be prevented by reducing boiler water concentrations by blowdown, elimination of sources of feedwater contamination, periodic cleaning of boiler, and proper regulation of water levels. Since operating conditions and the boiler equipment influence the amount and kind of solids that may be permitted in boiler water, no general concentration limits can be given.

**REDUCTION OF CONCENTRATION BY BLOWDOWN.** Maintenance of reasonably low concentrations in high-capacity boilers is facilitated by economical continuous blowdown, with or without flash tanks, and with one or more heat exchangers. Figure 4 indicates percentage blowdown required for any given percentage of make-up and ratio of concentration in make-up to that in boiler water.

**REFERENCES**

2. Edison Electric Institute, New York City, *Power Station Chemistry Committee Reports*.

**BOILER FURNACES * **

Revised and rewritten by W. A. Carter

21. BURNING OF COAL

See Section 2, Combustion and Fuels.

22. HAND-FIRED GRATES

See Refs. 1, 2, and 3.

In hand-fired boilers, ideal uniform combustion cannot be maintained because firing is intermittent. The best condition of fuel bed is obtained when the coal is fired frequently, in small amounts, and with proper distribution; when caked masses of coal (if any) are broken up as rapidly as formed; and when ashes and clinker are not allowed to clog the fuel bed.

* The author has drawn freely, by permission, on *Heat Power Engineering*, Part II, by Barnard, Ellenson, and Hirshfeld (John Wiley and Sons) for many of the data in this chapter.
METHODS OF FIRING. Three methods in general use for hand-firing boilers are:

Spread Firing. A small amount of fresh coal is distributed evenly over the entire surface of the fire. It is commonly used with anthracite and other low-volatile coals.

Alternate Firing. Fresh coal is fired on but one-half of the grate at a time. The freshly liberated volatile matter absorbs the necessary heat for combustion from the brighter parts of the fire. It is particularly suitable for noncaking coals.

Cokeing-Firing. Especially suited to coking coals. Fresh coal is placed on the front edge of the fire and allowed to coke. After distillation is complete, the coke is spread over the fire. Lower rates of combustion are obtained with this method than with the other two.

COMBUSTION CHAMBERS in hand-fired boilers usually have firebrick walls. These, when hot, help to maintain the high temperature required for combustion. The combustion chamber often is of special form to compel the volatile gases to mix with secondary air.

With anthracite and other low-volatile coals a firebrick arch sometimes is sprung over the grate to assist ignition. The more volatile coals produce longer flames, and consequently the furnace must be made longer by setting it in front of the boiler as a Dutch oven, or using a deflecting arch under the boiler to postpone contact of burning gases with the relatively cold boiler surface. The Dutch-oven furnace helps to attain smokeless combustion, except when the burning rate is high. Arrangements to mix air and volatile gases include multiple arches, piers, or wing walls, and jets of air or steam injected through the front, sides, or bridge wall of the furnace.

COMBUSTION RATES depend on the characteristics of the coal and ash, thickness of fuel bed, total grate surface, air passage area of the grates, and the draft. Average rates, in pounds of fuel per square foot of grate surface per hour are:

<table>
<thead>
<tr>
<th>Type of Draft</th>
<th>Anthracite</th>
<th>Semi-anthracite</th>
<th>Semi-bituminous</th>
<th>Bituminous</th>
<th>Lignite</th>
<th>Coke Breeze</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural</td>
<td>15</td>
<td>16</td>
<td>18</td>
<td>20</td>
<td>30</td>
<td>25</td>
</tr>
<tr>
<td>Forced</td>
<td>20</td>
<td>25</td>
<td>35</td>
<td>30</td>
<td>35</td>
<td>35</td>
</tr>
</tbody>
</table>

23. STOKERS

Principal advantages of stokers over hand firing are continuous delivery of coal; progressive and gradual distillation of volatile matter; ability to obtain better performance and smokeless combustion because of the ease with which the operations can be regulated at all times; greater combustion capacity obtainable in a furnace; ability to meet varying load demands quickly; ability to burn poorer and cheaper grades of coal with less smoke and higher efficiency; relief of operators from strenuous duties, thus permitting more time for adjusting operating conditions; decreased labor costs in large boiler plants where the number of firemen can be reduced.

CLASSIFICATION. Stokers are classified as overfeed or underfeed or combination overfeed and underfeed. Certain stokers of each type require forced draft; others operate with natural draft.

Overfeed stokers include (1) Front-feed, inclined-grate stokers; coal enters at the front and is fed down an incline to the ash dump or incline grinder at the bottom. (2) Double-inclined, side-feed stokers; coal is fed from both sides, down inclined grates to a refuse pocket at the center. (3) Chain-grate or traveling stokers; the entire coal bed moves

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Preferable Stoker</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anthracite</td>
<td>Traveling grate,† forced draft</td>
</tr>
<tr>
<td>Coke breeze</td>
<td>Traveling grate,† forced draft</td>
</tr>
<tr>
<td>Semi-anthracite</td>
<td>Traveling grate,† forced draft</td>
</tr>
<tr>
<td>Semi-bituminous (cooking)</td>
<td>Underfeed and inclined overfeed</td>
</tr>
<tr>
<td>Bituminous (cooking)</td>
<td>Underfeed and inclined overfeed</td>
</tr>
<tr>
<td>Bituminous (free-burning, ash &gt; 10 or 12%)</td>
<td>Traveling grate,† forced or natural draft</td>
</tr>
<tr>
<td>Bituminous (free-burning, ash &lt; 10 or 12%)</td>
<td>Traveling grate,† underfeed or side inclined ‡</td>
</tr>
<tr>
<td>Sub-bituminous</td>
<td>Traveling grate,† forced or natural draft</td>
</tr>
</tbody>
</table>

* The spreader stoker may also be used for any of the fuels shown except anthracite.
† Traveling grate includes chain grates as well as traveling carrier-bar stokers.
‡ If ash fuses at a temperature below 2600°F, traveling grates are preferable. If the percentage of ash is less than 7, underfeed stokers are preferable.
horizontally from front to rear. (4) Spreader stokers; coal is fed over the entire grate area by revolving paddles; grates are stationary dumping or continuous ash discharge (chain grate).

**Underfeed stokers** include (1) Single-retort stokers, usually horizontal, with lateral ash dumps. (2) Multiple-retort stokers, usually inclined with refuse discharge at the rear.

Table 1 shows types of stokers generally most suitable for the various fuels.

**OVERFEED STOKERS.** Inclined overfeed stokers usually operate with natural draft. A coking arch at the front of the furnace, maintained at a high temperature, reflects heat to and distills volatile gases from the entering coal. Air, heated or otherwise, usually is admitted with coal under the arch. As a rule, these stokers require more attention than other types and seldom are used on boilers larger than 600 hp.

Practically all kinds of coal, sawdust, tan bark, and hog fuel can be burned in these stokers, but they are used principally with high-volatile, high-ash Midwestern coal. Average combustion rate with free-burning coals is 15 to 25 lb per sq ft of horizontal projected grate surface per hour, with a maximum of 35 lb. With caking coal, the maximum combustion rate is 25 lb.

**Inclined front-feed stokers** include a hopper, coal-pusher feeding device, dead plate, coking arch, and inlet for secondary air under the arch. The action of the pushers and grate bars can be regulated so that when the coal arrives at the ash table, it has been completely burned.

**Double-inclined side-feed stokers** have coal magazines at each side of the furnace. They feed coal to a coking plate, where it meets heated secondary air brought through a refractory arch that covers the entire stoker. The grate bars are inclined, each alternate bar being in constant motion to feed coal down to the clinker grinder. Exhaust steam from the stoker engine sometimes is admitted to the grinder to assist in breaking the refuse of clinkerizing coal.

Stokers of this type have large coking spaces, ample coking arches, and large combustion chambers. Ordinarily they are satisfactory for both uniform and varying loads, but at high combustion rates and with certain types of coal, the fuel may avalanche.

**CHAIN- AND TRAVELING-GRADE STOKERS** comprise series of small links, forming a broad endless belt conveyor carried on rolls or skids. In the traveling-grate type, crossbars, extending from endless chains on either side of the furnace, support short interlocking grate bars. Both types are driven by sprockets at variable speeds, in conformity with the load on the boiler. Raw fuel is fed at one end and discharged as burned-out refuse at the other. The fuel bed is undisturbed while passing through the furnace. Natural or forced draft may be used, depending on the design. A minimum ash content of 7% is necessary to protect the back end of the stoker from heat. With a properly designed furnace, this type of stoker can burn high-volatile coals without smoke, with either natural or forced draft, and also noncaking, clinkerizing coal, high in ash. Special designs can burn small-size anthracite and brown coal, using forced draft.

Stokers of this type are relatively costly, but require little attention, and maintenance is low. They are not so well adapted as the underfeed stokers to meet sudden, heavy variations in demands for steam, unless forced draft is used.

**Arches** over the fire are necessary to cause mixing of gases from the rear of the grate, which are deficient in air, with excess air from the front. Another function is to maintain sufficient temperature to support combustion and to radiate heat to the front of the fuel bed to ignite entering fuel and distill volatile matter from it. Arches also prevent carrying away by a strong draft much of the fly fuel, which otherwise would be lost. Figure 1 shows typical installations.

![Fig. 1. Arch arrangements with natural draft chain-grate stokers.](image)

Secondary air introduced under the front arch prolongs its life. A fan is preferable to a steam jet or induced draft.
## Table 2. Height of Settings for Various Types of Stoker-equipped Boilers *

(Adapted from *Heat Power Engineering* Part II, by Barnard, Ellenwood, and Hirshfeld)

<table>
<thead>
<tr>
<th>Type of Boiler</th>
<th>Underfeed Stoker</th>
<th>Chain Grate Stoker</th>
<th>Overfeed Stoker</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Multiple Retort</td>
<td>Single Retort</td>
<td>Natural Draft</td>
</tr>
<tr>
<td></td>
<td>Types 12, 4, 11, 13, 15, 16</td>
<td>Types 24, 5, 11, 16</td>
<td>Types 1 2, 7, 8, 10</td>
</tr>
<tr>
<td></td>
<td>Min $</td>
<td>P.M. $</td>
<td>Min $</td>
</tr>
<tr>
<td>Water Tube</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| Horizontal, all sizes | 11'0" | 13'0" | 9'0" | 11'0" | 10'0" | 12'0" | 12'0" | 14'0" | 9'0" | 11'0" | 9'0" | 11'0"
| Inclined (H.M.D.), all sizes § | 7'6" | 8'6" | 6'6" | 8'6" | 6'0" | 8'0" | 7'0" | 8'0" | 3'6" | 5'0" | 4'0" | 5'0"
| Inclined (V.M.D.), all sizes | 6'0" | 7'0" | 5'0" | 7'0" | 4'0" | 5'0" | 6'0" | 8'0" | 3'6" | 5'0" | 4'0" | 5'0"
| Vertical (H.M.D.), all sizes § | 3'6" | 5'0" | 4'6" | 5'0" | 3'0" | 4'6" | 5'0" | 6'0" | 3'6" | 5'0" | 4'0" | 5'0"
| Vertical (V.M.D.), 1500 sq ft | 5'6" | 6'6" | 5'6" | 6'0" | 4'6" | 5'0" | 5'0" | 6'6" | 3'6" | 4'6" | 3'6" | 4'6"
| Vertical (V.M.D.), 2500 sq ft | 5'6" | 6'6" | 6'6" | 6'6" | 4'6" | 5'0" | 6'0" | 6'6" | 3'6" | 4'6" | 3'6" | 4'6"
| Horizontal Return Tubular | 8'0" | 10'0" | 7'6" | 8'6" | 7'0" | 8'0" | 8'0" | 10'0" | 7'0" | 8'0" | 6'0" | 8'0"
| 72 in.         |                    |                    |                  |                  |                    |                    |                  |                    |                  |                    |                  |                  |
| 84 in.         |                    |                    |                  |                  |                    |                    |                  |                    |                  |                    |                  |                  |

* Setting heights are defined as follows. Water-tube Boilers: Horizontal tubes, floor line to bottom of header above stoker; inclined tubes (H.M.D.), vertical tubes (H.M.D.) floor line to center of mud drum; inclined tubes (V.M.D.), vertical tubes (V.M.D.), floor line to top of mud drum. Horizontal Return Tubular Boilers: Floor line to under side of shell.

† When burning coke breeze and anthracite fines, the setting heights indicated should be materially increased to provide for proper arch and furnace design.


§ H.M.D. = horizontal mud drum; V.M.D. = vertical mud drum; Min = absolute minimum; P.M. = preferred minimum.

Air leakage around the grate may be minimized by: 1. Adjustable ledge plates to seal gaps between sides of stoker and furnace wall. 2. A tight ashpit to reduce infiltration at rear of stoker. 3. A well-fitted damper at the rear, between upper and lower runs. 4. A seal below lower run. A water back, connected in the boiler circuit, set into an overhanging bridge wall, close to the grate, will compress the back of the fuel bed and increase its density, thus decreasing air infiltration at this point. It also will reduce the amount of unburned fuel discharged to the ashpit, protect the bridge wall, and prevent adherence of clinker. Sidewall water boxes may be necessary to prevent clinker building up on the furnace walls, which then may cause increased air leakage.

Operation. The coal hopper outlet gate should be adjusted for proper thickness of fuel bed for the grade of coal burned, i.e., 2 1/2 to 5 in. for fine anthracite, 4 to 6 in. for Midwestern bituminous and lignite coals. The bed should be as thin as possible consistent with ignition and burning out at the proper point. Stoker speed and draft should be varied for load variations. For best results with the more volatile coals, coal that will pass through a 1-in. ring should be used, although screenings up to 2 in. will burn satisfactorily. A fuel bed of uniform density, offering correct resistance to air flow, is obtained with coal containing 50% fines. The addition of 3% moisture to the coal before firing will reduce sifting and blowholes in the fire, and thereby reduce excess air and improve ignition. This extra moisture reduces overall efficiency only a few tenths of 1%.

**NATURAL-DRAFT CHAIN-GRADE STokers.** Free-burning, high-volatile bituminous and sub-bituminous coals and lignite can be burned with high efficiency on natural-draft chain-grate stokers. The design of the arch depends on the percentage of volatile matter and heating value of the fuel, the combustion rate, and the stoker length. With natural draft, an arch height of about 36 in. at the front has been found to give good results. Figure 1 shows several arrangements of furnaces for natural-draft chain-grate stokers. Turbulence of the gases is insured by the arches a and b in furnace B, and by increased velocity of gases in the narrow throats of the other furnaces.

Combustion rates for most efficient operation with free-burning coal range from 20 to 30 lb per sq ft of grate surface per hour, with a maximum rate of 40 lb and a minimum
of 5 lb. Draft loss, up to combustion rates of 35 lb, is approximately 0.1 in. of water per 10 lb of coal per hour per square foot of grate, the loss increasing at higher combustion rates.

Operating results possible with proper operation, without an economizer or preheater, are monthly efficiencies of boiler and furnace of over 70%, with CO₂ at the boiler outlet of 12 to 13%. Combustible in refuse should range from 15 to 25% at combustion rates of 25 to 40 lb per sq ft per hr.

FORCED-DRAFT TRAVELING-GRATE STOKERS differ from natural-draft stokers in that a series of transverse independent forced-draft compartments, under the upper run of the traveling grate, are supplied, by a fan, with air under pressure from an air duct along the side of the boiler. Connections between the duct and compartments have dampers to control under-fire pressures in the various compartments. If the furnace has but a single arch, maximum under-fire pressure is carried only in the front compartment, the pressure tapering off to nearly zero in the rear compartment, as shown in Fig. 2. In furnaces with front and rear arches, maximum under-fire pressure is at about two-thirds of the distance to the rear, pressures of 1/4 to 1/3 in. of water being carried in front and rear compartments.

Used with Low-volatile Coals. For small-sized anthracite, air openings in the grate must be small enough to prevent sifting. Special arrangements are necessary for primary kindling of the coal before it reaches the first forced-draft air compartment, utilizing heat radiated from the hot refractory surface of the arch. Entering fuel must "see" the arch through a greater angle, as A in Fig. 3 than that at B, through which it sees any relatively cold surface. In one stoker design, a small suction compartment at the front of the stoker draws some hot furnace gas down through the fresh fuel to ignite quickly moist or low-volatile fuels.

Stratification of gases and carrying of fly ash by the furnace gases can be overcome by introducing air over the fire or placing the arch at the rear. (See Fig. 4.)

FIG. 2. Forced-draft traveling-grate stoker with independent air compartments.

FIG. 3. Arch arrangement with traveling-grate stoker for anthracite.

FIG. 4. Arch arrangement to reduce stratification and fly ash.

FIG. 5. Traveling-grate stoker with front and rear arches.

Front and rear arches often are used to form a narrow throat in which gases from the front and rear portions of the grate are mixed. Combustion is completed in the upper combustion chamber. (See Fig. 5.)

Used with Bituminous Coals and Lignite. Forced draft under traveling-grate stokers permits higher combustion rates of free-burning coals than natural draft. Efficiency curves are higher (5 to 6%), and flatter. Arches are smaller than with natural-draft stokers, but they must be set higher to prevent erosion. Side-wall water boxes and water backs are necessary. Caking and coking coals that could not be burned on these stokers with natural draft are burned successfully with forced draft by reason of the air pressure.
breaking up the fuel bed. Water-cooled arches and side walls avoid rapid destruction of brickwork by heat. An additional arch over the rear of the stoker is desirable when the coal varies in quality.

**Combustion rates** for best results with bituminous coal should range from 30 to 40 lb. per sq ft per hr, with a maximum of 60 lb when ash content ranges from 10 to 25%. A survey by NELA showed an average combustion rate of 43.5 lb and average stoker maintenance cost of 4 cents per ton of coal burned. With anthracite or coke breeze, combustion rates range from 30 to 38 lb per sq ft of grate per hour with forced draft of 1.5 to 2 in. of water, with maximum and minimum rates of 55 and 10 lb respectively.

**Operating results** with bituminous coal should show combined boiler and furnace monthly efficiencies of 70 to 77%; CO₂ of 12 to 15%; combustible in refuse, 10 to 20%. With anthracite and coke breeze, monthly efficiencies of boiler and furnace should range from 72 to 76%.

**UNDERFEED STOKERS** operate at combustion rates as high as 110 lb per sq ft of grate per hour if ash fusion temperature is not below 2400 F. The field of the underfeed stoker comprises bituminous and semibituminous caking or free-burning coals, and to a lesser extent other grades of coal, including culm, coke breeze, and small-sized anthracite mixed with bituminous coal.

The essential principle of the underfeed stoker is a reciprocating ram or rams which feed coal from hoppers at the front of the furnace into the bottom of horizontal or slightly inclined retorts. The raw coal is underneath burning coal at the top of the fuel bed, which distills the volatile matter from the fresh coal. The liberated gases pass upwards through the burning coal, and are burned with air entering through tuyeres at the upper edges of the retorts. The coke which remains after distillation of the gases gradually is pushed upwards by entering fresh fuel and burns on the surface of the fuel bed. The entire fuel bed is worked toward the rear of the stoker or on to dead plates at the sides of the retort, ash and refuse being discharged into an ash hopper or removed by hand.

Forced draft always is necessary. Rams and pushers, and sometimes also the ash-disposal equipment, are driven by a motor or engine. Fuel and air supply can be regulated automatically by variations in steam pressure. Arches are unnecessary, and considerable heat is transmitted to the boiler by radiation. This results in a relatively low temperature of gases passing through the boiler, even at high combustion rates.

**Simple single-retort stokers** (Fig. 6) use a steam-driven ram or a screw feed, together with supplementary adjustable-stroke pushers, to distribute coal properly in the retort. From the surface of the fuel bed, refuse is deposited on dead plates, whence it is removed by hand through doors in the front. In some designs the dead plates may be dropped to dump to the ashpit. Access doors on the sides of the furnace are unnecessary.

At moderate combustion rates, even with high-volatile coals, combustion is complete within a short distance of the surface of the fuel bed. The capacity of these stokers is 800 to 1200 lb of coal per hour. For greater capacities, two or three stokers may be set in a single furnace.

**Single-retort stokers** with lateral grates resemble simple single-retort stokers, except that stationary or movable overfeed grates are interposed between the retort and the dead plates or dump plates. Air to the overfeed grates should be suitably regulated. The capacity of these stokers ranges from 1200 to 9000 lb of coal per hour.

**Multiple-retort underfeed stokers** occupy the full width of the furnace. The fuel bed constantly moves from front to rear, and refuse is fed continuously to an ash dump. (See Fig. 7.) These stokers are 6 to 28 ft or more wide, with 3 to 16 retorts, and 8 to 27 ft or more long. Each retort may have 13 to 69 or more replaceable tuyeres. Underfeed stokers can operate at higher combustion rates than other stokers, and in large units occupy a greater proportion of the area under the boiler. For a given rate of steam generation, they require less heat-absorbing surface and permit individual units to have high steam-generating capacity. These stokers can be brought quickly from bank to full capacity and can meet wide and rapid changes in load. Some furnaces have a stoker at each end discharging to a common ashpit.

Control of the shape of the fuel bed to give proper air distribution is by adjustment of
the length of pusher strokes and speeds of the various groups of rams. This also keeps the fuel bed open and free of clinkers. The active area of the fuel bed may be zoned, with independent regulation of air supply to each zone.

Refuse discharging equipment comprises simple dump plates, double dumping grates, rocker plates, and clinker grinders. With clinker grinders, the final combustible in the refuse can be reduced to 5% if the grinder pocket is large enough to hold ash for 12 hr, and air is forced through its walls. Shortening the time of burning out refuse to 6 hr will raise the combustible to 15%.

Furnace walls for high combustion rates must withstand high furnace temperatures and erosive and slagging action of molten fly ash. Materials used are special grades of firebrick, silicon carbide blocks (if ash is not high in iron oxide), hollow perforated blocks through which secondary air is discharged, or water-cooled refractory or metallic blocks. The walls may be made hollow, and primary combustion air circulated through them. Protection from erosion and adhesion of molten clinkers may be obtained by the use of high air-cooled side-wall tuyeres (see Fig. 7) or water-cooled metallic surfaces (see Fig. 8). Boilers fitted with underfeed stokers must be set in batteries of not more than two, as access doors for inspection and cleaning of side walls are necessary in at least one side of the furnace.

Water-cooled underfeed stokers have been developed to burn low-grade Midwestern semibituminous coal, with ash fusion temperature as low as 1900 F, at a rate of 48 lb per sq ft of grate surface per hour (Ref. 5). Stoker tuyeres are cooled by forced circulation of water through groups of three tubes laid lengthwise of each tuyere stack, extending downward over stationary extension grates to a header near the clinker grinders. Groups of shorter tubes protect the remainder of the extension grates that register with the lower ends of the retorts. Side and rear furnace walls of such installations should be water-cooled to withstand the action of ash with such low fusion temperature.

Combustion rates range from bank to 60 lb of coal per square foot of projected grate area per hour for coal having an ash content in the neighborhood of 10%. They depend on furnace design and available draft. With zoned-air control, combustion rates as high as 90 to 100 lb have been carried successfully. Without zoned-air control, best operation is at combustion rates of 35 to 45 lb, although rates as high as 90 lb have been carried satisfactorily under favorable conditions and close attention to stoker operation and fuel bed condition.

Operating Conditions. Excess air required with underfeed stokers is relatively low, but it should not be reduced to a point where boiler exit gases contain CO, or furnace temperatures are greater than furnace walls can withstand. Forced-draft pressures range from 9/4 to 1 in. of water per 10 lb of coal burned per square foot of projected grate surface per hour. Air preheated to 300 to 500 F sometimes is used. The closure of stoker air passages by expansion and growth of metals must be avoided by proper design and material. Prohibitive stresses and distortion also must be avoided.

Power required to operate underfeed stokers may be, under extreme conditions, as much as 8/4 to 1 hp per retort, burning from 700 to 1100 lb of coal per hour.
GROSS EFFICIENCY of large steam-generating units with economizers, but without air preheaters, and equipped with multiple-retort stokers ranges from 90% at low loads to 75% at high loads. Under such conditions, excess air varies from 20 to 10%.

COMBINATION OVERFEED-UNDERFEED MULTIPLE-RETO RT INCLINED STOKERS consist of two sections, an upper, underfeed section, and a lower, overfeed section, the link-grate section. The link-grate movement is an up-and-down undulating movement. The up movement breaks open the fuel bed and permeates it with low-pressure air flowing up through the grates. When the grates move down, the movement crumbles and conveys the burning fuel, ejecting the ash continuously off the ash-discharge plate. The ash pit may be equipped with a clinker grinder. This type of stoker is particularly well adapted for burning low-grade bituminous or semibituminous coals.

Figure 9 shows this stoker, and an enlarged section indicates the up-and-down movement of the link-grate section. Coal-burning rates are the same as for underfeed stokers.

SPREADER STOKERS. In this type of stoker, coal is fed from a hopper into the path of rapidly revolving paddles, either overthrow or underthrow, which throw the coal into the furnace, where the finer portions are burned in suspension and the coarser particles on a grate. Figure 10, a, b, and c, shows three different types of coal feeders in common use. Spreader stokers are built up to 16 ft in depth and in varying width, single or multiple feeders.

The grates may be of three different types, (1) stationary grates, (2) dumping grates, and (3) continuous ash discharge.

Stationary grates are used on small installations where low first cost is of importance. The fires must be cleaned by hoeing ashes out through the furnace doors, limiting this type of grates to smaller boilers, 100 to 250 hp rating.

Dumping grates eliminate hand cleaning of fires, are operated either by hand levers or mechanically by pressure cylinders. The efficiency is somewhat improved in comparison with stationary grates because the cleaning period is reduced to a minimum. However, disturbance of combustion conditions does result, and the CO₂ drops until the fuel bed again reaches equilibrium. These grates may be used over a wide size range. There should be at least two feeder units on a boiler equipped with dumping grates.

Continuous ash discharge grates are of the traveling- or chain-grate type. Ashes may be dumped either at the front or at the rear. This type of grate assures a minimum of ash handling and greater efficiencies by allowing an undisturbed CO₂ curve. They may be used for units as small as 25,000 to 30,000 lb per hr steam output.

The spreader stoker burns a wide variety of coals, particularly those grades that are
marketed at a low price because either poor quality or size makes them unsuitable for other types of stoker. The spreader stoker is well suited for these coals.

1. Midwestern bituminous coal from Illinois, Indiana, Ohio, western Kentucky, and adjacent fields; high-volatile, high-ash, free-burning, clinkering coals, difficult to burn on underfeed stokers.

2. Sub-bituminous and lignite, high-moisture, free-burning, clinkering coals.

3. Eastern bituminous coal: Coking, low-ash, high-ash-fusion temperature. These coals are also successfully burned on underfeed stokers.

4. Coke breeze, at somewhat reduced combustion rates and efficiency as compared with bituminous coals.

Combustion Rates. It is desirable to limit the heat liberation for continuous rating to 500,000 to 600,000 Btu per sq ft of grate area per hour.

Furnace Design. Furnace-wall cooling is desirable where high rates of heat release are to be maintained. The heat-release rate should not exceed 35,000 Btu per cu ft of furnace volume per hour for all-refractory furnaces. Since much of the coal is burned in suspension, sufficient length of flame travel (14 ft or more) should be provided.

Cinder Losses. Because of relatively high rates of cinder emission with this type of stoker, it should not be used for plants in residential areas unless adequate dust collectors are installed. Cinder collected in hoppers and dust collectors may be reinjected into the furnace, thereby reducing cinder losses.

Air Requirements. Spreader stokers require forced draft, at a wind-box pressure of 2 to 3 in. of water. Air temperatures as high as 300 to 350°F may be employed.

OVERFIRE JETS. Overfire jets have been used for many years to reduce smoke and improve combustion efficiency. If the air deficiency is uniform over the fuel bed, a row of air jets strong enough to cover the entire fuel bed may be required. Air may be introduced by moderate- or high-pressure blowers, by steam jets, or by openings in the stoker front wall by induction only. (See Ref. 6.)

MANUFACTURERS of representative stokers are:


24. GAS BURNERS

Gas burners used in boiler furnaces differ in the degree of mixing fuel and air that occurs in the burner. Long, luminous flames result from burners in which mixing is slight; short, nonluminous flames come from burners that mix gas with all the combustion air.

![Fig. 11. Gas burner giving moderate mixing.](image1)

![Fig. 12. Combination burner for coal, oil or gas.](image2)

Aspirating burners generally are used in boiler furnaces. Figure 11 shows a type that produces a moderate amount of mixing. Gas is introduced in various ways. In Fig. 12,
which shows a combination burner for gas, pulverized coal, and oil, a film of gas flowing around the circumference of the burner throat replaces the numerous small jets of Fig. 11. Either natural or forced draft may be used.

The venturi-type burner, with a central nozzle for gas injection, is used for rapid mixing. Primary air is induced by the reduced pressure in the venturi throat. (See Fig. 13.) A modified venturi-type burner, in which mixing is done in two stages, is shown in Fig. 14.

![Fig. 13. Venturi-type gas burner.](image)

![Fig. 14. Modified venturi-type gas burner.](image)


### 25. OIL BURNERS

Principal requisites of an oil burner are (1) it must completely atomize or vaporize oil; (2) it must not clog or drool; (3) the jet must be so shaped that it will completely mix with the air necessary for combustion; (4) combustion must be complete, and excess air at a minimum over the entire operating range; (5) the burner must be accessible for cleaning, and require a minimum of attention. An improperly shaped flame may cause flame impingement upon furnace walls or boiler tubes with resultant unburned oil droplets and, eventually, tarry residue on the relatively cool boiler tubes.

Two classes of atomizing burners are used: (1) those that effect atomization by spraying, usually by steam jets, although jets of compressed air may be used; (2) those that atomize mechanically, without any atomizing fluid. Vaporizing burners are not used in large boiler furnaces.

STEAM-ATOMIZING BURNERS use the atomizing fluid to break the oil into minute particles and carry them into the furnace. These burners are either external mixing or internal mixing; those of the latter type employ the premixing principle. Steam for atomization should be at a pressure of 75 to 150 psig. The amount of steam required for atomizing, pumping, and heating the oil ranges from 2 to 7% of the total steam generated. The temperature of oil delivered to the burner at a pressure of 10 to 15 psig is 150 to 190 °F.

This type of burner seldom is designed to pass more than 1200 lb per hr of oil when using natural draft, but some designs can burn up to 5500 lb per hr when using air at a pressure of 5 in. of water in the air register around the burner.

External-mixing burners usually are confined to boilers operating at steady, moderate rates. Figure 15 shows a simple form, giving a flat flame. With this type of burner, the combustion air usually enters through checker-work forming part of the furnace hearth. The combination of flame shape and method of supplying air limits the furnace to a single row of burners. Forcing the burner causes incomplete atomization, resulting in slower burning, smoking, fouling of boiler surfaces, and decreased efficiency. Figure 16a shows another burner of this type that produces a flat flame, and in which wearable parts are readily replaced. Figure 16b shows an external-mixing burner that employs compressed air at pressures up to 1 1/2 psig as the atomizing fluid. Its application is rather limited because of excessive operating cost.

Premixing burners usually deliver atomized oil and steam in the shape of a hollow cone, although they can be furnished to produce a flat flame. Figure 16c shows one of these burners and the method of installation. The air doors control the amount of air induced
Fig. 16. (a) and (b) External mixing burners. (c) and (d) Premixing steam-atomising burners. (e) Spray nozzle burner. (f) Pressure-plunger controlled spray nozzle burner. (g) Recirculating burner. (h) Rotary burner.
by the furnace draft and by aspiration of the steam jet. Air pressure, at high combustion rates, is as high as 5 in. of water. These burners can be set in multiple rows, providing large range of boiler output, limited only by furnace volume. Oil-burning rate ranges of 10 to 1 can be obtained with the best burners of this type by varying oil pressure and steam pressure within certain prescribed limits. The burner shown in Fig. 16d cannot operate over such a large range of burning rates.

Under certain operating conditions, steam-atomizing burners may be noisy. The blowpipe action may injure the walls of improperly constructed furnaces. Other objections are additional moisture produced in flue gases and the cost of atomizing steam. Nevertheless, they are widely used in small plants because of their simplicity and low initial cost.

**MECHANICAL-ATOMIZING BURNERS** comprise spray-nozzle burners and rotary burners, the latter being used generally only under low-pressure boilers.

**Spray-nozzle burners** are practically the only ones used in power-plant boiler furnaces. Oil under a pressure of 50 to 300 psig and at temperatures of 100 to 250 F issues in a hollow cone from a small orifice in the burner nozzle. Suitable passages in the nozzle cause a whirling motion of the oil as it is liberated. Combustion air enters, under furnace draft or forced draft, through a register around the burner. Sometimes it is given a relative spinning motion with respect to the flame. Figure 16c shows a typical burner tube of this type.

The size of the openings in the tips depends on the quantity of oil to be burned. These burners are made with oil-burning capacities up to 5000 lb of oil per hour. The minimum operating rate on any single tip is about 40% of design flow. Several rows of burners can be installed in a furnace wall to obtain higher capacities. The steam equivalent of the power required to spray the oil seldom is more than 1% of the total steam generated.

Variation of oil pressure does not permit a large range of regulation of the oil-burning rate, as proper atomization is not obtained below 50 psig. Regulation by changing burner tips is objectionable because it interrupts operation. Regulation by varying the number of burners in operation is undesirable because it causes poor air distribution.

One method used to increase the range of oil-burning rate is to incorporate a pressure-loaded plunger in the burner tube that opens additional tangential holes in the nozzle as the oil pressure is increased. Such a design is shown in Fig. 16f. The range of this burner is 4 to 1.

Another method of increasing the capacity range, to as much as 14 to 1, is indicated in Fig. 16g. The burner line is supplied with a constant flow of oil by primary pumping to the burner line. The additional constant-differential (C/D) pump is controlled by steam demand on the boiler being fired by the oil burners, and varies the oil pressure to atomize the required amount of oil through the burner tips, while the remainder of the oil recirculates.

Still another method for increasing the range of operation (to about 7 to 1) provides two independent sets of oil feed to the burner tips, either or both being used in accordance with steam demand.

**Rotary burners** are sometimes used to burn oils of higher viscosity than can be used in spray-nozzle burners. The oil needs little preheating and only pressure sufficient to deliver it to the revolving cup, in which centrifugal force atomizes it as it is discharged into the furnace. Figure 16h shows one of these burners, of the horizontal type, in which the stream of high-pressure primary air passes through the blades of a small turbine and rotates the atomizing cup at 3400 rpm. Secondary air is induced through the adjustable louvers by furnace draft. Other designs of this burner incorporate electrically driven blower for supplying the primary air, cup drive, automatic gas ignition, and controls suitable for burning up to 2000 lb of oil per hour.


## 26. BOILER-FURNACE DETAILS

**FACTORS INFLUENCING FURNACE DESIGN.** Fuel and character of load variation are the most important items to consider in furnace design. The kind and characteristics of the fuel, including the properties of its ash, determine the method of burning it. For instance, solid fuels may be burned on grates, on stokers, or in pulverized form; the method of firing and type of burner are factors. Other items that will need to be con-
sidered in connection with the fuel are the amount of excess air, which influences boiler capacity and efficiency, and allowable carbon in fly ash and in refuse. The load characteristics include the minimum, normal, and maximum loads, and the duration of each. Heat release rates also are important, in that an increase in rate tends to decrease the size of the boiler for a given output of steam. This, in turn, affects the material and construction of furnace walls. Maximum temperatures for a given type of wall construction also must be determined. The number of variables involved require, for the most economical arrangement and construction, that each furnace be considered as a special case.

**TYPES OF FURNACE WALLS**, in the decreasing order of furnace volume per unit of steam output, and in the increasing order of heat release rates and furnace temperatures, are solid refractory walls, hollow air-cooled refractory walls, bare water-cooled metallic walls, and covered water-cooled metallic walls. The water-cooled walls are necessary for long-continued operation at high combustion rates and high temperatures. Solid refractory walls are suitable and economical for moderate rates and temperatures. For intermediate conditions, the hollow air-cooled wall or a combination of refractory and water-cooled walls may be satisfactory. Superheater or reheater surface may be substituted for some refractory or water-cooled surfaces.

Increasing excess air, to reduce furnace temperatures and decrease wall failures, is inadvisable in ordinary operation, as it also reduces efficiency; it may be justified at peak loads. The use of preheated air usually causes higher furnace temperatures than the use of room air. For long-continued, high-temperature operation, furnace walls should be designed with these conditions in mind.

**MAXIMUM ALLOWABLE FURNACE TEMPERATURE** depends on the behavior of the particular combination of fuel, ash, and material in the hot faces of the furnace walls. Depending on the composition of the ash, its fusion temperature, and the furnace-wall temperature, a refractory wall may be affected by slag penetration, chemical reaction, or erosion by molten slag running down the wall. If the temperature of a coal-fired furnace is not quite high enough to cause any of these effects on a solid refractory wall, solidified fly ash may deposit on it until the combined thickness becomes so great that the temperature at the surface equals the ash fusion temperature. Variation in furnace temperature causes the fly ash to melt or build up until equilibrium is established. The same is true of air-cooled or water-cooled refractory walls. Metallic walls give the least difficulty from adhering fuel ash, although fused ash flowing over them will, in time, be destructive.

**FURNACE VOLUME** depends on the total amount of heat required in a given time and on the permissible Btu release per hour per cubic foot of furnace volume. This heat-release rate depends on type of furnace construction, flame length, ash fusion temperature, method of firing, amount of excess air, and amount of turbulence in furnace. Table 3 gives permissible heat-release rates.

**Table 3. Average Heat-release Rates**

<table>
<thead>
<tr>
<th>Method of Firing</th>
<th>Solid Refractory Walls</th>
<th>Water-cooled Metallic Walls</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Continuous Operation</td>
<td>Peak Operation</td>
</tr>
<tr>
<td></td>
<td>Btu per hr per cu ft of Furnace Volume</td>
<td></td>
</tr>
<tr>
<td>Chain- or traveling-grate stoker</td>
<td>15,000</td>
<td>25,000</td>
</tr>
<tr>
<td>Underfeed stoker</td>
<td>25,000</td>
<td>40,000</td>
</tr>
<tr>
<td>Spreader stoker</td>
<td>30,000</td>
<td>40,000</td>
</tr>
<tr>
<td>Pulverized coal firing</td>
<td>15,000</td>
<td>20,000</td>
</tr>
<tr>
<td>Oil firing</td>
<td>20,000</td>
<td>40,000</td>
</tr>
<tr>
<td>Gas firing</td>
<td>20,000</td>
<td>40,000</td>
</tr>
</tbody>
</table>

Since the heat-release rate in hand-fired furnaces is limited, the grate in horizontal return tubular boilers can be set within 3 or 4 ft of the boiler surface, and within 4 to 4 1/2 ft in horizontal water-tube boilers fired with volatile coal. With anthracite the distance can be slightly less. With stoker-fired furnaces, the distance should be made greater. (See Table 2.) For very high rates of combustion, even greater distances are required.

**Pulverized-coal furnace volume** usually is larger or the heat-release rates lower than in furnaces of equal capacity burning any other fuel. In general, under identical conditions, higher heat-release rates are allowable in small units than in large, since the ratio of wall surface to volume is greater. Figure 17 (Ref. 7) shows approximate relations
between heat-release rates, amounts of excess air, fusing temperatures of ash, and fractions cold (Ψ), defined by

\[
Ψ = \frac{\text{Actual extent of cold surface in furnace}}{\text{Maximum possible extent of cold surface in furnace}}
\]

Furnace design should consider the conditions to be met by the various elements of volume and wall surface. The use in design of average heat-release rates and average temperatures (which have been used in the above discussion) may lead to trouble because localized temperatures may be much higher than average temperatures.

SOLID REFRACTORY WALLS are usual in the furnaces of externally fired boilers, with low heat-release rates. The walls usually are integral with the boiler setting and are built of high-grade firebrick, second-grade firebrick, insulation, or some combination thereof. Some typical furnaces are shown below.

HORIZONTAL RETURN TUBULAR BOILERS. Figure 18 shows approved constructions. Type B is the least costly but is more liable to air leaks than type A. The hollow space in type A should be filled with sand or ashes to retard air infiltration in the event of cracks in the inner wall. Type C is more costly than type B. The insulation reduces heat loss through the walls, and raises the furnace temperature. Higher grade lining, therefore, is necessary. Metal ties are advisable to bond the lining to the outer walls, as the insulating brick has little mechanical strength. Type D is the most costly setting. It is similar to Type B, except that 85% magnesia replaces the hollow space, and a steel casing of No. 8 gage steel plate encloses the entire setting.

Jointless monolithic wall linings are made of plastic fireclay rammed into position and tied to the outer walls; three methods are shown in Fig. 19.

WATER-TUBE BOILERS. Stoker-fired furnaces may have solid refractory walls, whose arrangement depends on the type of stoker and boiler. The boiler should be so suspended from overhead beams that it cannot at any time come in contact with the furnace walls. Bridge walls and furnace linings should be high-grade firebrick. Cheaper grades of brick can be used behind the lining. Relieving arches, amply buttressed to carry thrust, may be built into the walls to relieve the load on the lower brick, in high settings, or to assist in wall repairs; expansion space should be provided below them. The upper part of high furnace walls sometimes is anchored to external steel work to prevent the wall falling inward as a result of alternate heating and cooling.

The common wall of furnaces grouped in batteries of two should be entirely of high-grade firebrick and much thicker than the side walls. Figure 20 gives typical sections through one type of wall construction for horizontal water-tube boilers. To avoid overheating, steel work supporting the boiler should not be enclosed in the brickwork.

Clinker belts, i.e., the lower parts of side walls of the furnace, adjacent to and just above the fuel bed, usually require special construction, as they are subject both to intense heat and to adhesion of clinker if the wall is of ordinary firebrick. Several solutions are available to meet these severe conditions. The wall at this point may be built of special
sag-resisting blocks which may be solid or hollow, or air- or water-cooled metallic wall sections may be used.

Joints in refractory walls are vulnerable points for slag attack. The brick should be laid with a fireclay mortar with refractory properties equal to those of the brick itself. Finely ground raw fireclay and as much finely ground calcined fireclay or ground firebrick, free from slag, as will stay in suspension in a batter should be used in laying the brick.

Backing-up brick is bonded to the inner lining by header and stretcher courses. If the lining is only 4 1/2 in. thick, every fourth or fifth course should be a stretcher course as d in Fig. 20. A 9-in. wall can be laid as header courses with every fourth or fifth course a stringer course, i.e., a header course behind a stretcher course (a, Fig. 20).

![Fig. 20. Wall construction for horizontal water-tube boilers.](image)

AIR-COOLED REFRACTORY WALLS are either entirely self-supporting or sectionally self-supporting. Cooling air flows through ducts in the walls and into the furnace. Self-supporting air-cooled refractory walls may be built entirely of standard-size brick, or with special refractory tile in the furnace lining, bonded to the outer wall. Figure 21 shows two forms of this type of wall. In each, the inner wall is flexibly bonded to the outer wall, to provide for differences in expansion. Sometimes larger blocks are used, instead of the standard brick, to reduce the number of inner wall joints.

Special forms of air-cooled blocks sometimes are used in the clinker belt, and sometimes for lining the entire wall. Some blocks have openings that permit flow of air through the block and into the furnace in order to cool the surface next to the fire, thereby reducing adherence of clinker.

Self-supported hollow walls cannot be used in extremely high furnaces because of the inability of the lower part of the walls, when hot, to carry the load of the upper part.

![Fig. 21. Self-supporting air-cooled refractory wall.](image)

![Fig. 22. Sectional self-supporting air-cooled refractory walls.](image)
Sectionally supported air-cooled refractory walls usually are built in horizontal belts 2 to 3 ft high, attached to an outside steel structure. Static load on the brickwork is thus reduced and a means is provided to support the wall when refractory replacements are made. Figure 22 shows typical forms. Different makes vary in shape of the refractories, number of special shapes, brackets and type of supporting steel, methods of providing for expansion and for sealing joints.

Arches over the fuel beds are seldom curved or sprung. Flat suspended arches (see Fig. 23) are more desirable. They require less skill in erection, exert no end thrusts, do not distort when heated, and if necessary can be repaired while the furnace is in operation. The refractory tile are air cooled on the back side, flexibly supported, can expand or contract freely, and have no additional weight to support. One make, not shown, incorporates a veneer of silicon carbide, enabling the arch to withstand very high temperatures, rapid temperature changes, and slagging action.

Properties desired in a good refractory are relative infusibility, relatively low thermal conductivity, flexibility of structure, low thermal expansion, impermeability toward gases and liquids, chemical inertness, and resistance to abrasion. Failure of a refractory in a boiler furnace may be due to one or more of the following: fusion; subsidence under load; spalling; slag action; changes in dimension.

**WATER-COOLED METAL FURNACE WALLS** are of three types: bare-plate, bare-tube, and covered-tube walls. They are more costly than refractory walls, but can withstand more severe conditions. In general, they are used only in locations where the refractory wall would deteriorate rapidly, for instance, in the bridge wall of underfeed stoker furnaces, or that part of the side wall immediately adjacent to the fuel bed of traveling-grate stokers operating at moderate rates. If higher rates of combustion are maintained with either type of stoker, the entire wall surface and arches may require water cooling.

**Bare-plate wall** furnaces are those in all internally fired boilers, as Scotch marine boilers and locomotive boilers.

**Bare-tube walls** are connected into the boiler circulation system, as shown diagrammatically in Fig. 24. They may be constructed of plain tubes (Fig. 25), fin tubes (Fig. 26), or studded tubes (Fig. 32). The plain-tube walls usually comprise tubes fairly closely spaced, the distance between tube centerlines ranging from approximately 6 in. to tube diameter (tubes touching each other). Other arrangements stagger the tubes in two rows or use special bifurcated tubes, usually 3-in. OD, on 3 1/8-in. centers.

In Fig. 25a the back sides of the tubes receive heat by radiation from the firebrick backing, the effectiveness of this radiation depending on the extent to which the space between the tubes is filled with sintered fly ash or molten slag. Figure 25b shows a modified form of firebrick backing. Arrangements shown in Figs. 25c and 25d are usually employed in larger furnaces fired by pulverized coal, oil, or gas, or a combination of all three fuels. These tangent tube walls require only a minimum of firebrick backing, the principal backing consisting of block...
insulation to reduce the heat loss. The wall is usually enclosed by a welded steel panel construction. Figure 25e shows an arrangement used in stoker arches.

In the fin-tube construction shown in Fig. 26, the longitudinal fins are welded to each tube usually at opposite ends of a diameter. Fins are ordinarily limited to 1 1/4 in. in width, and broken every 3 in. or so, longitudinally to prevent cracking. The backing is similar to that used behind plain tube walls.

COVERED-TUBE WALLS usually consist of tubes protected either by integral blocks or attached blocks; the latter may be all metal, all refractory, or metal coated with refractory. The blocks generally are rectangular, with flat faces, and form a substantially continuous flat surface when placed close together.

Integral block construction is obtained by casting iron blocks on boiler tubes. (See Fig. 27.) Thermal contact between block and tube is good. Space must be left between blocks to permit growth of the cast iron. A close approximation to the good thermal contact of this construction is obtained by shrinking internally machined cast-iron blocks on accurately sized tubes. (See Fig. 28.)

Attached block construction comprises metallic blocks bolted to the water-wall tubes. Various types are shown in Figs. 29, 30, and 31. With such construction, furnace temperatures are higher than with bare-tube walls under identical conditions, because of the lower heat transmission of the block-tube walls. This may be important at light loads.

Either cast iron or steel or alloy steel may be used for the blocks shown in Figs. 29 and 30. Depending on furnace conditions, the face exposed to the fire may be bare or coated with refractory; the bare face may be plain or ribbed. Refractory-faced blocks are used where high-temperature walls are necessary to assist combustion, and bare blocks where cooling surface is desirable. The blocks span the space between the tubes to which they
are attached, and make good thermal contact by reason of ground joints and a suitable heat-conducting plastic filler.

In Fig. 31, the bare or refractory-faced blocks and tubes are brought in close contact by channels and toggle joints.

**Fig. 30**

- Cast-metal block
- Insulating cement
- Insulating block
- Insulating cement
- Steel casing

**Fig. 29**

Types of bolted-on block water walls.

**Refractory-protected water tubes** are shown in Figs. 32, 33 and 34. Walls of this type usually transmit heat less rapidly than walls of all-metal blocks. Refractory-protected water-tube walls materially assist in maintaining high furnace temperatures at low fuel-burning rates. In the stud-wall construction (Fig. 32), short iron studs are welded on the tube surface where plastic refractory is to be installed. The entire wall-tube surface in the hot parts of a furnace can be completely covered with a thickness of plastic refractory that will give the desired rate of heat absorption, while tubes in the cooler parts of the wall can be bare except for the refractory-covered studs between tubes. The studs support the refractory and cool it by providing a good heat conductor to the water in the tubes. In Fig. 33, small fireclay blocks are slipped around ordinary boiler tubes. The rate of heat transfer to the tubes can be increased by using silicon carbide blocks. Such walls may be backed with refractories, block insulation, or a combination of both. The outer surface of the wall should be coated with a sealing cement or steel casing to prevent infiltration of air. In Fig. 34, interlocking fireclay, silicon carbide, or cast-iron blocks maintain intimate contact with the tubes without the use of clamping devices. Horizontal structural-steel channels so support belts of the blocks that, by removal of key blocks, any block can be removed without disturbing any of those above it.

**Fig. 32**

- Rammed plastic refractory
- Iron studs
- Insulating block
- Insulating cement
- Steel casing

Types of refractory-protected water-tube walls.

**FURNACE BOTTOMS.** The type of furnace bottom used depends on the fuel, characteristics, and methods of removal of the ash, method of firing, initial cost, and maintenance costs. Hand-fired or stoker-fired furnaces, operated at moderate rates, usually have ashpits, cleaned by hand. (See Fig. 2.) Stoker-fired furnaces, operating at higher rates, have ash hoppers of large capacity.
The steel hopper is lined with second-grade, hard-burned firebrick, paving brick, or cast-iron air-cooled plates. The hot ashes usually are quenched by water sprays. In some installations, the ashes are carried away by hydraulic sluices, and in others by conveyor cars. (See Fig. 35.)

Oil- or gas-fired furnaces have solid bottoms, or bottoms with air-cooled passages. Air-cooled bottoms may be of refractory hollow tile, or of several layers of flat interlocking tile carried on standard brick on edge, but not in contact with each other.

Pulverized-coal-fired furnaces have either dry or wet bottoms.

**Dry bottoms** are the more common, and may be of two types, the water-tube-screened refractory-hopper or the water-cooled hopper-bottom type. In the latter type the hopper bottom is formed by bending the front and rear wall tubes at the lower end. The tube slope is greater than the angle of repose for ash, and in this way forms a self-cleaning, water-cooled floor.

Figure 36 shows a typical hopper bottom of this type.

**Wet bottoms**, used in slag-tap or slacking boiler furnaces, form a hearth in which the molten ash collects in a pool. It remains molten and is tapped off either continuously or periodically, similar to the tapping of a foundry cupola. The molten ash, as it flows out, is granulated by a high-velocity water jet driving it against a plate, or by falling through a spray of multiple water jets. Wet-bottom furnaces originally were built to handle ash of fusion temperatures of 1900 to 2000 F, but inasmuch as the flat incandescent furnace bottom aids combustion, an additional advantage accrues from the saving in space requirements. As a result, furnaces have been developed to burn coals with ash fusion temperatures as high as 2600 F. In these furnaces, flames from the burners must bathe the hearth. Operation at high combustion rates only may be necessary, as the ash may solidify at low rates. Fluidity of the ash can be increased by adding limestone or other flux. (See Ref. 8.)

Preheated air can be used to full advantage to aid combustion of pulverized coal in wet-bottom furnaces without the troubles of ash removal from the furnace bottom that occur in dry-bottom furnaces.

A type of all-refractory wet bottom, usually installed in furnaces with water-cooled walls, is built on steel plates carried on an air-cooled structure of piers and I beams. Three or four courses of 2 1/2-in. firebrick are laid on the plates, and covered with 7 1/2 to 9 in. of burned dolomite or plastic chrome refractory. Extra courses of firebrick, laid near the furnace walls, form a saucer-shaped bottom. The tap hole at the side of the furnace is plugged by a ball of fireclay.

Furnaces with all-refractory wet bottoms are fairly satisfactory only when used with coals of low ash-fusion temperatures, at uniform, high combustion rates. Whenever the bottom cools, cracks may develop which will fill with slag. With frequent cooling the size of the bottom continually increases, ruining the seal at the furnace walls and displacing the water-cooled side walls. Iron sulfide, formed from iron pyrites in the coal, has a particularly bad erosive effect on the refractory, especially in cracks. The amount of iron sulfide formed can be reduced by pulverizing the coal until 80 to 90% passes through a 200-mesh sieve, as compared with the usual 65 to 70%.

REFERENCES


PULVERIZERS AND PULVERIZED COAL

By V. Z. Caracristi

27. PULVERIZERS

PULVERIZED COAL utilized for the firing of steam-generating equipment is dried, ground, and classified to a fineness which may be transported and burned in suspension with air. The degree of fineness generally utilized ranges from 60 to 90% through a 200-mesh sieve. A typical sizing is represented by this screen analysis: 99.5% through 50 mesh; 96.5% through 100 mesh; and 80.0% through 200 mesh. The surface area of the particles of a pound of coal classified to this fineness is approximately 105,000 sq in. This area represents an increase of approximately 2300 times that of a single one-pound lump of coal.

Energy required for preparing, grinding, and transporting coal ranges from 10 to 20 kw-hr per ton of coal. The factors which materially influence the actual power required for a particular installation are type of equipment, grindability of coal, and degree of fineness. In general, the power is also influenced by the rating at which the equipment is operated with respect to the design capacity.

Cost of preparation varies from 3 cents to 15 cents per ton.

PREPARATION OF COAL FOR PULVERIZING. The necessity for supplying raw coal of uniform quality to the pulverizer at a metered rate requires cleaning, rough sizing, and bunkering of the coal. Cleaning necessitates the removal of foreign material, such as large pieces of wood, straw, rags, and iron. This foreign material, often present in the coal as delivered to the plant, is removed to facilitate uniform feeding and to protect equipment from damage. Iron may be removed by magnetic separators in the conveyor system; other foreign materials may be removed by screening, by manual removal, or by the equipment utilized for rough sizing or crushing.

Rough sizing or crushing eliminates oversized pieces of material which would jam the feeder or cause an irregular feed rate, and better distributes the moisture in the raw coal. The preferred sizing of the coal produced by the crusher is generally limited to a maximum of all through \( \frac{3}{4} \) in. round screen. For small-capacity mills and to obtain a more uniform moisture distribution, the coal may be crushed down to all through a \( \frac{1}{2} \) in. round screen. The bunker must be designed to give storage space for this prepared raw coal, and to provide a uniform supply of coal to the feeder. The method of filling the bunker must be considered as this is found to influence the degree of segregation and packing.

FEEDERS. An uninterrupted uniform feed to the pulverizer is essential to successful operation of a pulverized fuel system. In many cases the feeder is used as a source of metering the fuel supply to the system. Performance of the feeder is thus an important design consideration. Two types of feeders are generally used, the table type and the roll type. The table-type feeder feeds coal from a spout onto the table, the coal rotating with the table. The rate of feed is controlled by a cut-off arm, which scrapes off coal from the table, or by the speed of the table, or by a combination of the two. This type of feeder is subject to stoppages from foreign material and requires a relatively close sizing of raw coal to perform with any degree of uniformity. Simplicity, however, makes it well adapted for feeding where accurate metering is not necessary.

The roll-type feeder consists of a rotating spider with pockets which fill from the coal spout and discharge to the mill. The Raymond roll-type feeder is an example of this type.

PULVERIZERS. The function of a pulverizer is to grind, dry, and classify coal to a state in which it can be successfully transported and burned in mechanical suspension.

The principles of grinding are impact, attrition, and crushing. The application of one