

POWER-GENERATION SYSTEMS

Energy Systems Engineering

By the Editors of POWER
The McGraw-Hill Magazine of Energy Systems Engineering

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STEAM GENERATION

By [illegible] Associate Editor

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a Power special report

[illegible] Managing Editor JUNE 1964

STEAM GENERATION

By RENE J BENDER, *Associate Editor*

As world demand for energy continues to climb, steam grows in importance as a basic energy-transfer medium—for power generation, industrial processing, space heating. At the same time, fresh emphasis is placed upon reliability and efficiency of the steam generator.

Today a growing number of applications using electricity require a continuous, dependable supply. Applications using steam are equally demanding throughout industry. Thus steam generation in central stations, industrial plants, commercial buildings and service establishments is a key factor in energy systems. Therefore, the reliability of steam generators today is a major contribution to system dependability. With steam-generator size continually increasing, even a modest efficiency gain means substantial savings.

The pages that follow give you a better understanding of the modern steam generator and the many factors which influence its performance.

So that this 48-page report can be reasonably thorough, it is centered around the heat-absorbing surfaces, leaving to other reports the equally important matters of fuels and firing, feedwater treatment, nuclear steam generation.

Throughout the pages of this report are facts on:

Fundamentals of steam generation 2
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Watertube steam generators 16
Developing higher temperatures 24
Steam generators for higher pressures 31
Supercritical units and cycles 35
Designs for special applications 39
Selecting the steam generator 42
Maintenance and operation 44

The pages which follow blend principles and practice, equipment detail and system considerations, aimed to be of practical value to all engineers responsible for design and operation of steam systems across industry.

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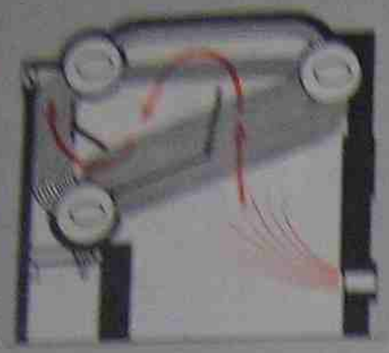
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R H MARKS, Managing Editor

JUNE 1964

What is a boiler?





Essentially, a boiler is a container into which water can be fed and in the combustion of fuels converted into steam. In such designs the boiler was a simple shell with a fire tube and steam outlet, mounted on a brick setting. Fuel was burned in a grate within the setting and the heat so released was directed over the lower shell surface before most of it was lost to the air.

Designers soon learned that heating a single large vessel of water was inherently inefficient; that it was necessary to bring more of the water into contact with the heat. One way to do this is to direct the hot combustion products through tubes within the boiler shell. Such a straight design (above, left) not only increases the heat surface exposed to the water, but also tends to distribute steam formation more uniformly throughout the mass of water.

In contrast to the straight idea, watertube designs feature use of many relatively small drums with a multiplicity of tubes in which water-steam mixtures circulate. Heat flows from outside tubes to contents. This subdivision of pressure parts makes large capacities and high pressures possible.

Fundamentals

Refresh your knowledge of such basic elements of steam generation as steam properties, heat transfer and circulation

Since steam generation is the business of turning water into steam for application of heat, first we need to know something about the factors involved in this process.

As the charts below illustrate, heating water at any given pressure will eventually cause it to boil, and steam will be released. The heat required to bring the water from 32 F (basic point for all water and steam properties) to the boiling point is the enthalpy of the liquid and is measured in Btu per lb.

Saturation. When water is boiling, both water and steam have the same temperature, called the saturation temperature. For each boiling pressure there is only one saturation temperature and vice versa. As we have seen, during the boiling process temperature remains constant, even though heat is being added. The heat is, of course, being used to change the water from the liquid to the vapor state. This heat, in Btu per lb, is the *enthalpy of evaporation*. Enthalpy of the saturated steam is enthalpy of saturated liquid plus enthalpy of evaporation; that is, total heat added to bring water at 32 F up to steam at a given state.

Superheating. As long as steam and water are in contact, temperature will remain the same — the saturation temperature for the given pressure. If we want to raise the temperature of the steam, we must *superheat* it — heat it out of contact with water. The enthalpy of the steam will increase by the amount of Btu added per lb, and the temperature will rise. Rate at which temperature rises depends to some degree on the pressure. This can be seen in charts below where shape of superheated steam lines varies at the different pressure levels.

Critical point. The charts below also reveal that there is a point where water turns into steam without boiling. This occurs at a temperature of 705.4 F and a pressure of 3206.2 lb per sq in. absolute. Parenthetically, the current standard abbreviation for lb per sq in. is *psi*. When this is measured on a gage (*psig*), it represents pressure above atmospheric (14.696 psi, usually rounded off to 14.7). *Absolute pressure* is thus *gage pressure* plus 14.696 and is designated *psia*.

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Mollier chart. Steam properties are also obtainable from charts which are often preferred for the way they show the relationships graphically and the ease with which cycles and processes can be traced on them. The chart most frequently used is the Mollier diagram, established at the turn of the century by Richard Mollier and adapted to English units and recent data by Keenan and Keyes.

HEAT TRANSFER

In the foregoing discussion of the process of turning water into steam, we referred constantly to the addition of heat. Let's look now at some of the basics of transferring that heat to water to make steam.

We can distinguish three types of heat transfer: conduction, convection and radiation. *Conduction* is the transfer of heat from one part of a material to another or to a contiguous material. Heat is visualized as molecular activity — crudely speaking, as the vibration of the molecules of a material. When one part of a material is heated, the molecular vibration increases. This excites increased activity in adjacent molecules, and a heat flow is set up from the hot part of the material to the cooler parts, Fig. 1. In any one material, if energy flow rate remains constant, temperature decreases uniformly from hottest to the coolest point.

Substances differ greatly in ability to conduct heat. Gases and vapors are the poorest conductors, liquids are much better, and metals are the best. Heat conduction is measured as *thermal conductivity, (k)* in Btu per hr, per sq ft, per deg F, per foot of thickness. Conductivity is affected by the temperature of the material. Variations are measurable but not great and stay within clearly defined limits for each material.

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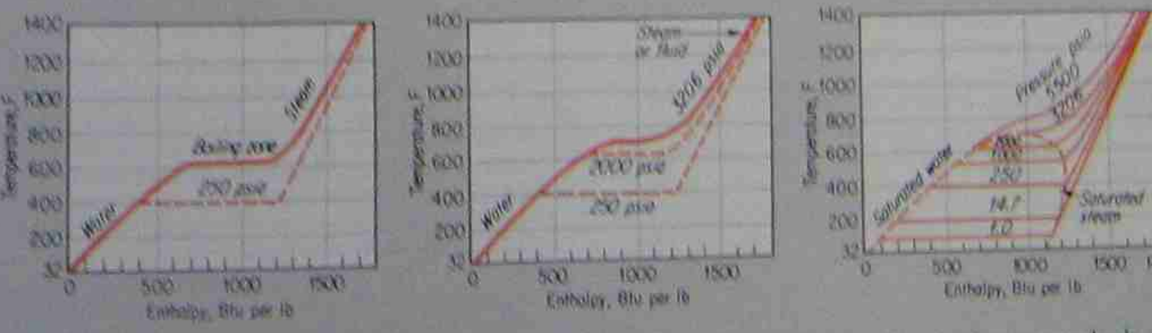
Radiation. All bodies radiate energy. *Radiation* does not require a transmission medium; it travels through a vacuum as well as through a gas. Radiation travels like light

What happens to a pound of water when changed to steam at various pressure levels



If we heat a pound of water in a cylinder with various pressures applied to the piston, we find that the same general sequence of events occurs at each pressure level. First, water temperature rises and its volume increases slightly. Then boiling begins, the volume increases greatly, but temperature does not change. When all the water has changed to steam, the volume continues to increase on further heating and the temperature rises. This is called superheating.

The charts above show these events occurring at pressures of 14.7 psia and 1000 psia. Note that the temperature at which boiling occurs is higher at the higher pressure, and that the amount of heat necessary to vaporize the water is less. Note also that the steam line is steeper at the higher pressure, indicating that the steam is superheated more rapidly.

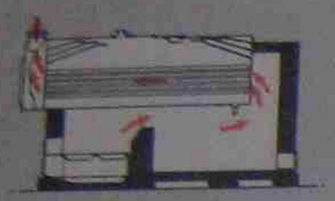


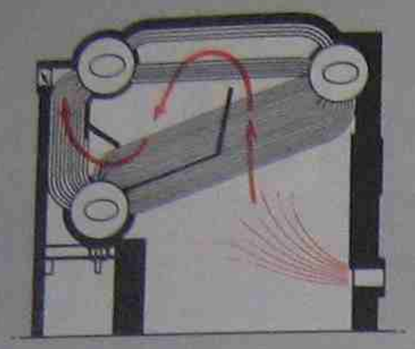
ing point goes up, while amount of heat necessary to vaporize it tends to get less. Eventually, at 3206.2 psia we reach a point where water turns to steam without boiling, and all the heat

shown on the preceding ones plus two other pressure levels.

If we heated water and its vapor in a sealed quartz tube, we would see, at any condition below the critical point, a clearly defined level, separating water and steam. Near this

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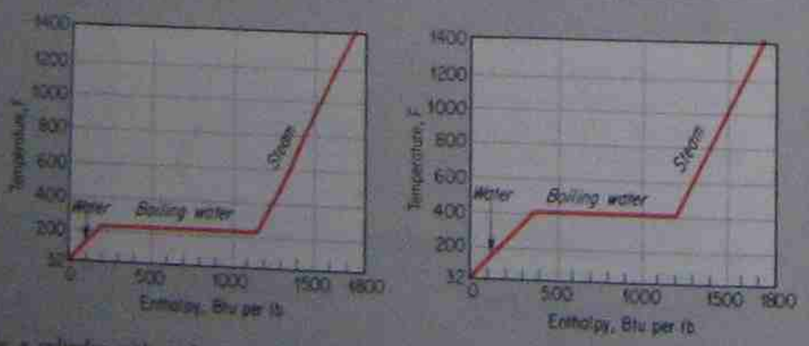
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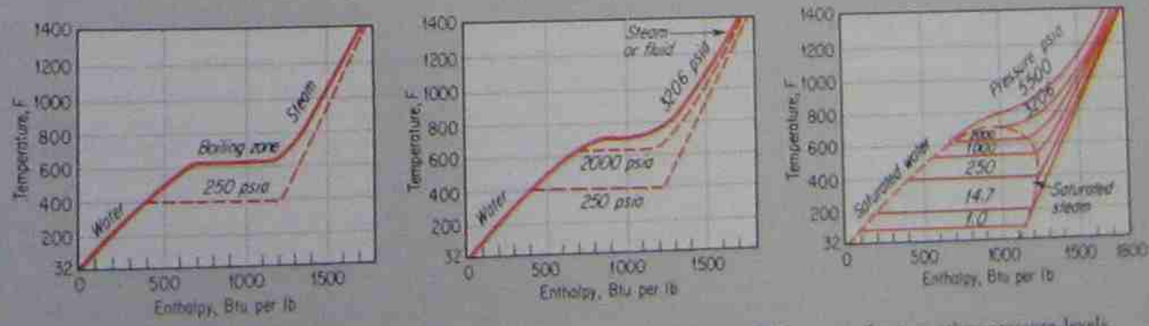
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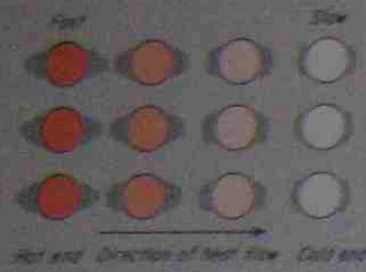
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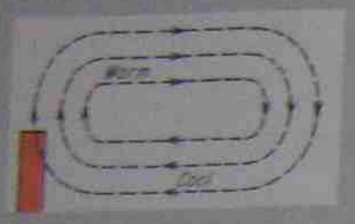
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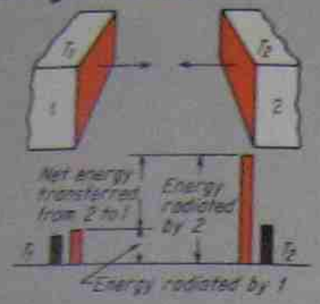
The three forms of heat transfer work together in steam generation



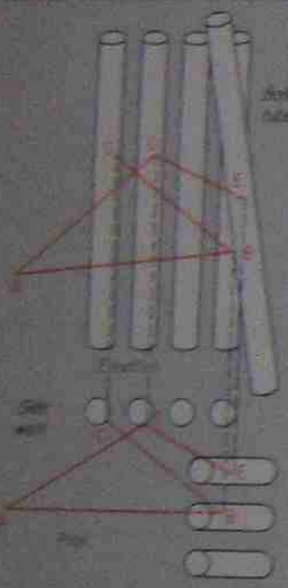
1 In conduction, heat flow results when fast, vibrating molecules in one part of a material strike neighbor in adjacent ones



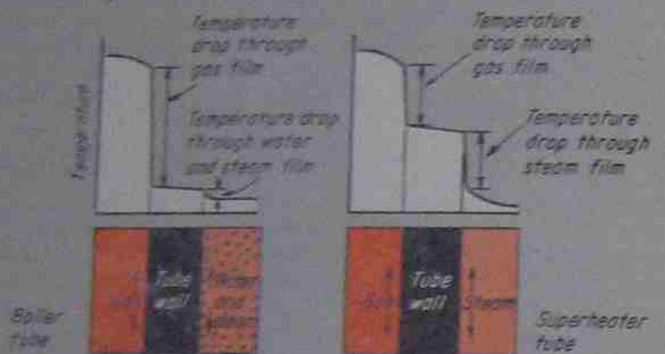
2 Convection is a movement of the heated fluid itself. It results when the cooler, heavier fluid displaces the heated fluid



3 All bodies give off radiation in amounts depending on their absolute temperature. Energy flow is net difference of radiations



4 In actual practice heat transfer is complex interaction of all types. Boiler tubes in diagram receive heat by conduction and convection from the hot combustion products. They also receive heat by radiation from other, hotter bodies and directly from the flame



5 Temperature gradients from hot gas through tube wall to fluid inside depend heavily on resistance of thin fluid films on tube surfaces. Diagram shows how high resistance of steam film inside superheater tube causes higher metal temperature than in boiler tube

warmer, a body exposed to radiation is heated only on the side exposed. Other side is in "shadow" and remains cool.

Amount of energy a body radiates depends to some degree on size, shape and substance, but mainly on the fourth power of the body's absolute temperature. Thus, if absolute temperature is doubled, radiation will become 2 x 2 x 2 x 2, or 16 times as much. It is important to remember also that two bodies in sight of each other radiate energy toward each other according to their absolute temperatures, Fig. 3. Net amount of energy transferred from hotter to colder body is difference of the two radiations.

Practical case. In Fig. 5 we see the familiar case of heat transfer into a tube placed in a stream of heated gas. The gas flow is a convection current, carrying heat from the furnace to the tube. A thin film of gas adheres to the outside tube surface and a similar water film adheres inside where there is a water convection current. Heat from the gas must flow, by conduction, through the gas film, tube metal, and water film. Poor conductivity of the gas film in comparison with those of metal and water film causes a large temperature drop outside the tube. This keeps outer surface of the tube metal relatively cool.

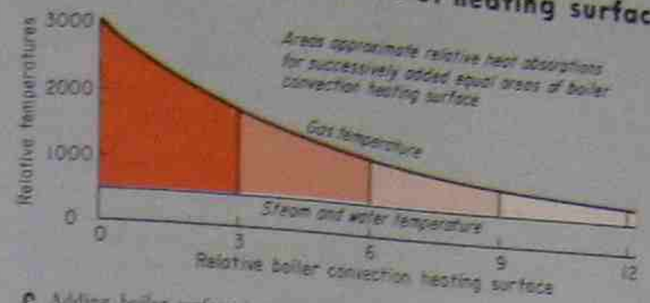
On the right side of Fig. 5 we have steam inside the tube instead of water. Now there is a vapor film, of poor conductivity, on the inside surface. Although overall temperature difference remains the same, the new set of resistances means a different temperature *gradient* and a higher temperature in the tube metal.

HEATING SURFACE LAYOUT

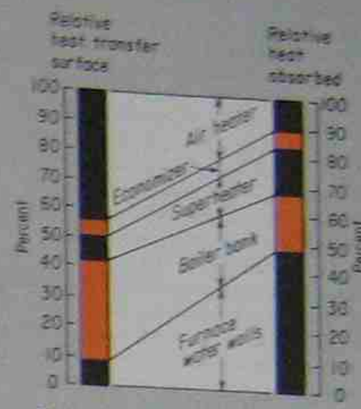
Since a boiler turns water into steam by the application of heat, amount of heating surface and the way it is arranged affects efficiency and capacity. For the moment, let's define efficiency as the fraction of heat released in the furnace that is absorbed by fluid in the boiler elements.

In the preceding page, we saw how adding firetubes to early shell boilers improved capacity and efficiency by increasing amount of surface that combustion products flowed past. Effects of changing amount and arrangement can be seen more clearly, however, in a simple watertube boiler. Imagine a unit of fixed width with successive rows of straight tubes exposed to heated combustion products

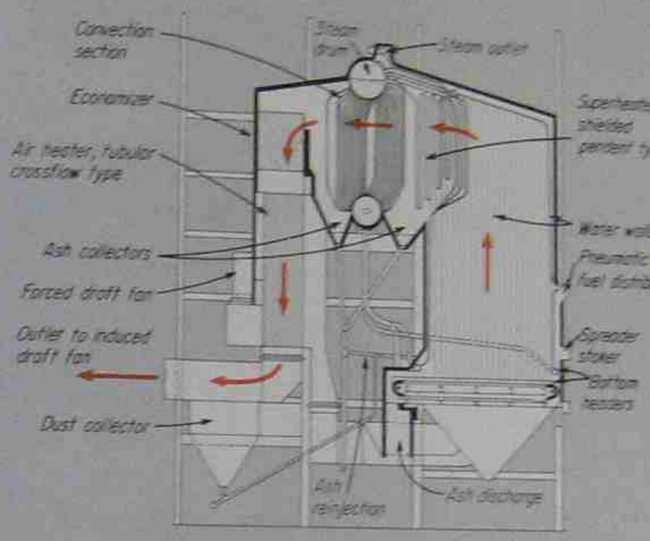
Specialized forms of heating surface boost efficiency economically



6 Adding boiler surface increases heat absorption but, because gas temperature is lowered, each equal increment added absorbs less heat. Thus, at some point, the cost of adding surface outweighs the gain in efficiency



7 Chart shows relative amount of heating surface of each type in unit of Fig. 8 and relative amount of heat absorbed by each



8 Modern steam generators employ specialized heating surfaces to achieve high efficiency. Waterwalls depend mainly on furnace radiant heat. Superheater may use both radiant and convection transfer. The convection surface works in a somewhat cooler convection zone. Economizer and air heater can utilize still cooler convection heat because they transfer it to low-temperature-level fluids — the feedwater and the incoming combustion air

carried in a convection stream. Assume gas temperature entering the first tube row is 3000 F and that we are generating steam at 600 psia (saturation temperature, 486.2 F). If we start with three tube rows, temperature leaving the last row might be 2000 F, having been reduced by heat absorbed in the tubes. If we add three more tube rows, gas temperature entering this added bank will be only 2000 F, and therefore less heat will be absorbed in it than in the first bank. The same thing will happen with each successive addition — each added bank, although of equal size, will be less effective than the preceding one, Fig. 6.

Diminishing returns. Each addition increases the amount of heat absorbed and hence efficiency and capacity of this imaginary unit, but it is evident that, at some point, cost of adding surface outweighs the diminishing gains from each addition. Furthermore, as gas temperature is reduced, there comes a point where difference between it and temperature of the steam-water mixture is so small as to put a practical limit on efforts to increase efficiency by adding more surface. We'll see soon how this seeming limitation on possible efficiency is overcome.

In their efforts to produce more efficient and economical steam generators, designers have developed a variety of specialized forms of heating surface. A modern steam generator, such as the one in Fig. 7, has its furnace virtually surrounded by heat-absorbing surface. As shown in Fig. 8, these waterwalls represent only 9% of the unit's total heating surface but account for nearly half (48%) of total heat absorption. This high effectiveness in heat absorbed per sq ft results from exposure to radiant heat in the zone of highest temperature.

Saturated steam from the drum of this unit is heated further in a *superheater* located in the upper portion of the furnace space where temperatures are still high and there is some radiation effect. Like the waterwalls, the superheater represents 9% of this unit's total heating surface. It accounts for 16% of heat absorbed.

Behind the superheater we have the main convection steaming surface. This boiler bank, in a lower-temperature zone than the waterwalls and superheater, contains nearly twice as much surface as the sum of their surfaces but accounts for less heat absorption. It has 33% of the total

surface and absorbs 20% of the heat. At this point we have reached the practical limit of heat absorption in convection steaming surface, as mentioned before. How can we recover more heat from the still-hot gas?

Low-temperature heat. Here the designer turns to the lower-heat-level portions of the cycle to make further gains in efficiency. Since feedwater temperature is below saturated steam temperature, it is possible to recover some heat from the gas stream by putting an *economizer* in the unit. This specialized heating device has 6% of the steam-generator's total surface and absorbs 6% of the total heat.

For further heat absorption from the combustion products before they go to the stack, the designer provides for transferring heat to a still-lower-temperature fluid — the air for combustion. Using an *air heater* to raise temperature of combustion air reduces fuel required to release a given amount of heat in the furnace. Because of low temperatures and, inevitably, poor gas-to-gas heat-transfer rates, the air heater surface must be large. In our example it represents 43% of total surface and accounts for 10% of the heat absorbed.

BOILING AND CIRCULATION

Now that we've considered the various elements of steam-generator heating surface, we can go back and take a closer look at what happens after the heat is transferred to the water. The objective, of course, is to produce boiling. In a simple shell heated from beneath, we can readily visualize what happens: Steam forms in bubbles at the heated surface. Bubbles and heated water are displaced by heavier, steam-free water, and circulation currents bring bubbles to the surface where steam is released.

In watertube boilers, water and steam flow in a relatively large number of tubular paths that are heated externally. The basic idea can be simplified by visualizing a single circuit like that of Fig. 9. A drum with steam outlet and water inlet (not shown) has connected to it a loop of tubing, one leg of which is heated and the other unheated.

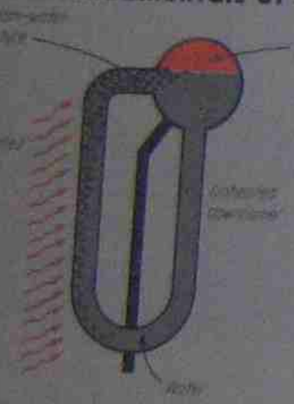
Steam bubbles form in the heated leg, generally called a *riser*. The resulting steam-water mixture is displaced by the relatively heavy water in the unheated leg or downcomer, and a circulation flow is established. Under operating conditions, there is a continuous flow of water from the drum through the downcomer and up the riser to the drum where steam is released.

An actual boiler consists of many circuits, like Fig. 9 in principle, with a drum or drums acting as a distributing and collecting device and releasing point for the steam. Actual boilers are not built up by merely multiplying number of simple individual loops; circuits are more complex and number of individual paths for steam-water flow varies from point to point. In Fig. 15, for example, there is a continuous loop from upper to lower drum and back to upper, but it is divided into a number of paths — specifically, into many riser tubes and a few large downcomers.

In the ideal case of Fig. 9, the downcomer was considered to be unheated. While unheated downcomers can be, and are, provided for in actual designs, many boilers have downcomers that are, for practical reasons, exposed to some heat. In Fig. 16 it can be seen that gas reaches the downcomers after it has given up much of its heat in flowing over the riser tubes. It is generally assumed that only sufficient heat is absorbed in the downcomer to raise the water to its saturation temperature, and that no steam is formed in this part of the circuit.

Positive circulation is highly important to successful boiler operation. What factors influence it? Referring to Fig. 12, it can be seen that the force producing circulation is the difference in weight between a column of steam-free water and an equal column of steam-water mixture. This force must overcome the resistance to flow, which varies with velocity. If force available to cause circulation is greater than resistance at a given velocity, flow will increase until resistance balances available force. If available force is less than resistance, flow will decrease until balance is reached.

How fundamentals of steam formation and circulation affect design



9 In simple watertube circuit, steam bubbles form on heated side. The resulting steam-water mixture weighs less than cooler water on the unheated side and is, accordingly, displaced. In drum, steam bubbles rise to the water's surface and steam is released

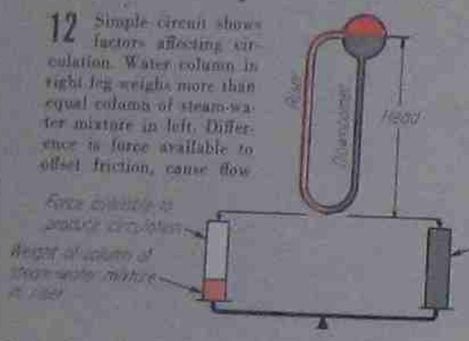


10 In what is defined as *nucleate* boiling, steam bubbles appear at the interface between water and tube, but there is always water present to wet heat-receiving surface

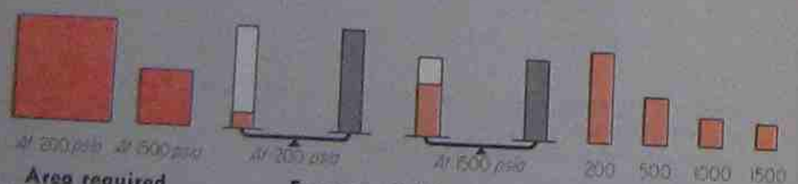


11 At higher pressures, nucleate boiling tends to give way to *film* boiling in which a film of steam covers heated surface. Here careful design becomes even more vital

12 Simple circuit shows factors affecting circulation. Water column in right leg weighs more than equal column of steam-water mixture in left. Difference is force available to offset friction, cause flow

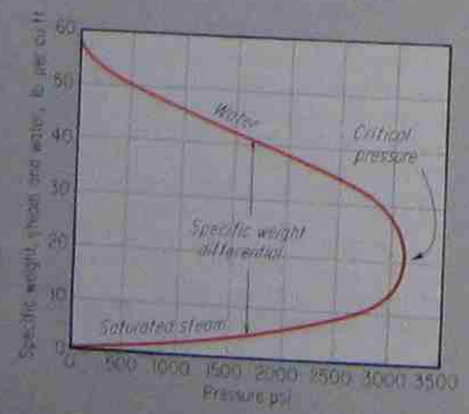


Forces causing circulation must always balance forces resisting it. If available head is greater than resistance at given velocity, an increase in flow will occur until increased resistance is in balance with the head

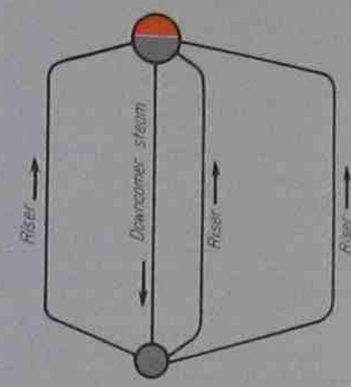


13 Pressure affects circulation in several ways: (*Left*) More tube area is required for low-pressure steam than for high. (*Center*) Force producing circulation is less at high pressure. (*Right*) In general, friction losses run less at high pressure

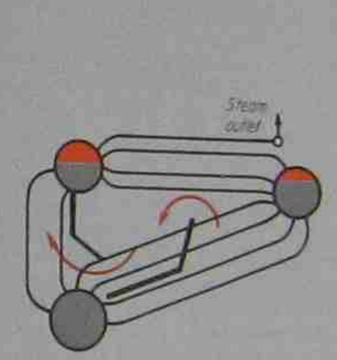
14 As a measure of the effects of pressure on the force producing circulation, chart compares specific weight of water and saturated steam. The differential between the specific weights shrinks as pressure increases until, at a pressure of 3206.2 psia, the critical point, there is no more differential



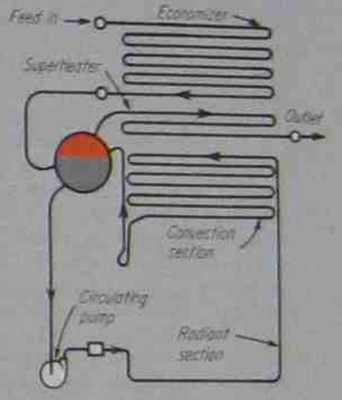
Several circulation systems fit a variety of design situations



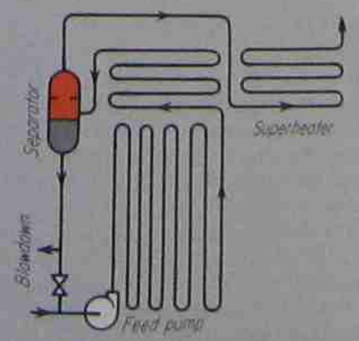
15 In actual natural-circulation units the principles of Fig. 9 and 12 apply, but there are usually many parallel riser circuits carrying steam-water mixture and a few, larger cold downcomers



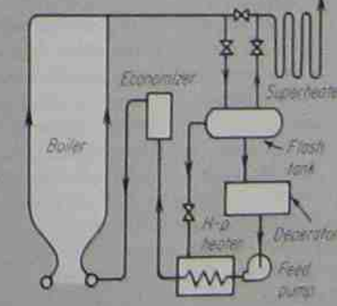
16 Circulation situation in a 3-drum low-head boiler is more complicated. Downcomers are partially heated, there is less head difference to produce circulation, more frictional resistance



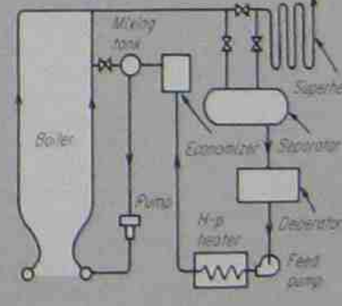
17 *Forced circulation* employs a pump to overcome resistances. It may be used at high pressures where natural circulation forces are small, or at lower pressures to give freedom in tube layout



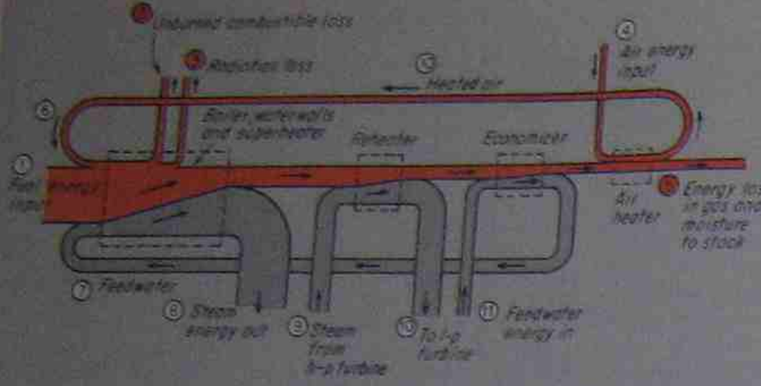
18 In *once-through* designs there is no recirculation: feedwater leaves the tubes as steam. When pressures are below critical, a separator may be used to remove any moisture present in steam



19 In *supercritical* units there may be need of special provisions for low loads and startup. One system, explained in more detail on p S 35, bypasses steam to a flash tank during low-flow periods



20 In another system for supercritical pressures, a forced controlled circulation hookup comes into play during low demand periods of startup, light loads. (For further details: pp S 36-37)



Energy flow diagram shows steam-generator operation

A steam generator is a complex form of energy exchanger. Fuel, air and feedwater carry energy into the unit, various interchanges take place, and the useful output appears as steam.

Since total energy out must equal energy in, other outputs appear as losses. These include energy lost in gas and moisture to the stack, unburned combustibles, and heat radiated from unit.

FACTORS AFFECTING CIRCULATION

Analysis of all factors influencing circulation is highly complex. The two most important factors, however, are: (1) difference in density between water and the steam-water mixture and (2) the frictional losses opposing circulation. Other things being equal, the latter are roughly proportional to the specific volume (cu ft per lb) of steam-water mixture and are also affected by viscosity of steam.

Density, or specific weight, and its reciprocal specific volume, change with pressure, as shown in Fig. 14. In general, the force available to produce circulation diminishes as pressure increases. This is partially offset by the fact that friction losses tend to decrease as pressure rises. As a net result, it is possible to design high-pressure steam generators for natural circulation, but as pressure rises, circulation factors demand increasingly careful consideration. This is one of the reasons some designers have turned to forced circulation, using a pump, Fig. 17.

It is apparent that the amount of water circulated in a boiler usually greatly exceeds amount of steam being generated. If 10 lb is circulated for each lb generated, *circulation ratio* is 10 to 1. Another way of expressing the same thing is in terms of *dryness fraction*, the percentage of steam by weight in the steam-water mixture. This may also be measured in percentage of steam by volume.

The percentage of steam by weight in a steam-water mixture at top of a riser tube where heating ceases is called *top dryness* — it varies with design, but normally runs from about 5% to 20%. If percentage of steam in the mixture becomes too high, there is a danger of steam "blanketing" — that is, passing from nucleate boiling (Fig. 10) to film boiling (Fig. 11), a condition in which a film of steam exists at inner tube surfaces. This condition is acceptable in superheaters, but not in wall tubes. It can, in certain cases, be remedied by internally ribbed tubes.

Watertube boilers with complex circulation loops — waterwalls, screen walls, radiant platen heaters, superheaters — are calculated to insure that sufficient *mass-flow* passes through each tube, at every load, to keep tube metal within a safe temperature limit. Mass-flow refers to the weight of fluid mixture in lb per hr passing through the tube. It is affected by velocity, density, specific heat, conductivity, fluid viscosity, tube diameter and internal surface. Designers must be able to take a calculated guess at some of these variables, for example, the percentage of steam by weight in the steam-water mixture, the "dryness-fraction" mentioned before, at various points in the circuit.

Once that approximation is made, relationship between these variables is governed by certain dimensionless numbers which have become the indispensable tool of the hydraulic engineer. Most commonly used among these numbers and applied to the gas side as well as the steam side of boiler surfaces is the Reynolds number. This brings into the picture mass-flow, tube diameter, fluid velocity and viscosity—all factors in flow resistance.

In contrast to natural circulation and forced circulation designs — in which more water is circulated than steam is generated and a drum or drums serve as a collecting and steam-releasing point — the once-through design consists, in theory, of a single tube (no drum) into which goes feedwater and out of which comes saturated or superheated steam. In actual units, of course, the theoretical single circuit becomes a number of parallel circuits.

At pressures below critical, a once-through unit may have a separator to deliver saturated steam to the superheater and to return collected moisture to the feedpump suction, as in Fig. 18. The once-through cycle is, of course, ideally suited for pressures above the critical point where water turns to steam without actually boiling. As will be explained in more detail when supercritical units are discussed (pp S 35-S 38), such units may require special provisions for satisfactory operation and control at low loads. This may be accomplished by a bypass hookup, Fig. 19, or by providing a forced recirculation system to take over automatically during low-flow periods, Fig. 20.

STEAM-GENERATOR RATINGS

The oldest measure of steam-generator capacity is the boiler horsepower, the amount of steam required to generate one horsepower in a typical steam engine of the time the unit was adopted. After a number of changes in numerical values, it is now defined as the ability to evaporate 34.5 lb of water to steam from and at 212 F. It is still used as the common measure of capacity for small boilers. Larger boiler capacity is almost invariably given in lb of steam evaporated per hr, with the steam conditions specified. Maximum continuous rating is the hourly evaporation that can be maintained for 24 hours, and a further rating on the basis of a 2-hour peak output may be given. Recent trend is toward rating large boilers in kw or mw of the turbine generator, thus including work done by reheater.

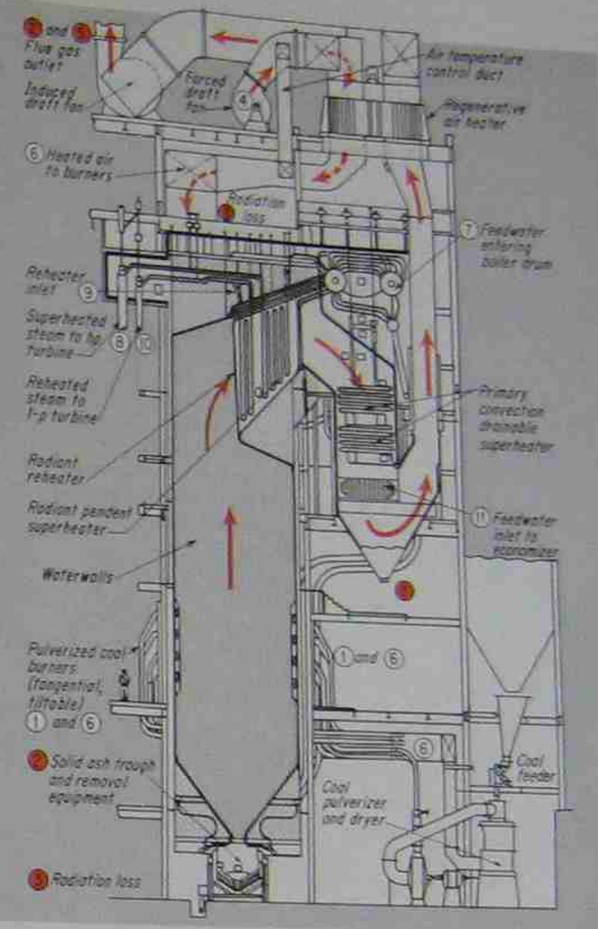
A steam-generating unit coordinates many elements

While the term "boiler" is broadly used, it should apply, strictly speaking, only to the elements in which a change of state takes place. The term "steam generator" is also used for the many combinations of heating surfaces, such as waterwalls, superheaters, reheaters, economizers, and air heaters. A "steam-generating unit" consists of a steam generator and its associated equipment, such as fuel burning, ash removal, and draft systems. Such a steam-generating unit is pictured at right.

It can be seen that a complete steam-generating unit represents a combination of many elements, all of which must be integrated properly if the unit's operation is to be efficient.

Expressed another way, performance of the total unit can be affected by limitations of any of the systems external to the steam generator — inadequate draft, for example, or fuel-burning equipment that does not supply the heat release on which steam-generator design was predicated. Thus, there is an increasing tendency for the manufacturer of the steam generator to be responsible for coordinating entire unit.

Numbers on drawing correspond to numbers on diagram on opposite page, identifying energy inputs and outputs.



A steam generating unit would be 100% efficient if it absorbed the entire heating value of the fuel. The fuel-burning equipment and furnace, however, cannot develop the full value of the fuel, and thus the steam generator proper starts with one strike on it. Theoretically, the steam-generator efficiency is the ratio of the heat absorbed by the feedwater to the heat released in the furnace. Because it is difficult in practice to separate furnace losses from steam-generator losses and because, in the last analysis, it is overall efficiency that is of interest, it is customary to express steam-generating unit efficiency as the ratio of heat output in the steam to heat input in the fuel.

EFFICIENCY AND LOSSES

Diagram on opposite page shows energy changes that take place in a steam-generating unit. Energy enters the unit in fuel and, measured above a base of 32 F, in incoming combustion air and feedwater. It leaves as useful output (steam from the superheater and reheater) and losses.

Some losses can be reduced by good design and operation, others cannot. The major loss is heat going up the stack. The biggest part of this is dry-gas loss (heat represented by so many lb of flue gas at some temperature above standard atmospheric conditions). This can be reduced by cutting down the amount (reducing excess air) or by lowering the temperature (adding more heating surface, for example). Another part of the stack loss is represented by the heat absorbed in evaporating and superheating moisture that comes in with the fuel and superheating the moisture in the combustion air. Moisture also results from the burning of hydrogen in the fuel. Flue gas may also contain some unburned combustible.

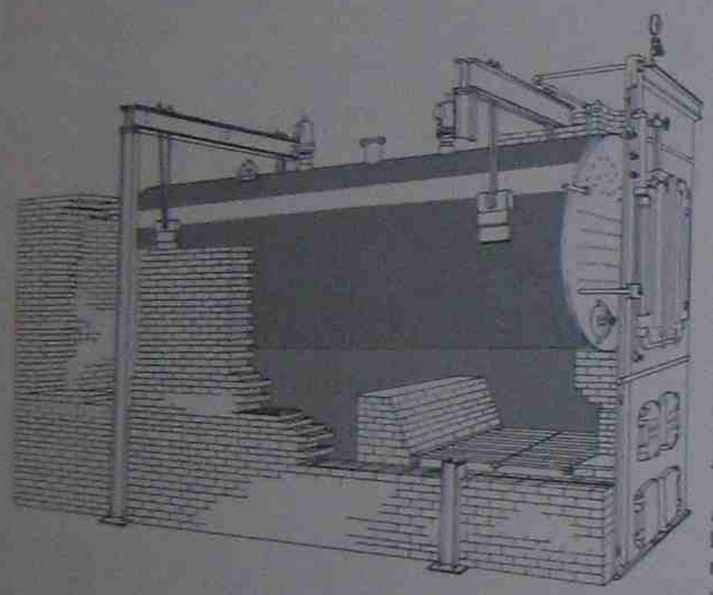
All other losses are negligible in comparison with what goes up the stack. Where solid fuel is fired, some unburned or partly burned combustibles are lost in the ashpit, and some heat loss is represented by the hot ash itself. Additional small amounts of heat are lost by radiation from the steam-generator casing and by blowdown from the unit.

Firetube boilers

They provide compact, low-cost answers for steam loads up to about 25,000 lb per hr and 250 psi

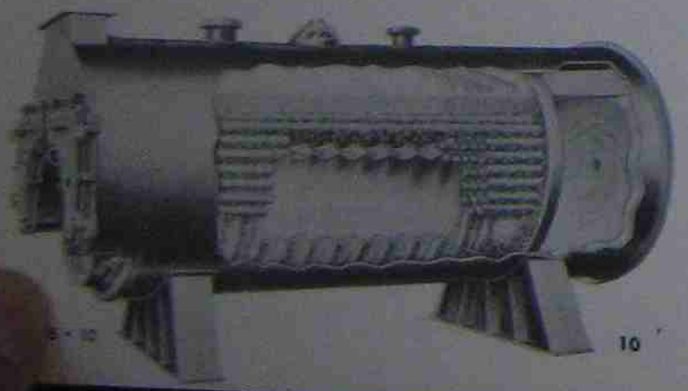
The name *firetube* derives from the fact that in boilers of this type all or most of the work is done by heat transfer from hot combustion products flowing inside tubes to the water surrounding them. They may also be classified as shell boilers — that is, water and steam are contained within a single shell housing the steam-producing elements.

Although the ideal shape to resist internal pressure is a sphere, practical considerations lead to the use of basically cylindrical shells. Non-cylindrical sections and flat surfaces are given added resistance to internal pressure by various means: diagonal stays, through-bolts, or tubes themselves which are designed to be used as stays.



1 Horizontal return-tubular boiler has fusion-welded drum suspended from a steel structure independent of brickwork forming furnace and rear reversing chamber. Steel front has smokebox doors giving access for cleaning

2 This Scotch-type boiler also employs welded construction. Combustion occurs in corrugated internal furnace; dryback refractory-lined rear chamber reverses flow, directs gas forward through tubes to smokebox at the front



In such a shell the force tending to burst it along the length is twice that tending to burst it around the girth. In the critical longitudinal direction the strength required to resist bursting is proportional to the product of the pressure and the diameter. It can be seen that high pressures and large diameters would lead to extremely thick shell plates. Hence, there is a rather definite economical limit on pressure and capacity that can be reached with shell-type boilers.

An operating pressure of 250 psi may be considered the practical ceiling, and in this country capacity rarely exceeds 25,000 lb of steam per hr — roughly 750 boiler hp. In Europe, where larger firetube boilers have always been popular and economic and boiler-code conditions are different, units of 30,000 lb per hr are not unusual.

As a class, firetube boilers feature simple and rugged construction and relatively low first cost. Characteristic large water capacity makes them somewhat slow in coming up to operating pressure but provides some accumulator action that makes it possible to meet load changes quickly.

Horizontal return-tubular boilers (Fig. 1) consist of a cylindrical shell, now usually fusion-welded, with tubes of identical diameter running the length of the shell throughout the water space. Space above the water level serves for steam separation and storage. A baffle plate or dry pipe is ordinarily provided near the steam outlet to obtain greater steam dryness. Feedwater is generally brought in along the top of the steam space and the blowdown connection is at the back.

Because the brick setting may be designed to accommodate many kinds of firing equipment, horizontal-return-tubular boilers can handle many types of fuels. This may be an asset, for example, where waste fuels are available.

Brick-set boilers may also employ a 2-pass construction. In these designs the cylindrical front portion of the shell fits into a larger cylindrical or oval rear section. Combustion products enter short tubes in the lower part of the rear section and then reverse to flow forward through the upper full-length tubes.

Internal-furnace boilers of the so-called Scotch type are essentially self-contained. Combustion takes place in a cylindrical furnace within the shell. Firetubes run the length of the shell at the sides of, and above, the internal furnace. Gas from the furnace reverses direction in a chamber at the rear and travels forward through the tubes to a smokebox located at the front.

The Scotch boiler illustrated, Fig. 2, is a dryback design, with a refractory-lined rear chamber. When the rear chamber is submerged in the water

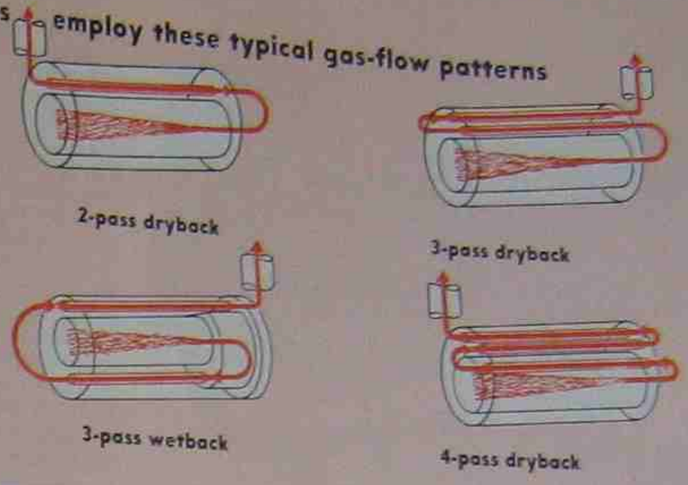
Today's packaged units employ these typical gas-flow patterns

3 Diagrams, right, show the basic gas-flow patterns used today. All use an internal furnace or firebox as a first pass, then route the gases into various tube layouts.

Like the basic Scotch type, the 2-pass construction needs no baffles at rear tube sheet. It can be dryback or wetback design.

For longer gas travel, flow is turned again. The rear chamber of dryback 3-pass units has a refractory baffle to reverse gas; in wetback units the submerged rear chamber effects the reversal.

To further increase length of the gas path, direction may be reversed again: the 4-pass design



space (wetback design), we have the distinctive Scotch marine boiler.

The internal furnace is subject to compressive forces and so must be designed to resist them. Furnaces of relatively small diameter and short length may be self-supporting if wall thickness is adequate. For larger furnaces, one of four methods of support may be employed: (1) corrugating the furnace walls, Fig. 1, (2) dividing the furnace length into sections with a stiffening flange (Adamson ring) between sections, (3) using welded stiffening rings, and (4) installing staybolts between the furnace and the outer shell. If solid fuel is to be fired, a bridgewall may be built into the furnace at the end of the grate section.

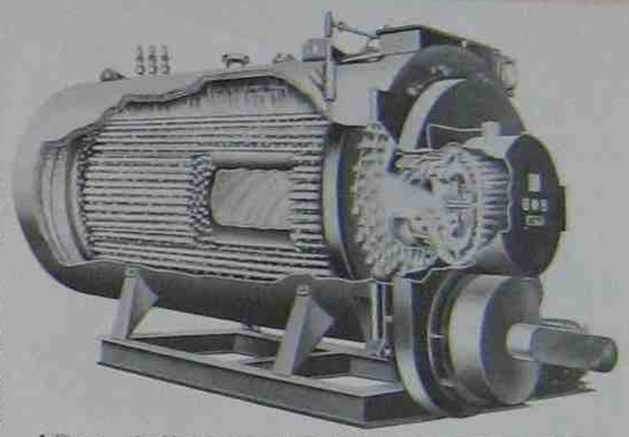
Also essentially self-contained are the several firebox boiler types. The firebox is lined on all sides with a water-cooled shell (waterleg) constructed of flat plate stayed to withstand internal pressure. "Locomotive" and other firebox boilers are often used as portable units.

PACKAGED FIRETUBE BOILERS

Lineal descendants of the basic Scotch design, packaged boilers represent the bulk of firetube boilers being manufactured today. The American Boiler Manufacturers' Association defines a packaged firetube boiler as "a modified Scotch-type boiler unit, engineered, built, fire-tested before shipment, and guaranteed in material, workmanship and performance by one firm, with one manufacturer furnishing and assuming responsibility for all components in the assembled unit, such as burner, boiler, controls and all auxiliaries . . ."

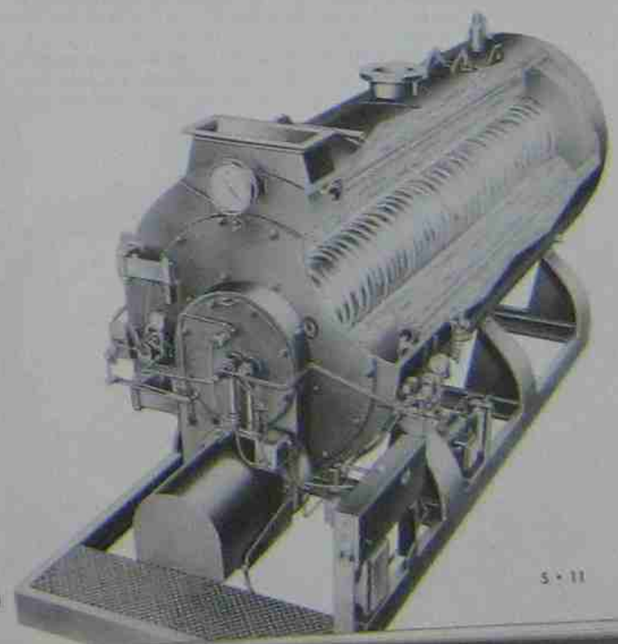
2-PASS DESIGNS

These boilers tend to be simplest in design and other things being equal, may be somewhat lower in first cost. A variety of arrangements are employed to extract most of the heat from

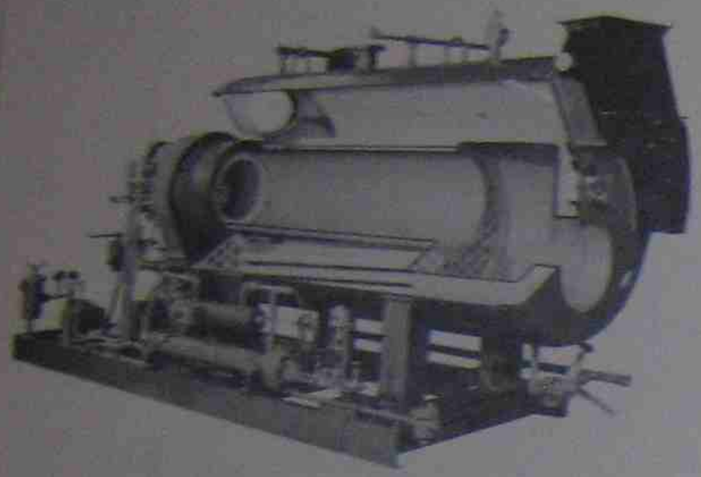


4 First pass in this unit is a centrally located corrugated furnace with a spinning flame pattern. Second pass consists of a multiplicity of tubes in a staggered layout. "Impellers" at tube entrances impart spiral gas action

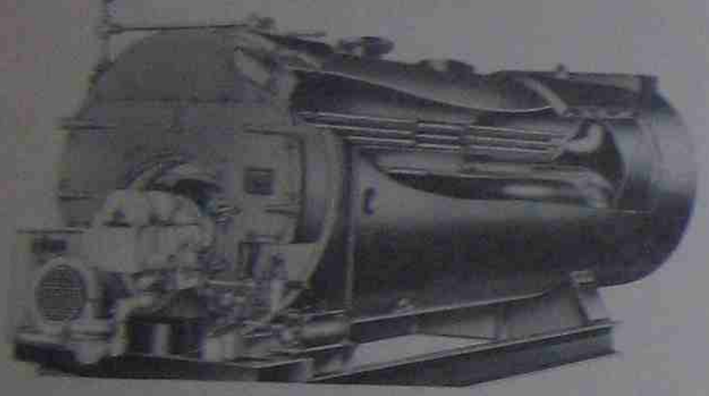
5 This 2-pass design features a corrugated furnace of generous proportions to maximize radiant transfer from a highly turbulent flame. The second pass consists of two staggered rows of relatively widely spaced return tubes



A wide range of 2- and 3-pass designs are available

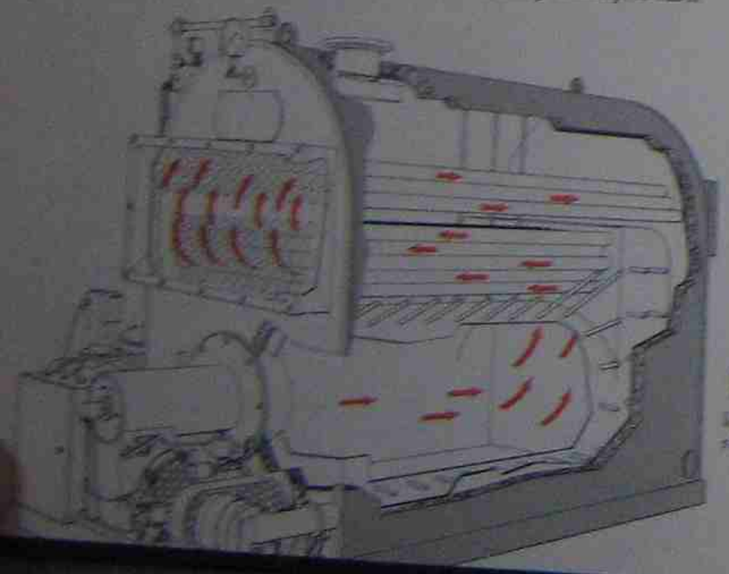


6 The reversing chamber at the rear of this 3-pass wetback unit is wet cooled by water. From it, gas flows forward through tubes mainly in the lower part of the water space. Then gas flows to rear through third-pass tubes



7 Furnace and rear combustion chamber contain almost half of heat transfer surface. Second and third tube passes account for remaining five subregions, with final pass taking gas temperature down to just above dew point

8 Large slurred finishes of this unit has arched crown sheet; rear reversing chamber has slurried waterlegs at sides with a submerged top. Flow is forward in short second-pass tubes, to the rear in the longer third-pass tubes



the combustion gas during the relatively short travel time between the burner and stack. For one thing, designers put great emphasis on maximum heat transfer from the furnace tube, usually by imparting a vigorous swirl or turbulence to the flame and the combustion products.

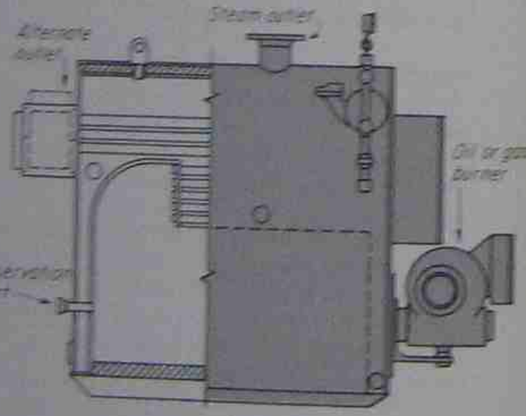
Designers also give attention to the number and arrangement of the second-pass tubes. While waterside inspection and cleaning are easier when tubes are lined up vertically and horizontally, a staggered layout tends to give a more circuitous flow of water around these tubes, promoting increased heat transfer. One builder seeks improved transfer from gas to water by using slip-in fittings at the tube inlets to impart a swirl to the hot gas.

3-PASS DESIGNS

Judging by the variety of designs available, the 3-pass design offers a popular approach. It adds another boiler length to the travel of the hot gas at the cost of some added complexity. In the case of dryback units, the rear chamber must be baffled with refractory to separate the gas being directed into the second-pass tubes from the gas being discharged out of the third-pass tubes. In wetback units this is accomplished by the design of the submerged rear chamber. Fig. 6.

Models differ not only in rear chamber construction but in number, size and placing of tubes. Thus, we find relatively small-diameter furnace tubes surrounded by a multiplicity of firetubes and other units featuring large furnace tubes with fewer firetubes. There seems to be little agreement on the best ratio of primary surface (exposed to fire) and secondary surface (heated by flue gas).

In the 3-pass category we find a number of designs that are basically firebox boilers as distinguished from the internal-furnace type with its cylindrical furnace tube. Typical units have a firebox with a flat bottom and vertical sides going into an arched crown sheet that forms the top.



9 Partial section of another firebox design reveals water-cooled rear reversing chamber, short second-pass tubes leading forward, and third-pass tubes discharging to the rear. Combustion chamber is large, as is furnace surface

Fig. 8. This furnace shape requires stays, as do the waterlegs at the sides of the rear chamber into which the firebox discharges. Here the aim of the designer is for a large combustion space and a higher ratio of furnace to tubular surface.

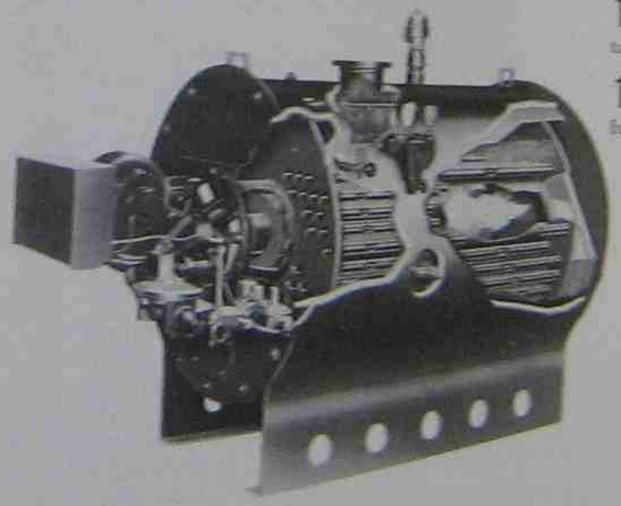
In this country packaged firetube boilers are almost invariably designed for firing oil or gas, both of which lend themselves to compact, automatically controlled units. In England particularly, the internal-furnace boiler is frequently fired with coal. Fig. 12 illustrates an interesting packaged unit built in that country for stoker firing. The traveling grate is fitted into the internal furnace that forms the first pass of a 3-pass design.

Another interesting English unit, not illustrated, is designed with particular concern for noise reduction. The rear tube plate is of hemispherical shape, and the ends of the firetubes bend into it. This arrangement is said to reduce rumbling and noise substantially.

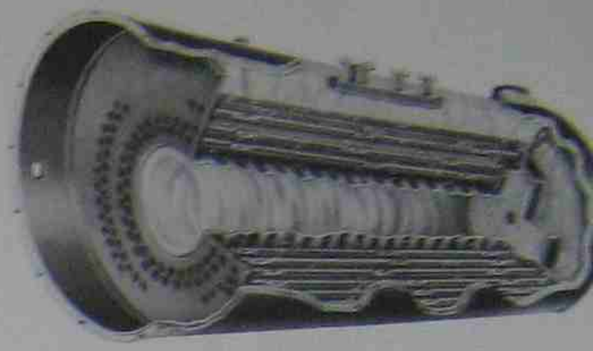
4-PASS DESIGNS

In the effort to further increase the travel of gas from furnace to stack and hence increase efficiency, designers turn to the 4-pass construction. In some units the flow of gas is generally upward from the second-pass tubes into higher third-pass tubes and still higher fourth-pass tubes. Other builders prefer the "downdraft" design in which flow is generally downward from second-pass tubes above the furnace tube. Downdraft construction allows the fourth-pass tubes to be between the bottom of the furnace and the shell, and facilitates the use of an induced-draft fan. This can be located on the base, at the front, where the fourth pass discharges in this type.

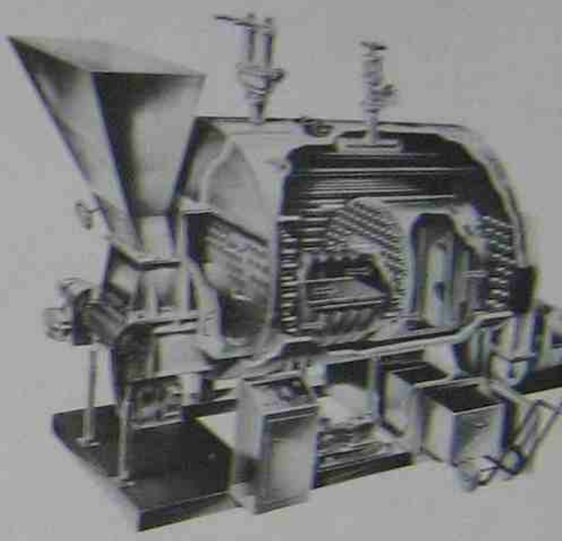
While careful proportioning of tube surfaces is important in all units, it is obviously of greatest significance in the 4-pass design. To maintain high gas velocities throughout the extended travel path, builders decrease the total cross-sectional



10 In this compact unit, note refractory target ring in furnace tube to shape flame. Bottom tube bank forms second pass and top bank forms third pass. Baffle just below main steam outlet keeps moisture content low



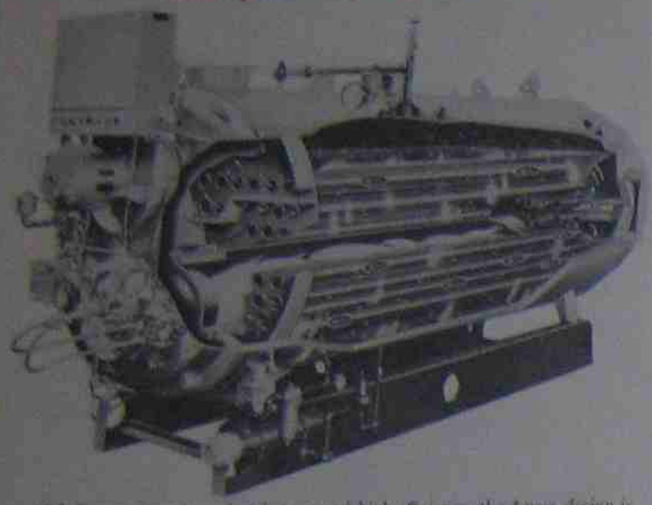
11 Water shell for 3-pass unit shows concentric arrangement of second- and third-pass tube banks. Instead of usual horizontal or vertical rear-flame baffle, a circular refractory-lined plate forms the reversing chamber



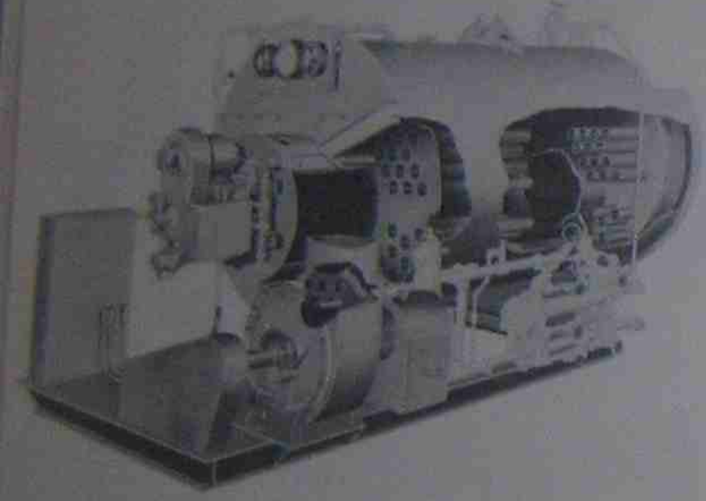
12 Packaged unit built in England has its corrugated furnace fitted with a traveling-grate stoker. Ash dumps into a submerged rear chamber. Inner tube bank forms second pass, outer bank a third. Note the induced-draft fan

13 In this design the furnace tube is relatively small in diameter; water space and number of heating tubes are large. Modulating control positions fuel valve and burner air shutter to adjust fuel-air ratio at varying loads

Four passes give longer gas travel

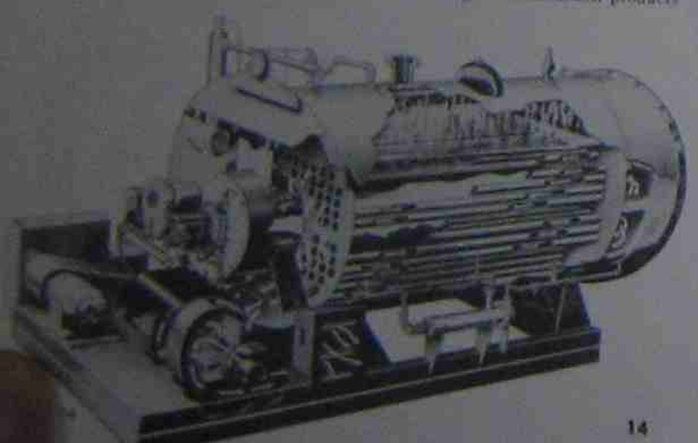


14 For maximum travel of hot gas and high efficiency, the 4-pass design is employed. In this boiler gas velocity is maintained by a decrease in the number of tubes to give each succeeding pass a smaller cross-sectional area



15 This unit has second-pass tubes above and at upper sides of the furnace, third pass at lower sides, fourth below. Enlarged duct section between last pass and induced-draft fan cuts velocity, traps heavy noncombustibles

16 Four complete passes of diminishing area maintain high gas velocities. Downdraft arrangement traps heat during "off" periods. Negative pressure created by induced-draft fan prevents leakage of combustion products



area of each succeeding pass. This is usually accomplished by reducing the number of tubes in each of the successive passes.

Theoretically, there is nothing to prevent the use of additional passes beyond four. The fact that four represents a practical current limit is an example of the economic balances that always concern the boiler designer. He must weigh the need for greater fan power, increased complexity of construction, perhaps a larger shell diameter and hence thicker shell plates against the performance advantages to be gained by going from two to three or to four passes. In like fashion, the boiler purchaser must weigh possible performance gains against possible higher first costs and strike the best economic balance for his conditions.

GENERAL FEATURES

Thus far we have looked mainly at the boiler proper and particularly at such considerations as furnace and tube arrangement, gas flow, etc. Now let's look at some characteristics of packaged firetube boilers as developed in recent years.

A number of the construction changes reflect efforts to produce more compact and less costly packages. Skillful design has made it possible, however, to achieve these objectives while maintaining desirable performance characteristics. For example, the general tendency to make shells longer rather than larger in diameter has permitted the use of thinner plate and has made possible other advances in fabrication procedures that yielded economies in cost without in any way jeopardizing safety. Similarly, the use of welded construction has affected many economies and simplifications and at the same time increased structural integrity of the finished product.

More skillful use of heating surface with higher rates of heat transfer makes it possible to secure more output from a given number of square feet of surface. Most of today's packaged units, for example, are designed to develop a boiler hp from 3 to 5 sq ft of heating surface.

One inevitable result of working heat exchange surfaces harder has been to make it imperative to keep both fireside and waterside clean. This puts a greater premium on good water treatment and on maintenance. More compact designs, however, tend to make surfaces less accessible for inspection and cleaning. Thus, builders have given increasing attention to improving access by means of larger opening and by hinging or davit-mounting rear heads and sometimes front heads including burners and controls. Modern units are encased and insulated so effectively that radiation losses have been reduced to a minimum.

As mentioned, some packaged firetube units employ induced-draft fans, but the majority use forced draft, either integrated with the burner or mounted separately. Combustion-control equipment has been continuously improved, and an increasing number of units employ modulating control, some with plug-in type circuits for easy maintenance and replacement of parts. This means that

major control repairs can be handled by the manufacturer in his shop rather than in the field.

PERFORMANCE AND RATINGS

It was rare for the makers of conventional firetube boilers to know in advance what firing, setting and draft conditions their products would encounter in actual application. So it became customary to assume that, under average conditions, 10 sq ft of heating surface would produce 34.5 lb of steam per hr, from and at 212 F—equivalent to one boiler hp. Such ratings were almost invariably ultraconservative, and it was not unusual for boilers working under favorable conditions to operate at 150 or 200% of "rating."

In contrast, makers of packaged firetube units control all the conditions affecting capacity and, in addition, can shop-test complete units. Thus, their rating of continuous maximum boiler output means exactly what it says. This is of particular importance when a brickset boiler is to be replaced by a package—the rating of the old boiler cannot be used as a guide in selecting the new package. It is necessary to estimate actual steam loads to be met and to select the capacity of the new unit to meet these needs.

EXTENDED-SURFACE DESIGNS

Particularly where heat is to be transferred from gas to a steam-water mixture, the idea of extending the exposed surface on the gas side seems attractive. One American manufacturer produces tubing with internal fins, Fig. 19. The use of these tubes in a 2-pass firetube boiler yields units of great compactness.

The Swedish design shown in Fig. 17 is interesting on two counts. Copper-alloy studs are welded on the exterior of the heating tubes. These, however, are actually water tubes, with gas flowing outside and water inside. Since all the water and steam space is within a single shell, this unit could be classed as a shell-type watertube.

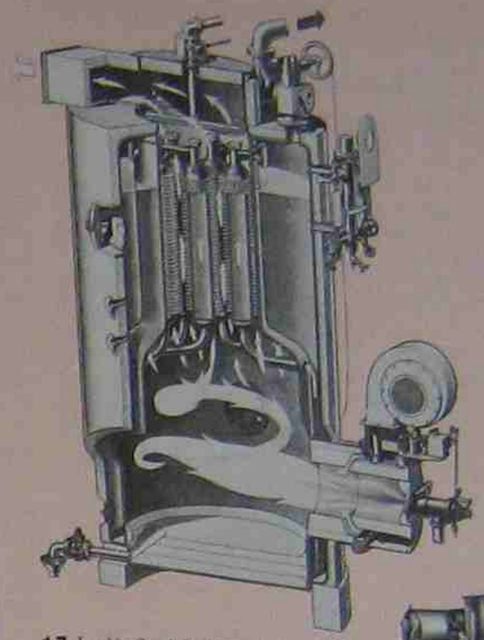
VERTICAL BOILERS

With the exception of the unusual design just discussed, we have considered only horizonal types. Yet the vertical design is one of the oldest and is still popular for many applications because of its space-saving character. The typical design of Fig. 18 illustrates the general construction. The firebox is surrounded by a waterleg, and the fireplate is submerged to avoid overheating and leakage. To increase heat transfer during the single pass, helical fittings inside the tubes spiral hot gas against tube surfaces.

While obviously not a "firetube" boiler, the electric unit of Fig. 20 is a vertical shell-type design in which resistance of water between all-metal electrodes provides heating action.

Protection against overheating in case of low water level is automatic since current flows only through water. If there is no water, there is no current flow. Chemical treatment to improve conductivity of water is usually recommended.

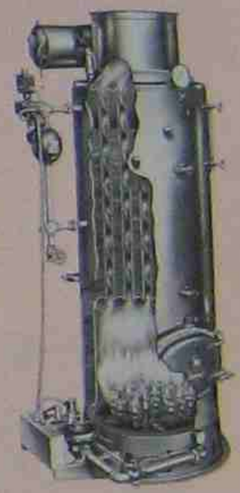
Designers seek to boost heat transfer

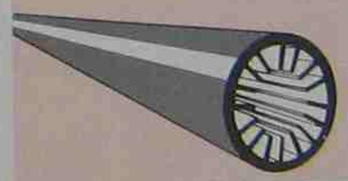


17 In this Swedish design studs welded on exterior of tubes provide added surface for transfer of heat from hot gas outside of tubes to water flowing up through them

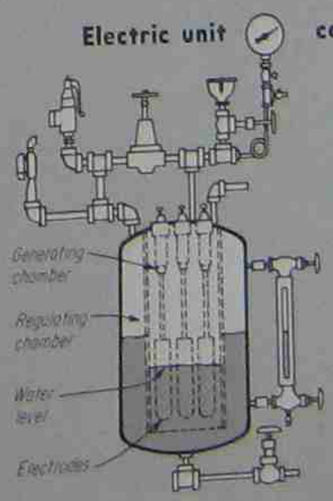
18 In this vertical firetube unit special tube inserts spiral hot flue gas against heat-transfer surfaces. A waterleg surrounds firebox at boiler's base to avoid overheating

19 Internally finned tubes have 350% more surface in contact with flue gas than bare tubes of same length. Compactness results from their use in 2-pass boilers





Electric unit controls by level



20 Resistance of water between solid-metal electrodes generates heat in this electric boiler. Under ordinary operating conditions, the water levels in the generating and regulating chambers are seldom equal. They will reach a balanced condition with water level in the generating chamber at a height that will provide immersion of the electrodes necessary to generate steam at the rate required by the load. By this means, a built-in control system regulates pressure and temperature

Watertube designs

Reliable watertube steam generators span the capacity range from small portable boilers to large central station units

Introduction of the watertube boiler dates back to the 18th century. But the original model, patented by Blakey, is a far cry from today's designs. The past 25 years in particular have been a period of significant change.

Horizontal-tube boilers with vertical or slightly inclined sectional headers, having a longitudinal or transversal drum, were quite popular during the first quarter of the 20th century. Today they are no longer built.

Bent-tube boilers were found to be more flexible. Where headroom is limited, they can be made wide and low, or narrow and high where floor space is at a premium. Also, bent-tube boilers allow more of the surface to be exposed to radiant heat of the furnace. As a final factor, they can be built at a lower cost.

Drums serve as convenient collecting points in the steam-water circuit and for separation of steam and water. Thus, boilers with two, three and sometimes four drums were popular up through the mid 1920's.

As boilers grew in size, the demand for more active furnace cooling increased. It was then that waterwalls and other changes in design came into the picture. A better knowledge of fluid dynamics resulted in simpler and much safer methods for the calculation and monitoring of circulation of waterwall fluids—both on the gas side and the steam side. In short order, it became practical to eliminate one, sometimes two drums. Two-drum boilers, even boilers with but one drum at the top and one or two large headers at the bottom, became usual designs, Fig. 3.

Yet thousands of boilers of the vertical-header type and of the multidrum bent-tube variety are still operating satisfactorily today. Many feel that the average life of a well-designed, properly installed and adequately maintained boiler is about 50 years.

TUBE MATERIALS

Modern boilers consist of thousands of feet of steel tubes of various diameters and wall thicknesses, and the type metal used is of great importance. Low-carbon steel is used in most watertube boilers operating over a wide temperature range. Convection temperatures run between 500 and 700 F. Medium-carbon steel, with 0.35% max of carbon, permits higher stress levels than low-carbon steel at temperatures up to 950 F. For superheater tubes, which must resist temperatures above 950 F, alloy steels are required. These may contain chromium, chromium-molybdenum and chromium-nickel. They may be of a ferritic structure or, for the highest temperatures at which modern boilers operate, of an austenitic structure. All grades of metals entering in the construction of a boiler must comply with rigid specifications, laid down by the ASME.

Both seamless steel tubing and electric-resistance-welded tubes may be used in watertube boilers, the latter becoming increasingly popular for most applications—except for high-pressure boilers where wall thickness makes the use of seamless tubes more practical.

Seamless tubes are made by piercing, rolling, reeling and sizing solid rounds of carbon steel or stainless steel. To obtain the smooth surface and the close tolerances required for stainless steel tubes, they are generally finished by cold-drawing, a supplementary process, sometimes followed by a further heat treatment (annealing, normalizing and tempering, stabilizing or quenching).

Hot-extrusion process, developed in France, is sometimes used for high-temperature steel-alloy tubes ranging in size from 1½- to 3½-in. OD, with wall thicknesses from 0.16 to 0.600 in. and lengths from 20 to 60 ft according to unit weight. These are finished by cold-drawing.

Electric-resistance welding is used for producing tubes mainly of carbon steel. They may be from ¾-, to 4-in. OD, in gauges from 0.049 to 0.180 in. Tubes are inspected by ultrasonic devices, tested to hydrostatic pressures from 1000 to 6000 psi according to intended use, and further checked for quality and metallurgical control.

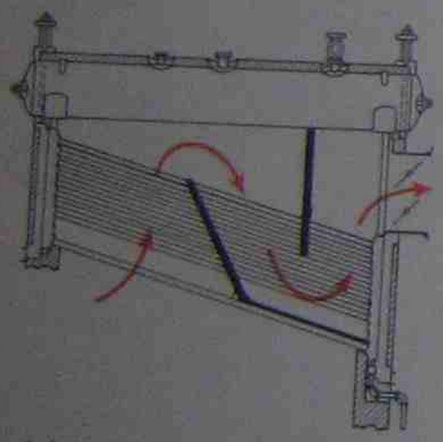
Welding has replaced riveting for boiler construction since the early 1930's. Welding methods have improved significantly. Today, covered electrodes are used for continuous automatic deposition without breaking the arc, using ac or dc of either polarity.

TYPICAL DESIGN FEATURES

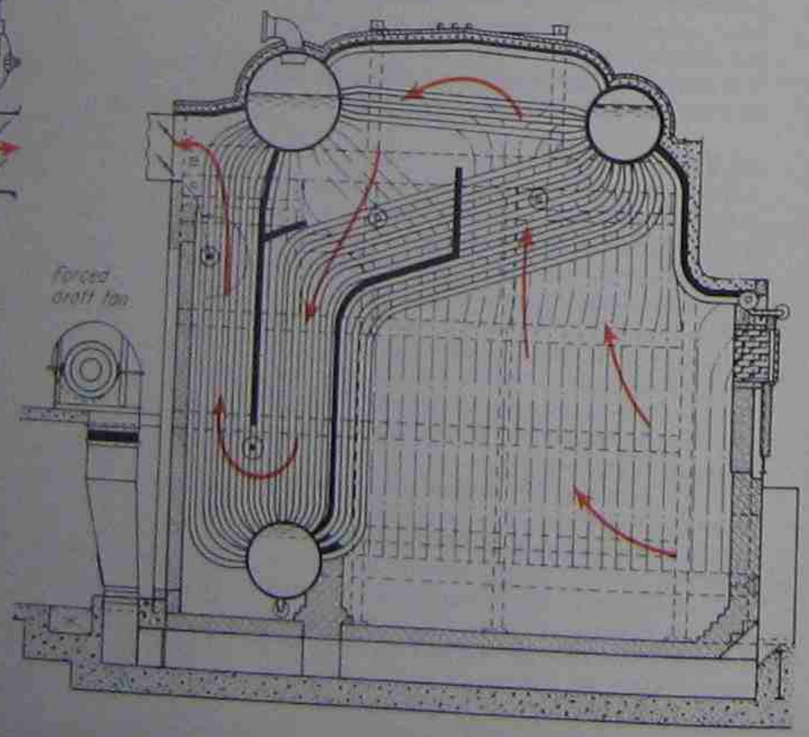
Watertube steam generators built today for space heating and industrial processing, may have their design features summed up by the following points: In general, there is a maximum use of vertical, or near vertical tubes, both in the radiant and convection sections. Through further use of waterwall surfaces, there is maximum utilization of radiant heat. Much of the exposed refractory surface is further reduced, even to the extent of having baffles in the form of tangent tubes, which serve to guide gas flow in the desired direction.

Designers are leaning toward tighter setting construction as a practical assurance against air or gas leakage. There is a gradual trend toward elimination of the i-d fan, simply by keeping furnace and boiler under some pressure. Another trend is toward increased rate of heat liberation and absorption which is made possible by more active circulation through boiler elements. And there is an increasing use of heat recovery equipment—air heaters and economizers—in flue gas exhaust. Soot blowers are being installed in more adequate fashion, frequently cycled for more effective operation (see pp S 46-47). Steam generator designers fully expect units in operation will get more effective feedwater treatment plus generally better care given to internal cleaning of boilers.

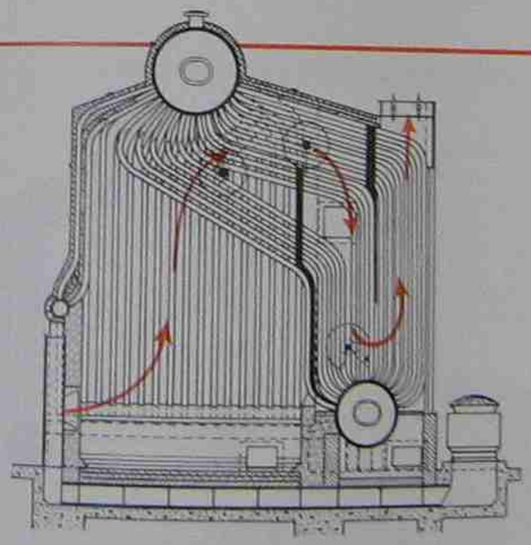
Waterwall construction is an important portion of boiler design. Tube spacing is intimately dependent upon construction of the entire waterwall. Several designs are illustrated on p S 18. Many boiler designers have adopted tangent-tube construction with an eye toward getting the greatest area of watercooled heat-absorbing surface per sq ft. They can show that swaging and other installation



1 Inclined-tube design with sectional, cast iron, vertical headers has been the workhorse of steam generation for nearly 100 years. Crossbox at bottom of rear headers forms the mud drum. Several designs of this basic boiler are seeing service today

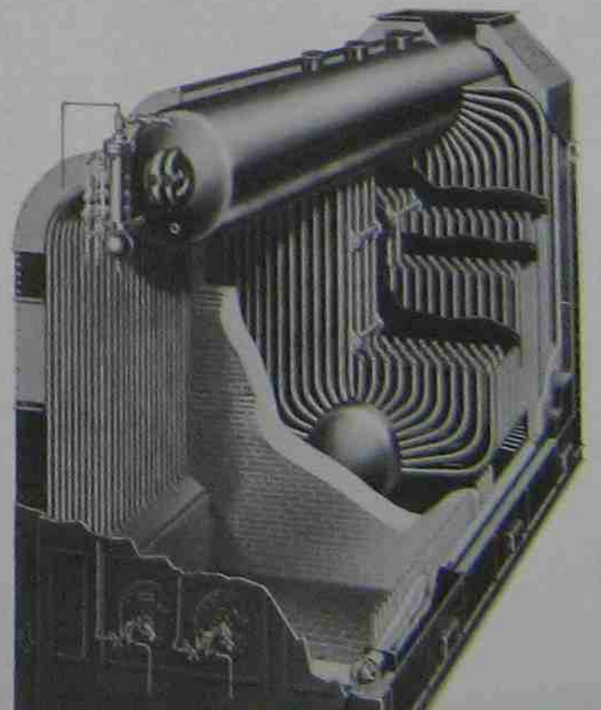


2 Bent-tube boiler, using all-steel construction, first became popular around the turn of century. By moving the relative position of their two, three and sometimes four drums, they are quite flexible and are readily adapted to a variety of space limitations



3 Water-cooled furnace walls were developed because of the increasing rate of heat release in furnace proper. Water from drum is supplied to lower header. Steam, actively generated in walls, rises to upper drum where it separates from boiler water

4 Water feed is from upper to lower drum in this design. Flow then divides into two portions: One goes to wall headers, then absorbs radiant heat in water walls; other is fed to convection tubes where the steam



techniques used with tangent tubes in furnace walls have long since overcome earlier problems of inserting and rolling tangent tubes to drums and headers. Such designers are quick to point out that the furnace area is the logical choice for installing tangent tubes, since this is where the most active heat release and absorption occur.

If one tube out of two is removed and replaced by a welded fin, and the metal fin does a good job of transferring heat to the tubes, circulation within the tubes will be much more rapid. It should take care of the greater heat absorption per tube without reaching extremely high metal temperatures.

Those using tangent tubes in boiler furnaces frequently favor finned tubes in the walls of the convection section of the boiler since the heat transfer rate is much lower there. Wider tube spacing tends to reduce the discrepancy in transfer rates between tubes in the furnace walls and in the convection wall zone.

Finned waterwalls in small and large boilers are designed with a fluid mass flow sufficient to hold metal temperature within safe limits at every rating. Thus, the saving accomplished by eliminating every other tube is partly counterbalanced by the need for higher capacity pumps to obtain more active circulation.

PACKAGED WATERTUBE BOILERS

Modern packaged boilers have experienced an extraordinary growth in popularity and size since their inception in the latter 1940's. They have established an attractive price advantage. Some energy-systems engineers, when estimating costs, place $1 per lb of hourly steaming capacity on a packaged boiler within the 10,000- to 60,000-lb per hr range. For the same rating, the total installed cost of a field-erected boiler approaches $2. They might go a step further and place a $2.50 minimum figure on a field-erected stoker-fired unit and at least a $3 per lb figure on a pulverized coal-fired unit.

Today most packaged watertube boilers follow one of the structural configurations shown on pp S 18-19: types *A*, *D* and *O*. Where a larger capacity is desired beyond the normal upper size for these units, the manufacturer must take due account of limitations of rail transportation. Thus length would be the most logical dimension to increase.

Usable space on either side of the upper drum of an *A* or *O* type steam generator has sometimes been adapted, in outdoor units, by installation of fuel-oil storage tanks. In both the *A* and *O* type it is the symmetry of design that exposes the least tube surface to radiant heat.

The *D* type permits the designer a high degree of flexibility while allowing large combustion-chamber volume. Example: Superheaters and economizers can be added to the *D*-type radiant or convection zone with relative ease. Oil, gas or combination burners may be located in one of the end walls or between tubes, adequately bent, in the buckle of the *D*. Firing is then at right angles to the drum length. In this design, proper baffling can give the gases correct direction and maximum residence time in the unit.

Controls have played an important part in the success of packaged boilers. Users have come to expect high reliability in flame monitoring, low-water alarms, over-pressure cutoff. There is increasing use of annunciator panels installed to inform the operator which device may have operated to shut down the installation. Lack of such annunciators often leaves the operator hard put to find out, with safety, the cause of the shutdown.

There is ever-widening acceptance of the critical need for adequate feedwater treatment, even for the smaller sizes of packaged boilers.

By definition of the American Boiler Manufacturers' Assn, a packaged boiler is "*a boiler equipped and shipped complete with fuel-burning equipment, mechanical-draft equipment, automatic controls and accessories.*" There is a loose line of distinction between the "packaged" boiler and the "shop-assembled" unit. In general, the latter term is applied to larger steam generators where all assembly is handled in the maker's plant, but with some leeway in selection of controls and auxiliaries.

Actually, several manufacturers are now giving a hard look at the possibility of designing a boiler in two or even three sections which could be assembled in the field with a minimum of labor. This would not only allow shop-assembled boilers to reach capacities well over 200,000 lb per hr, but would also result in more desirable boiler geometry. Whether a boiler shipped in several sections can still be referred to as "packaged" is for ABMA to decide.

SHOP-ASSEMBLED BOILERS

Technique has improved to the point where shop-assembled boilers are now available in capacities ranging up to 200,000 lb per hr for steady operation, a recently announced maximum. Average ratings probably run closer to 35,000 lb per hr. The majority of such units generate saturated steam, with superheaters installed when specified.

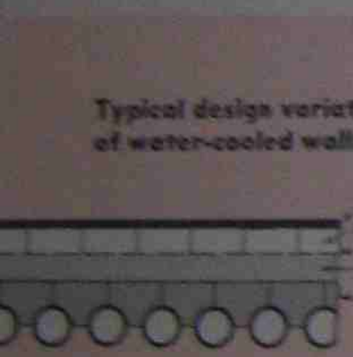
Railroad traffic managers have contributed to the practicality of the shop-assembled boiler by preparing routings through suitable tunnels and underpasses. Here the manufacturer generally supplies a template of the complete boiler before completion and shipping.

The shop-assembled boiler of today is more tailor-made than ready-packaged. Manufacturers generally have available, or have easy access to, components that energy-systems engineers are likely to specify: burners, fans, controls and pumps. Thus, shop-assembled boilers can generally be made ready for delivery on reasonably short notice.

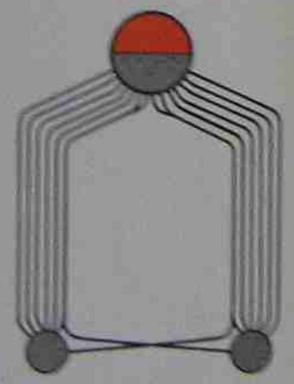
Many feel that the shop-assembled boiler, put together under close supervision in the manufacturer's plant, is built in a more favorable environment than normal field conditions would permit. Perhaps these factors help explain why, during the period from 1959 through 1963, out of 3,985 watertube boilers sold in the U.S. for capacities up to 100,000 lb per hr, 2681 were of the packaged type.

More sophisticated designs for shop-assembled boilers are sure to appear. And higher capacities are part of this picture: that is, in excess of 100,000 lb per hr. It will be necessary to provide higher heat release—for example, on the order of 90,000 Btu per cu ft average; also, higher heat absorption, running to 60,000 Btu per sq ft. Pressures will be higher. Superheaters and heat recovery

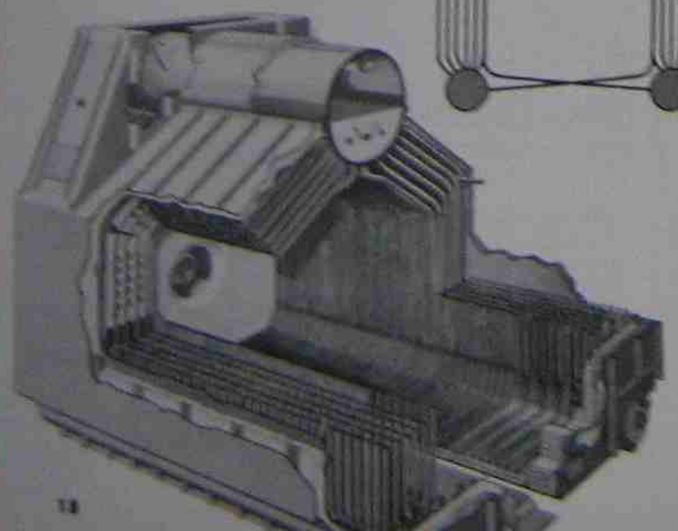
Typical design variations of water-cooled walls



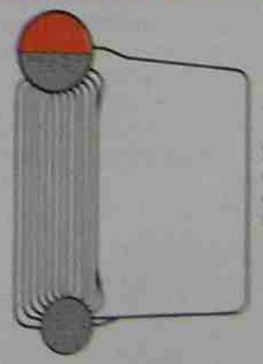
Medium-size watertube boilers...



8 A-type has two small lower drums or headers. Upper drum is larger to permit separation of water and steam. Most steam production occurs in center furnace-wall tubes entering drum



... may be classified according to three basic tube arrangements

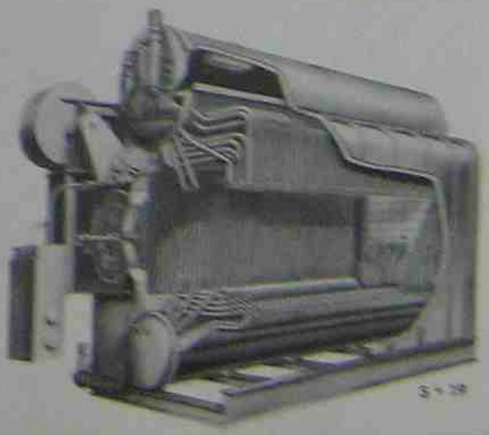


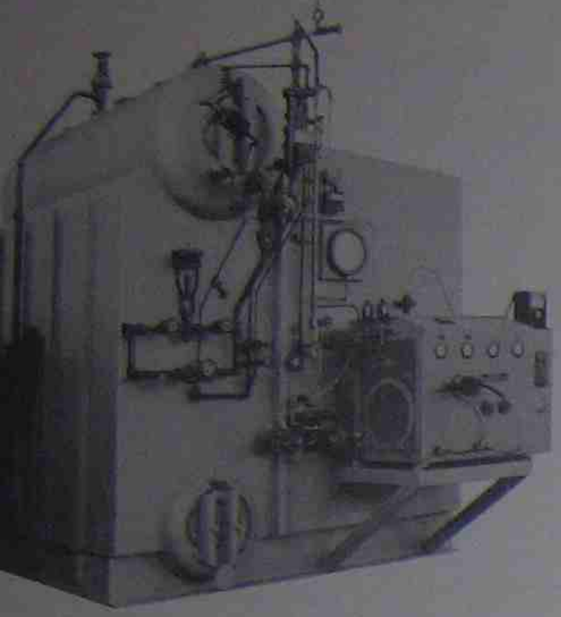
9 D-type allows much flexibility. Here the more active steaming risers enter drum near water line. Burners may be located in end walls or between tubes in buckle of the D, right angles to drum



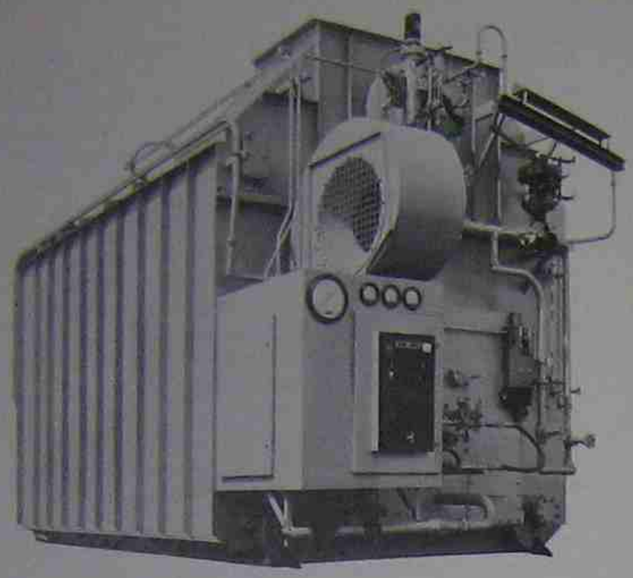
10 O-type is also a compact steamer. Transportation limits height of furnace so, for equal capacity, longer boiler is often required. Floors of D and O types are generally tile-covered







11 D-type packaged boiler with a 10,000-lb per hr rating, houses gas-fired pressurized furnace. Large-diameter drum assures proper steam-water separation. Note steam-operated soot blower, left. Boiler safety controls are located for maximum accessibility



12 Packaged firing unit on this boiler consists of a burner to handle oil, gas or a combination, is equipped with flame-monitoring, forced-draft fan, all-electric control. Complete unit is designed for installation on many types of existing watertube boilers

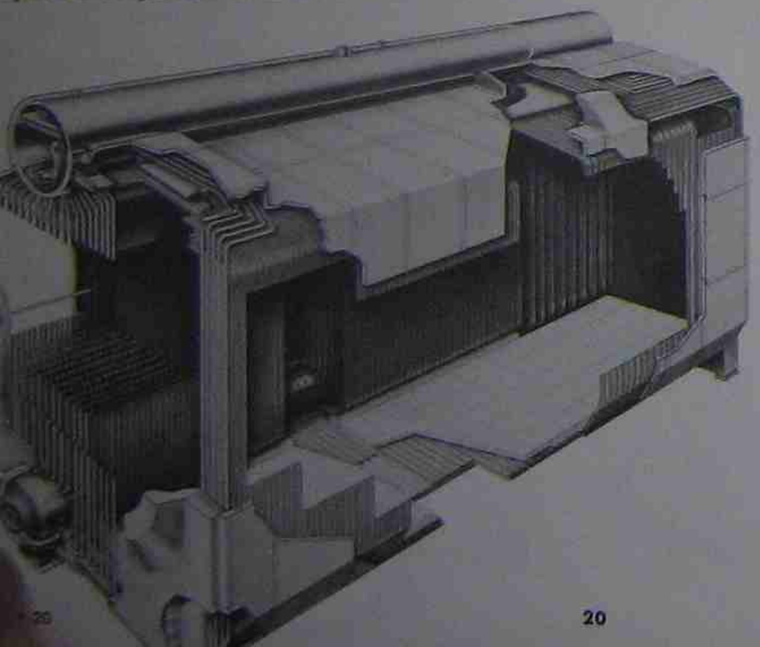
will be in order. All this will, of necessity, add to initial boiler cost; possibly as much as 50% in some sizes.

Actual designs for large shop-assembled boilers are on the drawing boards of most manufacturers. Designers are working to meet transportation limitations without making their units too long or violating any design rule compatible with complete safety and accessibility for maintenance.

Coal firing is practical for the shop-assembled units and is being developed by some makers of packaged boilers. Pulverized-coal firing may someday be applied to large shop-assembled boilers whenever the cost of coal justifies the expense of pulverizing and burning and removing the ash. Gas velocities with pulverized coal can be kept at an acceptable level without excessive tube erosion in shop-assembled boilers. When firing with oil or gas, acceptable combustion gas velocities are generally higher.

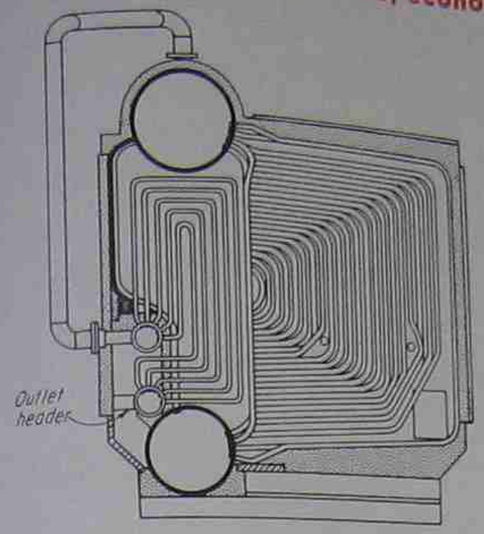
Many engineers visualize the adaptation of a shop-assembled boiler, of the *D* type for instance, to oil, gas or pulverized coal. They would install the unit at some elevation above ground and build an ashpit under it. Should coal become economically attractive, the floor tile could be removed and lower tubes provide a slag-screen effect.

The stoker-fired packaged boiler has had some measure of success to date. Boiler manufacturers and designers of fuel-burning equipment—assisted by Bituminous Coal Research, Inc—have designed dependable packaged watertube boilers with underfeed or spreader stokers for capacities in the 4000- to 60,000-lb per hr range.

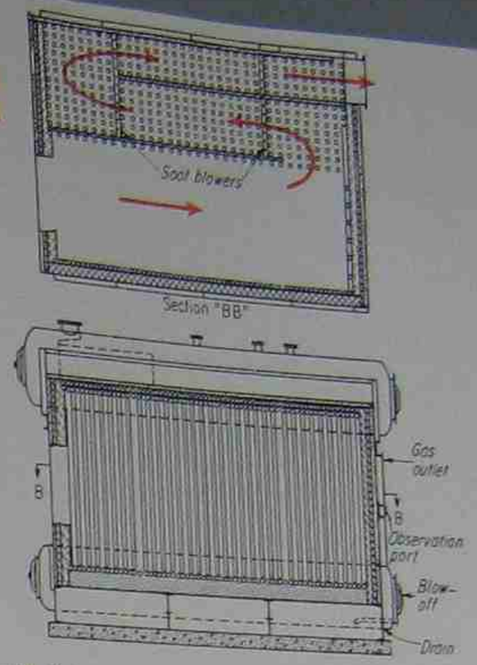


15 Circulation pattern of water, steam and gases may be readily traced on this D-type boiler: From mud drum and lower headers, water and steam rise in finned waterwalls and enter drum near its waterline (note the drum internals). Some of the convection tubes above mud drum act as downcomers, the rest serve as risers. Gases from burner at left (not shown) make a 180-deg turn at the far left end of furnace, enter convection zone of boiler between non-tangent, nonfinned tubes. They may leave boiler at front left. As an alternate in some designs, gases turn into an additional pass toward rear. This rerouting is accomplished by a baffle made of refractory or simply tangent tubes. Superheater and economizer can easily be installed in the convection portion of this unit. Furnace floor is tiled

Packaged boilers may be equipped with superheaters, economizers



13 Superheater-equipped packaged boiler incorporates slight redesign of convection section. Here saturated steam from boiler drum enters upper superheater header, leaves through lower header. Superheater headers are protected from excessive heat



14 Refractory baffles, in contrast to baffling formed by tangent tubes, direct gases in this D-type packaged boiler. Unit is equipped with stationary soot-blower lances to keep surfaces clean. Valve-in-head soot blowers are provided on units for oil firing

Boilers illustrated on these pages are generally packaged or shop-assembled units. Most are skid-mounted and generally require a minimum of headroom. Field-erected generators are illustrated, p S 16, Fig. 2, 3.

Firing unit, illustrated in Fig. 12, is a compact package which makes it possible to convert a coal-fired boiler to oil or gas in simple and economical fashion. Cabinet at left in this photo houses all electrical controls which are properly interlocked for complete safety. Located on top of cabinet is the fan supplying combustion air to burner.

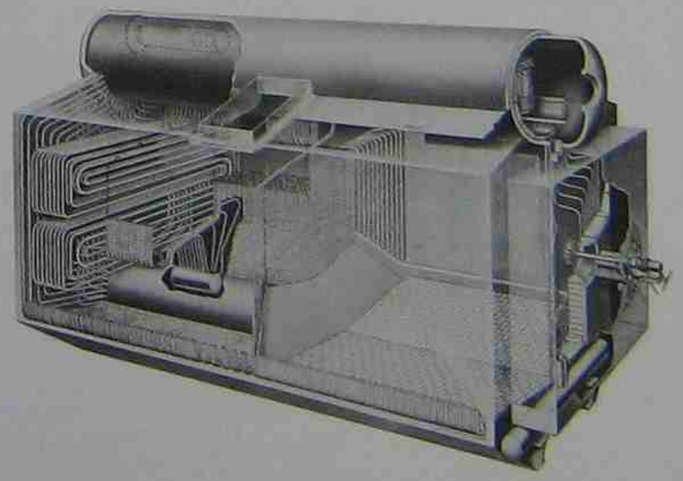
Additional control of furnace temperature in boilers of the types shown can often be exercised by removing a portion or all of the tile covering the floor tubes, thus exposing them to intense heat. Designer, of course, must provide for sufficient mass-flow through these floor tubes when they are charged with the additional heat absorption.

One version of a drainable superheater, Fig. 13, also shows a watercooled target wall, the end wall of the furnace opposite to that containing the burner.

DESIGN TRENDS

Builders of the modern shop-assembled boiler are:

- Liberally sizing headers and drums for better steam quality and ready access for inspection.
- Improving design of small steam separators, adequate for the size of the drum in which they may be located. Several manufacturers offer external steam-purifying units which, in certain cases, may be just what is needed.



16 Compact O-type unit is skid-mounted. This packaged boiler may generate over 100,000 lb of superheated steam per hr at a maximum of 775 psi and 750 F. Note the double steel casing and cyclone-type drum internals to assure drier steam. Convection superheater is located at point where flow of gases, directed by finned-tube waterwalls, splits into two parts. Each turning point of 180 deg directs flow toward a flue-gas exit located on either side of upper drum.

Forced-draft fan (not shown) may be located at any convenient place. Furnace is pressurized and no induced fan is required. Four soot blowers, two per bank, serve to keep convection banks clean. Symmetrically arranged surface is designed for balanced heat absorption. Tubes are arranged in rows with alternate wide and narrow spacing



Coal-fired packaged boiler is automatic, dust-free

With a rating to 10,000 lb of steam per hr, this packaged watertube unit burns bituminous coal on a pulsating-grate stoker. Furnace is cooled with water-jacketed walls. Provision is made for ash removal by a screw conveyor into ash cans. Banked fire can be maintained and normal operation resumed without any need for human intervention. Although not shown above, unit is equipped with both forced-draft and induced-draft fan

- Adding more radiant heating surface, perhaps with a partial or full tile floor.
- Increasing gas travel in the same volumetric space.
- Using fully-drainable superheaters.
- Switching to multiple burners for greater turndown. Example: two burners, each with a 1-to-6 range.
- Adopting built-in soot blowers matching needs of unit with suitable automatic controls.
- Placing additional emphasis on protecting the boiler casing against corrosion: welded-wall is one method.

The last point is of particular importance when the shop-assembled boiler, using fuel oil with a high sulfur content, is located outdoors and connected to a short stack. Cold climate plays havoc with many conventional casings. Several solutions have been tried with varying success.

An inner-skin casing and a variety of protective coatings on the outer casing is one approach. Also, an outside casing of aluminum has been proposed which would have the double advantage of protecting the inner casing against corrosive attack and, at the same time, allowing it to remain at a temperature above the dew point.

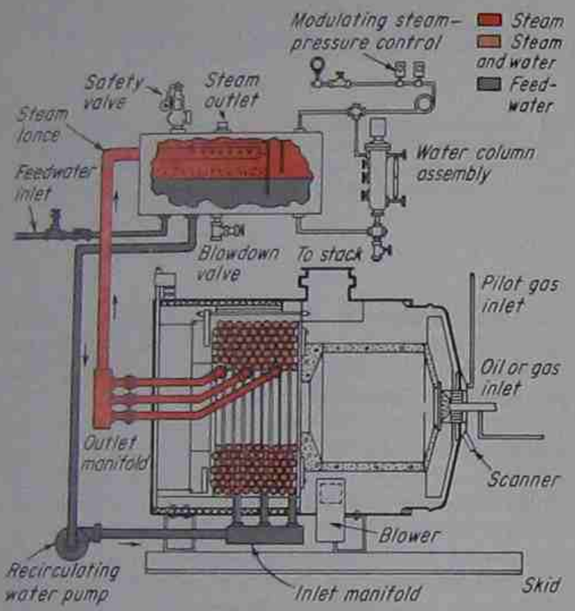
QUICK STEAMING

Rapid steaming ability is a feature of a number of watertube boilers, Fig. 17, 18, 19. These designs are characterized by small, generally coiled steel tubes, with forced circulation and intense heat release from a gas or oil burner. They usually come to full capacity and pressure within five minutes after startup. Operation is automatic.

These boilers – the quick steamers – also serve as low-capacity units or for standby. They may generate as little as 1500 lb per hr, although some makers offer sizes producing 15,000 lb per hr at 900 psi.

Where decentralized steam generation is desired, these boilers can be used to advantage. This approach is particularly valuable in a plant where steam, in variable quantities, is needed at various points some distance from one another and at different times. The use of small steam generators may cost substantially less and prove most convenient. One manufacturer offers a quick-steaming unit, truck mounted, for emergency steam service.

With minimum modification of the firing equipment, another quick-steamer takes, as heat input, the exhaust gases from a gas turbine or internal combustion engine, Fig. 19. Other boiler designs may be readily adapted.

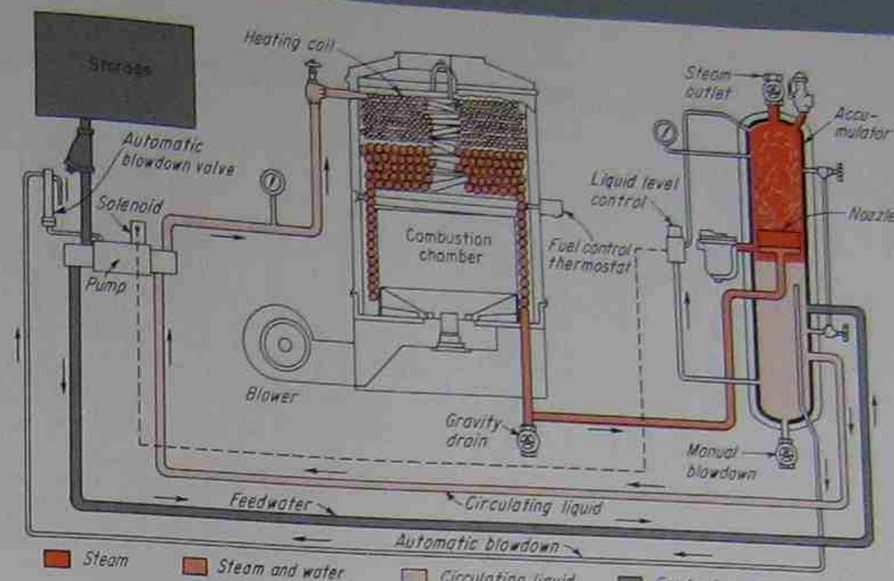


17 Multiple coil in this fast-steaming generator produces up to 10,000 lb of steam per hr. Forced-circulation watertube unit can be fired with gas or oil, has drum for water-steam separation

LARGER UNITS

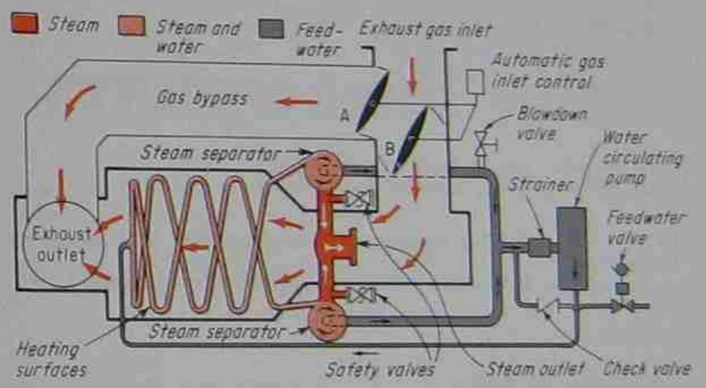
Stoker-fired field-erected units with the pressure range of say 100 to 250 psi, are still more widely used than oil or gas-fired boilers. In this pressure area, boilers range all the way from 15,000 to 200,000 lb of steam per hr capacity. It's in the portion between 15,000 and 80,000 lb per hr that most of the water-tube packaged boilers can be found, and here is where oil and gas fuels are becoming increasingly popular.

Heat release in the field-erected stoker-fired boilers may reach 1-million Btu per hr per sq ft of grate surface and 50,000 Btu per cu ft of furnace volume; average heat release figures are some 25% lower. Keep in mind that "heat release per cu ft" is a valuable indication only when the volume, shape and general configuration of the heat-absorbing portions of the furnace are known.

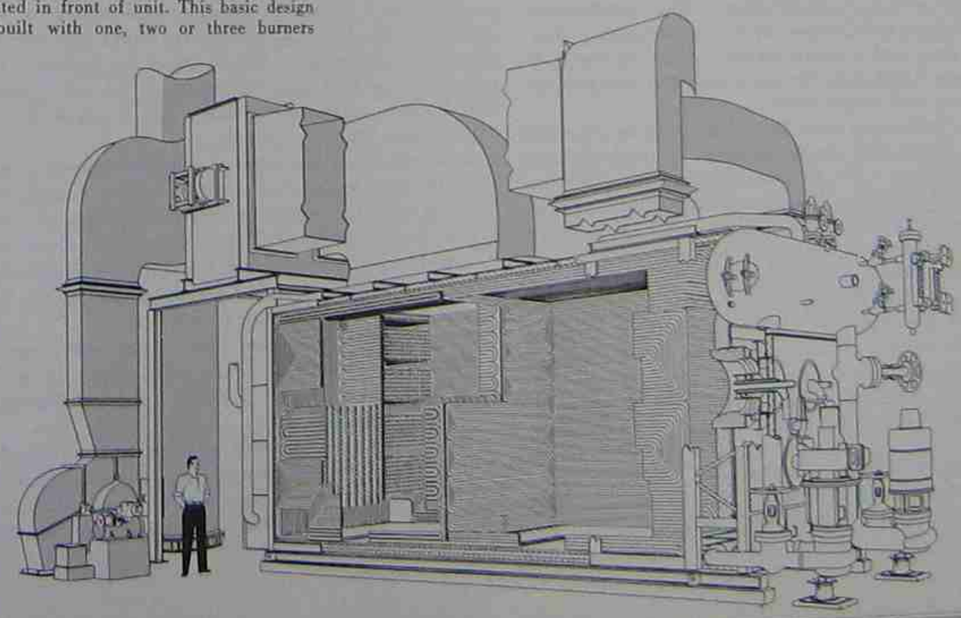


18 Monotube coil is helically wound in this quick-steaming watertube unit. Diaphragm circulating pump transfers hot water from coil to vertical steam accumulator. Here steam and water are separated by centrifugal force. Unit has many uses

19 Doughnut-shaped centrifugal steam separator is key feature of this generator. Dry steam collects at center, water gathers at the periphery. Unit was originally developed to use exhaust heat from gas turbine or internal combustion engine



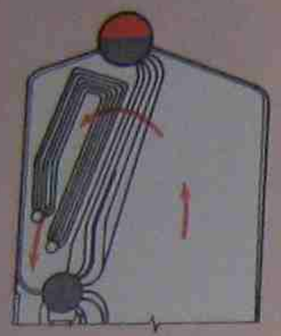
20 Controlled-circulation Lamont-type generator is available for producing high-temperature water or steam. One steam separation drum and a circulation pump are located in front of unit. This basic design is built with one, two or three burners



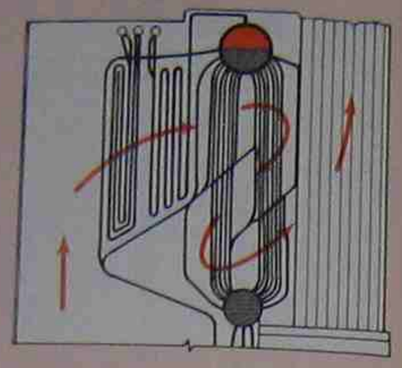
Superheaters may be located in boiler convection zone, exposed to



1 Interdeck superheater in this horizontal-tube, vertical-header boiler is located above tube bank. Moderate superheater temperature results. Apparatus is completely drainable because of use in convection area



2 Fitted-design unit in this bent-tube boiler may be protected against excessive temperature by many rows of boiler tubes. Superheater may be positioned to alternate in boiler-tube rows. Unit is made drainable



3 Pendent-type superheater in this boiler is partly shielded against radiant heat by a screen of boiler tubes built in either one or two rows. Designer may vary the tube spacing to obtain desired steam temperature

Designing for higher temperatures and pressures

Rising values of temperature and pressure bring additional equipment into play which substantially increases the cycle efficiency

Growth is a fact of life in every area of energy-systems engineering. In the area of steam generation, growth was promoted by the parallel development of the steam turbine, superheat and reheat. Temperatures of 650 F, representing a superheat of 250 F, were about the maximum accepted up to the early 1920's. Improvements in power station economy were sought along the line of regenerative cycles, not of higher steam temperatures.

Some progress in metal technology made temperatures of 700 F acceptable shortly thereafter. This was the time when reheat came into its own as another means of boosting overall efficiency. Here, steam leaving the high-pressure turbine is returned to the boiler and reheated close to initial superheated temperature before entering the low-pressure turbine with a substantially higher enthalpy.

The pages which follow describe the equipment and practices associated with higher steam temperatures and pressures which contribute to improved boiler efficiency. Superheaters, reheaters and heat-recovery equipment are examined, as are many designs of modern medium- and high-output steam generators.

SUPERHEAT AND REHEAT

Superheaters and reheaters are heat-absorbing surfaces which raise the temperature of steam above its saturation point. There are many reasons for doing this. First, there is a basic thermodynamic gain in efficiency, explained on pp S 2-3. Second advantage is that superheating dries the steam before it enters the turbine, and of even more importance is the fact that superheated steam has less tendency to condense in the last stages of the turbine. Total gain in station heat rate, attributable to the use of superheated steam, varies with pressure, but is approximately 3% for every 100 F of superheat.

Both superheater and reheater must be designed to meet about the same temperature conditions. They must deliver steam at uniform temperature over a wide range of loads, Fig. 4. Steam mass-flow (lb of steam per hr, per sq ft of flow area) should be sufficient to create a pressure drop that will distribute steam uniformly to the tubes, thus maintaining tube temperature at a safe limit.

Because heat transfer takes place between a hot gas and a vapor in the absence of liquid, metal temperature in a superheater or reheater is often the most critical temperature in the steam generator.

Most practical way to classify superheaters and reheaters is by their location in the boiler—thus, the *convection* and *radiation* classification. Importance of such a distinction stems from the fact that steam temperature is affected differently as load varies, Fig. 5.

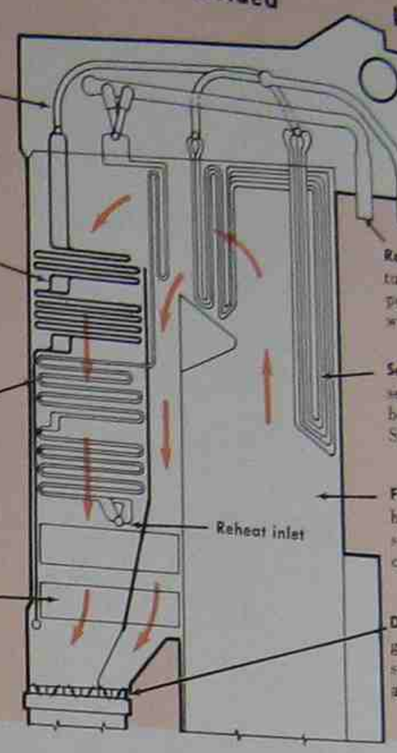
higher temperatures of radiant area, or divided between both

Control of steam temperature by attemperation is often done in header between horizontal primary and pendent final superheaters

Primary superheater, in convection zone, is fully drainable. Steam emerging from it goes to platen in radiant section of furnace

Primary reheater receives heat from h-p turbine. Final reheat is performed in pendent section partly shielded from radiant heat

Economizer raises feedwater temperature, squeezes more heat out of flue gases before they reach air heater for final cooling



Reheated steam, up to temperature equal or close to initial temperature, is led to l-p turbine, will then be condensed for reuse

Secondary superheater platen sends steam, for final temperature boost, to pendent superheater. Steam then goes to h-p turbine

Furnace delivers intense radiant heat to waterwalls and pendent superheater. Then flue gases enter cooler convection boiler section

Dampers by-pass some of the flue-gases to control reheated and superheated steam temperature, in addition to attemperation

Convection superheaters and reheaters may be of the horizontal or pendent type. Here steam temperature rises as load increases because mass-flow of gases on fireside increases faster than steam flow within tube.

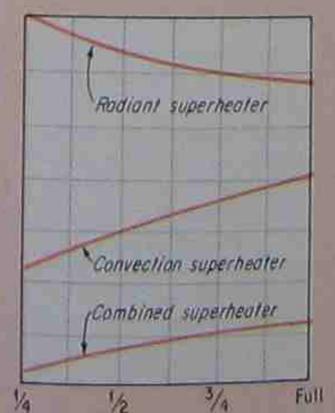
Drainable superheaters and reheaters are of greater importance in the convection section, since there is more likelihood of condensation during a short-time shutdown, temperatures being lower. Pilot-operated valves are being used with pendent superheaters to get rid of moisture and grit after shutdown (POWER, April 1964, p 66).

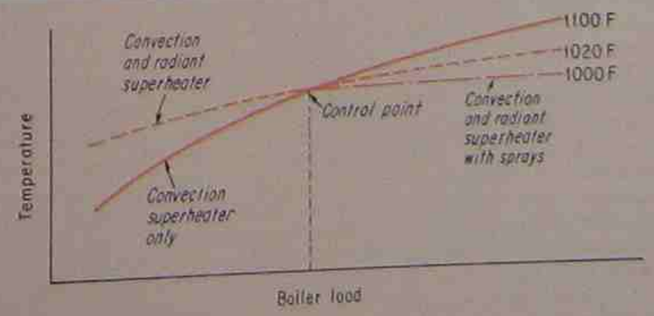
Radiant superheaters, located in the furnace and receiving intense heat by direct radiation, will drop their steam temperature as load increases because of the high rate of heat absorption in furnace walls as load rises. Heat available to the radiant superheater does not increase at the same rate as steam mass-flow within tubes—thus steam temperature decreases.

To hold steam temperatures reasonably uniform as load varies, superheaters and reheaters are often divided into *primary*, *secondary* and sometimes *finishing* sections in large steam generators. As illustrated above, some sections are in the furnace, others farther back in convection zone.

A *platen* superheater consists of tube circumvolutions all in one plane, connecting to inlet and outlet headers. They have proved so effective in absorbing radiant furnace heat that they are also being applied to saturated steam.

External superheaters are used when it is not practical to have a superheater within the boiler settings; for example, where steam is generated in a heat exchanger or evaporator in some chemical heat-recovery process or in

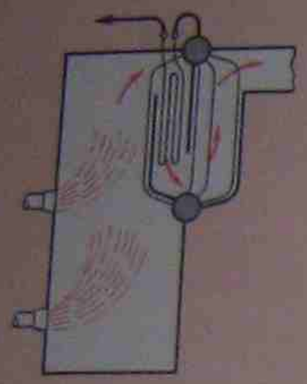




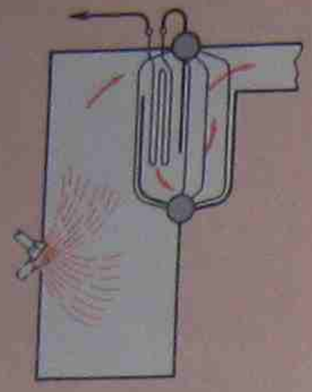
4 One way to hold steam temperature uniform at all loads is through the use of combined radiant and convection superheaters, materially aided by water-spray attemperation

5 As boiler load increases, superheated steam temperatures decrease in the radiant-type superheater. The opposite is true — temperature increases — in convection type

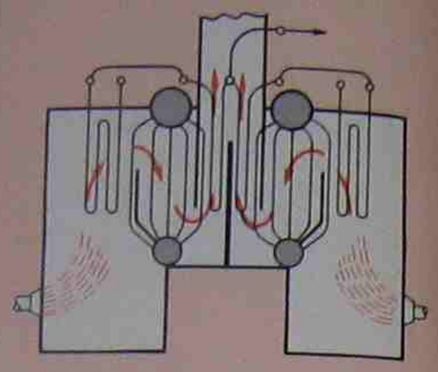
Steam-temperature control may follow one of many techniques



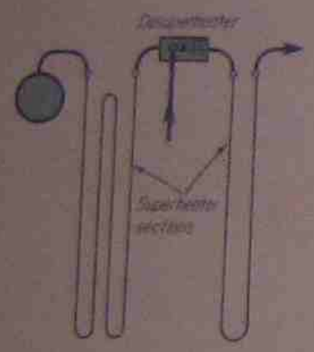
6 Lighting off additional burners raises steam temperature, increases superheater action; upper burner row is most effective



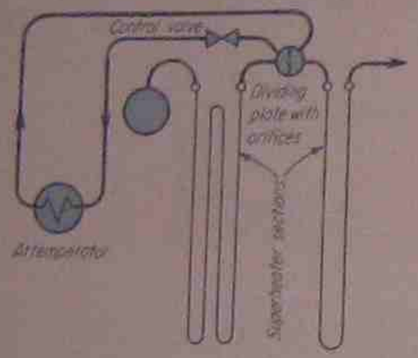
7 Tilting burners varies superheat. Heating is lowered by directing flame downward; raising increases superheater temperature



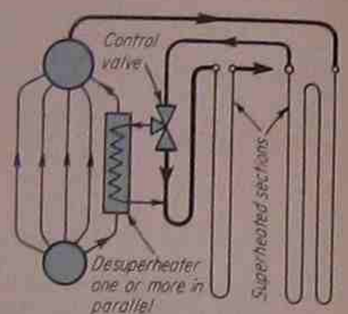
8 Twin-furnace design permits independent firing rates. This flexibility makes it easier to control the steam temperature



12 Pure water sprayed into the superheated steam vaporizes. Degree of superheat is reduced by heat of vaporization



13 In an effort to avoid steam contamination, desuperheating can also be done through use of shell-and-tube heat exchanger



14 This arrangement has de-superheater, between primary and secondary sections, receiving controlled amounts of steam

a nuclear reactor. External superheaters are of the once-through type and may include a reheater section.

WHY STEAM TEMPERATURE VARIES

Precise regulation of superheated steam temperature is one of the requirements for successful operation. Steam temperature tends to fluctuate as a result of many operating conditions, such as changes in excess air, in feedwater temperature, in type of fuel, and depending on the state of cleanliness of the heat-absorbing surfaces.

Excess air affects convection and radiant superheaters quite differently. In the former, an increase in excess air raises superheater temperature because gas flow over the surfaces is greater. For radiant superheaters and reheaters, an increase in excess air lowers steam temperature simply because furnace temperature is reduced. This varying of excess air is sometimes used to control steam temperatures; however, it is not recommended because unit efficiency is adversely affected by higher air quantity.

Feedwater temperature may be increased to lower steam temperature. Here, since less fuel is needed because of higher feedwater enthalpy, gas weight and temperature decrease and superheaters receive less heat. Inversely, heavy use of steam for plant auxiliaries tends to increase steam temperature because more fuel is fired.

Fuel changes come into the picture too, partly because of the Btu content and partly because of different effect various fuels may have upon heating surfaces.

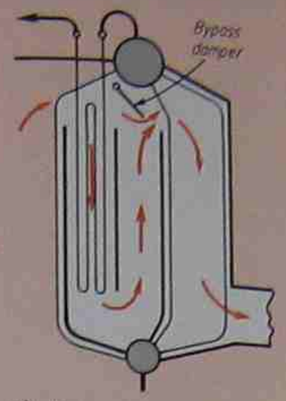
TEMPERATURE-CONTROL METHODS

Various methods, Fig. 6-16, are used to control steam temperature. Some act on the *fireside*, others on the *steamside* of superheaters and reheaters.

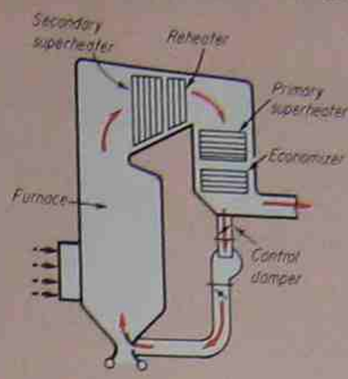
Fireside control may be accomplished by action on the burners (Fig. 6, 7), use of twin furnaces (Fig. 8), diversion of a portion of the gases away from superheaters or reheaters (Fig. 9), or by gas recirculation.

The last method is one of the most attractive. It consists in bringing back into the furnace a portion of the flue gases, generally taken at economizer level. The point at which these flue gases are admitted into the furnace (Fig. 10, 11) determines their effect upon furnace and outlet

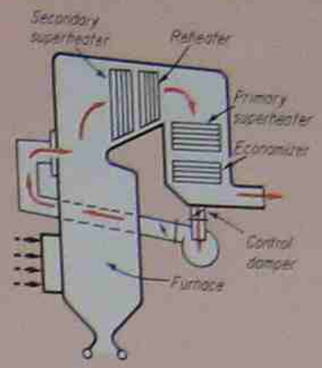
on the fireside or the steamside of superheaters and reheaters



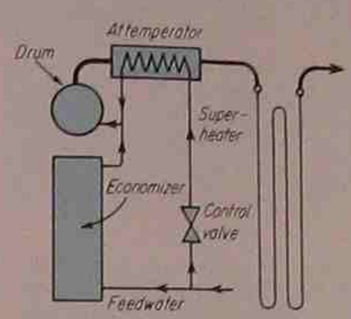
9 Dampers bypass portion of combustion gases around superheater and reheater; are most effective in upper steaming range



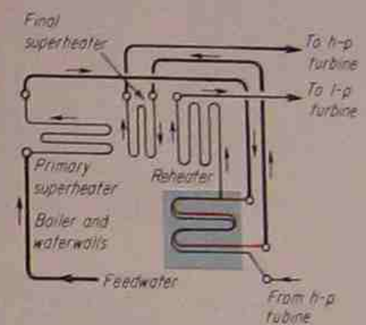
10 Partial gas recirculation affects the overall furnace temperature and, as a result, influences the total heat absorption



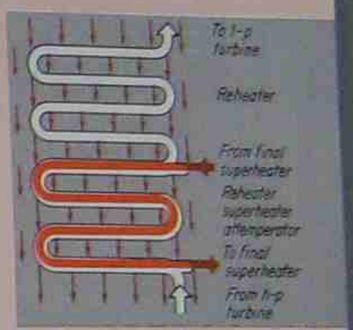
11 Here recirculated gases bypass most of furnace, affect only temperature at the furnace outlet and convection surfaces



15 In this hookup the saturated boiler steam is partially condensed by feedwater, controlling the steam temperature



16 Tube carrying steam from radiant superheater is located within the reheater tube in convection portion of the steam generator. In this design both the reheat and superheat temperatures are interrelated by the individual mass-flow of the two fluids



gas temperature and, as a result, final steam temperature.

Steamside control also gives a series of solutions to the temperature-control problem. *Steam attemperation* is the process whereby steam temperature is lowered by a partial desuperheating. This can be accomplished by spraying *pure* water into the steam—the direct contact system—or by passing all or a portion of the superheated steam through various types of heat exchangers, Fig. 12-15.

Direct contact attemperation is generally done in a header between primary and secondary superheaters. Steam which is moistened by spray, becomes throughly dry in secondary superheater before going to turbine.

Mutual attemperation, involving both superheater and reheater, is still another manner of regulating steam temperature, Fig. 16. There are several ways of doing the job. In the method illustrated, superheater tube is actually located inside the reheater tube in convection section of reheater. In another design a separate attemperator is brought into the picture. Thermostatic valve regulates proportion of reheat and superheated steam.

Several methods are often used together in boiler. Which one predominates may be an operating decision.

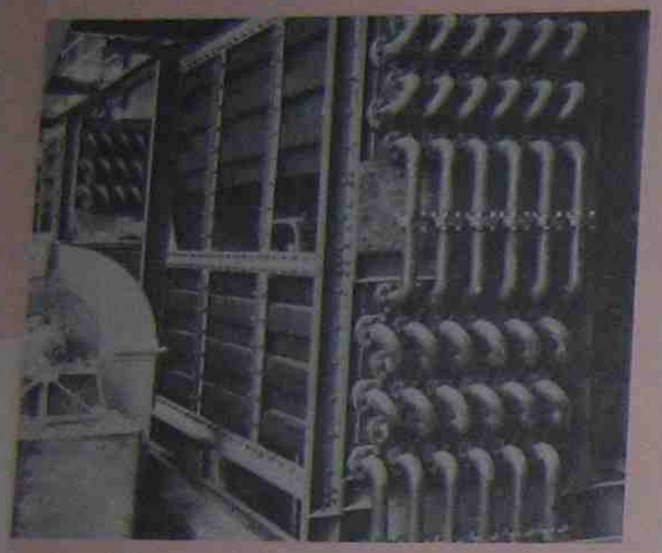
Instruments are used to inform the operator how the equipment is performing and guide him in his adjustments. These, in turn, can be made manually or automatically, right at the boiler or by remote control.

HEAT RECOVERY

When the flue gases leave the heat-absorbing section of a boiler, they contain a considerable quantity of heat energy. The heat in dry flue gas is the largest single loss in a steam generator. A substantial portion of that heat can be recovered by *economizers* and *air heaters*.

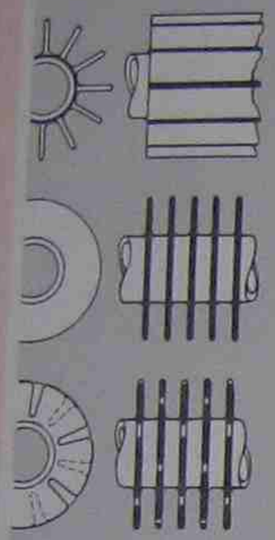
The economizer heats the feedwater. For every 10-11 F increase in feedwater temperature, steam-generator efficiency increases about 1%. In the air heater, the last available heat in the flue gas is transferred to the incoming combustion air. With the common fuels (coal, oil, gas) and considering identical furnace conditions, steam generator efficiency increases by about 2.5% for a 100 F drop in exit gas temperature. From the air end, this means a gain of 2% for each 100 F increase in air temperature.

Economizers and air heaters squeeze heat from flue gases to boost . . .



17 Economizers using cast iron, with extended surfaces, are often located before air heaters, sometimes outside boiler

Extended surfaces increase heat absorption



Welding continuous fins onto tubes lengthwise increases heat transfer. This design also improves anti-sag feature. Typical fins used today may be ¼ in. thick, 2 in. high

Another extended heating surface consists of gilled ring tubing made of cast iron or steel. Fins may be square-shaped, totally independent or a continuous spiral

One design favors separate lentil-shaped steel lugs that are welded around the tube. They keep soot from accumulating and are easy to keep clean

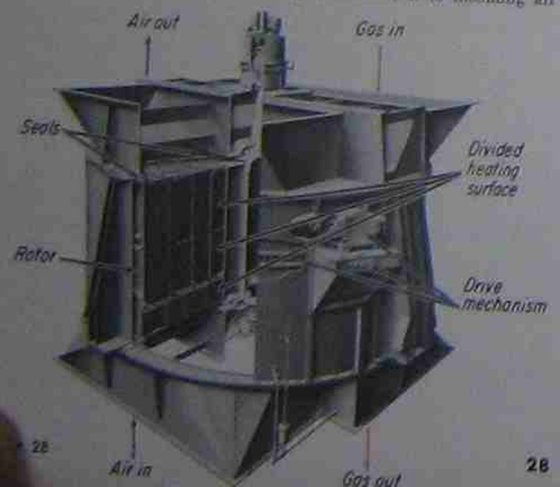
ECONOMIZERS

Probably the oldest method used for recovering heat from boiler flue gases consisted of passing gases through a cast iron heat exchanger to preheat feedwater. Cast iron economizers are still used today when flue gas temperature is low and acid condensation may be expected, Fig. 17. But steel tube designs are the general rule. Steel tubing can be thinner, spaced closer, offers greater heating surface per cu ft, weighs less, and is more economical. Because of the relatively low temperatures at which economizers operate, much exposed surface is needed. For this reason, extended heat-absorbing surfaces are often provided to increase contact between metal and gas (see box above).

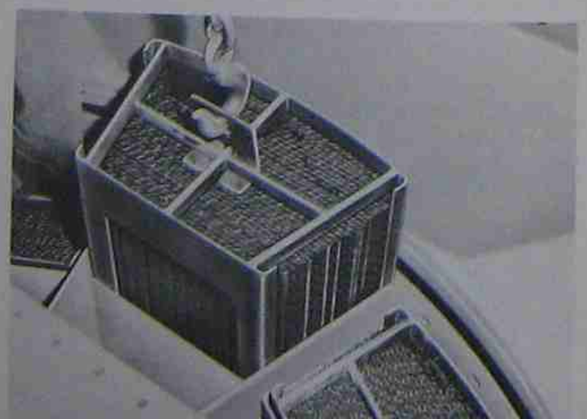
To avoid internal corrosion, water to economizers is generally deaerated. It is also good practice to maintain a fairly high pH—about 8-10. Water temperature at inlet should not cause sweating of outer surfaces. This factor limits inlet water temperatures to a 200 F minimum for low-pressure boilers, near 400 F for high-pressure units. Where maximum resistance to corrosion is desired, both externally and internally, many engineers prefer a combined steel and cast iron design.

Economizer locations vary. *Integral* design is akin to a bank of boiler tubes having their own drums. It may be located within boiler settings as part of convection surface. Sometimes one drum only is used and economizer ties directly into boiler drum. *Independent* arrangement uses a continuous tube design in flue gas flow generally

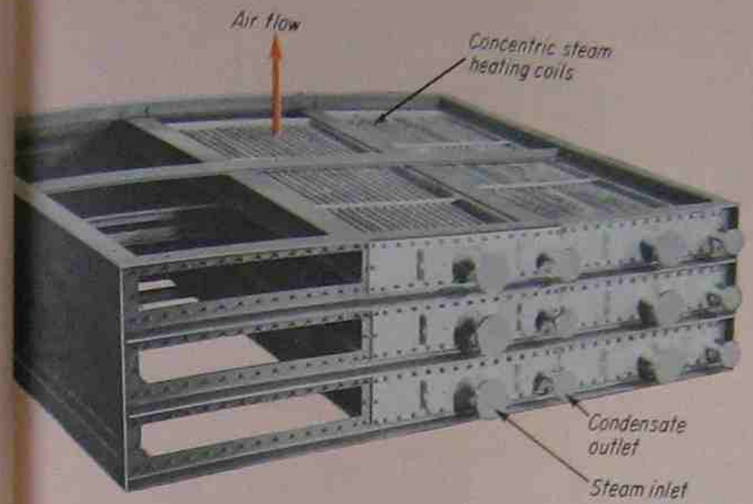
23 Regenerative air heater containing rotating heat-storage elements takes heat from flue gas, transfers it to incoming air



24 Individual baskets house thin, corrugated metal used for heat transfer. Unit is designed for ease of inspection, maintenance



. . . incoming water and air temperatures



18 Here steam enters ⅝-in. perforated inner tube, concentric to a 1-in. tube. Superheated portion of steam is desuperheated by passing through holes. When in outer chamber, steam heats air, condenses, is carried off. Unit, which will not freeze, is used to protect main air heater against corrosive condensation

before air heater. This is most common. Methods now used for internal cleaning of boiler elements have minimized need for easy access to economizer tubes. *External* economizers are used where space limitations within boiler settings rule out internal location or where an economizer is added to an existing installation.

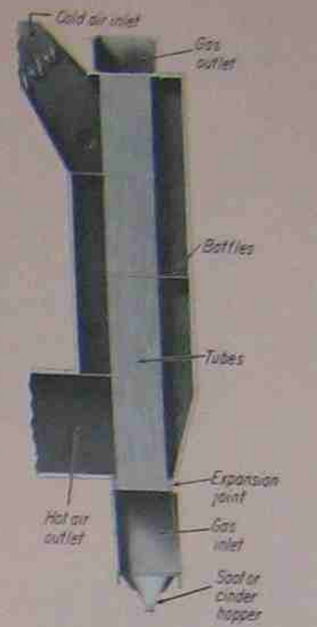
AIR HEATERS

Final heat recovery from boiler flue gases is accomplished in the air heater. Here, gas temperature is reduced close to the dew point – the temperature where moisture starts condensing out of gas. This point is the lower temperature limit for operation. Stepping below that point will invite corrosion, aggravated by acids formed from sulfur products in the flue gas. Air heaters may be classified as *tubular* or *regenerative*.

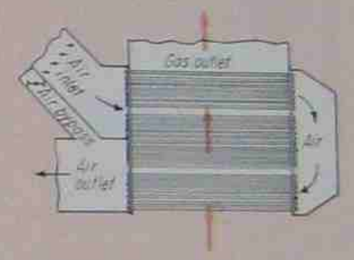
Tubular design, Fig. 19, is available in cast iron or steel. In essence it is a nest of tubes in tube sheets, enclosed in a reinforced steel casing. This casing serves as the air or gas flue and is provided with air and gas inlet and outlet openings. The vertical type is shown. Dust and cinder hoppers are required under the heaters. Different arrangements of tubular air heaters are shown, Fig. 20, 21.

Steam is sometimes used as heat source in a preliminary air heater, Fig. 18. Here the unit is installed in duct to protect main heater against condensation and corrosion. In the design shown, concentric tubes are used to desuperheat any superheated portion of the incoming steam flow, thus increasing heat transfer, improving temperature distribution, protecting heater against freezing.

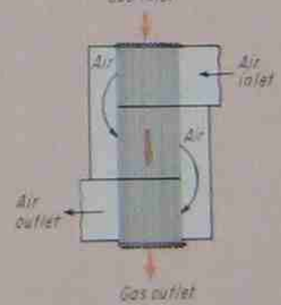
Regenerative air heater, Fig. 23, 24, consists of a rotor, turning at about 2 or 3 rpm, filled with thin corrugated metal elements. It offers a large surface of contact



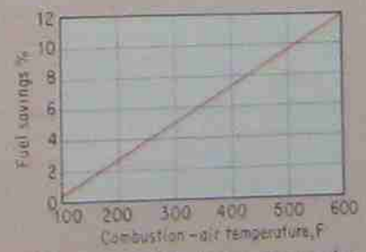
19 The tubular air heater is basically a nest of tubes enclosed in a steel casing



20 In this design, air passes inside tubes while the gas crosses at right angles



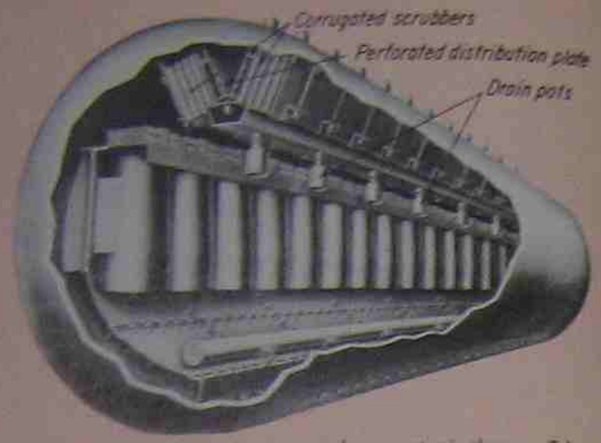
21 Gases flow through tubes here, while air is directed across tubes by baffles



22 Figure on 2.5% higher efficiency for each 100 F increase in combustion air

Drum internals improve steam quality, waterwalls boost performance





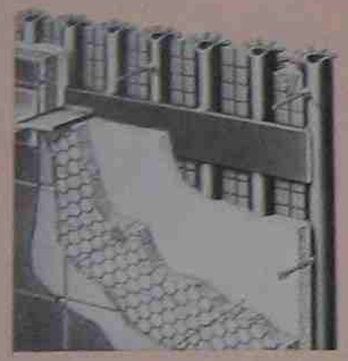
25 Horizontal steam separator in boiler drum is done with corkscrew and corrugated scrubber assembled along length of drum. As steam-water mix enters cyclones, water is thrown off by centrifugal force. As the steam rises, scrubber completes job



26 Welded-wall furnace composed of tubes and welded bars. Result is tight furnace with lagging, minimum insulation



27 Tangent tube requires added supports and provision for expansion. Smaller tubes are used with once-through designs



28 Stud-wall technique generally used for slag-tap furnaces, around cyclonic furnaces. Molten slag does its own coating

for heat transfer with little resistance to gas or air flow.

Hot gases pass through one half of the heater, air through the other half. As rotor turns, the heat storage elements transfer heat, picked up from the hot zone, to the incoming air zone. As with other heaters, this unit may be installed in a vertical or a horizontal position.

Corrosion can be a problem in the low-temperature gas zone. It may be aggravated when residual oil is burned because of the sulfur, sodium and vanadium in the ash. Some solutions are pointed out in the discussion on maintenance and operation, pp S 46-47.

STEAM-DRUM INTERNALS

As steam pressures increase, certain aspects of boiler operation take on increased importance. Steam quality is one. Contamination of the steam by water or solids cannot be tolerated if high turbine performance and long equipment life are expected. The steam must be free of possible impurities picked up in the system and reintroduced into the boiler with the condensate or makeup water. And steam must not carry over water droplets. It's in this area that the boiler drum internals play a most essential role.

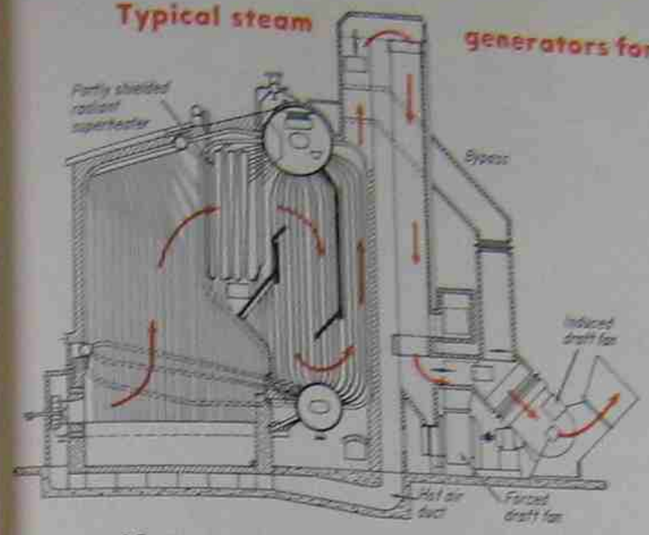
One design for drum internals is shown, Fig. 25. Here the separation of water from steam is done in cyclones installed along the length of the drum with steam *scrubbers* above the cyclones. This procedure is often supplemented by a third step, steam *washing*. Here pure water is sprayed into the scrubbers to wash out silica vapor from the steam and return it to the water.

To avoid harmful silica deposits in turbines, silica in steam should be kept below a concentration of 0.025 ppm. This means that 2000-psi boiler-water silica content should be well under 1 ppm.

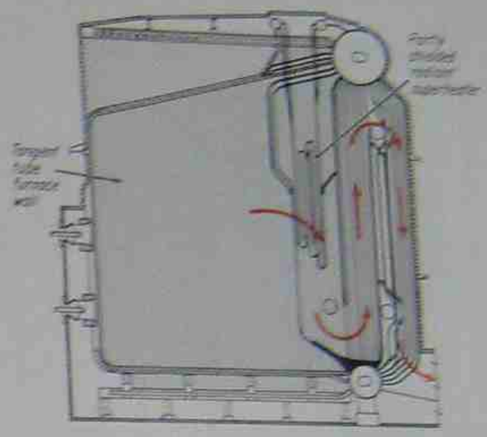
Furnace wall construction becomes even more important as pressures, temperatures and boiler sizes increase. Operating conditions are more stringent. Example: Internal mass-flow of fluid in furnace walls must balance out with external gas temperatures in order that adequate furnace temperature, maximum heat absorption and proper gas cooling occur at the same time.

Typical wall constructions are illustrated, Fig. 26, 27, 28. Specifically, the wall construction shown, Fig. 28, is used where the designer wishes to have slag from the coal build its own coating on the tubes; for example, in

Typical steam generators for industry, small utilities

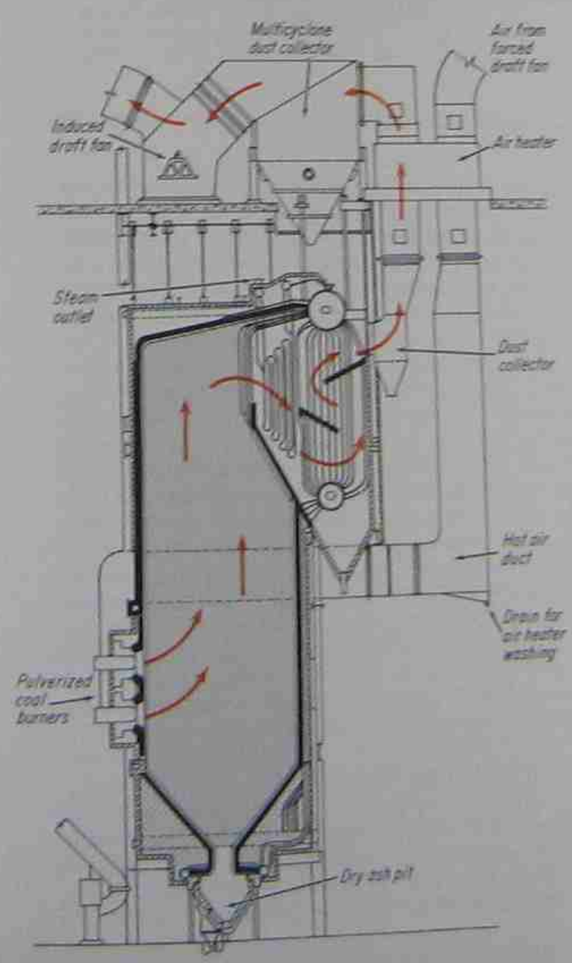


29 This 40,000-lb per hr steam generator operates at 450 psi and 750 F. Note large diameter drums and headers designed for easy access. Other features include wide spacing of wall tubes backed by refractory. The air heater can be bypassed at low ratings

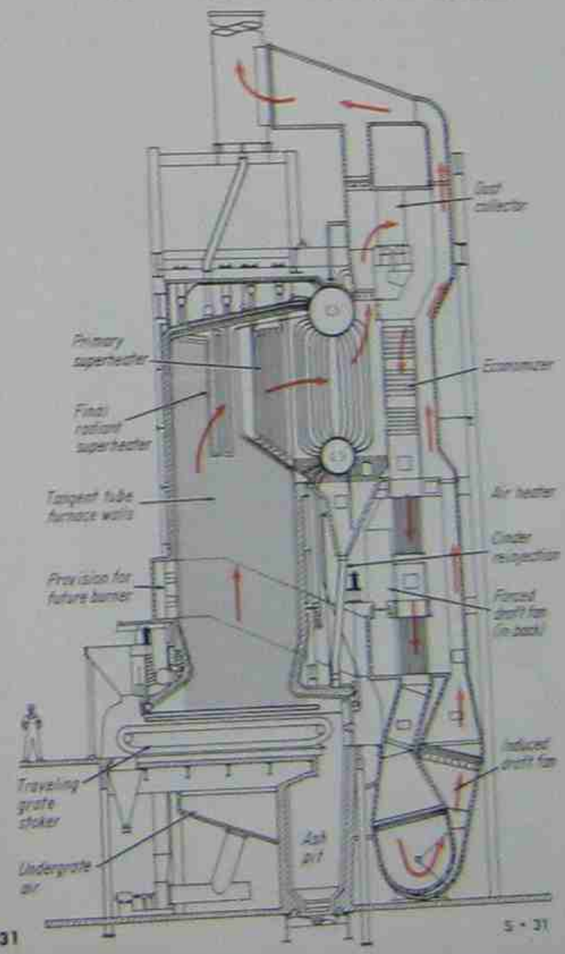


30 Steam generator shown is another manufacturer's approach to popular two-drum vertical-tube design. The furnace tubes are tangent and run entire length of furnace. Gas or oil burners receive air from a regenerative air heater. Superheater follows long design

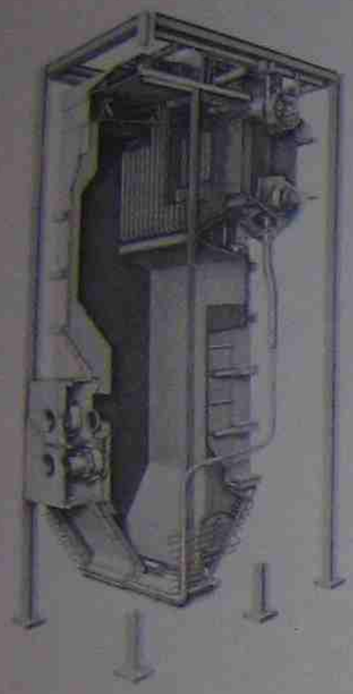
31 Area of water-cooled furnace walls with tangent tubes is large compared to modest area of convection section. Height to drum is 75 ft for this 245,000-lb per hr steam generator. Duct, right, carries air from the regenerative heater to pulverized coal burners

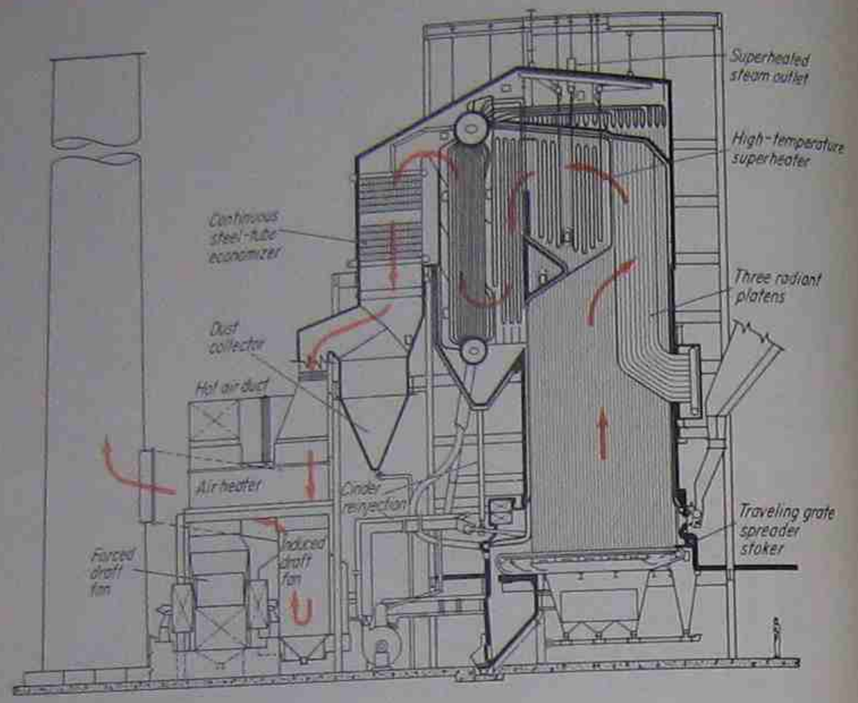


32 Typical spreader-stoker-fired steam generator with both radiant and partially-shielded superheaters, dust separator, economizer. Cross-flow heater delivers combustion air to both spreader and traveling grate. Design provides for bypassing of dust separator



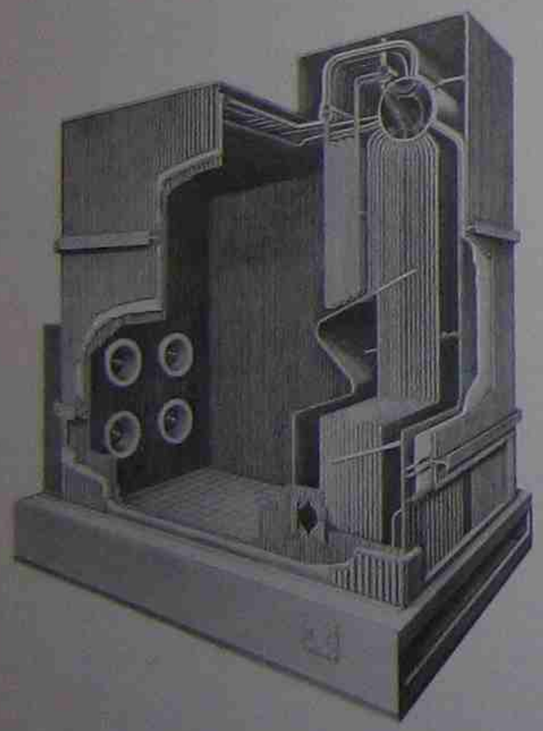
Flexibility and modular design emphasized as unit size increases





33 Capability exceeds ½ million lb per hr at 1500 psi and 960 F. No baffling in boiler section; finned-tube wall is used

34 Lignite is fired in this steam generator on a twin-spreader stoker believed the largest in operation. Stoker is 38 ft wide by 27 ft on shaft centers. Unit has peak capability approaching 700,000 lb per hr at 1300 psi, 955 F; uses two-drum, natural circulation



35 Modular construction includes waterwalls of welded tube-and-fin design. Shop-constructed panels shipped complete with headers. Rating depends on modular additions

the lower area of a slag-tap furnace or for a cyclonic-action furnace. Here the desired temperature can be maintained automatically because slag coating melts when furnace temperature rises. This melting tends to increase the cooling effect from the tube behind, which re-establishes optimum thickness. In some, a chrome-base refractory coating is applied initially to aid the slag-forming process.

Steam generators shown on these pages serve to illustrate how furnace design is varied with type of firing. Height of unit, Fig. 33, gives fuel burned in suspension sufficient time to complete combustion before reaching furnace outlet and the heat-absorbing surfaces in boiler convection zone. Furnace height in the stoker-fired unit, Fig. 34, can be lower since a portion of the solid fuel burns slowly on the traveling-grate section of the spreader stoker.

Furnace side of steam generator is becoming more the designers' concern for reasons of accessibility, a major factor in erection, maintenance and repair. Some manufacturers today ship drums and headers equipped with shop-welded stubs. In the field, the superheater and reheater tubes are butt-welded in position. Repairs to steam generators can often be made from furnace side.

LARGE-BOILER DESIGNS

Of the many developments in large steam generators, several are illustrated by units shown on these pages. Module construction is one feature being used by manufacturers to economically build medium- and large-size units.

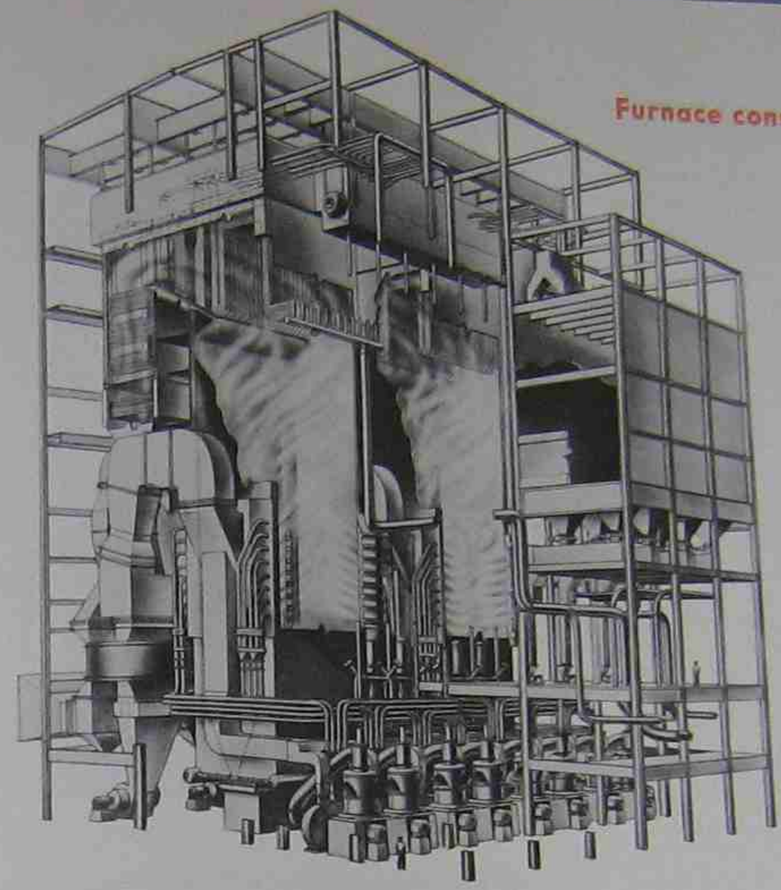
The largest number of steam generators designed for a conservative temperature, pressure and capacity range find their way into industrial plants, also into smaller utilities for power generation (POWER, Oct. 1962, pp 80-84; Oct. 1963, pp S 6, 39, 44). These units are generally the two-drum, natural-circulation, vertical-tube types and may generate between 100,000 and 400,000 lb of steam per hr. Most are field-erected. To construct them economically, manufacturers often follow the module scheme.

Modular construction leads to designs where larger units can be built by simply adding more sections, Fig. 35. The modules are essentially waterwall panels which may be shipped completely assembled with drums and headers. Unit shown is supported on four corner piers with space beneath the furnace floor constituting a plenum chamber for heated combustion air. Location of superheaters, one in radiant zone and the other shielded, generally control steam temperature without need for attemperation.

Radiant heat generates all the saturated steam in unit, Fig. 36. There is no convection section until steam reaches superheaters. In the convection zone are found the drainable primary superheater, the economizer and the main section of the tubular air heater. The final superheater is pendent. Steam attemperation can be handled between the primary and the secondary superheater sections. A preliminary section (closest to the stack) of a tubular air heater is shown, right. Being in the cool-gas section, it can be readily inspected and replaced.

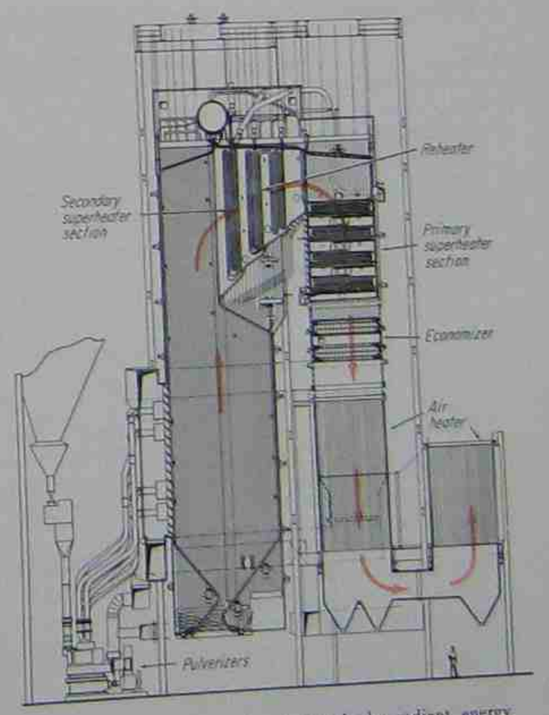
Unit illustrates pulverized-coal firing with dry-ash removal in solid form; oil or gas may also be used. A slag-

Furnace construction plays key role



Twin-furnace design with positive circulation produces 1.8 million lb per hr of steam at 2100 psi, 1050 F and one reheat to 1050 F. Many features of modern steam generators are illustrated. Multinozzle burners in each corner of the furnaces cause pulverized coal flames to impinge on each other, creating a vortex of flame properly centered in each furnace. Since burners can be tilted, steam temperature in each half of unit can be controlled independently (see pp S 26-27). Exit steam temperature is held steady over entire boiler load range.

Unit has a platen superheater on top of one furnace, a platen reheater atop the other. Wall separating twin furnaces is generally watercooled and an active steamer. Furnace tubes in this unit are 1¼ in. OD compared with the usual 3½ in. in many watercooled furnaces. This means thinner walls, higher velocities through tubes, rapid startup time. Operation is fully automatic, including flame-failure protection, remote starting.



36 Here steam generation is largely by radiant energy transfer – there are no boiler convection sections. Capacity from 300,000 lb per hr up, multiple furnace if needed

tip furnace can be installed when the fusion temperature of the ash is low. In such a case, burners with cyclonic action may also be suitable.

Stoker-fired unit. Fig. 34, is designed to fire lignite and will produce 650,000 lb per hr. Operating pressure is 1300 psi and 955 F. To meet the maximum capability of the turbine, a peak steam capacity of 685,000 lb per hr was set as the design limit. Unit is a two-drum natural-circulation design. It has three saturated steam platens to increase steam generation in radiant part of furnace.

At full-load, feedwater enters the economizer at 438 F and exits at 502 F through six 6-in. OD feeder tubes.

Boiler heating surface consists of a boiler bank and the furnace radiant surface, including the platens. Furnace walls, fed by external circulators, are 5¼-in. OD tubes entering the drum either directly, or through leftward tubes. Furnace is over 39 ft wide, 21 ft deep, with a volume of 43,000 cu ft. Total radiant surface is 8586 sq ft.

The superheater has both radiant and convection sections. Steam-temperature regulation (see pp S 26-27) is provided by a spray unit located between superheater sections. A regenerative air heater is used which will provide preheated air at 355 F from a 80 F ambient.

This unit is a semi-outdoor installation located in an area where sub-zero air is common. This extremely cold air, in combination with high moisture fuel, demands cold-end protection in the form of a hot-water coil heater to raise air from −10 F to +90 F, utilizing turbine extraction as the heat source.

LARGEST STEAM GENERATOR

The largest steam-generating unit to date is presently under construction. It will supply steam for the 1000-mw Unit 3 of Consolidated Edison Co's Ravenswood Station in New York City. This boiler will generate up to 6.5-million lb per hr of steam at 2570 psi, 1000 F, with one reheat to 1000 F—thus, a subcritical unit.

Boiler is actually designed for a pressure of 2990 psi. It will operate about 5% above its nominal pressure of 2400 psi. Feedwater will enter the economizer at a temperature of 490 F, and steam will come to the reheater at 650 F. The boiler will be a twin-furnace unit and, outside of size, will mark one important step forward: one furnace and one-half of the boiler will be able to keep operating if the other half fails. Load reduction would be only 500 mw. Each half of the boiler has its own drum and circulating system, its own air and gas ductwork. Hot air for combustion will be supplied by four regenerative air heaters. Fuel will be heavy oil, and steam air heaters will preheat to about 150 F, the air going to the main air heaters. Pulverized coal may be used at a later date.

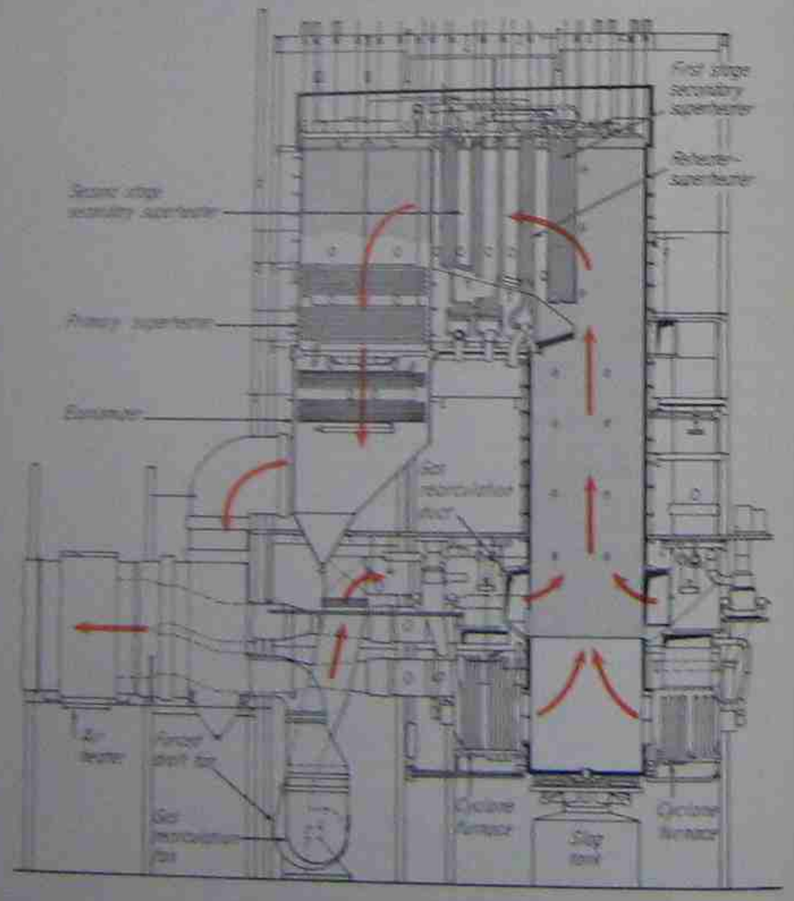
Steam temperature and feedwater regulation, as well as combustion, are to be electronically controlled, with solid state parts—valves, dampers pneumatically actuated.

Once-through steam generator spans wide-pressure range

Once-through boilers receive feedwater at one end of a continuous tube and discharge steam at the other. Entire process of heating, steam formation and superheating is carried out in a single tube. Note the complete absence of a steam drum. Actual design, right, consists of a great multitude of such once-through circuits discharging into a common outlet. This unit handles pressures either below or above the critical pressure of 3206 psia.

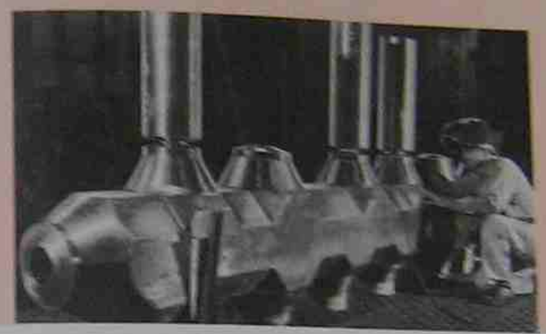
Water-steam flow is through furnace walls, primary horizontal superheater and, finally, the first and second sections of secondary (pendent) superheater.

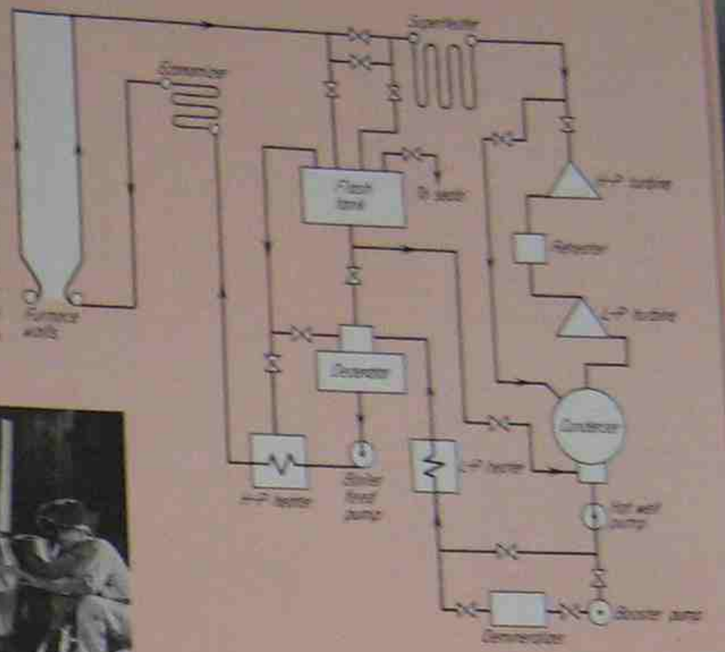
Furnace with cyclonic action shown operates on pulverized coal, gas or oil. Fuel is fed tangentially with air into horizontal furnace. With coal of low-ash fusion temperature, intense heat melts slag which flows into a receiving tank at the bottom. Equipment erosion and air pollution are minimized because of insignificant flyash release. Upon starting, or at low load, steam bypasses superheater, goes to flash tank, then returns directly to the boiler as shown on flow diagram, facing page.



Bypass system handles unit startup and low loads

Supercritical-pressure cycle must maintain active furnace-wall circulation at low loads and startup when little or no steam goes to the turbine. In system, right, the steam generated discharges to a flash tank. Steam separated from this fluid is directed to turbine seals, deaerator and h-p heater. It can also be used for rolling the turbine. Automatically controlled high-pressure stop valve and reheat line valve between flash tank and superheater return cycle to normal when quarter load is reached. Photo below shows heavy thickness of tubes and headers at these pressures.





Supercritical pressure systems

Attractive heat rate and inherent economy of large-capacity plants spur trend to big supercritical pressure steam generators

Popularity of supercritical-pressure generating stations for public utilities is on the increase. Nearly 50% of the steam-generating capacity bought by U.S. utilities during 1963 was for supercritical-pressure cycles. This represents a total of eleven units with a combined output of 6690 mw compared with only four units totaling 1965-mw purchased the year before. In the U.S., Germany and Great Britain there are now about 40 supercritical-pressure boilers in operation, under construction or on order.

At the critical pressure of 3206.2 psia, steam and water coexist at the same density. When this high-pressure mixture is heated above its 705.4 F saturation temperature, dry superheated steam is produced. Steam generators employed for this service are the once-through type illustrated on the facing page and on page S 30.

Supercritical units may be fired with gas, oil or coal. For a given capacity the gas-fired unit is the least expensive. Coal firing costs the most, mainly because of wider tube spacing and additional heating surface needed. Coal firing is generally accomplished either with a cyclonic furnace or with tilting multinozzle burners. In either case, furnace protection is integrated to perform several functions, including: (1) purging, (2) control of startup air and fuel, (3) burner programming, and (4) flame monitoring. System is interlocked with fail-safe features.

The first U. S. supercritical unit was pioneered by American Electric Corp at Ohio Power's Philo station. In operation since early 1957 their unit No. 6, rated at 120 mw, employs a once-through boiler designed to produce 675,000 lb per hr at throttle steam conditions of 4500 psi and 1150 F with two stages of reheat at 1050 F and 1000 F. The steam generator is fired with three 9-ft diameter cyclonic-action furnaces.

Shortly afterward, in Germany, the Huls Chemical Works installed a 675,000-lb per hr boiler designed for 4350 psi 1100/1050/1050 F. This was followed by Eddystone No. 1 of Philadelphia Electric Co. having a design pressure of 5000 psi, throttle temperature of 1200 F and two reheats to 1050 F. This 2-million-lb per hr boiler features two furnaces with each housing one reheater.

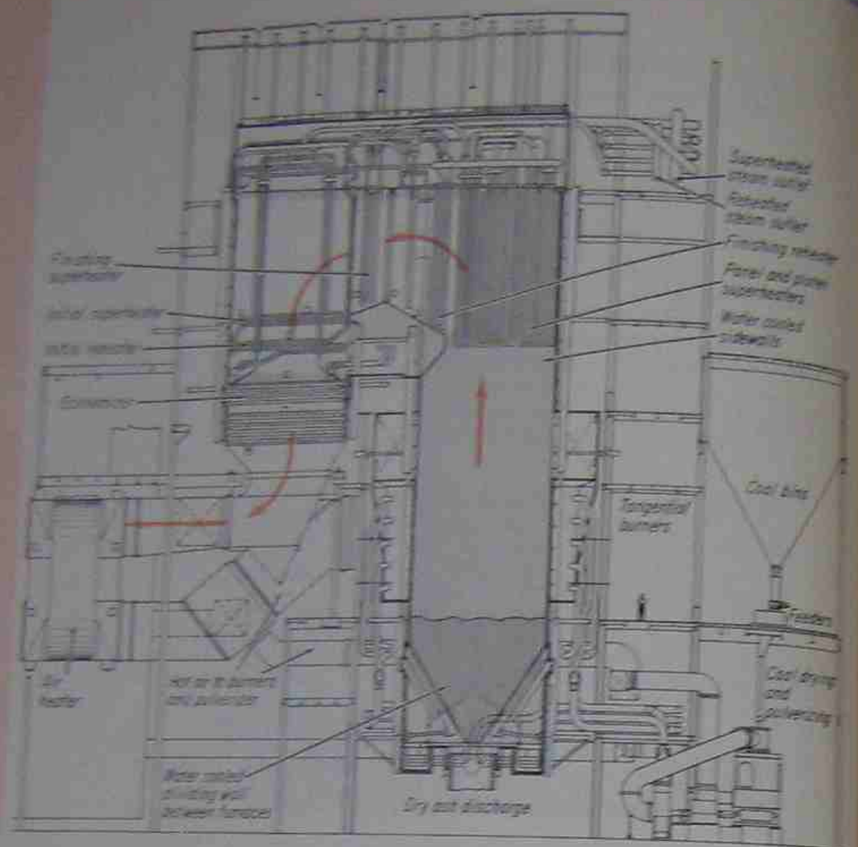
UNIT SIZE AND PRESSURE

Long-term trend in the electric utility industry has been to take advantage of the inherent economy of large capacity units. Plants of 300-mw capacity and higher are becoming more common even in smaller utility systems. But there is still considerable discussion about the relative merit of subcritical versus supercritical cycles in the 300- to 600-mw range. Recent studies indicate that 3500-psig operation will be more economical than 2400-psig cycles

Huge supercritical boiler is heart of 900-mw cycle

Steam generator, right, is designed for a primary steam flow of 6.4 million lb per hr at 3500 psig and 1000 F, with a single reheat to 1000 F for a rated turbine capability of 900 mw. Positive circulation employed at start-up and low loads is shown on the flow diagram (opposite page). Unit has a two-pass furnace and is fired with pulverized coal in multiburner burners.

Flow goes from economizer to center wall. From there it goes to water walls and enters rear gas-pass walls. Next come four distinct sections of horizontal, platen and regular pendant superheaters before discharge to the hp turbine. Steam returns to a two-section reheater before entering the ip turbine. Waterwalls are constructed of all-welded panels. Tubes are 1¼-in. OD on 2¼-in. centers. All high-absorption gas surfaces are constructed of Cr-Mo steel alloys.



in single boiler-turbine unit sizes above 300 mw, with the fuel costs prevailing in many geographical areas.

Much of the added cost of a supercritical 3500-psig cycle is due to the heat-transfer equipment (boiler and feedwater heaters), pumps and feedwater piping. A 3500-psig boiler costs more than a 2400-psig design because it requires more steel. Heating surface for a given fuel is the same per unit output, but tube thickness, and therefore the quantity of metal, increases. Total added cost then varies with the heating surface required per kw. Steam-piping cost is about the same for a 3500-psi, 1000/1000 F cycle as for a 2400-psi, 1000/1000 F hookup because lower specific volume offsets higher pressure.

Higher initial cost must be charged against savings due to improved heat rate at 3500 psi. Additional cost per installed kw for boiler, feedwater heating and pumping equipment may vary from $1.25 for a gas-fired unit to $1.80 for a pulverized coal job; the difference due to the greater heating surface needed for coal firing. These differentials are a big improvement over those which have existed until just recently and should lead to increased application of the supercritical cycle. Major steam-generator cost reductions have resulted from the use of smaller diameter tubes, welded, gas-tight furnace wall panels plus other design and erection simplifications.

Another important factor in comparing 2400 to 3500-psi boiler designs is that of tube metal temperature. Operating temperature of both metal and fluid varies greatly with a single-phase fluid at critical pressure. This makes control of mass flow through tubes extremely important. Adequate mass flow must be maintained, particularly at low loads and startup when once-through demand-flow alone would be insufficient to provide full tube protection.

Supercritical and once-through boilers also pose special water-treatment problems. Since there isn't any boiler drum, all water entering the circuit flows out as supercritical fluid. Any solids present in the feedwater will be carried off with the steam. These can form troublesome deposits in superheater or turbine. One source of impurities in the cycle is the presence of minerals in makeup and in the condensate, usually from leakage through the condenser from the cooling water. Another is metal oxides from preboiler corrosion. Condensate stream is treated by sending it through a polishing filter-demineralizer system, designed to keep total dissolved solids below 0.04 ppm and silica below 0.01 ppm. Vapor-type chemicals, such as hydrazine and ammonia, are employed for oxygen scavenging and corrosion control in the preboiler cycle. Copper and iron oxide pickup must be closely watched.

First of the 3500-psi cycle designs was the 250-mw unit at Avon station of Cleveland Electric Illuminating Co. Capacity of this boiler is 1.7 million lb per hr with steam at 1100 F. It features a double combustion chamber, one housing the superheater and the other a 1050 F reheater. Unit size continues to grow with every new installation.

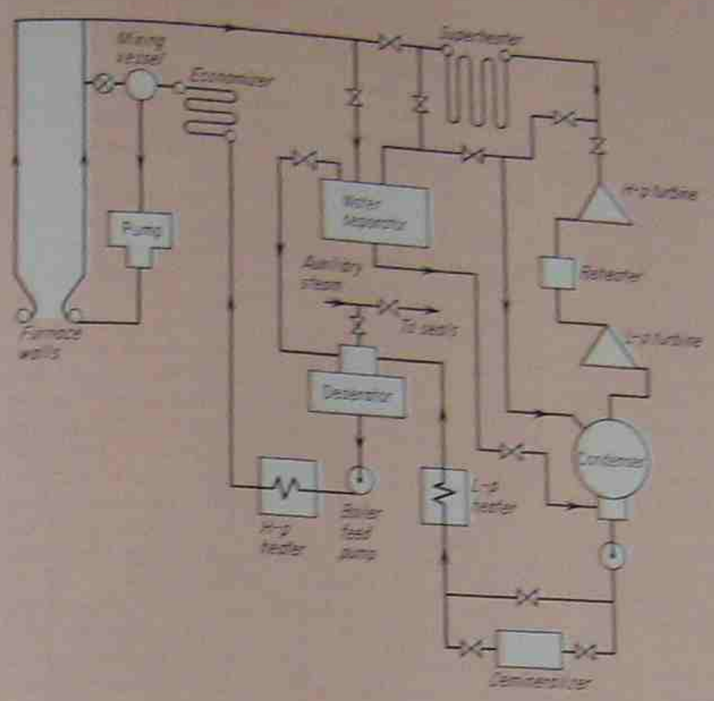
Today's largest supercritical installation, above, under construction for a 900-mw generating cycle will produce 6.4 million lb of steam per hr. Steam generator is of the twin-furnace type with a water-cooled center wall in-between. Feedwater enters at 550 F and picks up about 100 F in the economizer. Recirculating pump, which is a feature of this particular design, circulates the fluid between successive water walls. When it reaches the first section of the horizontal superheater at a temperature of around 800 F, the fluid is no longer water. It is now a mixture of steam and vapor which must be dried and superheated. After passing through horizontal and pendent superheaters, 1003 F steam is ready for the h-p turbine.

Temperature is maintained at the exact control point by attemperation before entering finishing superheater. When that area is reached, the steam has absorbed about 83% of boiler capacity. Most of this energy is then released in the h-p turbine. Exhaust steam returns to the boiler and circulates through two sets of reheaters, bringing temperature back up to 1003 F, using final energy available in the boiler. Reheated steam discharges to an i-p turbine, then to 1-p turbine and condenser. Resulting condensate is treated by a filter-demineralizer, more heat is added in a series of feedwater heaters and a deaerator. Feedwater is pumped through high-pressure heaters into the steam generator, ready for a new cycle.

Since this is a once-through design, without the recirculation feature in boilers with drums, provision must be made to supply enough cooling fluid to prevent overheating the furnace walls. This can be done in several ways. One method makes use of a mixing vessel and a recirculation pump, as diagrammed above. Fluid taken from the mixing vessel automatically recirculates through the heat-absorbing surfaces. This pump "floats" on the once-through system. Above half-load, the pressure drop through the furnace-system equals head produced by the circulating pump. At this point it no longer contributes to quantity of flow. Feedwater flow alone is then sufficient to fully protect the furnace walls. But circulating pump still maintains its role as a booster to the main feed pump. Pumping a supercritical fluid which constantly changes temperature with rating – as much as 140 F in furnace walls – is a far cry from handling just water, but the circulation pump is not adversely affected. It merely handles a given volume of fluid at constant speed.

An auxiliary source of steam is needed at startup for the steam-turbine feed-pump drive, turbine seals, deaerator and the feedwater heaters. It is supplied – unit, p S 36 – by a group of house boilers capable of producing some 100,000 lb per hr of steam at 500 psi with 100 F superheat.

Another supercritical system in widespread use employs a bypass method, diagrammed on page S 35 for starting and low loads. Enough flow is diverted around turbine and reheater to maintain required mass flow in boiler tubes. System returns to normal when quarter load is reached.



Positive circulation uses pump and mixing vessel

In supercritical cycle, both start-up and low-load operation are handled by a recirculation pump and a mixing vessel. Other elements of the cycle are similar to bypass arrangement detailed on page S 35. The recirculation pump starts at low loads and boosts water-steam flow, first through waterwalls and then through other heating surfaces, in the boiler. Recirculation continues up to about half of full load. Exact point may vary with each installation. Since this recirculation pump "floats" on the once-through flow, a major portion of the power consumption reduces power needs of the main boiler feed pump. Fluid velocity in the furnace walls can be controlled independently of steam demand. This means pressure drop through furnace walls can be reduced. Steam from an auxiliary boiler is needed during startup.

WHAT'S AHEAD?

A critical evaluation of early very high-pressure units caused engineers here and abroad to lower their sights to a 3500-psi level for the present. Economic limit on superheated steam temperature today is 1100 F and many conservative engineers feel that 1050 F should be the maximum. But even these temperatures cannot be reached without using high-quality alloys containing chrome, nickel and molybdenum for the superheater and reheater sections. Further increase in pressure and temperature now depends on the development of materials capable of physically and chemically resisting higher temperatures. Without higher temperature further increase in pressure

will not improve efficiency enough to be profitable.

Increase in thermal efficiency from higher pressure and temperature operation is closely related to the proportion of alloy steel which replaces carbon steel or of high-alloy steel which replaces a low-alloy steel. Savings from higher efficiency must be greater than additional cost of the special alloy tubes that make higher efficiency possible.

Goal of metallurgists is to develop alloys that have: (1) high-temperature strength, measured by their resistance to long-term creep, (2) structural stability to resist microstructural changes from severe service conditions, and (3) surface stability to resist corrosion and oxidation either on the gas side or the steam side. In addition, these alloys must be easy to fabricate and reasonably priced.

Waterside corrosion of steel and its alloys at high temperatures and pressures is not fully understood. But it is generally agreed that the protective film of magnetite, which tends to form during initial boiler operation, affords some corrosion protection, at least until proper feedwater treatment and control can be established.

Fireside corrosion is also a problem. Research laboratories are actively engaged in studying the role of sulfur, sodium, vanadium and other fossil fuel impurities.

SUPERCHARGED OPERATION

One way to improve cycle efficiency may be to combine a supercharged furnace with the high efficiency of operation at supercritical pressure and elevated temperature. Proposed design, below, based on experience with supercharged boilers in the marine field, is designed for a pressure of 3500 psig on the steam side and 5 atmospheres or 75 psi on the gas side. Tightness of high-pressure gas passages is essential. For additional insurance, flow of pressurized combustion air surrounds the gas-flow passages both in the central shell containing superheaters and reheaters, and in the two furnaces.

Design is an example of what can be referred to as a "combined cycle." Steam is discharged to h-p and l-p steam turbines for electric generation. Flue gases discharge to a gas turbine which drives an air compressor delivering hot combustion air at high pressure to the boiler.

The gas turbine may or may not drive a generator, depending on the type of fuel used. Main factor is temperature of flue gases at the turbine inlet. When gas is the fuel, resulting temperature of 1450 to 1550 F is quite acceptable. Then, perhaps with a little supplementary fuel, the turbine can also develop enough power to drive a generator.

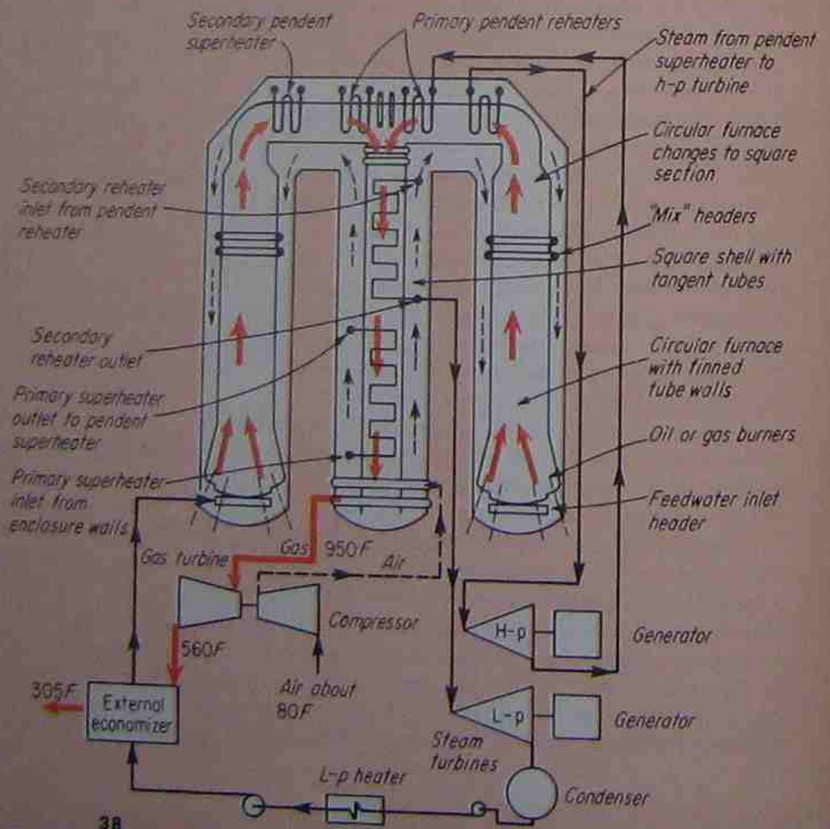
However, with heavy fuel oil the gas turbine inlet temperature must be kept well below 1000 F to protect turbine blades against erosion and corrosive attack by ash in the fuel. In this case the gas turbine is still self-sustaining since it develops power to drive the air compressor.

Coal is not completely out of the picture. Plans are being drawn and research conducted on coal gasification, with gas used in the supercharged boiler in a combined cycle.

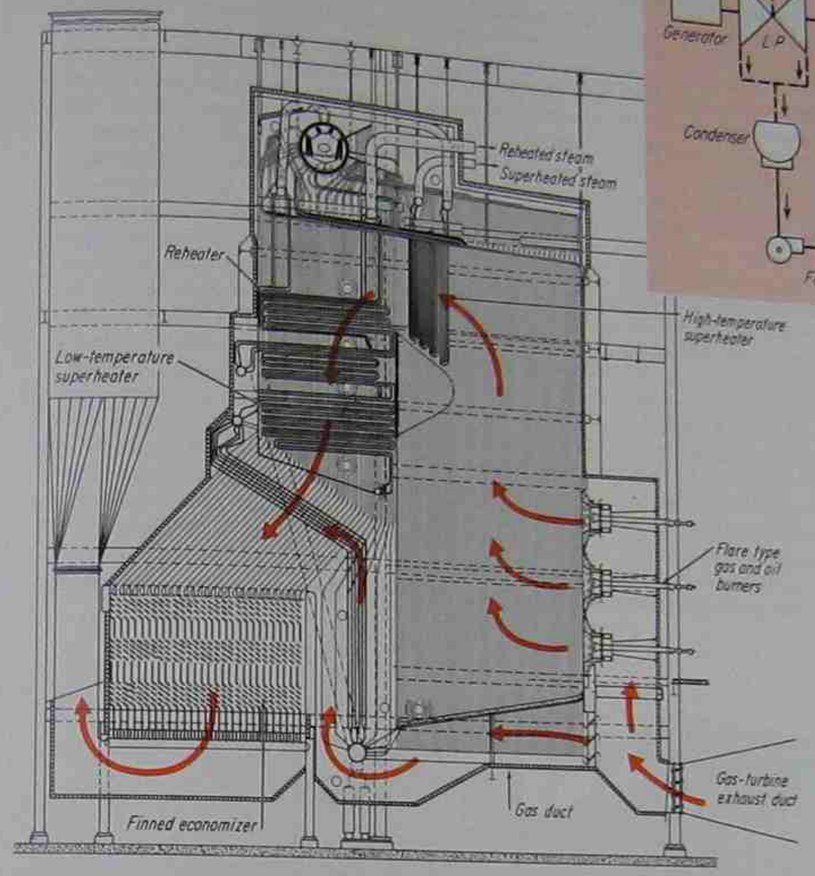
More conventional combined-cycle, right, uses exhaust of a gas-turbine to supply heat and combustion air to a boiler supplying steam turbine generators.

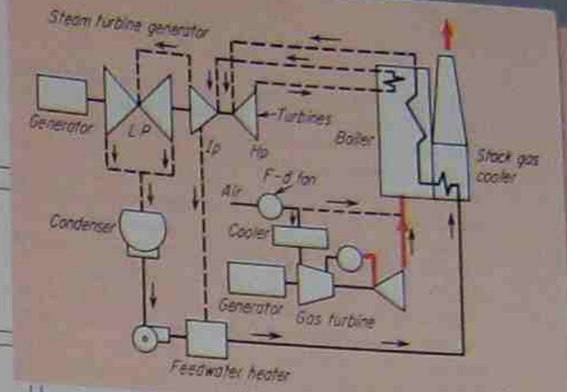
Combined cycle unit at supercritical pressure is promising newcomer

Unique-looking once-through steam-generator with supercharged twin furnace is designed for 3500-psi, 1000 F steam and 1000 F reheat. Exhaust gas leaves central shell at pressure and temperature sufficient to operate a gas turbine which, in turn, drives compressor supplying combustion air to high-pressure oil or gas burners. Turbine exhaust gas is used to preheat the feedwater. Furnaces and central shell – housing primary superheater and secondary reheater – are entirely water-cooled. Air, compressed to 75 psi and 525 F, flows through annular passage in central shell and furnaces. Heat exchanger, between reheater and superheater circuits, controls reheat steam temperature. Gas turbine is self-sustaining, but it does not drive an auxiliary generator in this case. Supercharging the unit to about 75 psi allows for substantial size reduction over conventional steam generation equipment of equivalent capacity.



Combined cycle unit reclaims heat from turbine exhaust





Combined-cycle generator, left, produces nearly 600,000 lb per hr of steam at 1538 psi, 1005 F with one reheat to 1005 F. In contrast with combined cycle on facing page, exhaust from gas turbine discharges to the boiler. Recovery of heat from the flue gas is accomplished by a large extended-surface economizer integral with the boiler. The steam turbine cycle, above, utilizes a single low-pressure feedwater heater and a deaerating heater. No high-pressure feedwater heaters are used. Normally the plant operates as an integrated unit with gas turbine supplying heat and combustion air to the boiler with varying amounts of additional fuel fired in the steam generator to maintain constant throttle pressure and temperature at the steam turbine

Steam generators for special applications

High fuel costs plus advances in waste energy utilization have led to many specialized designs for recovery of heat and chemicals

Main source of energy for generating power and steam in most industrial plants is oil, natural gas or coal. These primary fuels have high heat value and other favorable properties which make them ideal for firing in modern boilers. But if byproducts are available from a manufacturing process or an energy system, with appreciable heat content, they can be used to generate steam. This explains why examples abound of steam generators which do not depend on conventional fuel for operation, but make use of energy from gaseous, solid or liquid by-products.

GASEOUS BYPRODUCTS

This form of energy is typically found in steel mills, oil refineries, cement plants and nonferrous-metal plants. Utility power plants and various industrial and commercial on-site generating systems also employ prime-mover exhaust gas as an energy source.

Combined cycle, above, in a utility generating station utilizes heat from gas-turbine exhaust to generate steam needed for a steam turbine-generator. Supplemental oil or gas firing keeps steam pressure and temperature at required level. Since a substantial number of Btu's are recovered from gas-turbine exhaust, this unit operates at relatively high efficiency. Combined cycle, therefore, has a relatively attractive heat rate compared with a conventional steam turbine generating plant.

Variation of the combined cycle, facing page, which shows promise, employs a supercharged steam generator.

Exhaust flue gases discharge to a gas turbine which in turn drives a compressor that supplies combustion air to high-pressure burners on the pressurized furnace.

Gas turbines are particularly good as a heat source because their exhaust gas temperature is relatively high. Combination of gas turbine and heat-recovery steam generator is responsible for much of the current interest in on-site generating systems for commercial buildings, schools, institutions and small industrial plants. These "total energy" installations use gas or oil to produce all the energy needed for air conditioning, heating, lighting and electrical equipment.

Steel industry has large quantities of gaseous by-product energy available. Heat content varies from less than 100 Btu per cu ft for blast-furnace gas to 525 to 600 Btu per cu ft for coke-oven gas. Main problem is getting this gas clean enough to avoid fouling the burners.

Oil refineries, where catalytic cracking of crude petroleum is performed, produce large volumes of gas as a by-product of catalyst regeneration. This gas contains 5 to 8% CO, about twice that much CO_2, and air. Gas temperature is around 500 F, with a heat content of about 145 Btu per lb. Increasingly, refineries reclaim this energy by burning the gas in a CO steam generator together with oil or gas and additional air. A CO unit is also a must in any area where air pollution is a critical problem. These CO steam generators not only save heat but burn up the CO and any unburned hydrocarbons that escape from the regenerator of a catalytic cracking unit.

Cement-industry kilns discharging hot gases are another fruitful source of byproduct energy. Nonferrous metal production yields hot gas from melting furnaces and roasting ovens. In all these areas steam can be produced from reclaimed gaseous byproducts. Air heaters frequently found in exhaust-heat steam generators complete the heat recovery job. Hot air needed for metallurgical processes can then be obtained at substantial savings.

Cleaning of flue gases emanating from steam generators burning industrial byproducts is generally necessary to keep solids concentration in gases at an acceptable level to avoid air pollution. This cleaning can be done with mechanical dust separators of the wet or dry type, electrostatic precipitators and sometimes a combination of both. Each works best in a different range of particle sizes.

SOLID BYPRODUCTS

Solid byproduct fuels are many. Among them are wood chips, sawdust, hulls from coffee and nuts, corn cobs, bagasse (the waste product from sugar cane), coal char (residue from low-temperature carbonization of coal), and petroleum coke (the final solid residue from a refinery). Each product must be handled in a special manner because of differences in moisture content, consistency, specific weight and heat content.

Properly speaking, it's the furnace rather than the steam generator that is affected when these special fuels are used. Some products like bagasse, with about 50% moisture, require a Dutch-oven. The Ward furnace is a popular design for bagasse, both in the U.S. and abroad. Bagasse fuel is partly dried and burned in refractory cells below a radiant arch. Combustion of gases is completed above the arch. Spreader stokers can also be used.

Art of burning wood refuse ranging from hogged-wood to sawdust has progressed to point where a spreader type stoker or a cyclone burner does an efficient job, generally in combination with some coal.

Municipal garbage is perhaps one of the most difficult solid products to handle as a boiler fuel because of wide variations in its nature and quantity. Nevertheless, the practice of using heat from garbage incineration to generate steam shows promise (POWER, March 1964, p 68). The boiler may be located directly over the incinerator or the hot gases led to it through a duct. Several types of stokers can be used for this service.

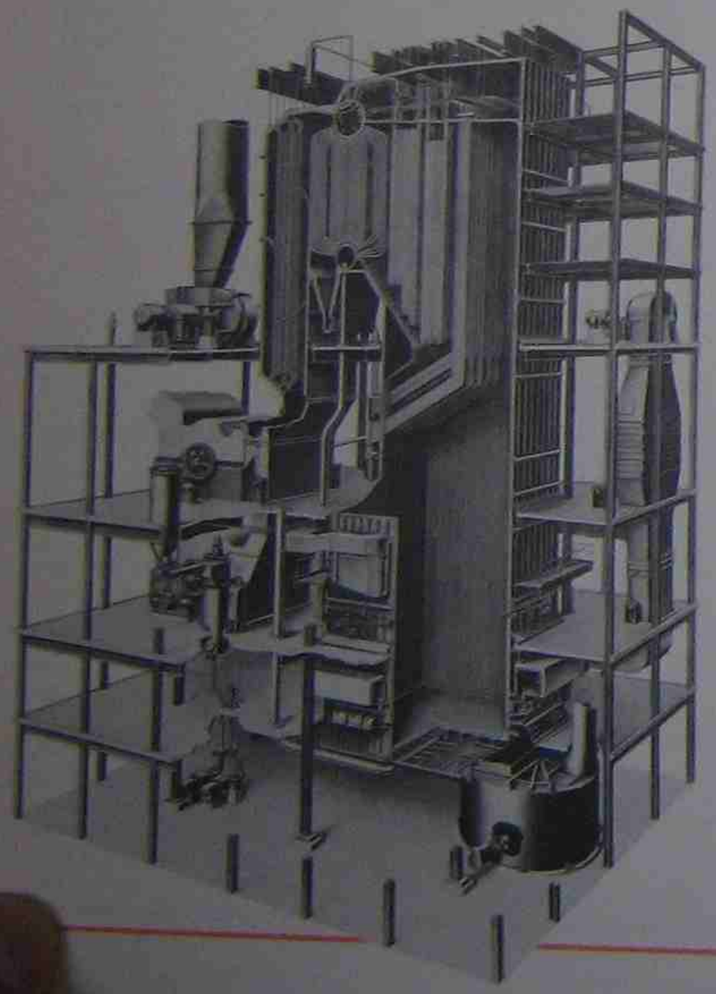
LIQUID BYPRODUCTS

This category includes residue from chemical processes, such as tar and pitch. These can be handled in conventional oil burners but, for satisfactory results, must be heated to maintain viscosity at the proper level. Filtration is also required to remove any solid contaminants. High moisture content can be handled by decantation or thorough emulsification of the mixture.

Recovery steam generators are practically indispensable in the pulp and paper industry. These units recover chemicals used for pulping from either the "black liquor" alkaline process, facing page, or the "red liquor" acid process shown below. In addition, they economically generate a high proportion of the plant's steam load.

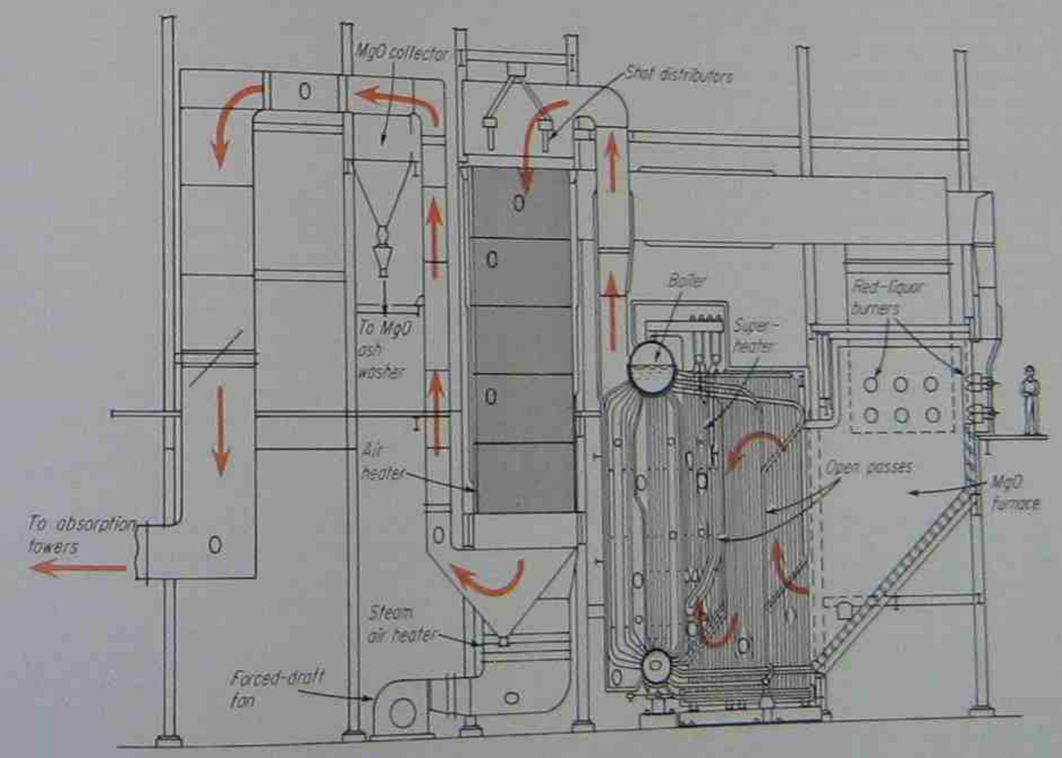
Different configuration of black-liquor and red-liquor steam generators is the result of basic differences in fuel behavior. Black liquor in the kraft process is very difficult to burn. Large furnaces are needed to keep temperature relatively low because the liquor has a high content of low fusion-temperature ash. Smelt is collected on the refractory sloping hearth and a reducing atmosphere must be maintained in lower part of the furnace for chemical conversion. Since superheater and boiler surfaces readily coat with slag they operate at low-absorption rates.

Red liquor in the MgO process, on the other hand, burns completely in suspension, makes little or no slag. This means a smaller steam generator can be used for an equivalent amount of steam production. Soot blowers and shot-cleaning are essential adjuncts of all recovery units.



Black-liquor fired boiler, heart of recovery process

Kraft recovery is an alkaline process performed in a highly integrated system. Waste "black liquor" is first concentrated in evaporators to about 67% solids, using heat from flue gases. Some sodium sulfate is added to make up chemical loss, then heavy liquor is sprayed into finned-tube wall furnaces. Furnace, with chrome refractory hearth, performs several functions: evaporates moisture, burns organic liquor constituents, converts sodium sulfate to sodium sulfide in a reducing atmosphere. Resulting smelt, mostly sodium sulfide and carbonate, is then dissolved in water to form "green liquor." Subsequent treatment by a caustic produces "white liquor" ready for return to the pulping process. Hearth must be tight as smelt reacts explosively with water.



MAGNESIUM OXIDE AND SULFUR DIOXIDE RECOVERY coupled with steam generation is an important feature of the fairly recent sulfite process for wood pulp production. Waste, red liquor, with a concentration of about 50% organic solids, is fired with steam atomizing burners into a highly refractory furnace with air heated to about 700 F. MgO ash is recovered from both furnace floor and flue gas. Latter then passes to absorption towers where SO_2 is absorbed by MgO slurry to produce cooking acid for pulping process

Steam-generator selection

Choosing a unit for maximum long-term economy and reliability calls for decision-making on many matters beyond first cost

Responsibility of the engineer in selecting a steam generator is keyed to system know-how: He must have a complete understanding of all conditions under which the unit will operate. These conditions and resulting needs, must then be translated into a performance specification for the equipment manufacturer. This important step calls for an appreciation of many variables.

SYSTEM REQUIREMENTS

Steam-generator selection requires a nucleus of straight economic comparisons. Yet specific job requirements often weigh heavily in the decision—for example, in provision made for fuel flexibility, in the need for duplicate auxiliaries evaluated against the degree of reliability required, in the extent of stack emission control as governed by plant location and social climate. And it is in all these areas where sound judgment rules.

For space heating and industrial processing, steam temperature is generally the most important consideration. Technological progress in recent years has chalked up substantial gains in efficiency which is reflected in the quantity of steam needed for both heating and processing. More efficient heat exchangers, more effective radiators, better insulations, materials with higher heat-transfer coefficients—all contribute to more effective steam use.

Steam pressure is the prime consideration in some industrial applications. Typical examples are steam blasting for cleaning, atomization of fuel in oil burners, and processes requiring humidification in depth—adding moisture to textile felt, expansion of polystyrene beads.

Prime movers, either reciprocating or rotary, require close control of both pressure and temperature.

In the area of power generation, the continually decreasing heat rate is one significant sign of progress. Less than 20 years ago, a pound of coal was needed to generate one kwhr. Today the heat rate for a modern electric utility boiler-turbine-generator system is equal to the Btu's from less than ¼ lb of coal or its equivalent in other fuels.

Rigid specifications for steam may be spelled out for needs requiring close tolerance of pressure and temperature. And for power generation, where turbines demand precise steam condition for top performance, the steam generator must be equipped with devices that will maintain uniform steam pressure and temperature as described on pp S 24-S 30. However, in most other applications, operating requirements can be stretched within a given range.

UNIT SIZE

Generator size can be approximated by the quantity of steam required. But fitting a new boiler into an existing space may pose problems. Often a boiler may be selected to fit the space at hand. Still, in other instances it may be wiser to split the load among several smaller units located where space is available. It may be practical to discharge steam into a common header or, on the other hand, feed directly to the steam-consuming unit with little or no connection between units. This, once again, is an energy-systems decision that will vary with specific conditions.

More generally, the energy-systems engineer may select, within limits established by load demands, one of the standard steam generators available commercially. The following pressure-capacity relationships were widely followed in 1964, yet were not exclusive: 1450-psi units ran up to 750,000 lb per hr, 2000 psi saw application at about 1-million lb per hr, 2400 psi was widely adopted to 2-million, while 3500 psi became a likely candidate above 2-million lb per hr.

Chart on opposite page outlines a representative pressure-capacity relationship for today's steam generators—from the small low-pressure heating boiler to the large central-station supercritical steam generator.

In general, firetube boilers meet needs up to about 25,000 lb per hr capacity. The typical area enveloped by the packaged and shop-assembled watertube boiler is loosely defined: It overlaps much of the firetube domain and is also common to the area of the small and medium field-erected watertube boiler. Natural-circulation field-erected steam generators span a wide area.

Capacity, pressure and temperature listed in each area of chart are far from random dispersions. They are concentrated around certain preferred centers. This may be explained readily by the fact that manufacturers develop standard models incorporating designs applicable to one *design* pressure which are usually most economical for *working* pressures somewhat below and up to that value.

As pressure levels rise, there are, of necessity, design changes involved as specified by the ASME Boiler & Pressure Vessel Code. These changes will, quite naturally, increase the cost of manufacture.

Examples of standardization may be found at most pressures. In the low-pressure range, boilers are generally selected from a design pressure of about 160 psi for working pressure between 140 and 150 psi. Stepping above this range we find 225 to 250 the next working pressure favored. For what we might call industrial boilers, design pressures of 450, 650 and 900 psi are presently widely adopted with steam temperatures up to 950 F. It is mutually advantageous to maker and user to select standard designs where possible.

In the range from 2000 to 2600 psi, steam-generator circulation may be either positive or natural. Some boiler manufacturers feel 2600 psi is an upper limit for natural circulation, others put this limit at 3000 psi. Some feel positive circulation is desirable above 2000 psi.

Central stations are looking favorably on ever-larger units with pressures in the subcritical range between 2400 and 2500 psi and superheated temperatures between 1000 and 1050 F (see pp S35-38). In the larger units there is also increasing interest in supercritical designs at 3500 psi and 1000 to 1050 F. Reheat cycles are proving out for top efficiency of large power steam generators.

FUEL SURVEY

More often than not, the fuel used will be determined by local conditions. A systematic fuel survey must be made in the planning stage, covering fuel analyses, availability, initial cost, and transportation—all factors which enter into the final decision. Coal, gas, oil and byproduct fuel may all be considered and selected as engineering economics dictate. Equipment for the storage, handling and burning of these fuels must be evaluated and their costs included in the final analysis.

For oil, the cost of storage tanks, storage and circulation heaters, filters and atomization medium—steam, compressed air or mechanical means—must be considered.

For gas, standby equipment must be provided where the rate structure includes an interruptable clause, which is quite common for natural gas supplies during winter. This standby may come in the form of LP gas storage and combustion equipment or it may be fuel oil.

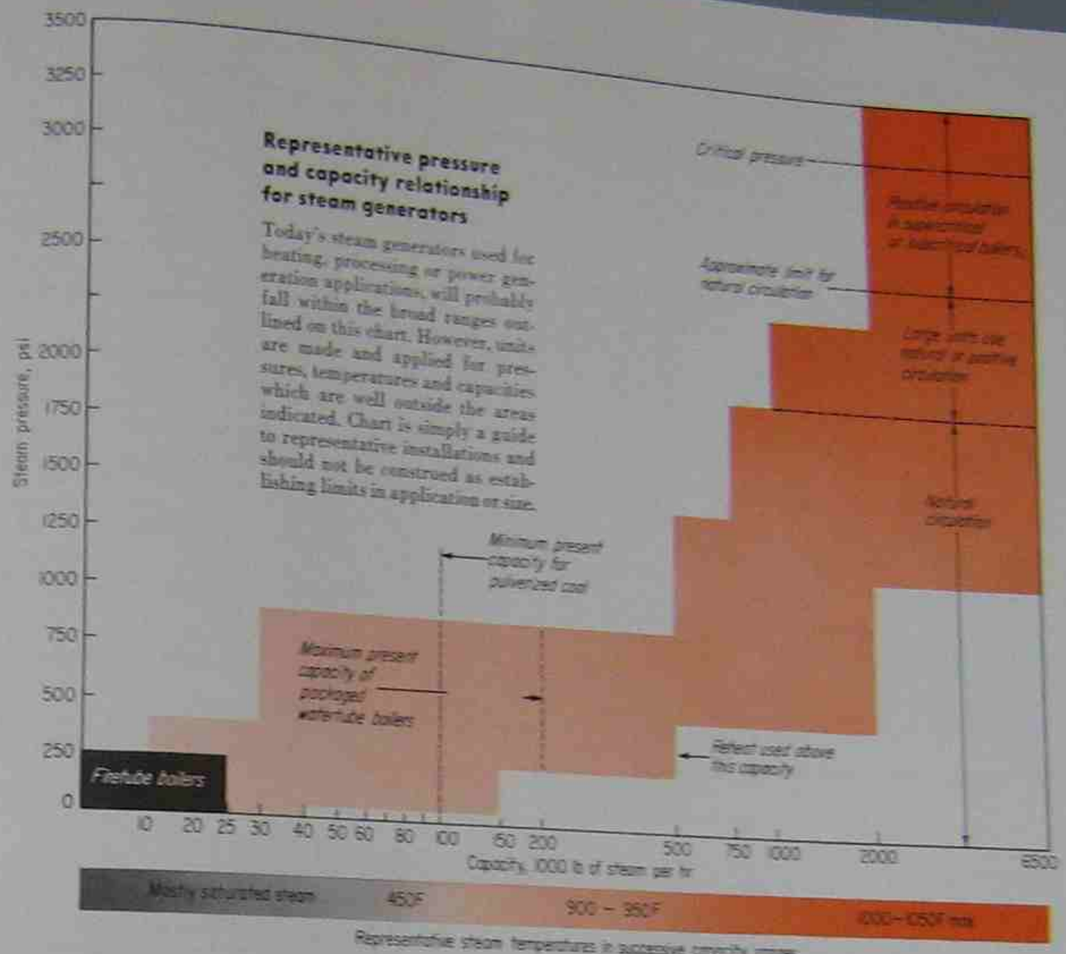
For coal, choose the most suitable firing method. Here coal quality plays an important role. Coal volatility, ash content and ash-fusion temperature are important.

Basic factors in selection

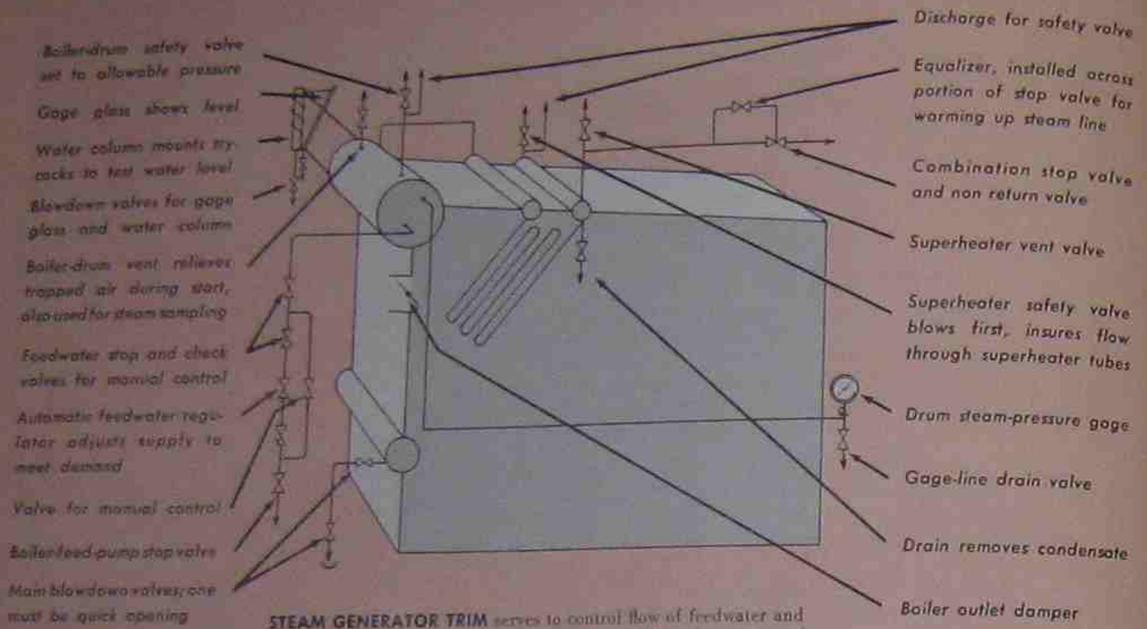
Steam characteristics head list with temperature and pressure prime considerations. For large units, these parameters and other cycle conditions are determined from heat balance and estimated operating costs.

Unit size and type decision hinges on quantity of steam required and available space. Latter may be reason for choosing several smaller boilers, located close to loads.

Fuels most suitable should be determined by survey, to obtain maximum economy and availability over life of unit. Geographical location of plant, current and anticipated fuel charges are important.



First understand the important role of steam generator auxiliaries . . .



STEAM GENERATOR TRIM serves to control flow of feedwater and steam, relieve excess pressure, remove unwanted condensation and solids, indicate water level, temperature, and pressure in boiler

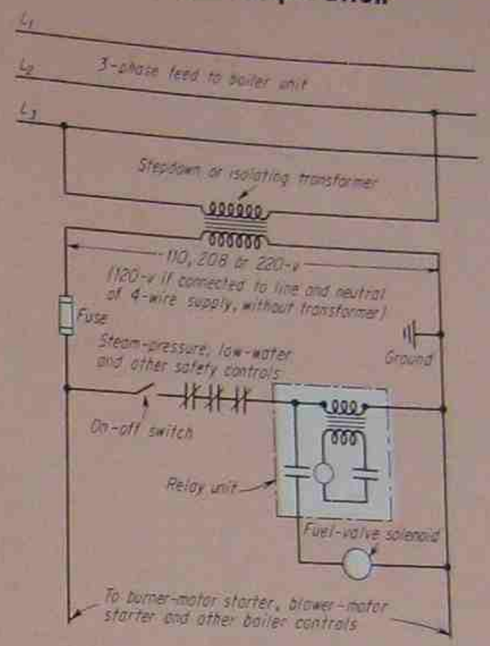
. . . then master fundamentals of equipment care and system operation

Routine weekly checkup for low-pressure heating boilers

Safety or relief valve . . . . . pull try-lever with pressure on
Water column or gage glass . . . open, then close, drain quickly
Low water fuel cut-off . . . . . check if burner stops at low water
Pump and return system . . . . . visual examination
Burner operation . . . . . check proper start, see if flame is clear

Twice daily check—test for high-pressure boilers

Water level . . . . . test water column or gage glass
Steam pressure . . . . . keep records
Feed-pump pressure . . . . . important auxiliary record
Feedwater temperature . . . . . needed to check efficiency
Condensate temperature . . . . . see if it remains constant
Flue gas temperature . . . . . important index of efficiency
Low-water cutoff . . . . . check if burner stops at low-water level
Water-level control . . . similar in operation to low-water cutoff
Water column and gage glass . . drain and check prompt refill
Feed pump . . . . . visual inspection
Condensate tank . . . . . check constancy of level
Burner operation . . . . . check for proper start and clean flame
Water treatment . . . . . take sample for water analysis
Boiler blowdown . . . . . take samples for analysis



Why control circuit is important

Control circuitry, above, is designed to fail-safe should an accidental ground occur. Grounded neutral connects to relay unit, fused hot line runs to control contacts. This circuit arrangement avoids possibility of an accidental ground on one side of line, impressing 120-v across burner relay unit. In past, and where supply came from an ungrounded source or across a 208-v line, an accidental ground kept burner operating even through steam-pressure switch or low-water controls tripped (POWER, Jan 1963, pp 64-65).

Maintenance and operation

Safety, maximum reliability and top system efficiency call for proper steam generator operation, sound external and internal maintenance

Many of the boiler auxiliaries shown above are incorporated primarily with safety in mind. The bare equipment essentials listed are more often than not expanded on in real life for greater safety and better steam plant operation. Although safety is a fundamental consideration for all steam generators, let's pause and examine a few facts about the automatically controlled low-pressure boiler.

Low-pressure boilers with full automatic control will receive even wider acceptance throughout industry, in commercial buildings, schools, institutions and apartment houses. We must recognize that such boilers will be operated without the constant attention of trained people. This is only sound engineering economics, since the equipment is designed to operate automatically.

However, the real safety problem arises when such equipment gets little or no periodic attention. Even in the face of constant urging by control makers, boiler manufacturers, and insurance people, many plant owners still take the position that as long as a boiler keeps producing, there is no need for maintenance or periodic testing. And this attitude is not likely to change in the foreseeable future. If anything, even less maintenance will be given.

Still, no matter how automatic the unit may be, some maintenance is necessary. The self-cleaning and self-checking low-pressure boiler has yet to be developed. Recognizing the limited care some owners give their boilers, the nontamperable, factory-calibrated, factory-sealed boiler control would seem a most welcome development.

Safety valves will probably best illustrate the factory-sealed concept. Serious accidents resulting from the explosion of low-pressure boilers are a matter of record. In many such cases the safety valves simply failed to operate when steam pressure rose beyond the nominal operating limit. Lack of proper maintenance may be a cause; faulty design may also be a contributing factor. The fact remains that the final safety device in a steam boiler should never be allowed to become inoperative.

One answer, of course, is fail-safe design. Here "fail-safe" would mean that any failure in the normal operating function of the device would shut down the boiler — or at least relieve the overpressure. A step has been taken in this direction with the development of low-pressure safety valves with a built-in fail-safe feature: Should the pop-valve fail to function on overpressure, a static calibrated relief plug will step in to relieve the steam pressure.

The whole boiler must be considered in any true safety evaluation: waterside, fireside, controls. One aspect of the whole-boiler approach is the control circuitry. When steam pressure in a low-pressure automatic boiler builds beyond the nominal limit, the boiler has been known to remain on line. This may be the result of an error in the circuit hookup, a fault in the pressure-control element, or a basic shortcoming in the control system design (sketch above). Here an improper circuit grounding—or total lack of grounding—might prevent the burner from shutting down even though the steam pressure switch operates (POWER, Jan 1963, pp 64-65). This is a fundamental error in circuit design that exists today in many operating boilers.

Perhaps the time is at hand for code-writing bodies to take major steps in the direction of the whole-boiler code. It is encouraging to see an effort being made in this direction by some, yet there is a long way to go.

Larger boilers present a somewhat different series of operating and maintenance considerations. But again, the prime factors are safety and overall efficiency. In a broad sense, this might be boiled down to a direct concern about waterside and fireside operating conditions. In sharp contrast to the small boilers, we now have equipment that normally is attended by a trained operator. Therefore, he should be intimately aware of such conditions as water level, maintenance of solids concentration in boiler water at acceptable level, and prevention or removal of deposits on either side of heat transfer surfaces.

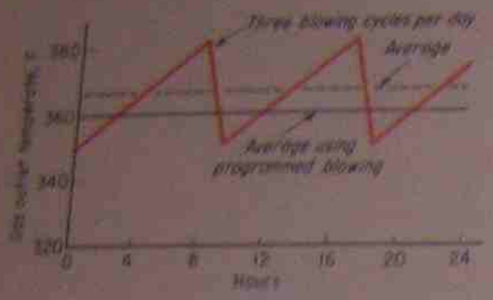
Let us, for the moment, look at the operating problem of water level control. What must be done if a serious low-water condition should develop?

Water level below the established norm calls for immediate action by the operator. For units with suspension firing, the fires must be shut down and air supply reduced to the lowest permissible level. Steam outlet valve must be closed to prevent a sudden loss of pressure and the corresponding lowering of temperature. This condition would also require shutting off feedwater supply.

And what about sudden changes in drum temperatures? Normal limits have been set governing the safe rate to change boiler-drum temperature on startup or shutdown. There was a time when protection against overheating of superheaters or reheaters determined the rate at which a boiler could be brought up to full load. However, with today's higher pressure and thicker drums, the time required for starting up and shutting down is often determined by allowable thermal stresses in the drums. The rule of thumb which formerly limited steam temperature changes to 100 F per hour seems overconservative today.

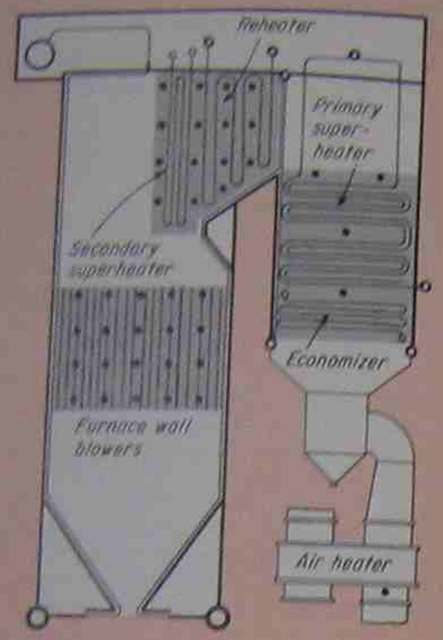
For a more accurate determination of acceptable rates for heating or cooling, many energy-systems engineers believe it best to insert thermocouples on both the drum

Modern soot blowing may follow a set time cycle or a programmed . . .



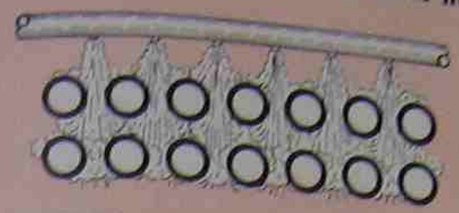
Automatic soot blowing of boiler elements will, in most installations, reduce average flue gas temperature. Soot-blowing operation starts automatically when flue gas temperature at some selected spot exceeds a predetermined value. Sketch above shows that by simply substituting automatic soot blowing for a conventional three-a-day blowing cycle, average flue gas temperature can be reduced from 366 to 360 F at full boiler load. In this specific case, fuel savings exceed $10,000 a year, yet economic advantages may vary.

Further refinement calls for programmed operation of soot blowers according to specific requirements of the various steam generator parts. This automatic control takes guesswork out of soot blowing and saves labor, steam and fuel. Further improvement can be achieved by careful integration of cleaning operations where several soot-blowing units are involved, to reduce total steam used at any one time.

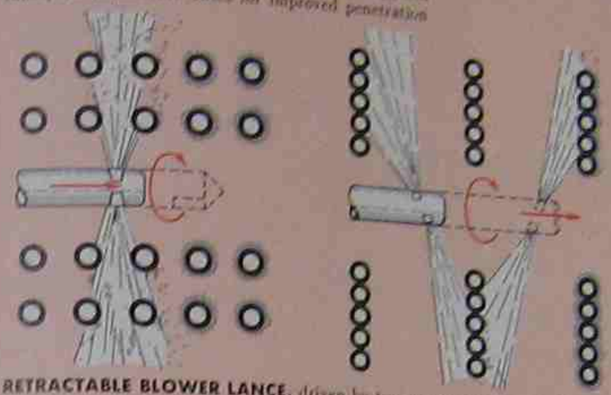


SOOT BLOWER LOCATION may vary with installation. Units may be grouped and operated independently according to the specific demands for each group

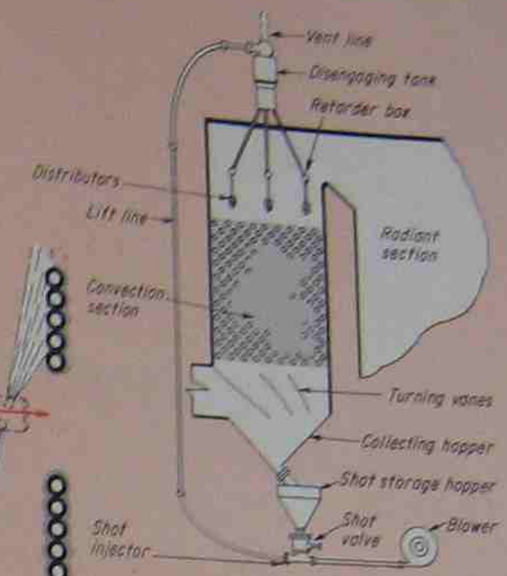
. . . sequence linked to specific needs of various steam generator elements



STATIONARY SOOT BLOWERS employing straight nozzles clean banks of in-line tubes. With staggered tubes, the nozzles are offset for improved penetration



RETRACTABLE BLOWER LANCE, driven by two motors, traverses boiler at one speed, retracts at twice that speed. Result: about a 25% saving in cleaning time and in blowing medium. Speed of lance rotation is held throughout the cycle



SHOT CLEANING technique calls for cascading metal balls on to heating surfaces. The cycle is automatic, utilizing pneumatic lift

exterior and interior surfaces. Boiler manufacturers have prepared charts giving the maximum allowable rates for varying temperature of saturated steam for corresponding variations of metal temperatures.

Standby service for steam generators presents special problems. Such units remain in a wet-storage condition, yet must be available for immediate startup. Many central stations and industrial boiler plants bank some boilers at night and over weekends. However, an effort is made to hold boiler conditions close to steaming to minimize losses and decrease time needed for return to service. Manufacturer's recommendations must be carefully followed.

Protracted outage of steam generators calls for laying up, following wet or dry method. Here the boiler must be thoroughly clean and checked beforehand.

EXTERNAL MAINTENANCE

Proper maintenance of heating surfaces on both water and fire sides accomplishes two main objectives—optimum performance by virtue of cleanliness and preservation of material by avoiding corrosion and erosion.

On the fire side, soot and slag deposits not only reduce heat transfer rates but, if permitted to build to substantial thicknesses, increase draft loss. Keep in mind that exit gas temperature and draft loss serve as a check on fire-side surface conditions as well as other factors. It is a fact that a $\frac{1}{8}$-in. layer of soot on a surface insulates as effectively as a $\frac{5}{8}$-in. layer of asbestos.

Soot blowers are tools for cleaning the fireside surfaces. The frequency of this cleaning depends on type of operation and nature of the fuel. It's important to keep the boiler steaming at a reasonably high rate while operating soot blowers. This avoids the possibility of flameout or the explosion of dead pockets filled with unburned combustibles or fuel-rich gas in some portions of the boilers. Also, increase draft slightly before blowing soot.

Blowing fluid may be either steam or air. Steam is by far the more popular, with about 60% using steam versus 40% using air. In large power plants air is used mostly to avoid loss of costly treated water.

Interest is still growing in retractable soot blowers operated automatically and by remote control. Often a saving up to 25% in time and blowing medium can be achieved using dual electric motors and retractable soot blowers. One motor rotates the lance at constant speed while a 2-speed motor handles travel — one speed going in and twice that speed on the return. Programming of automatic soot blowing can be based on time or on type of boiler surface. Here is where experience is a key factor in determining the true economics of operating method.

Water-washing is still another method for keeping boiler fire-side surfaces clean. Washing when unit is out of service and, in some instances, with unit operating at low load, may be practical for the low-temperature portion of the boiler or for the entire fire-side area. Manually operated lances or stationary sprays are used for this service. Hot water with a high pH, in carefully regulated quantities, is generally safe. Alloy steel superheaters should not be washed because of the possibility of thermal shock.

Shot cleaning is still another means for removing soot. This method is particularly adapted to those portions of the unit which need it most: the economizer, air heater and superheater. The technique is akin to sandblasting. Developed some years ago for the cleaning of vertical sections, procedure calls for use of $\frac{1}{4}$-in. diameter shot. Released above the portions to be cleaned of ash and slag, the shot cascades through at increasing speed. When completing its travel, the shot is collected on the bottom and lifted pneumatically for the next operation. To keep a practical bouncing hardness of the metals in contact, method is generally limited to a temperature of 800 F.

Many boilers are equipped with the shot-cleaning system, particularly in the paper industry. It is also used with oil-fired units in central stations. The system can be made entirely automatic, with the same quantity of shot cleaning an entire vertical section regardless of height.

Corrosion protection is another major consideration. Here the spraying of slurry, consisting of dolomite or magnesium oxide with or without additives, has been found effective. The slurry is sprayed through the soot blowers. Results are significant, especially in oil-fired boilers with fuel rich in sulfur, vanadium and sodium.

Where such protection is desired in the hot portion of the boiler unit as well, spraying may be performed — including the spraying of magnesium metal powder — right into the furnace, above or within the burners.

Keeping the water and steam side of a boiler, superheater and economizer clean and free from scale and other deposits is extremely important. Developments in chemical cleaning and water treatment have made this task easier.

INTERNAL MAINTENANCE

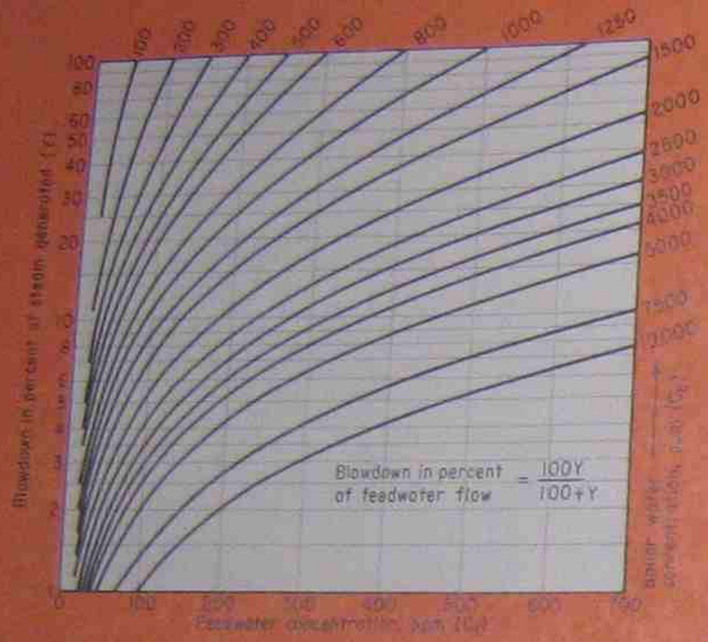
Chemical cleaning now employs a wide variety of chemicals — typical: weak inhibited hydrochloric acid, ammonium citrate or formyl hydroxyacetic acid and inhibited tetra ammonium or tetra sodium salt of EDTA (ethylenediamine tetra acetic acid). This latter product is called a chelating agent since it forms a stable complex known as a chelate with most metal ions.

Chemical cleaning can be performed rapidly in comparison with mechanical cleaning methods. Extensive dismantling of the unit is unnecessary. The procedure is rather straightforward: Heating surfaces are washed, internally, with the chemical selected either by circulating the fluid or by soaking. Afterward the boiler is drained and flushed with clean water.

Next step is the boiling out, generally with soda ash, to neutralize whatever acid traces remain and to release hydrogen from the metal. Final flushing is done with clear water. Boiler is then ready for refilling and placing back on line. Field results prove that chemical cleaning is a most effective and practical way to remove deposits.

Feedwater treatment is a prime requirement for all size boilers of both firetube and watertube design. Increasing pressures and temperatures, along with the adoption of once-through circulation for boilers at subcritical as

Internal maintenance calls for feedwater treatment and blowdown



How much blowdown?

Chart, left, is a practical guide to help you determine how much blowdown is necessary to maintain a given boiler-water concentration in ppm. Amount of blowdown Y is given as a percentage of the steam generated. Allowable boiler-water concentration C_b is shown as a family of curves ranging from 100 to 10,000 ppm. At a given boiler-water concentration, the amount of blowdown varies with the concentration of dissolved solids in the feedwater C_f. With 200-ppm feedwater solids and an allowable boiler-water concentration of 1500 ppm, required blowdown Y equals 15% of steam generated. Expressed in per cent of feedwater flow, this equals 1500 divided by 135 or about 13%. When steam is used for processing with a high percentage of makeup, blowdown can be excessive unless makeup is treated to reduce dissolved solids. When makeup is small, blowdown can be negligible.

Importance of feedwater treatment

Main objective of feedwater treatment is to eliminate troubles caused by scale formation, corrosion and caustic embrittlement. Table right, based mainly on data from the American Boiler Manufacturers Assn, shows quality requirements. Today's subcritical and supercritical pressures call for complete makeup treatment in the form of evaporation or demineralization. In addition, condensate in these systems is treated or "polished" by filtration, demineralizing or a combination of both. Minute traces of metal picked up by water or steam must be removed to prevent damage to boilers or steam turbines. Chemical treatment programs are also employed with considerable success to prevent corrosion. Both morpholine and hydrazine are effective under normal operating conditions.

Boiler-water limits vary with operating pressure

Boiler pressure, psig	Total solids ppm	Alkalinity (Total) ppm	Suspended solids, ppm	Silica ppm
0-300	3500	700	300	125
301-450	3000	600	250	90
451-600	2500	500	150	50
601-750	2000	400	100	35
751-900	1500	300	60	20
901-1000	1250	250	40	8
1001-1500	1000	200	20	2.5
1501-2000	750	150	10	1.0
2001	500	100	5	0.5

Maximum limits for boiler-water concentration in units with a steam drum

well as supercritical pressures, have placed even greater demands on water treatment systems. A successful feedwater treatment program must prevent deposits, corrosion carryover and caustic embrittlement. For complete details on this subject, see POWER's special report, *Water Treatment* (Dec 1958 and March 1959).

Blowdown denotes draining, under pressure, of some water from the lower part of a boiler to remove whatever impurities may have accumulated. During the boiling-out period of a boiler, blowdown must be frequent. In normal operation blowdown is called for at least once every 24 hours. Amount of blowdown depends on quantity of steam generated and analysis of both feedwater and boiler water.

Charts, such as the one above, serve as a guide. For practical reasons economizers, water-cooled furnace walls, stoker sidewalls or bridgewalls should not be blown down while the boiler is in service — overheating of some portions of the equipment may occur because of low water.

Best time for periodic blowdown is when the boiler is steaming at a reduced rate. Immediately after blowdown, bring water back to normal level in gauge glasses. Sequence of valve operation is important, especially for high pressures. Open the quick-opening inner valve first, followed by the outer shutoff valve. Thought behind this sequencing is simply to concentrate wear of blowdown on the outer valve which can be overhauled without taking boiler off the line. Both valves should be opened slowly.

Continuous blowdown is now widely used. It has the obvious value of not interfering with boiler circulation. It also has the economic advantage of passing boiler blowdown water through a heat exchanger to recover thermal energy by preheating the feedwater makeup.

STEAM TURBINES

By B G A Skrotzki, Associate Editor

THE world's unquenchable thirst for more and more electric power has made extraordinary demands on the talents of steam-turbine designers. And they have met this challenge — today the steam turbine claims first place in number of stationary prime movers used for electric generation and in addition does yeoman service in driving a wide variety of energy-systems equipment.

An important facet of the turbine's versatility: its steam supply can be generated from any type of fuel. Another is its ability to handle an almost endless number of electric-power and process assignments. These units can be built in sizes from fractional horsepower to over 1,000,000 kw, speeds to over 20,000 rpm. Designs can be tailored to fit the cycle and economics of each installation. Future development in materials and other areas promises to achieve even better performance and hold down cost of supplying our growing energy needs.

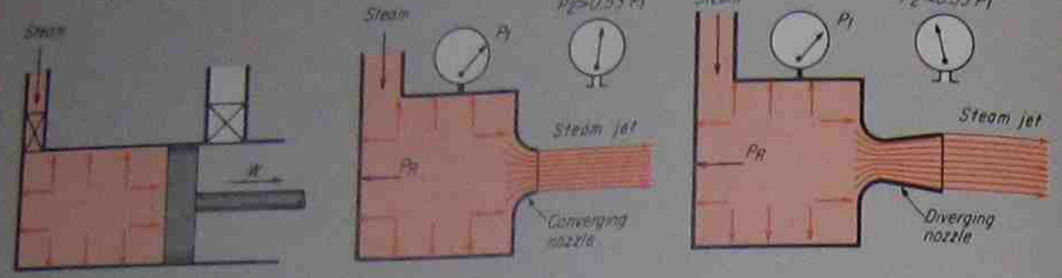
Throughout the 40 pages of this special report, you'll find essential facts on:

How turbines use steam's energy . . 2
How turbines are put together . . . 4
Key elements in turbine design . . 7
Turbine materials 13
Turbine designs and applications 14
Governing a turbine 24
Controls and instrumentation 30
Lubrication and hydraulic systems 32
Thermal performance that can be expected of various turbine cycles 35

a **Power** special report • June 1962

R H MARKS, Special Projects Editor

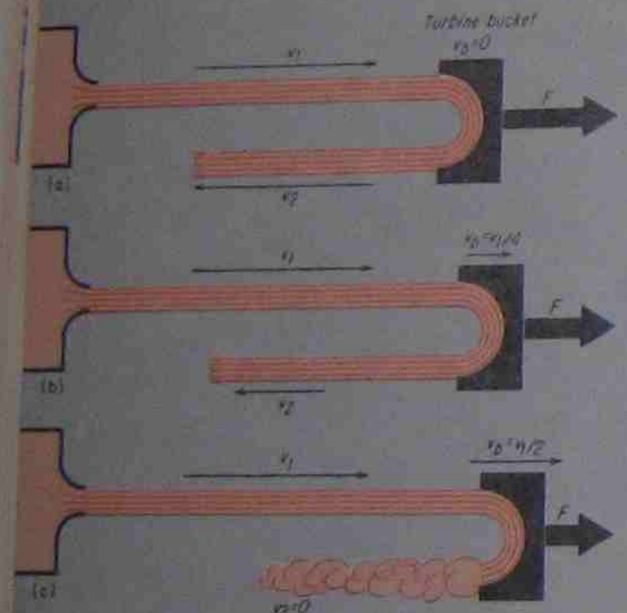
Nozzles use internal energy of pressurized steam to create working forces

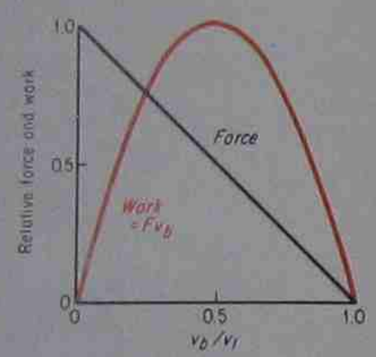


EXPANDING STEAM in engine moves piston, converts internal energy to work

NOZZLE expands steam, creates unbalanced reaction force on opposite wall

DIVERGING NOZZLE is required if discharge pressure is under 53% of initial





Work varies with bucket speed

(a) Steam jet exerts maximum force on locked impulse bucket, but no work is done since bucket doesn't move. (b) When bucket moves with ¼ speed of steam jet, force diminishes. Steam leaves bucket at lower speed but first does work by moving the bucket. (c) When bucket speed equals ½ speed of steam jet, force drops to half the locked condition. Steam leaves bucket with zero speed, does maximum work. Graph shows how force and work vary with the bucket speed.

HOW TURBINES USE STEAM'S ENERGY

In an engine, shown above, steam presses equally on cylinder walls and piston. Since piston moves, the steam does work, using some of its internal energy to do this. The steam cools as its pressure drops. Similarly, steam in nozzle box, center above, presses equally on all walls. But it escapes through nozzle to form a high-speed jet.

Reaction pressure P_R on wall area opposite the nozzle is not balanced by the escaping steam. If box is fixed, steam leaves at top absolute speed and exerts pressure P_R on anything in its path. If the box moves, P_R does work on it by speeding it in a direction opposite to jet motion. In that case, absolute jet speed is correspondingly slower.

When steam discharge pressure is 53% or more of box pressure, the nozzle needs only a converging cross section. When discharge pressure is much less than 53%, the converging section should be followed by a diverging section. Area of exit cross section depends on the pressure ratio.

Impulse-turbine nozzles organize the steam so it flows in well-formed high-speed jets. Moving buckets, above, absorb kinetic energy of the jet, convert it to mechanical work in a rotating shaft. When the bucket is locked, the jet enters and leaves with equal speed and develops maximum force F. But no mechanical work is done. As the bucket is allowed to speed up, the jet leaves more slowly and force F shrinks. Graph above shows how both force and work done vary with blade speed. Steam jet does maximum work when bucket speed is just half the steam speed. In this condition, the moving bucket leaves behind it a trail of inert steam, since all kinetic energy is converted to work. Starting force or torque of this ideal turbine is double the torque at its most efficient speed.

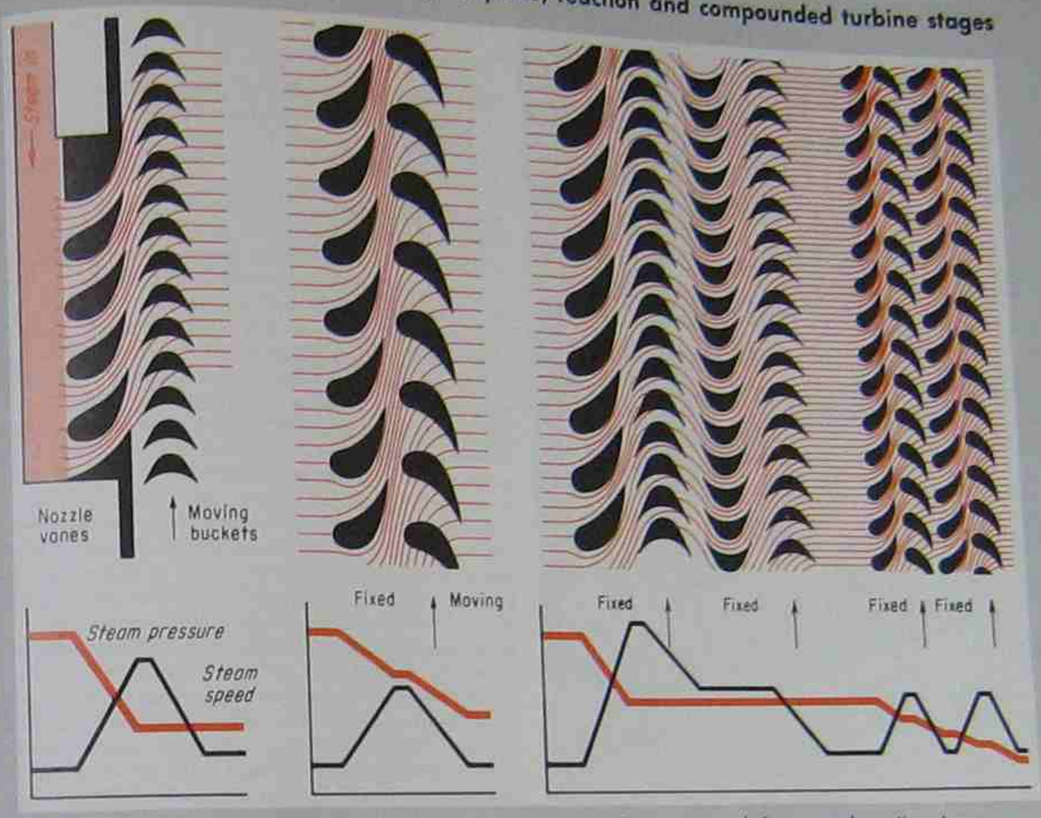
Nozzle and rotor layouts. For practical reasons most impulse turbines mount their buckets on the rims of disks. Nozzles feed steam from one side as shown above. Pressurized steam from the nozzle box flows through parallel converging nozzles formed by vanes or foils. Steam leaves as a broad high-speed jet to flow through the slower moving-bucket passages. These turn the steam flow to an axial direction as they absorb its kinetic energy. The steam leaves with lower internal energy and speed.

Steam pressure and speed vary through the true impulse stage, as graphs above show. When impulse stages are pressure-compounded: exhaust steam from one stage flows through following similar impulse stages where it expands to a lower pressure. If velocity-compounded: steam velocity is absorbed in a series of constant-pressure steps.

In the reaction stage, above, steam enters fixed-blade passages; it leaves as a steam jet which fills entire rotor periphery. Steam flows between moving blades that form moving nozzles. There it drops in pressure, and its speed rises *relative to the blades*. This creates the reactive force that does work. Despite rising relative speed, overall effect reduces absolute steam speed through one stage. When enthalpy drop is about equal in moving and stationary blades, it's called a *50%-reaction stage*.

Velocity-compounded control stage, above, is followed by two reaction stages. The high-speed steam jet gives up only part of its kinetic energy in the first row of moving buckets. Then come reversing blades which redirect the slowed-up steam into the second row of moving buckets where most of its remaining kinetic energy is absorbed. Steam then enters the series of reaction stages.

Steam flow through impulse, reaction and compounded turbine stages



Impulse stage — *Reaction stage* — *Velocity-compounded stage and reaction stages*

In impulse stage above, nozzles direct steam into buckets mounted on rim of rotating disk. Steam flow changes to axial direction as it goes through moving passages. In the reaction stage, stationary blades direct steam jets into passages between moving blades; pressure drops across both fixed and moving blades. In impulse stage it drops only across nozzle. Velocity-compounded control stage, above, discharges steam into two reaction stages. Velocity stage uses large pressure drop to develop high-speed steam jet. Part of kinetic energy is absorbed in first moving bucket row. Fixed buckets turn partly slowed steam before it enters second row of moving buckets where most remaining energy is absorbed.



Turbine foundation supports h-p and l-p turbine casings, bearing pedestals and steam chest. The high-pressure inner cover with its blade rings fits into the outer cover. Intermediate-pressure rings are carried by the outer part of the h-p cylinder. The drum type spindles or rotors fit into the lower halves of the assembled casings. Fit is tight, with very small clearances between moving and stationary parts.

When it's in place, the h-p spindle is covered by top halves of blade rings, inner and outer cylinders. Upper half of blade rings correspondingly covers the l-p spindle. H-p outer cover and l-p cylinder covers with crossovers and main steam connections, plus a turning-gear motor, complete the unit. Lubricating-oil reservoir supplying the turbine's hydraulic system may be placed at any convenient site below the turbine

HOW TURBINES

We've seen the basic methods used to convert internal energy of pressurized steam into mechanical shaft work. By allowing the steam to drop in pressure while it flows through a nozzle, we can get it to form a high-speed jet. We have a large amount of leeway as to where the pressure drops take place in the turbine.

Impulse stages—single, pressure-compounded or velocity-compounded—involve pressure drops mainly in the stationary nozzles of actual turbines. Pressure level across the moving buckets drops slightly.

Reaction stages are used to drop pressure in both stationary and moving passages. Ratios of the two drops fall in a wide range. One that's often used is a 50% reaction: pressure ratio nearly equal across stationary and moving passages. The 50% reaction produces most efficient energy conversion when speed of the moving blades about equals speed of the steam jet as it leaves the stationary-blade passages.

Many of today's so-called impulse-stage turbines actually use about 5 to 10% reaction in their design. This means there is a small steam-pressure drop through the moving-blade passages. These buckets, instead of taking the symmetrical shape of those shown on the previous page, have a longer tail on the right to form a slightly converging passage at the exits, see p 8, Fig. 7.

Multistage steam turbines have large cross-sectional areas of steam flow, so choice of blade and bucket sections becomes complicated. A stage may begin as pure impulse at the root of the bucket and nozzle and then increase the percentage of reaction along the length of bucket and blade toward the outer tips—more about this later, p 9.

ARE PUT TOGETHER

Other parts must guide the steam flow and carry the mechanical shaft work out of the unit, if nozzles and buckets are to do their job. The buckets and moving blades ride on rotating parts, either *disks* carried on a *shaft*, or a *rotating drum*. Drawings, left and below, show the rotating-drum type of turbine construction. Where percentages of reaction are higher, more stages will be used over a given pressure range to limit steam leakage past blade tips and seals. Because of the larger number of stages, drum construction is more practical.

A shaft carries the drum and is supported in turn by *journal bearings* at each end. A thrust bearing controls the rotor's axial position to hold clearances between stationary and moving elements of the stages. *Couplings* mounted on shaft ends transmit the mechanical energy from the buckets to the driven equipment (electric generators, in the case of the turbines shown here).

Motor-driven turning gears on the shaft rotate the drum when the turbine is warming up prior to loading, and while the unit is cooling after it's been unloaded and the steam shut off. This prevents unequal expansion or contraction which might kink the rotor assembly, creating a serious unbalance. Turning-gear motor automatically declutches when the rotor accelerates above a given (slow) speed; some engage automatically at this speed when the rotor is decelerating during shutdown.

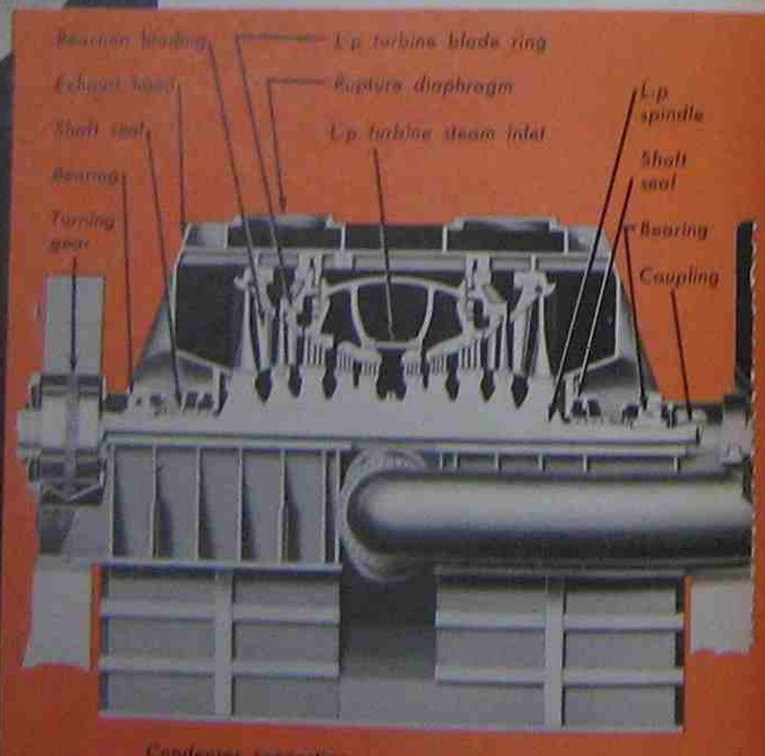
The casing carries bearings for the rotor and holds structure needed to guide steam flow through nozzles and buckets. Steam enters a turbine through a *stop valve* and *steam chest*. In high-temperature units like the two shown here, these elements are separate from the main turbine structure. In smaller units shown on next page, the steam chest usually mounts directly on the casing, either as an integral part of it or as a separate casting.

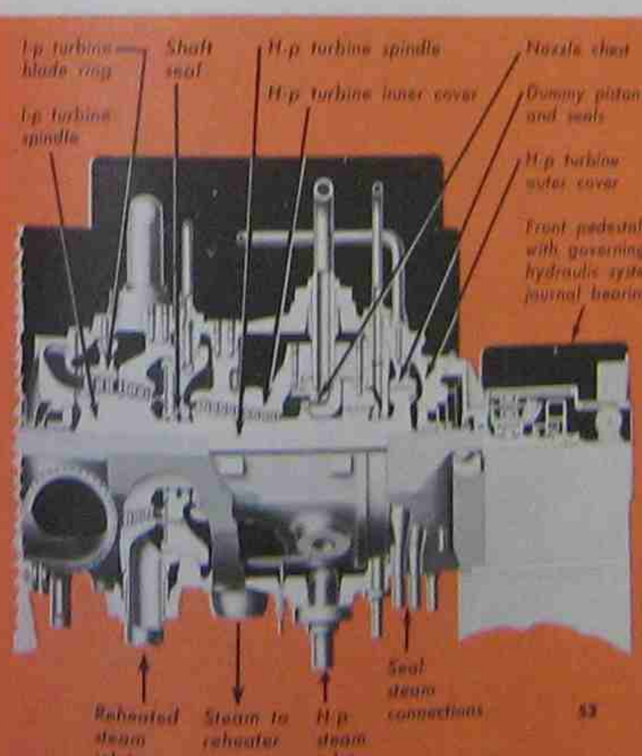
Governing valves in the steam chest admit steam to the *nozzle bowls, chests, chambers* or *boxes* of the first stage. Both units shown here have for their first stages velocity-compounded impulse or *control stages*.

The casing supports nozzles and reversing blades of all stages held in the *blade rings* and *covers*. It also holds the seal strips, which limit steam leakage at all points where the shaft passes through. Seals must also be provided at diaphragm openings and reaction-blade tips.

Since a reaction force acts on stationary nozzles and blading, the casing must be securely anchored to resist these forces. On the other hand, steam temperature swings widely between shutdown and operating conditions, which means rotor and casing expand and contract. The front, high-pressure end must be allowed to move axially so it can expand and contract as needed. At the same time the casing must stay axially aligned to maintain clearances from the rotating parts.

An *exhaust hood* guides the flowing steam from the last stage of the turbine to point of disposal—a pipeline, condenser, etc. This hood must be designed to minimize pressure loss, which otherwise reduces turbine's thermal efficiency. In highly refined central-station units the hood may be a diffuser to develop pressure at the outlet of the last-stage buckets lower than at the hood outlet. It does

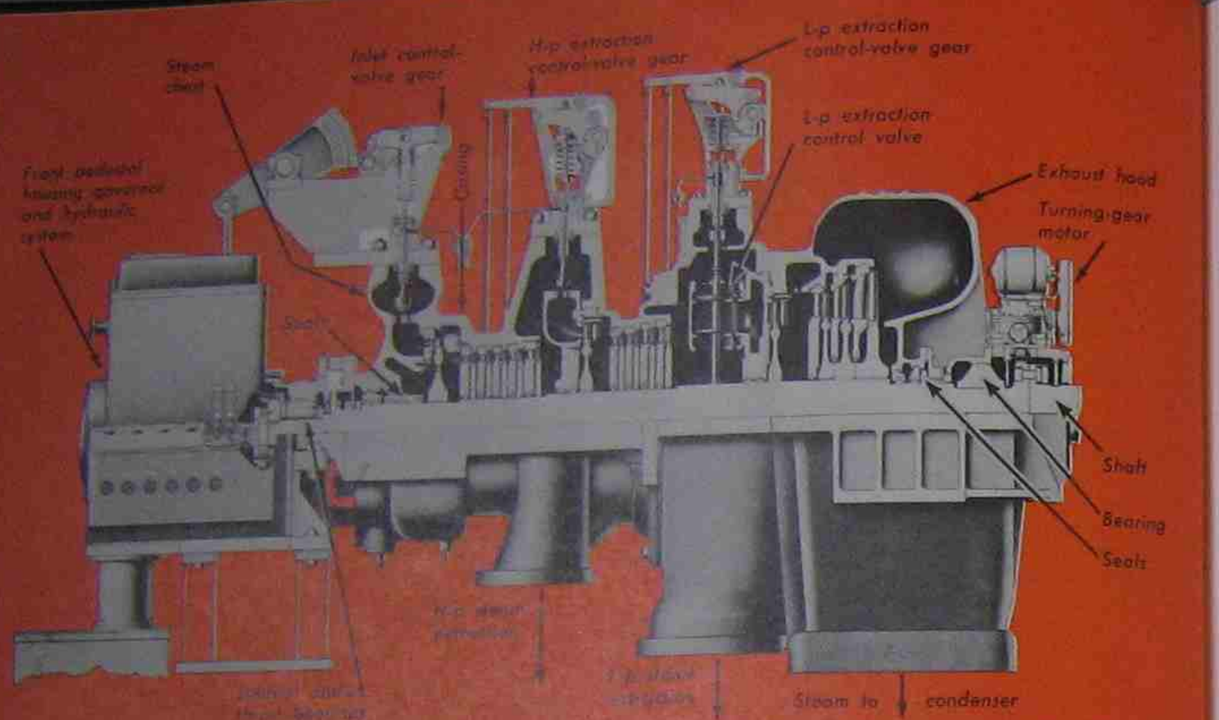




Typical drum type turbine has two main casings

This large steam turbine, as diagramed on p 16, is a tandem-compound double-flow reheat unit with two main casings. Steam from a separate steam chest (not shown) enters a ring type nozzle chest that expands independently of inner casing. After flowing through control stage and following reaction stages, steam leaves the turbine for reheating. Then it returns to complete its expansion in remaining stages of first casing (intermediate-pressure turbine).

Steam leaves the l-p casing to flow through crossunder to center of double-flow low-pressure turbine element. Steam divides equally to flow in opposite directions through paralleled l-p stages, finally exhausting to the condenser below. Steam is extracted from this unit at several stages for feedwater heating. Dummy piston at right end of h-p spindle is designed to balance force developed by reaction blading.



DOUBLE-AUTO-EXTRACTION ... to nozzle chests. Extraction-control valves hold ... by regulating its flow to following stages

this by converting leaving kinetic energy of the last stage into internal energy.

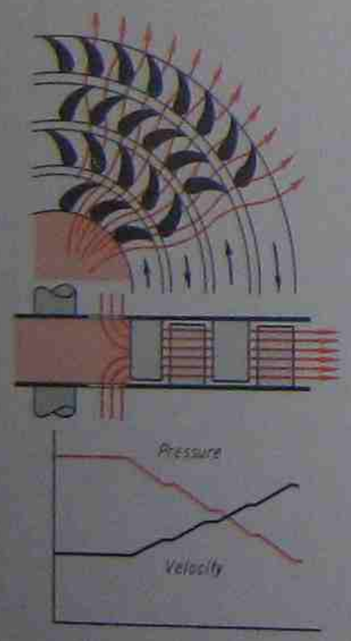
Rupture diaphragms in the exhaust hood prevent excessive pressure buildup, should the condenser lose its vacuum. A *governor* geared to the shaft in the front bearing pedestal operates the governor valves through a hydraulic servomotor system. Main governor can be mechanical or hydraulic; it opens and closes the valves in response to fall and rise of shaft rpm.

An *overspeed governor* is usually located in the shaft at the front bearing pedestal. Its function: shut a main stop valve ahead of the governing valves when shaft rpm exceeds rating by about 10% (15% on small turbines).

Disk-and-diaphragm type of turbine shown above is used where impulse staging predominates with higher pressure drops per stage, and percentage of reaction is relatively low. This unit handles mechanical or generator drive. It features two points of *automatic extraction* where part of the steam may be withdrawn from the turbine at constant pressure. Steam chest is integral with the casing. Control and extraction valves respond to both shaft speed and steam pressure at the extraction points.

In this turbine the moving buckets ride on *wheels* or *disks* that are shrunk on and keyed to the shaft. The nozzles are carried in diaphragms that have centered holes through which the shaft passes. Seals at these openings set a limit to steam leakage bypassing the nozzles; construction of the diaphragm limits the cross-sectional area available for leakage through the seal.

All turbines need a *lubricating system* for their bearings. Usually it acts as the hydraulic system for actuating valves and servomotors, as well. The oil reservoir is often remote, at a lower level to facilitate drainage.

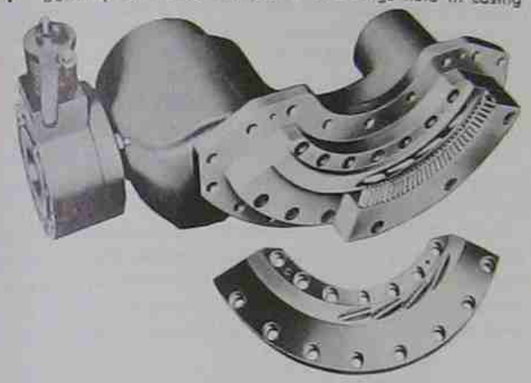


RADIAL-FLOW double-rotation reaction unit has only moving blades. Intermeshing "cylinders" of blades mount alternately on oppositely rotating plates. This turbine has two shafts, usually drives alternators. It can handle high-speed steam jets because there are no stationary blades; steam can be extracted

KEY ELEMENTS in turbine design



1 Nozzle block has three groups of converging nozzles built up of vanes welded in two rings held in casing



2 Steam chest holds nozzle block. Block has converging-diverging nozzles, plus a row of reversing blades

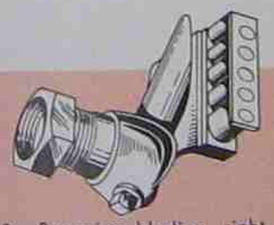
Every stage of a turbine has two basic elements: (1) stationary nozzle and (2) moving bucket or blade. Design of these parts depends on factors such as entering steam conditions, exhaust steam pressure, shaft speed, rated capacity, steam flow, where part is located in the unit.

Nozzles may be either converging or converging-diverging, as we saw on p 2. Selection depends on pressure ratio of steam across the nozzle. Fig. 1 shows upper half of nozzle block for the first stage of an intermediate-size turbine. Nozzles are grouped so they can be controlled by individual valves. These are typical converging nozzles: in cross section, the steam passage is rectangular.

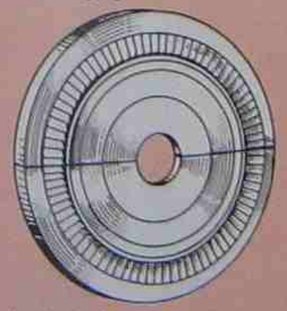
Some shapes of vanes making up this type nozzle are shown on p 2. In the high-pressure end of the turbine, nozzle vanes are usually welded into the nozzle diaphragm. In the low-pressure end, nozzle vanes may be cast as an integral part of a diaphragm.

Fig. 2 is a steam chest for a small-capacity turbine. Converging-diverging nozzles are drilled into the block and a set of stationary reversing buckets attached for the 2-row control or velocity-compounded stage. Steam passages through the nozzles have a circular cross section.

Single converging-diverging nozzle, Fig. 3, has attached reversing blading. This nozzle fits a small turbine with a 2-row single wheel. Typical nozzle diaphragm for a lower stage of a disk-and-diaphragm turbine is shown in top drawing, Fig. 4. Its two halves dovetail to make it tight against leakage. Lower drawing shows a nozzle row for a drum type unit; no inner diaphragm is needed because the drum occupies this space. Fig. 5a shows nozzle, wheel, stationary-blading layout for the 2-row single-wheel unit.

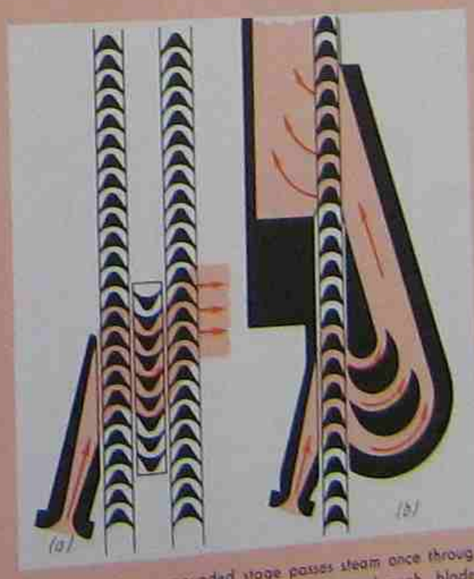


3 Reversing blading, right, attaches to a converging-diverging nozzle, left



4 Typical nozzle setups are for disk-diaphragm unit, above; drum type, below

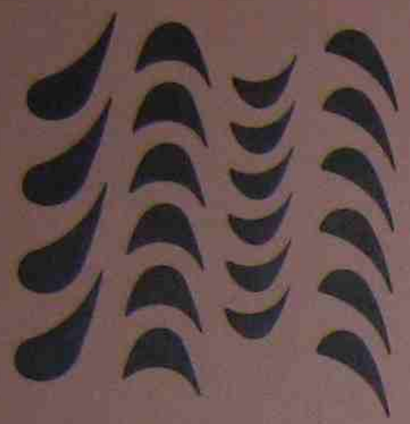
Steam may flow more than once through blade row



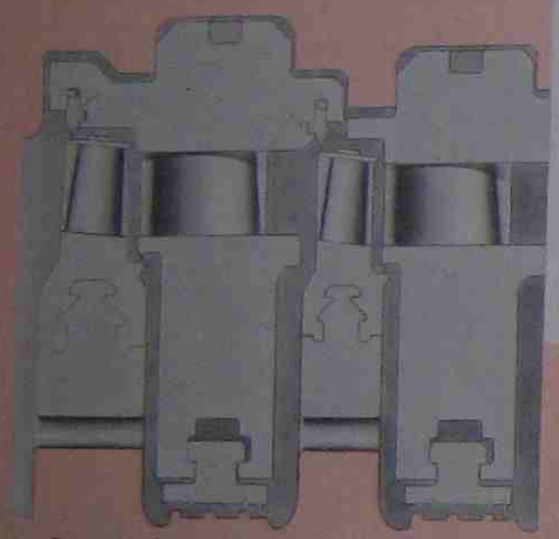
5 (a) Velocity-compounded stage passes steam once through moving blades (b) steam flows twice through blades



6 Velocity-compounded impulse wheel: three passes



7 Control stage for large unit has low percentage reaction, steam-pressure drop



8 Two rows of moving buckets with nozzle between have sealing strips over shroud bands to limit steam leakage



9 Side-entry blades dovetail into disks to transmit force to turbine shaft. Shrouds tie groups of blades together

Velocity compounding can be done with a single row of moving buckets. Steam may pass just once through the blades, as in Fig. 5*a*. In 5*b*, stationary reversing nozzle at right guides high-speed steam into a second pass through the moving buckets. In another method of velocity compounding, Fig. 6, steam flowing from a converging-diverging nozzle makes three passes through buckets milled into the edge of a solid wheel. Stationary reversing chambers return the high-speed steam to the wheel buckets along a helical path. Control stage for large turbine, Fig. 7, differs slightly from those on p 2 since vanes have a small percentage of reaction built in.

Blades or buckets take many forms. Fig. 8 shows buckets of two succeeding stages in a disk-and-diaphragm turbine, along with the intervening nozzle. Buckets receive the working force of the steam, transmit it as a moving torque into the wheels or disks that carry them.

Height of buckets and diameter of stages increase in succeeding stages to accommodate volume of the steam, which expands as its pressure drops. Shroud bands cover the bucket tips to keep steam from spilling out radially.

In high-efficiency turbines every effort is made to confine steam flow to the working passages through nozzles and buckets. Sealing strips between bucket shrouds and casing diaphragms, Fig. 8, minimize steam leaking past the bucket tip into the following nozzle.

Some turbines use pure impulse buckets without any pressure drop across them. In other units, Fig. 7, stage may have some low degree of reaction—10% or less—to produce a small pressure drop across the bucket. This small drop can be very useful—it keeps all buckets running full of steam, shaft thrust positive in one direction.

In Fig. 9, blades of five stages mount on their disks or wheels. Side- or axial-entry roots attach them to the wheel rims. Shrouds, usually riveted to the blade tips, are used to fasten groups of blades together on a wheel. They prevent steam from spilling, minimize bucket vibration.

Reaction blading for drum type turbines, Fig. 10, has stationary blades fastened to the upper stationary-blade ring, which is supported by the turbine casing. Moving blades dovetail into mating slots on the drum rotor.

Since steam pressure drops across both moving and stationary blading, radial seal strips opposite the shrouds minimize steam leakage past the blades. Turbine of Fig. 10*a* uses two seal strips per blade row; 10*b* uses three.

In many turbines that use velocity-compounded control stages, steam flows over only a part of the total periphery of the stage. In the "idle" section, buckets churn the stagnant steam. This windage loss reduces turbine efficiency. To minimize it, shields fit closely over the idle part of the bucket travel. They limit amount of steam whipped about by the nonworking buckets, Fig. 11.

When blade height becomes a significant part of the total stage diameter, ratio of steam and bucket speed changes over the length of the bucket. Then warped buckets, Fig. 13, must be used. Fig. 12, an exploded view, shows a nozzle diaphragm, steam vortex flow, a bladed or bucketed wheel and the leaving exhaust steam. Ideally, steam enters the nozzles in an axial direction and leaves in a circumferential direction, forming a vortex flow or eddy that is contained by the turbine casing before steam enters the moving buckets. To avoid cross currents in the vortex flow, product of linear velocity of steam and radius of circle it travels in must be constant: $v_1 r_1 = v_2 r_2$. Steam pressure must be higher at outer than inner radius.

Steam leaves nozzles at the inner radius with higher linear speed than at outer radius. But buckets' linear speed increases with radius. So we get a steadily growing ratio of blade to steam speed as we move from root to tip.

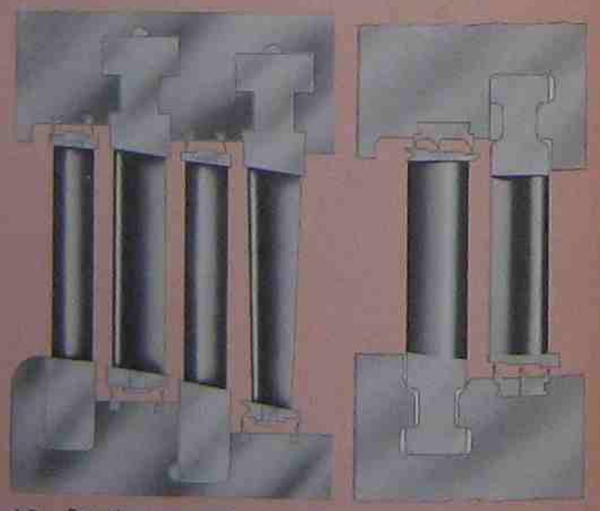
Fig. 13 shows velocity diagrams at root and tip of a blade that receives a steam jet moving in vortex flow. Root of the blade has been designed for impulse flow, which is equivalent to 0% reaction, no pressure drop.

Entrance angle of the blade is fixed by angle of approach of the steam's relative speed, so steam slides smoothly over the blade. In the ideal situation, absolute steam speed should just about double the blade speed. At blade's exit edge, vector difference of relative steam and blade speed shows that steam has a residual absolute speed in an axial direction.

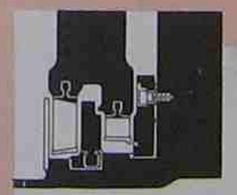
In our example, blade speed at its tip is about double the absolute steam speed. Relatively, then, steam approaches the blade from a direction almost opposite to its motion. Blade section must be twisted to receive the steam smoothly all the way up the blade. But since entering steam pressure is higher at the tip than at the root, there will be a pressure drop through the blade. This means we must use a reaction-blade section, with relative steam speed higher at the blade exit. A pure reaction force acts at the blade tip, a pure impulse force at the root.

At the tip exit, vector difference of relative steam speed and blade speed indicates that steam leaves with low velocity in an axial direction, same as at the root.

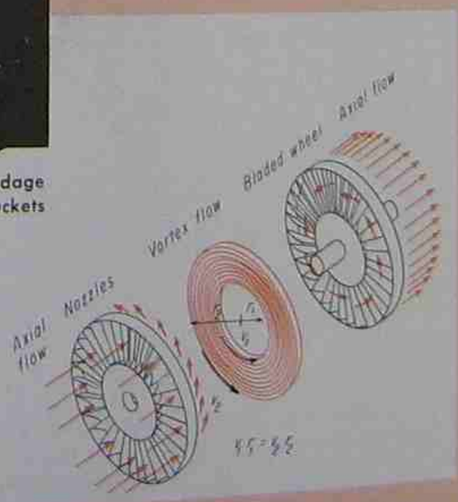
Designs of blades, roots, shrouds, seals and shields influence unit efficiency



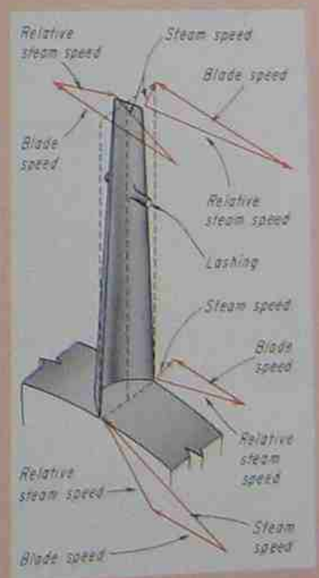
10 Reaction stages of drum type unit need sealing strips, which limit steam flow past stationary, moving blading



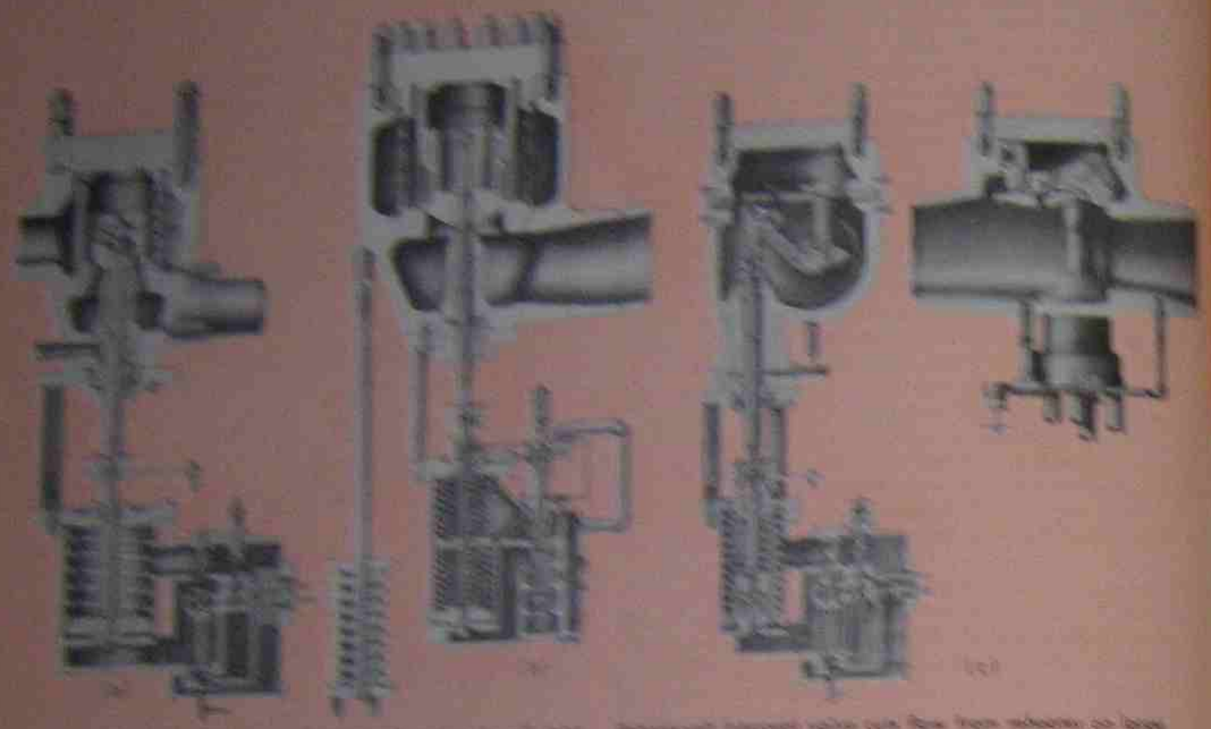
11 Shields cut windage loss on idle buckets



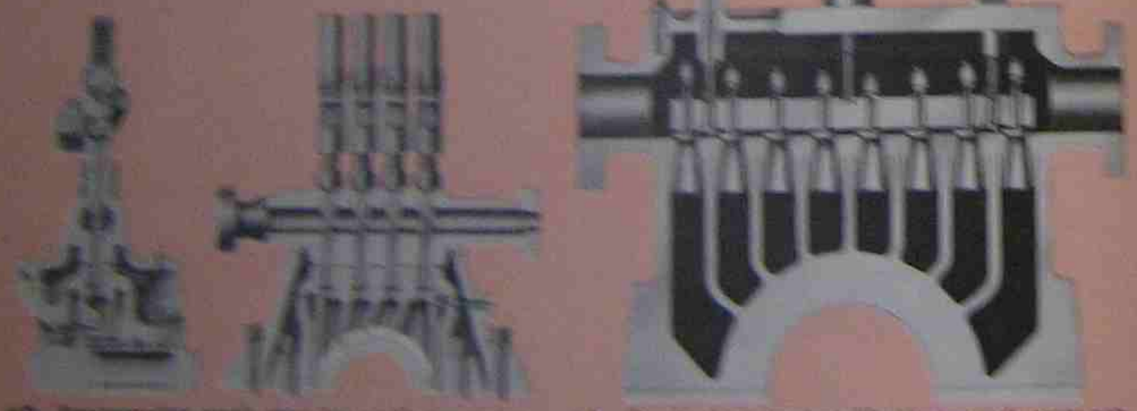
12 Steam flows axially in entering-stage nozzles, leaves with vortex flow. Twisted blades return it to axial



13 Twisted blade works with impulse flow at root, reaction at tip



14 (a) A throttle-stop valve controls steam to all nozzles in starting, shuts off flow in emergencies. (b) Automatic bleeder valve cuts flow from reheaters on large load changes. (c) It's backed up by stop valve in same



15 Interconnecting nozzle chest has nozzle groups controlled by cam-operated poppet valves in steam chest

16 Openings in steam chest, lifted by two rods, admit poppet valves in sequence to control flow to the nozzles

Rotors for disk-and-diaphragm turbines may be machined from a single forging for smaller-capacity units, or built up of separate disks shrunk and keyed on a forged and machined shaft. Edges of the disk are milled to hold the buckets. Shaft usually has integral journals for the bearings and also carries a thrust collar. Drum type turbine rotors increase their diameter from front to rear end of the unit. They're usually made as one forging, then milled to receive the blade seats.

Casings hold the blade rings, bearings and other



17 Combined throttle-stop valve and steam chest for two units may be placed in front of the turbine as in one side. Throttle valve, no. 1 in nozzle group



18 Pressure-relief grid valve controls flow in automatic-extraction unit



19 Balanced throttle valve controls steam flow to smaller turbine

auxiliary parts. A small unit's casing may split vertically, but all large ones split horizontally at the shaft center line. For high-pressure, high-temperature service, most designers have been built with two casings—steam flows between the inner and outer one. This design allows thinner shells, so expansion and contraction aren't so much of a problem. Casings may be cast or built up of welded plate.

Valves control the flow of steam through a turbine. Combined stop-throttle valve, Fig. 16a, regulates steam flow during warmup by opening the inner valve first. When the unit is ready to take load, main valve is opened wide and nozzle-chest valves pick up the control function. In an emergency, the stop valve shuts shut when oil pressure is released from the operating cylinder below. This oil pressure can be regulated manually during warmup. Fig. 17 is a throttling valve on a steam chest.

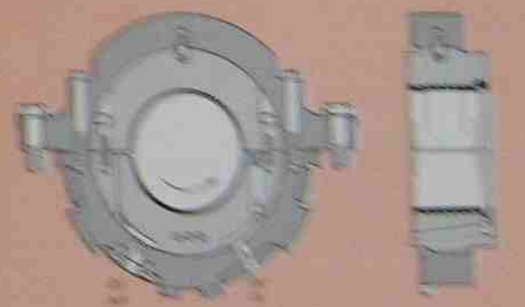
Reheat turbines need both intercept and stop valves. Fig. 14b and c, between boiler reheater and turbine-exhaust inlet. Steam in the reheater and its connecting lines can seriously overspeed the unit during a large load drop or loss. The intercept valve closes part way during rapid load changes; both valves shut on overspeed.

Changes in steam flow to meet varying loads are controlled by valves in a steam chest, Fig. 15, 16, 17. These admit steam to groups of nozzle chests, an arrangement giving high part-load efficiency. Valves in Fig. 15 are opened by cams on a governor-controlled shaft. In Fig. 16 the bar in the steam chest is lifted by two rods moved under governor control. Seats have varying heights to open the valves in sequence. Fig. 17 shows an entirely separate steam chest; here the valves are lifted by an external hinged lever.

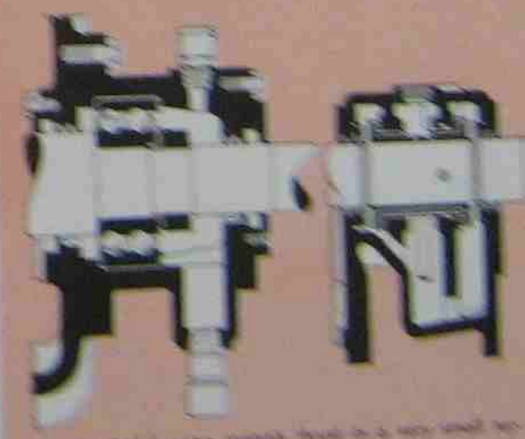
Balanced governor-controlled single-admission valve, Fig. 18, handles small-steam-turbine flow. It may feed several parallel nozzle chests on the unit; intervening hand valves can cut them in and out as wanted.

In automatic-extraction turbines, three different types of valves may control steam flow through the downstream sections. On p. 6, cam-operated poppet valves control the first opening, with cam-operated spool valves for the second and third. Piston-operated grid valve, Fig. 18, may be used for

Bearings range from journals to simple ball types

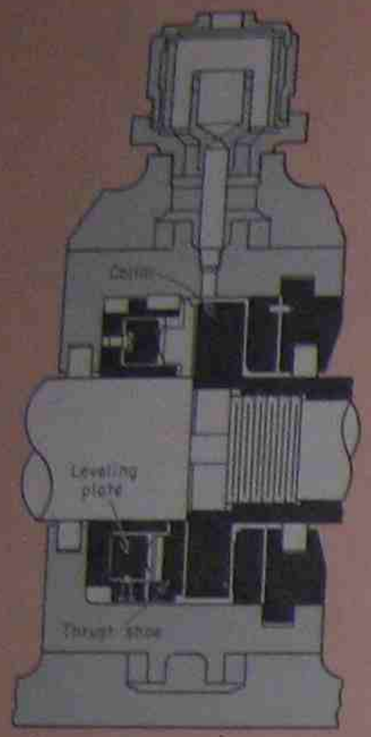


20 Journal bearing has spherical seat for self-alignment. Sleeve is cast babbitt, of copper, steel, cast aluminum



21 In ball bearing, outside thrust is in very small section. In integral journal is used on small unit

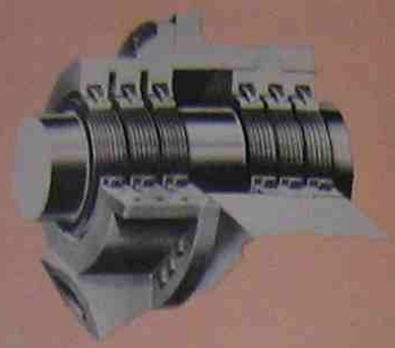
Thrust bearings hold rotor in position; shaft seals limit steam leakage



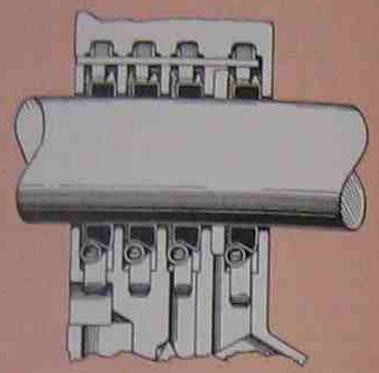
22 In Kingsbury type of thrust bearing, tilting shoes form oil wedges



23 Ball-seat bearing has tapered lands for shaft thrust bearing



25 Stepped labyrinth-gland seal limits both shaft steam and air leaks



24 Carbon packing rings form simple seal against shaft steam leakage

low pressure drop across the valve—about 50 psi or less.

Bearings range from pressure-lubricated journal types for large units, Fig. 20, through ball bearings for very small turbines, Fig. 21a, and ring-oiled journal bearings for small units, Fig. 21b. Larger bearings are almost universally designed with oil grooves in their top halves to build an oil wedge that presses down on the journal.

Steam-pressure differential across most turbine stages creates a net thrust along the shaft. This must be counterbalanced to keep the rotor in proper position. Fig. 22 shows a Kingsbury thrust bearing. Individual movable thrust shoes bear on leveling plates, left. Thrust collar, fixed to the shaft, pushes on the shoes from the right, and holds clearance between moving and fixed components.

Fig. 23 shows bearing surfaces, on the side of a journal-bearing housing, for a tapered-land thrust bearing. A thrust collar fixed on the shaft pushes against the surfaces to hold the shaft in place. Oil wedges build up between collar and tapered lands.

Steam leakage can't be avoided entirely. Some steam will leak out of turbine casings where the shaft must pass through. In condensing turbines, air tries to leak along the shaft into the low-pressure condensing space.

We've seen sealing arrangements used to limit leakage around blades. Same idea comes in for shafts. In a slant-top carbon packing-ring seal, Fig. 24, carbon packing rides directly on the shaft. Springs anchored at the top hold packing segments in place and against the sealing surfaces at right. Steam that does manage to leak past the seals may be led to a lower-pressure stage of the turbine, to a heater, or vented to atmosphere. Condensed steam usually accumulates in the last section of the seal, then drains to waste.

Step-type labyrinth gland, Fig. 25, also controls shaft leakage. Intermediate leakoffs direct the steam to lower turbine stages or heaters. The large intermediate chamber may connect to the suction of a blower which holds a vacuum lower than the turbine's last stage. This would draw in l-p steam from the right and air from the left. Blower discharges the mixture to a condenser where the steam is recovered. L-p steam might be fed into the outer left chamber to block air flow into the seal.

Seal strips have tapered edges so any accidental rubbing will wear them down quickly without overheating the shaft. Steps milled in the shaft match longer seal strips, forming a long, tortuous path with high flow resistance. Enough axial distance is needed between strip and step to avoid contact when shaft and casing expand or contract at different rates. Where movement is relatively large, the shaft may be smooth with the seal strips all of equal depth. Some turbines use labyrinth seals in series, then add a set of carbon-ring seals at the shaft ends.

MATERIALS include steels, newer alloys

The many parts of a steam turbine work under varying service conditions. Effective design selects, from appropriate materials for each part, combination promising long life at low cost. Critical parts of a modern turbine are those handling the entering steam. It's at high pressure and temperature, because higher entering conditions mean more energy can be converted to shaft work. But using too costly materials can wipe out fuel savings.

Casings . . .

as well as steam and nozzle chests are usually cast of steel. A sample composition for 825-F service may be 0.3 C, 1.0 Mn, 0.6 Si, 0.06 S, 0.05 P. At the other extreme, 1050-1100 F may use austenitic steel with 0.08 C, 16.00 Cr, 13.00 Ni, 2.00 Mo and 0.8 Cb. Wrought parts: 0.08 C, 18.00 Cr, 9.00 Ni, 0.8 Cb.

Rotors . . .

are made up of shafts, disks or drums and blades or buckets; each element offers a choice of materials. Shafts for lower temperatures vary from hot-rolled heat-treated carbon-steel bar stock to alloy-steel forgings. Up to 1050 F the shaft may be a forging: 0.37 C, 1.00 Mn, 0.35 Si, 0.035 S, 0.035 P, 1.25 Cr, 1.50 Mo, 0.50 Ni and 0.30 V.

At 1050 F, drum would be a ferritic-alloy forging: 0.30 C, 0.50 Ni, 1.00 Cr, 1.25 Mo and 0.25 V.

Wheels for 650-F service may be 0.45 C, 0.90 Mn, 0.15 Si, 0.035 S, 0.035 P. H-t wheels are usually of the same composition as h-t drums.

Buckets . . .

made of cold-rolled drawn stock may be stainless steel: 0.06 C, 0.25 Mn, 0.50 Si, 0.03 S, 0.03 P, 11.5 Cr, 0.40 Mo, 0.5 Ni. Milled blades for h-t service would be about the same as the drawn blades, but made from hot-rolled bars. Shroud bands would be annealed stainless strips, perhaps with the Mo left out. Stellite shields may be brazed on leading edges of l-p buckets running in the wet-steam region.

Nozzle rings and diaphragms

for 500-F service are often cast iron or Meehanite; as temperatures go higher, materials range through steel plate, cast steel, steel and stainless-steel forgings. Some diaphragm nozzles for 950 F are rolled, some cast aluminum-chromium steel.

Seal and gland packing . . .

around the shaft varies from carbon to stainless steel, leaded bronze, leaded nickel-brass, non-hardened stainless iron and corrosion-resistant chrome-molybdenum materials. Springs to hold packing in place vary: Inconel, monel, stainless steel.

Bearings . . .

use high-tin babbitt as the inner lining, cast on bronze, steel or cast-iron backs. Their shells are often cold-rolled steel. Journals and thrust collars are usually an integral part of the shaft, and of the same material, though some journals are built up of sprayed metal to make a long-wearing hard surface. Oil rings, like smaller bearings, are usually brass—a softer material than the journal.

Bolting . . .

of high-pressure casings running at high temperature raises special problems because of creep. Gradual elongation or growth of materials under stress relaxes bolt's hold on the casing joints. One builder uses a 13-chrome tungsten-moly-vanadium alloy steel for 925 F and above. This material resists temper embrittlement and oxidation, has higher notched-bar rupture strength.

As bolts creep they must be tightened periodically; when they're strained to their rated level they must be replaced. If bolt material has a lower coefficient of thermal expansion than the flange, less initial tightening stress is required.

Piping . . .

materials range from carbon steel for temperatures below 900 F and medium pressures to Type 316 stainless steel for service up to 1150 F. All materials lose rupture strength as temperature rises. For example, at 800 F, Type 316 has a 100,000-hr rupture strength around 47,000 psi; at 1150 F it drops to 14,000 psi. H-p piping must have heavy walls.

Inlet pipe seals . . .

for turbines in the 1000-1050-F range may be stellite. These sealing rings let pipe connections between separate steam chest and nozzle chests move axially and transversely during startups and shutdowns. Piping oxidation at joints must be prevented. It freezes the seal rings; resulting rigid connection transmits piping expansion and contracting forces to the turbine casing—perhaps causing serious misalignment. In one design, stellite rings bear against a terminal ferritic-stainless-steel section welded on the pipe leads.

Governing valves . . .

at the front end of a turbine are usually made, like the steam chest, of a carbon-chrome alloy, one of the alloy steels. Stems must resist oxidation to prevent freezing in the packing. One manufacturer plates them with 13-chrome tungsten-moly-vanadium to be sure of good service above 950 F.

TURBINE DESIGNS span broad system needs

In industry, steam turbines handle an almost endless variety of jobs. Top steam conditions are 4500 psig and 1200 F; lows are subatmospheric pressure and 100 F.

Capacities begin at less than 1 hp for mechanical drives, run up to 1,000,000 kw for generator drives—with larger sizes in sight. In the U.S.A., turbine-generators usually run at 1800 and 3600 rpm; other countries often use 1500 and 3000 rpm. Industrial turbines run up to 20,000 rpm for lower capabilities with smaller diameter rotors.

Basic types of turbines, opposite page, divide into two main classes: *condensing* units exhausting steam at less than atmospheric pressure; *noncondensing* units exhausting at higher than atmospheric.

These classes may be further sorted according to steam flow in the turbine: (1) *straight-flow* (2) *reheat* (3) *automatic-extraction* (4) *nonautomatic-extraction.*

Straight-flow uses full-throttle steam from nozzles to exhaust. In reheat, main steam flow exhausts from the unit at an intermediate stage. It's resuperheated, usually in the boiler furnace, then returns at the next lower stage for further expansion to exhaust. Some units have two stages of reheating.

Automatic-extraction unit bleeds off part of the main steam flow at one, two or three points. Valved partitions between selected turbine stages control extracted-steam pressure at the desired level. Proportion of main steam flow extracted for process at various points may be controlled in any manner within design limitations. When extracted steam flow through the unit does not produce enough shaft power to meet the demand, more steam flows through to exhaust. These turbines are put between steam-supply and process-steam headers, diagram below. Automatic governing systems correlate steam flows, pressures, shaft speed and shaft output for any one unit.

Nonautomatic-extraction turbines bleed steam at as many as nine different stages. Pressure of extracted steam at each stage varies with the turbine shaft load. But pressure variations like this can seldom be tolerated for process work. So these units usually work as generator drives; extracted steam is used for feedwater heating.

Generator-drive turbines often combine condensing, reheating and nonautomatic-extraction. Mechanical-drive turbines are designed to meet varied needs of industry for prime movers to drive fans, pumps, compressors and other machines. This service generally calls for small noncondensing units with exhaust steam used for heating.

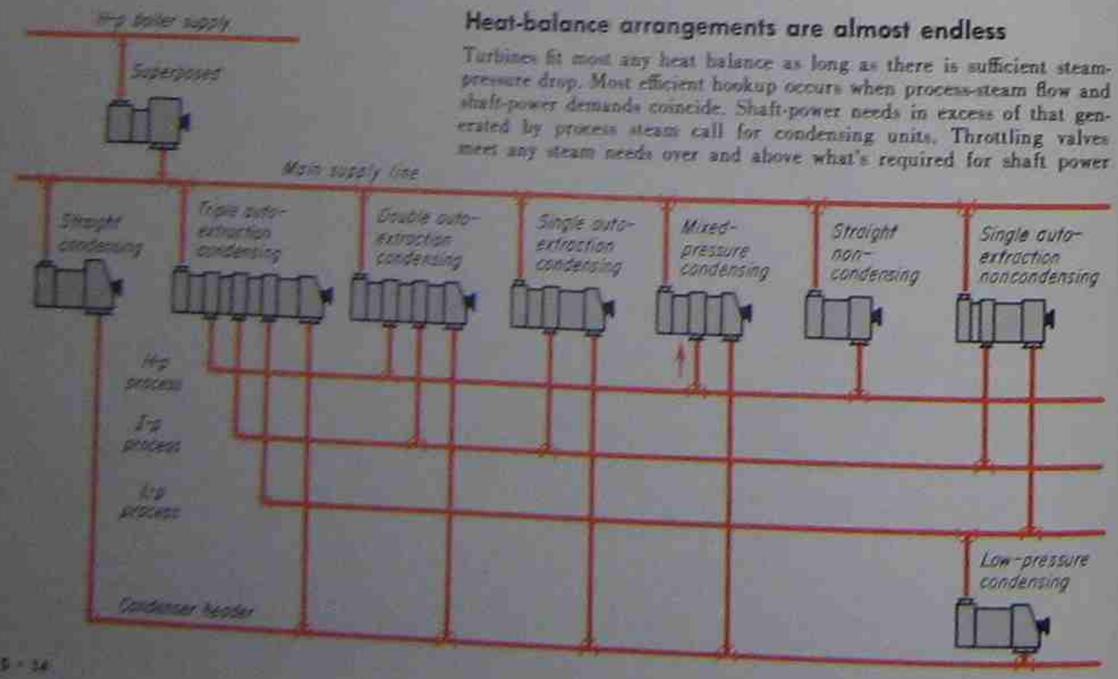
Special types of turbines include the double-flow-exhaust, sometimes used for mechanical-drive units. This design permits high shaft speeds and low backpressures where steam volume grows enormously and calls for very large passages between last-stage buckets.

Mixed-pressure turbines take steam from h-p or l-p sources or both to generate shaft power. Automatic-extraction units may also act as mixed-pressure turbines.

Straight-noncondensing turbines work over a wide range of throttle and exhaust conditions. When extra shaft power and steam are needed, an additional h-p turbine can be added. Supplied with steam by a new h-p boiler, superposed unit in diagram below exhausts at high backpressure into existing main steam-supply lines. Typical turbines of each class and construction are illustrated on the following pages.

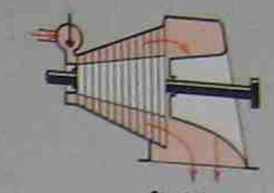
Heat-balance arrangements are almost endless

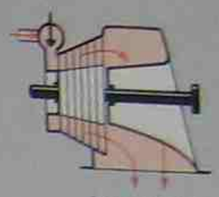
Turbines fit most any heat balance as long as there is sufficient steam-pressure drop. Most efficient hookup occurs when process-steam flow and shaft-power demands coincide. Shaft-power needs in excess of that generated by process steam call for condensing units. Throttling valves meet any steam needs over and above what's required for shaft power

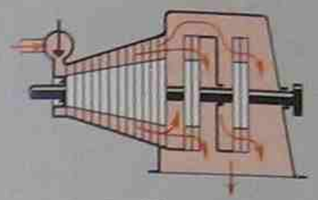


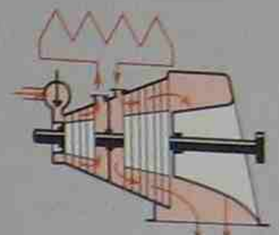
Fifteen basic turbine types: condensing and noncondensing

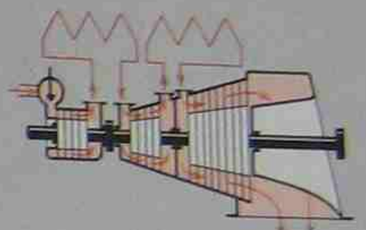
Condensing turbines exhaust at backpressures less than atmospheric

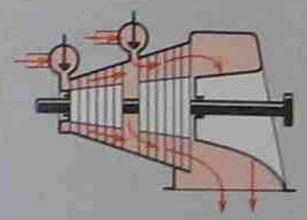

Straight-flow

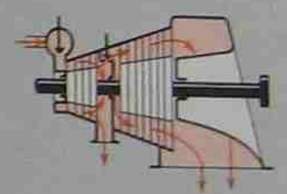

Low-pressure

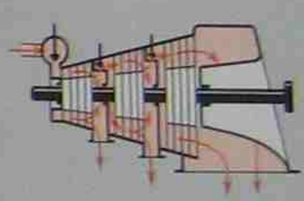

Double-flow-exhaust

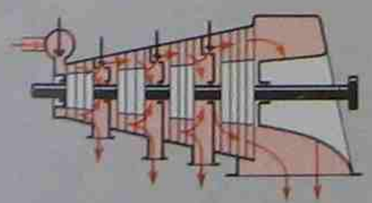

Single-reheat

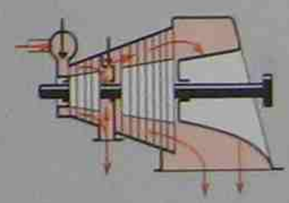

Double-reheat

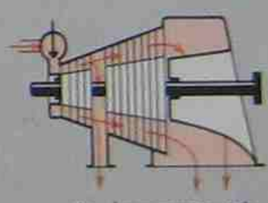

Mixed-pressure


Single-automatic-extraction

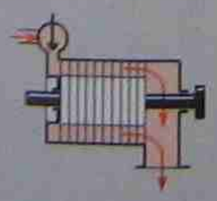

Double-automatic-extraction

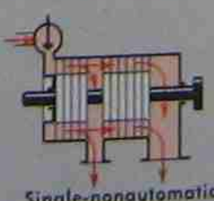

Triple-automatic-extraction

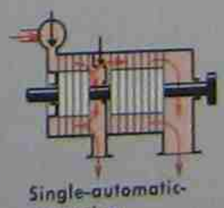

Single-automatic-extraction mixed-pressure

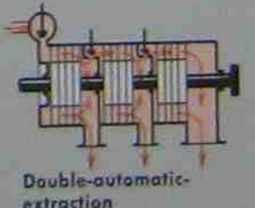

Single-nonautomatic-extraction

Noncondensing-turbine backpressures cover a wide range


Straight-flow

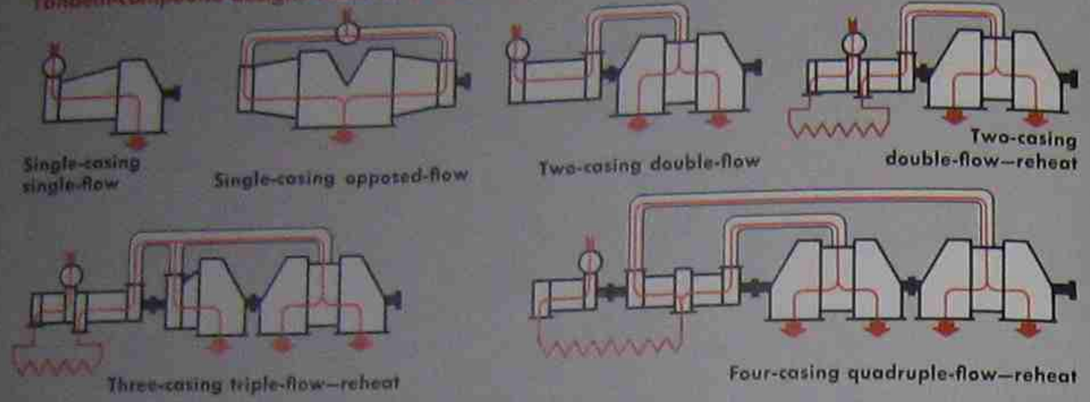

Single-nonautomatic-extraction


Single-automatic-extraction

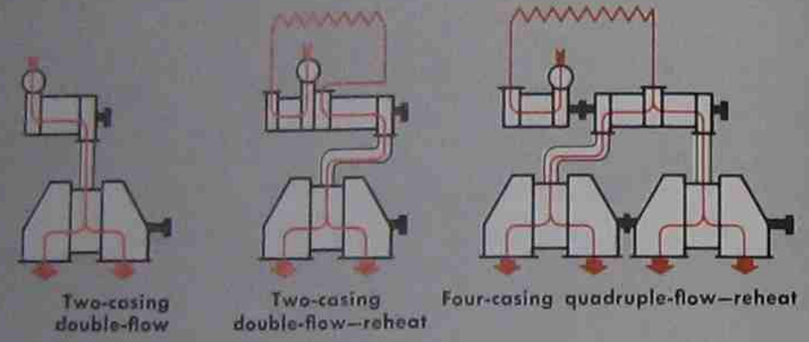

Double-automatic-extraction

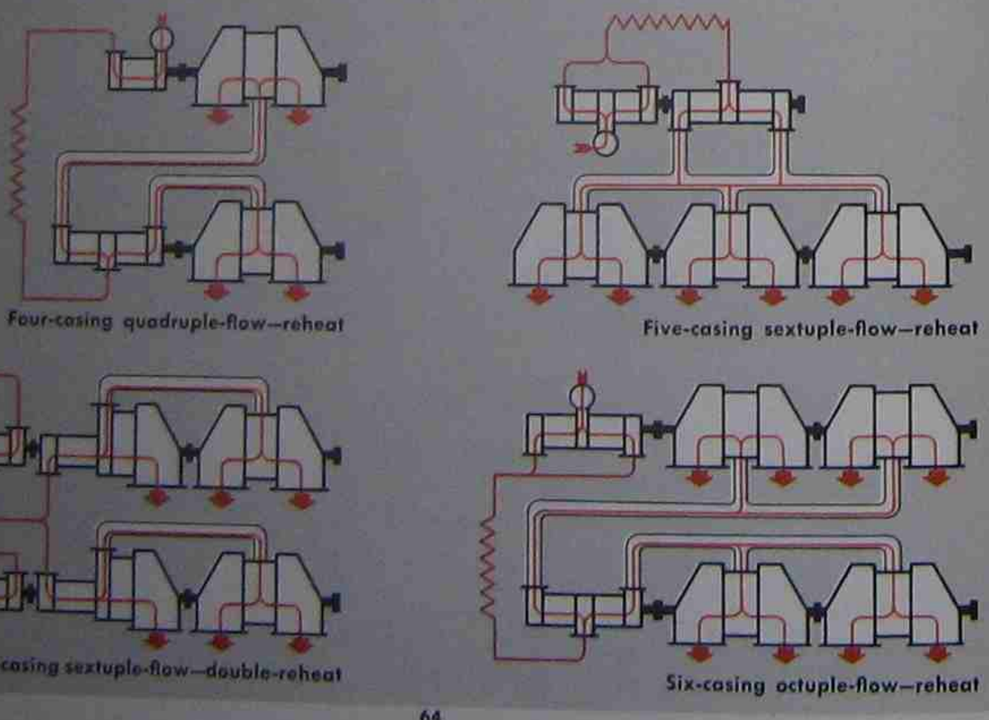
Casing and shaft arrangements depend on capacity, steam conditions

Tandem-compound designs work on a single shaft



Cross-compound turbines usually have two shafts, sometimes three

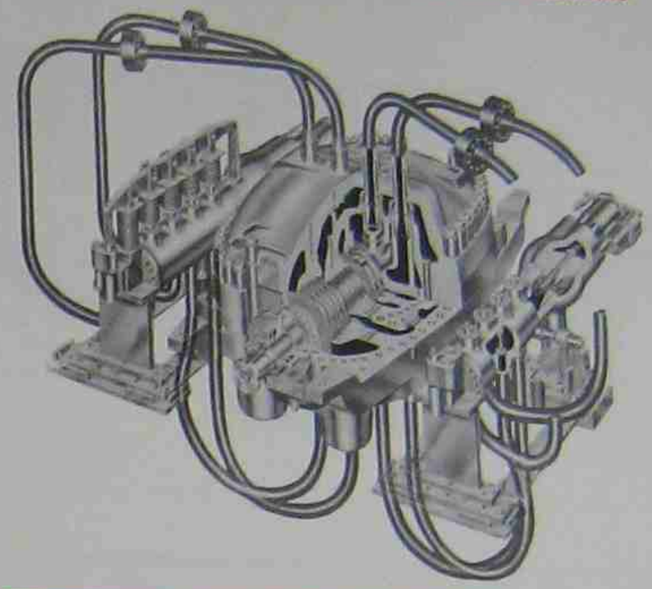




Large compound turbine units may have three main elements

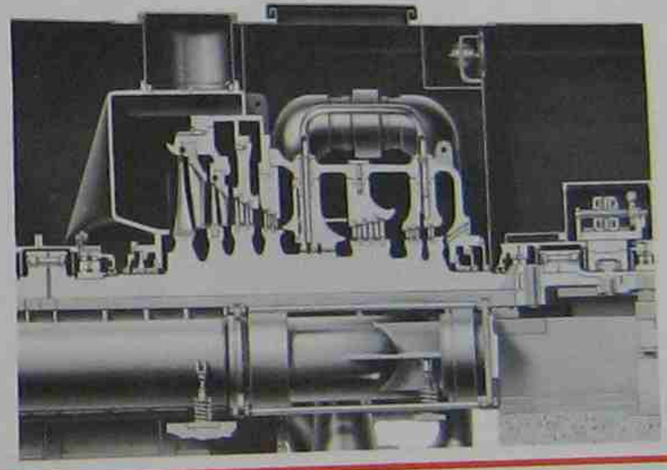
First element receives h-p h-t steam from boiler

High-pressure high-temperature casing for a tandem- or cross-compound turbine features separate steam chests with integral stop-throttle valves. Flexible inlet piping connects chests to separate nozzle chambers in turbine casing. Double-casing construction allows steam cooling for high-temperature parts; it also means the inner and outer casings can have thinner shell sections, reducing thermal stresses in shells and flanges. Exhaust from 3600-rpm element of this type usually goes to reheater in boiler furnace. Shaft gland leakage is normally piped to a lower stage of the turbine where it does useful work.



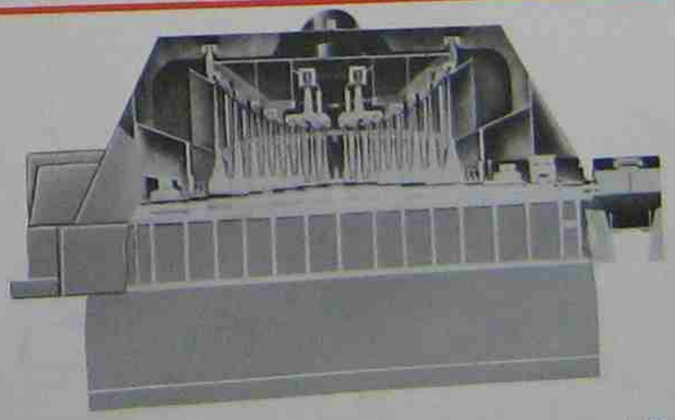
Intermediate-pressure casing takes steam from reheater

Intermediate-pressure casing is shown here along with one-third of the exhaust-flow turbine of a triple-flow unit. Steam from the boiler reheater flows through intercept and stop valves before entering initial stage of this casing (to right of center). After passing through three reaction stages, one-third of total flow goes through three more stages at right and then through crossover to enter last six stages before exhausting to condenser below. Two-thirds of flow leaves intermediate stages through cross-under, then enters double-flow low-pressure element, not shown.

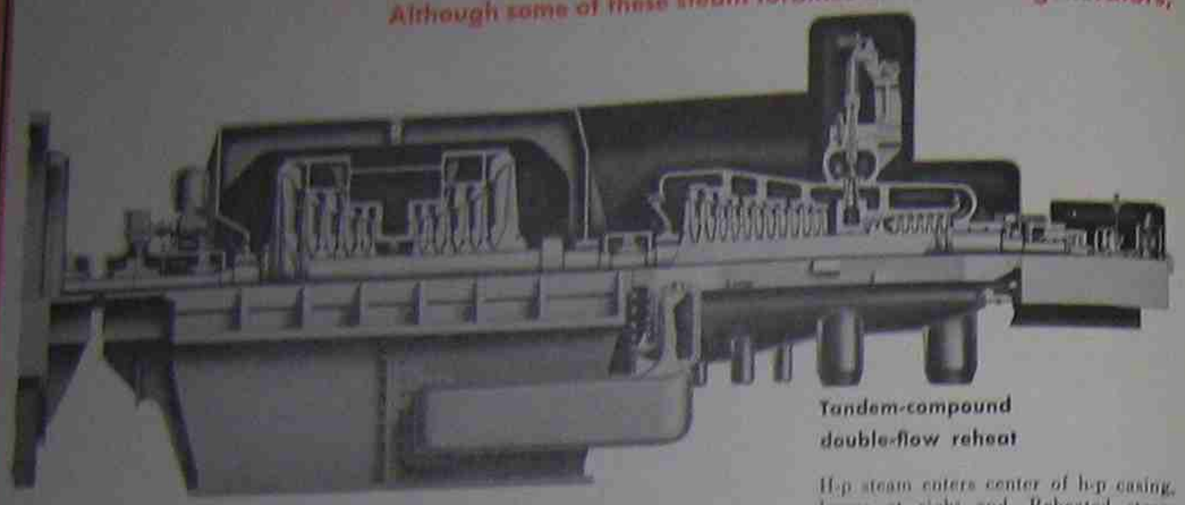


Low-pressure casing extracts remaining energy

Double-flow low-pressure casing receives steam at center through crossover from an i-p casing. Steam divides, flows through paralleled l-p stages in opposite directions. Last stages are followed by diffusers, which recover some energy from steam velocity before the steam flows downward in exhaust hoods to condenser below. Buckets are warped in the latter stages because they make up a large part of total stage diameter.

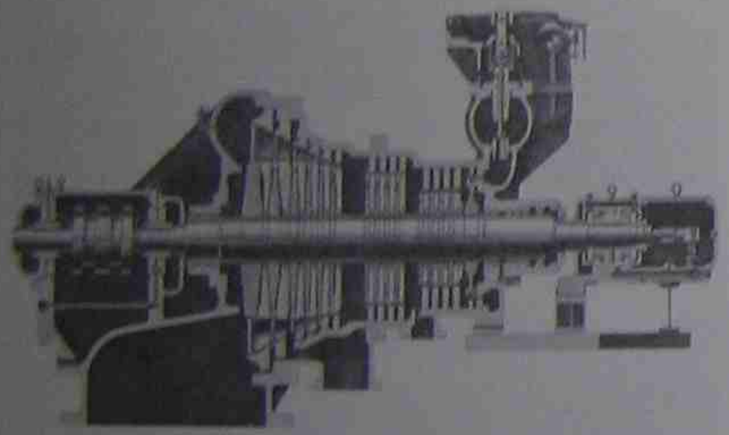


Although some of these steam turbines drive electric generators,



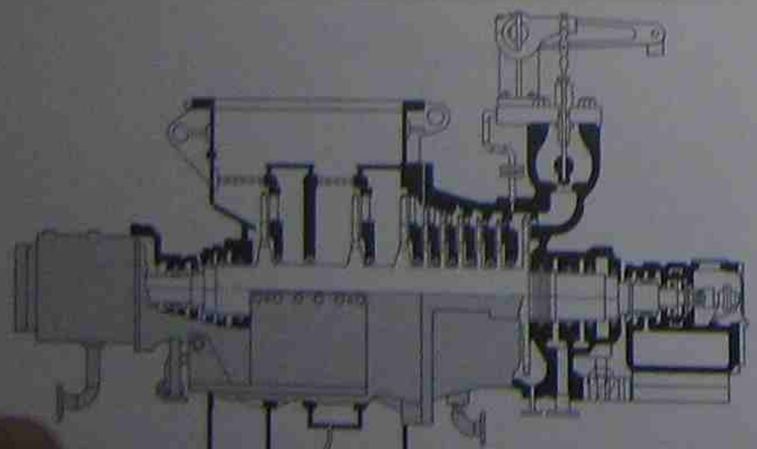
Tandem-compound
double-flow reheat

H-p steam enters center of h-p casing, leaves at right end. Reheated steam enters at center and flows to left end, then through crossunder to double-flow l-p turbine exhausting to condenser.



Single-casing
multistage condensing

Integral steam chest has cam-operated governing valves; velocity-compounded first stage has full arc admission. Two nonautomatic extraction points in this disk-and-diaphragm design withdraw steam for feedwater heating. Last five stages use twisted blading, varying reaction along the blade length; other stages have impulse blading. Ball-seated front journal bearing carries thrust-bearing surface on each of its sides for two thrust collars shrunk on main shaft. Diaphragms fit directly in single casing.



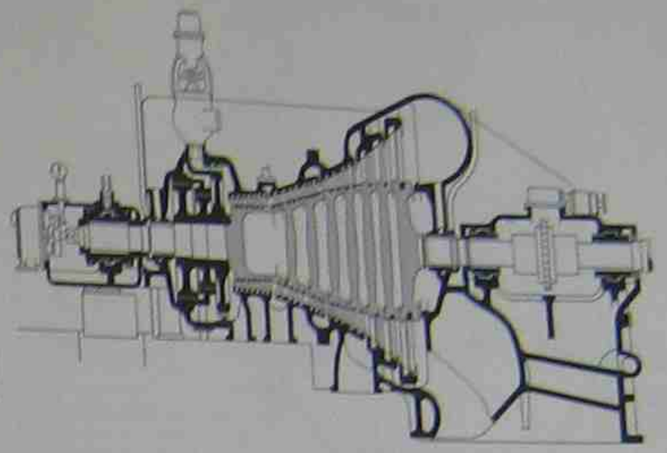
Single-casing
double-flow-exhaust condensing

Steam expands from 600 psig, 750 F to 3.5-in.-Hg abs. Double-flow arrangement of last stage permits shorter blades so unit can run at higher speed—up to 6500 rpm—at good engine efficiency for mechanical-drive service. This unit has its exhaust opening at top. It can develop 13,100 shaft hp at rated speed. Disk-and-diaphragm design uses impulse blading in all its stages, has one point of nonautomatic extraction for boiler-feedwater heating.

other general-purpose units offer a wider shaft-speed range . . .

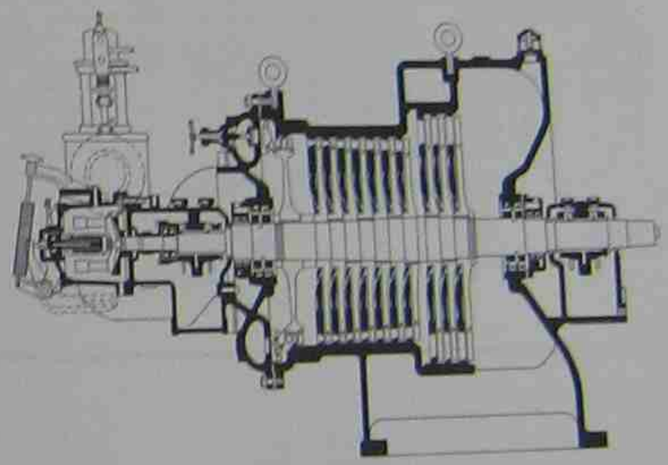
Single-casing
condensing

Velocity-compounded first stage precedes all reaction stages in this drum type design. Dummy piston at left of first stage helps the thrust bearing counterbalance unbalanced force of reaction stages. This European design features a drum made up of forged sections welded together. After heat treating, drum is slotted to receive reaction blading. Steam is removed for feedwater heating at four nonautomatic-extraction points. Turning gear mounts on shaft between two journal bearings, at right.



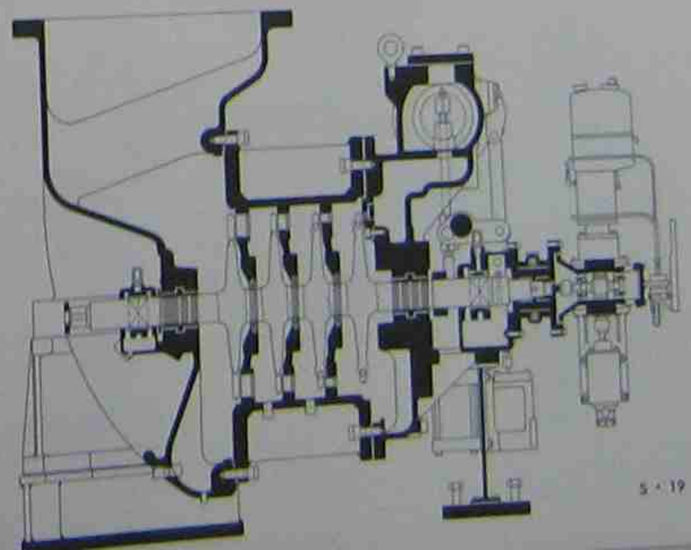
Single-casing
condensing

Velocity-compounded first stage is followed by ten impulse stages. Ball-thrust bearing keeps shaft aligned axially. On left end of shaft, a centrifugal governor controls steam-flow valve through linkages. Hand valves, as on upper-left casing, control nozzle groups for more efficient part-load operation. This unit can be fitted with nonautomatic-extraction openings, to withdraw steam for feedwater heating. Carbon-ring seals are used at diaphragms and casing glands; brass oil rings, dipping into reservoirs to pick up the oil, lubricate this steam turbine's two journal bearings.

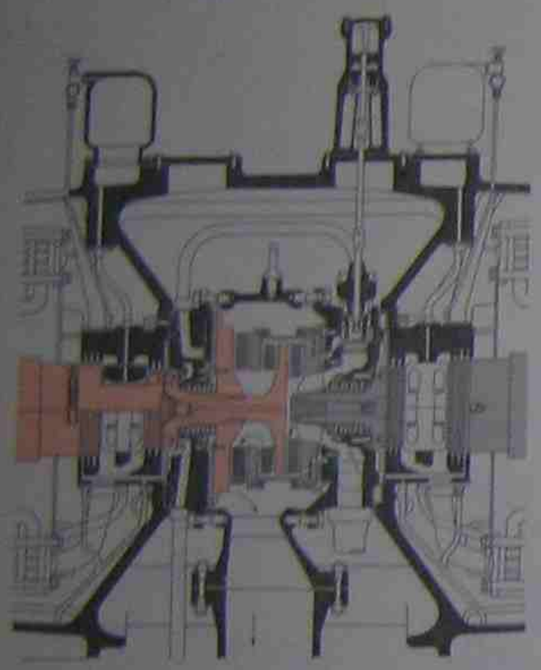


Four-stage
condensing

Steam chest is equipped with bar-lift control valves; lift rods move bar from below. This disk-and-diaphragm design uses impulse staging only and exhausts through an upward-directed hood. All shaft seals are of the stepped-diaphragm type. Since inlet-steam conditions are moderate the unit does not need a velocity-compounded first stage. Governor and speed changer mount on right end of shaft. Thin web beam under front end of turbine allows axial expansion during startups with minimum strain on casing and keeps the turbine's shaft properly aligned.



. . . meeting the needs of both electric-generator and mechanical drives



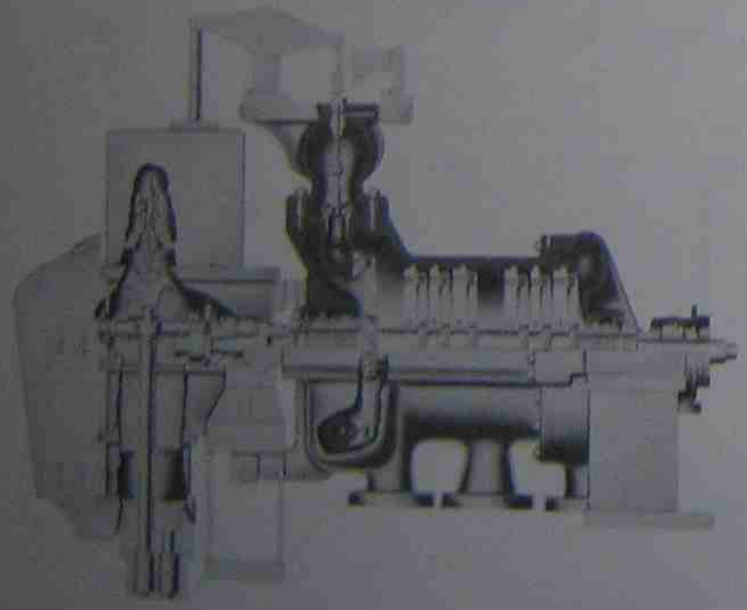
Radial-flow double-rotation

This unit drives two alternating-current generators, one on each shaft. Generators are tied together electrically, to keep the oppositely rotating shafts in synchronism for best blade-steam-speed ratio of the reaction stages. Multidisk turbine is arranged so h-p steam from supply line and throttle valve enters from below. It flows first into the annular steam chest, then through holes in the overhung blade disk to the center area at the shaft.

Oppositely rotating shaft and blade assemblies are shown in light gray and light color. Oppositely moving blades have seals to minimize steam leakage past their tips.

Steam flows outward radially through first concentric set of blades. Then it turns 180 deg to flow inward radially through a second set of concentric blades. It again makes a 180-deg turn to flow radially outward through the third set of blades. From here steam flows into annular space leading to exhaust pipe at bottom of turbine. Bypass valve to right of disk in annular steam chest lets h-p steam skip first set of blades to enter the second set, providing overload operation at reduced efficiency.

Backpressure turbine develops 7500 kw. It can be designed for automatic or nonautomatic extraction of partly expanded steam. Strip type labyrinth seals on the moving blade rings minimize steam leakage past the blades, while concentric labyrinth seals between overhung disks and inner casings cut down leakage short-circuiting the blading. Labyrinth-gland seals at the two shafts control steam flow through these clearances. This unit handles generator drives only.



Noncondensing nonautomatic-extraction

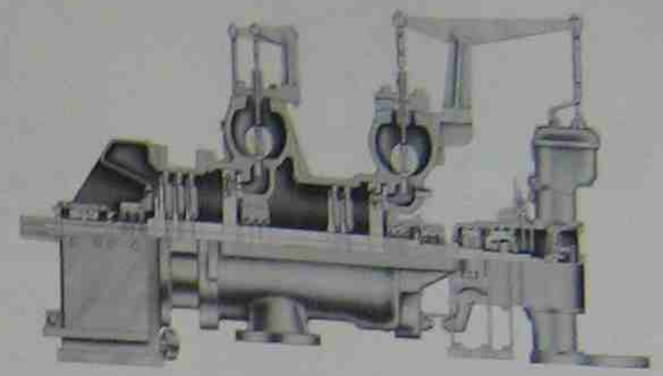
In addition to generator service, industry uses turbines as prime movers to drive pumps, compressors and other types of machinery. Their prime advantage is heat-balance flexibility: throttle steam can be used at boiler or process pressure; exhaust steam can be used for heating and process, or condensed. Extraction and high-backpressure or topping service are possibilities, too. If extraction or exhaust steam can be used, a steam drive has definite economic advantage.

The central-station boiler-feed-pump-drive turbine at left takes steam at high pressure from main line or at lower pressure from reheat line. Sketch shows alternate-nozzle-box design for h-p, below, and l-p, above. Control valves are double-lift poppet type. Unit has seven impulse stages with two nonautomatic extraction points for feedwater heating. It exhausts noncondensing to main cycle.

Noncondensing single-automatic-extraction

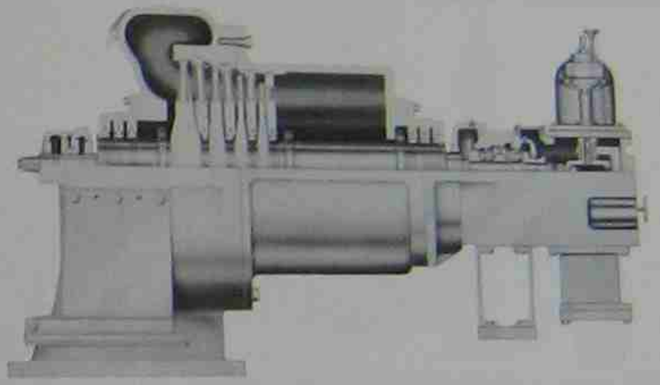
First stages are velocity-compounded in h-p and l-p sections. H-p section has two impulse stages and l-p section has three. Secondary-steam-chest poppet valves control steam flow into the second section, maintain constant extraction-steam pressure for process flow.

Unit is fitted with step-labyrinth interstage and shaft seals. Kingsbury thrust bearing, multiple valves in each steam chest. Disks of this unit are shrunk onto the main turbine shaft.



Low-pressure condensing

This turbine takes low-pressure steam, at 100 psig or less, available from process exhaust lines. Its four stages use twisted blading for high stage efficiency. For high shaft speed, unit has rotor milled out of a solid forging; for low speeds, steel disks would be shrunk on a solid shaft. Journal bearings and Kingsbury thrust bearing position shaft.

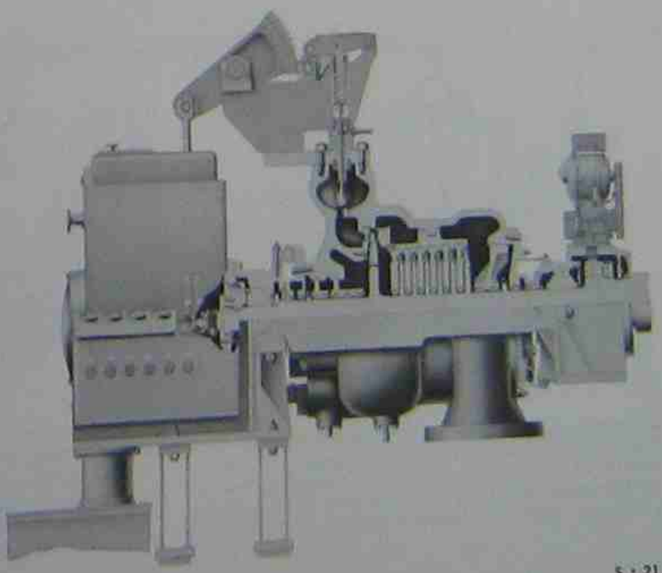


Noncondensing or backpressure

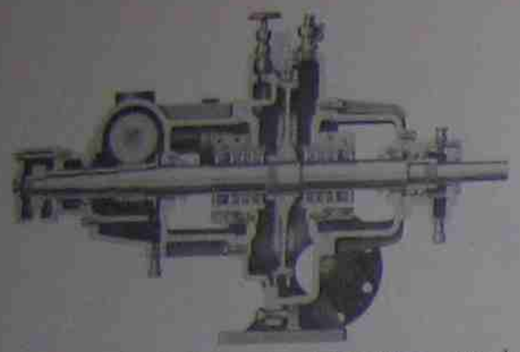
Seven impulse stages are controlled by a multivalved steam chest. Since backpressure is high, this unit needs only a small exhaust hood. Turbine is used where lower-pressure process steam and electric generation are needed simultaneously by an industrial plant.

The exhaust-pressure governor holds whatever exhaust-steam pressure the process requires. But as a result, steam flow through the turbine and its shaft output vary. The turbine must run in parallel with other generators that can meet variations in electric load; it cannot follow them when under exhaust-pressure governing.

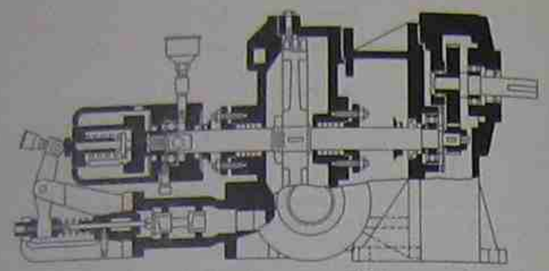
This turbine may also "top" lower-pressure turbine-generators, taking steam from a new h-p boiler and exhausting at lower pressure into the existing steam main of existing turbines.



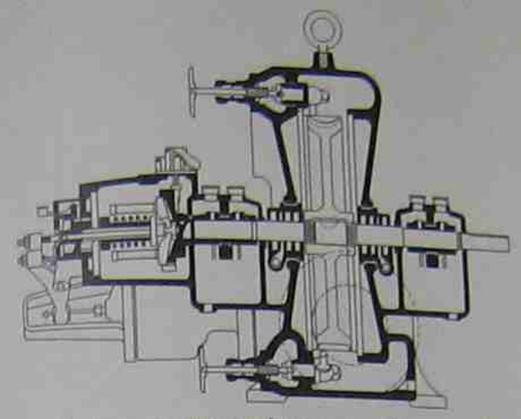
Many mechanical-drive units are single stage, velocity compounded



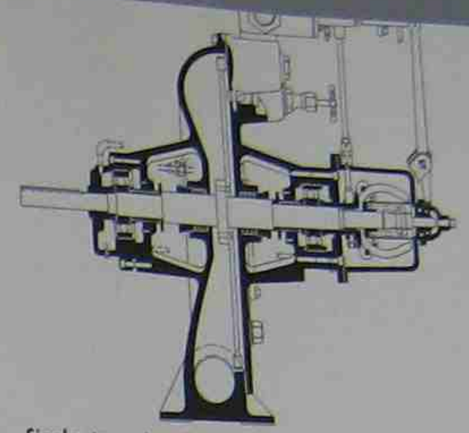
Single-wheel velocity-compounded turbine may be designed for a range of capacities—from less than 1 hp up to 250 hp and more. Design uses one of two standardized blading types for all conditions: 450-psig 750-F and down at inlet; 0- to 80-psig exhaust. Unit may exhaust to process.



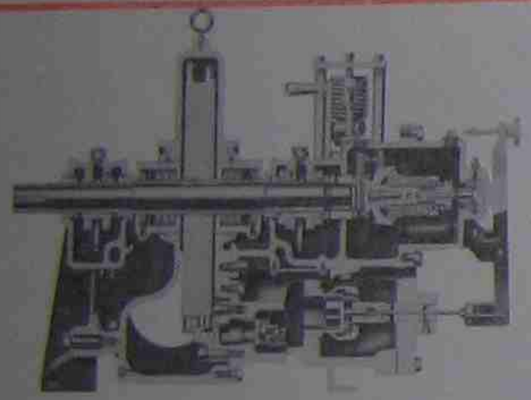
Mechanical-drive design for up to 100-hp capacity takes steam at 600 psig, 750 F, exhausts at 75 psig. Shaft speed of 3500 rpm drives load at up to 300 rpm through integral reduction gear. Flyball governor on shaft end controls balanced valves through linkage. Carbon rings seal shaft.



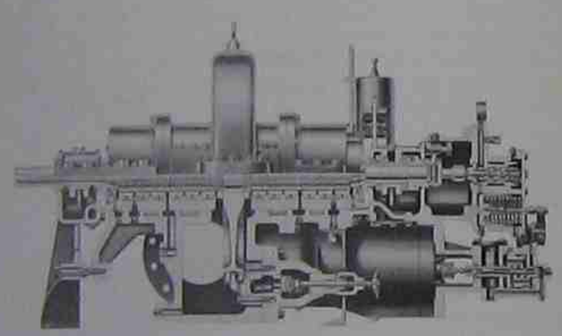
Single-stage re-entry turbine uses solid rotor with circular blades milled out of periphery. Wheel is pressed on and keyed to shaft. This unit develops up to 650 hp with 650-psig saturated steam exhausting at atmospheric. Hand-valve nozzle control helps realize better part-load efficiency.



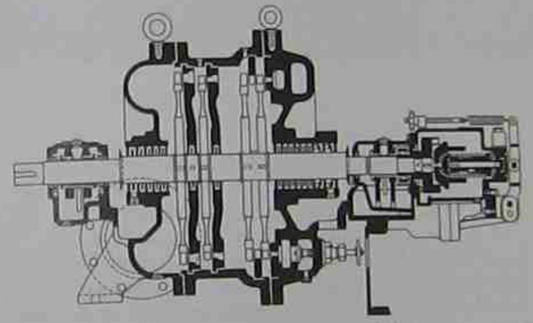
Single-stage impulse turbine has 100-hp maximum rating with 275-psig 525-F steam and 50-psig backpressure, runs at shaft speeds up to 4000 rpm. One of its two groups of nozzles is fitted with hand-controlled valve for part-load efficiency. Stuffing boxes use semimetallic packing at glands.



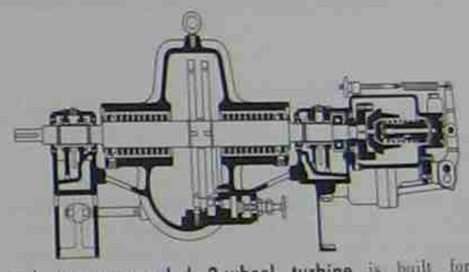
Velocity-compounded turbine has close-fitting casing at top, reduces windage loss on wheel and blading. Converging-diverging nozzles are used because steam's pressure ratio runs less than 53%. Overspeed-emergency-governor trip is in shaft at left of constant-speed-governor flyweight assembly.



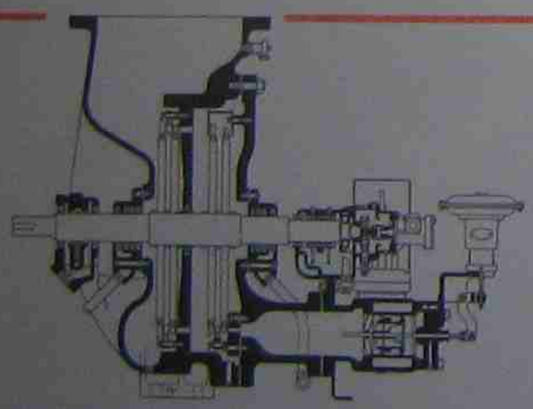
Velocity-compounded turbine with single wheel and high backpressure features extensive spring-loaded shaft sealing. Steam sealing and gland leakoffs must be used to control steam leakage along shaft. A shaft-driven oil pump provides governing. Hand valves up part-load efficiency.



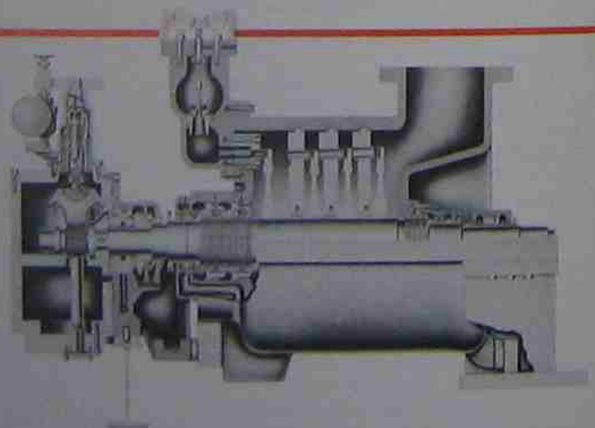
Multistage turbine's velocity-compounded first stage uses two separate wheels. This type may be condensing or non-condensing, runs at shaft speeds up to 10,000 rpm. It has carbon-ring seals, ring-oiled journal bearings and a double-thrust ball bearing to control position of the shaft.



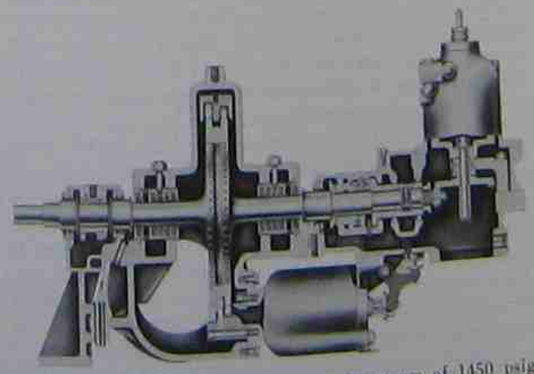
Velocity-compounded 2-wheel turbine is built for 165-psig backpressure. Each shaft gland has ten carbon-ring seals. Gland leakoffs dispose of a little condensed-steam leakage. Hand speed changer attached to governor linkage varies speed range by 20%; maximum: 4500 rpm.



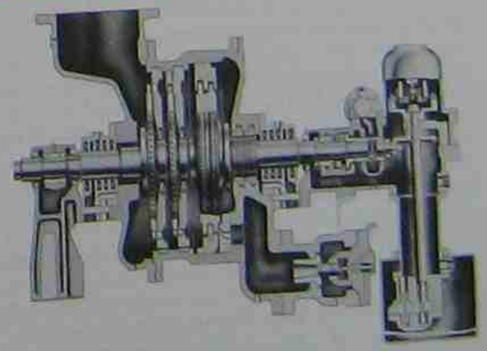
Variable-speed turbine handles compressor drive, with speeds ranging from 3500 to 6000 rpm. Turbine uses 250-psig 500-F steam exhausting at 2- to 6-in. Hg abs. There are two velocity-compounded stages; upper half of first-stage wheel is shielded, which helps avoid excessive windage losses.



Noncondensing high-backpressure turbine is built to run up to 10,000 rpm and above. For high speeds, rotor would be a machined solid forging. Unit has four impulse stages. Flyball governor, left, positions pilot valve of hydraulic-governor system controlling bar-lifted valves in steam chest.

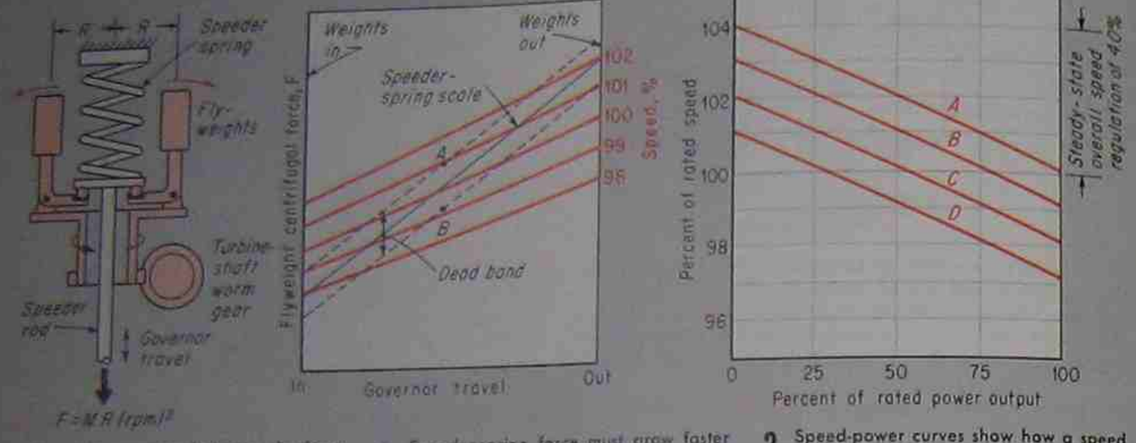


High-speed turbine is built for inlet steam of 1450 psig and 1000 F to exhaust at up to 75 psig. Upper half of velocity-compounded wheel is closely shielded against windage losses. The 12,500-rpm shaft is designed to run well above first-critical speed but well below the second-critical speed.



Condensing turbine has velocity-compounded first stage followed by two impulse stages. Combined labyrinth and carbon seals are used at h-p end; l-p end has carbon rings only. Shaft drives gear type oil pump and flyball governor at right end; thrust bearing is included to position the shaft.

Flyweight governor opposes centrifugal force of pivoting weight with mechanical force of spring

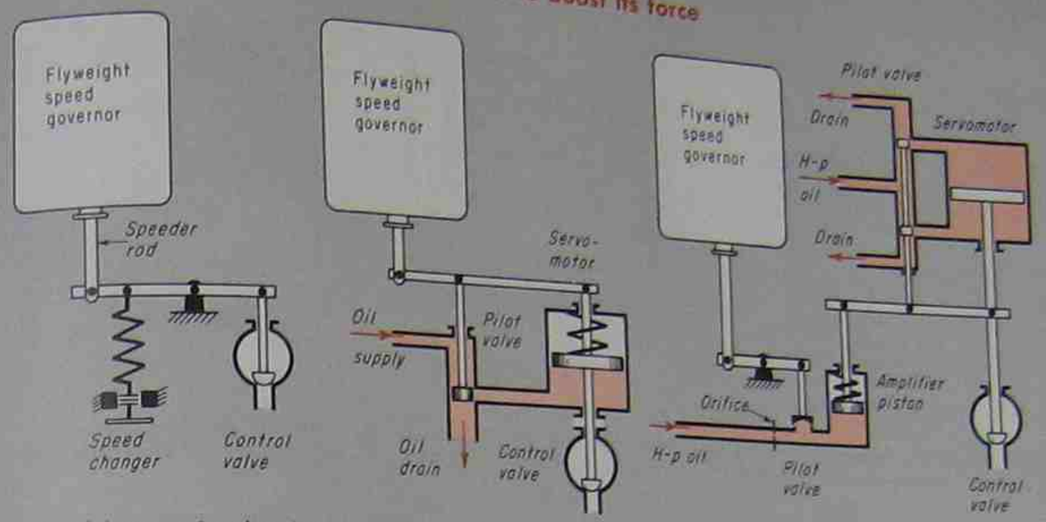


1 Flyweight governor balances the force of spring and weights, moves speeder rod

2 Speeder-spring force must grow faster than the weight force as speed rises

3 Speed-power curves show how a speed changer shifts droop characteristic

Basic turbine governor adds refinements to boost its force



4 Speed-changer spring alters force acting on the steam-control-valve lever

5 Pilot-valve-controlled servomotor lets weak governor force move steam valve

6 Double-relaying system helps governor handle the very large steam valves

GOVERNING controls shaft speed

A turbine's governing system functions to control steam flow through the unit. It usually does this to keep some factor constant. Often we want to hold steady at all loads: (1) turbine shaft speed (2) exhaust-steam pressure (3) automatic-extraction pressure (4) inlet-steam pressure (5) driven-equipment discharge pressure (6) driven-equipment differential pressure or (7) any combination of these factors. Since shaft speed is most frequently controlled, let's study it to see how turbines are governed.

Turbine speed will stay constant even without governing, just as long as shaft load and throttle-valve opening are unchanged and steam conditions remain steady. But when shaft load decreases with constant throttle-valve opening, the turbine speeds up because it's getting too much steam. To bring shaft speed to normal the valve must throttle steam flow to match the new load. When shaft load rises and valve opening is constant, the turbine slows down; to return shaft speed to normal, the valve must open wider, admit more steam. A shaft-speed governor can make these changes automatically.

A flyweight assembly measures shaft speed. Fig. 1 shows one form of it: two flyweights mount on a plate which turns about a vertical axis driven by the turbine shaft through a worm and gear. Weights are pivoted so as centrifugal force tilts them outward, they compress the stationary *speeder spring* and lift up the *speeder rod*. Speeder-rod movement can be hooked up to open and close the turbine throttle valve, Fig. 4.

How does a governor behave? As a first step to understanding, we can remove the speeder spring in Fig. 1 and find out how flyweights act by themselves. First let's hold the weights in their innermost position—weights in—with the speeder rod, and turn the assembly at its rated 100% speed. We'll exert a downward resisting force F on rod while weights turn through circle with radius R.

If weights move through a circle with larger radius, we find that force on speeder rod is larger, though speed is still 100%. Force $F = MR\ (rpm)^2$ where M is the flyweights' mass, R is radius of their motion and rpm the number of turns per minute.

Plotting force F against governor travel or speeder-rod position for various speeds from 98 to 102%, we get the family of straight-line curves in Fig. 2, which ideally converge at a common point off to the lower left of the chart. Slope of each speed curve has a scale reading in lb force per inch of governor travel.

A speeder spring with a scale to match the 100% curve develops the same resisting force F for a given lb per inch of compression or governor travel. Spring scales set at the middle of governor travel at 100% speed would be fine as long as all factors stayed constant. But as soon as load on the unit decreased, the shaft would speed up. Then weights would develop more force than the spring over the range of governor travel. Weights would fly to their weights-out limit, shutting the steam valve.

As steam flow stopped, unit would slow down. Slightly below 100% speed the springs' mechanical force would overbalance the weights' centrifugal force and slam them to weights-in, completely opening the steam valve. So if weight and spring scales are equal they're continually fighting, producing wild hunting from fully shut to wide-open throttle valve, without hope of reaching a balance. Obviously, this is no way to govern a turbine.

Speed droop. To get out of this dilemma, spring force must grow faster than weight force as speed rises. Spring scale should be steeper (larger) than the flyweight scale, solid black line in Fig. 2.

Suppose the turbine is running at 100% speed, where the speeder-spring curve crosses the red 100%-speed curve. When shaft load drops, shaft speed rises. Then increased force of the flyweights momentarily overbalances the spring force, raising the speeder rod to decrease throttle-valve opening. Decreased steam flow limits shaft speed rise, so spring force again balances the higher flyweight force at the new higher speed. Governor can't travel to its weights-out limit because the spring exerts greater force than the weights beyond the new point of balance.

If the turbine is running at 100% speed and load rises, the shaft slows down. Then flyweights' lesser force lets the overbalancing spring force lower the speeder rod to open the throttle valve wider. Increased steam limits the speed drop so diminishing spring force matches weight force at the lower speed. Governor won't travel to its weights-in limit because the weights exert more force than the spring below the new balance point.

At each point in governor travel the turbine runs at a definite speed, slower at full load and faster at no load. For the spring scale in Fig. 2 speed varies by 4% from full to no load. This is the governor's *regulation* or *speed droop*. Fig. 4 shows speeder-rod and control-valve hookup.

Frictional effects, ignored in the ideal model, play a big part in design of a working governor. Suppose the unit is running at 98% speed in Fig. 2 at the weights-in position, and then speeds up. Weights' force rises, but because of friction in the linkage and glands the governor doesn't move immediately. By the time the turbine reaches 99% speed, force is large enough to overcome friction and the governor travels along the upper dotted curve.

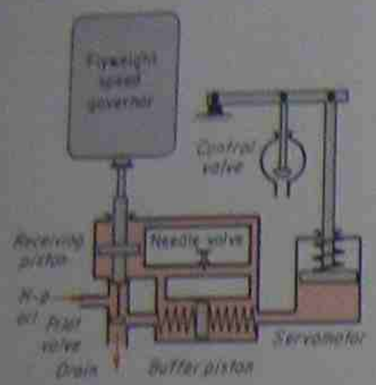
Now let's bring speed up to 101% at A by reducing turbine load. Next, we'll start to load it again; the turbine slows down to 99.4% speed at B before the governor responds by moving toward its weights-in limit along the lower dotted line. Vertical distance between upper and lower dotted lines measures the governor's *dead band*, which in turn defines *sensitivity*: speed change needed to produce a corrective movement in governor travel.

Speed-output curve, Fig. 3, shows how a governor varies shaft speed with load. A given spring scale A produces 100% speed at full load. As turbine is unloaded the shaft speed rises until it reaches 104% speed at no load. But usually we want to keep shaft speed constant at all loads. So a *speed changer*, Fig. 4, is added. It puts additional spring force on the lever controlling the steam valve, is regulated by hand or remote-controlled motor.

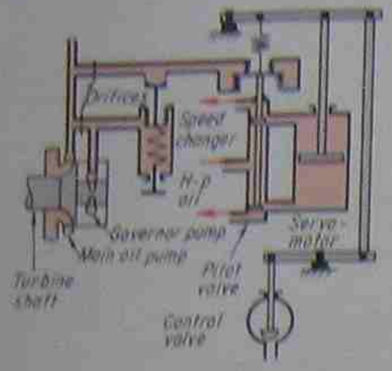
Suppose we have a 100% load at 100% speed and bring load down to 75% in Fig. 3. Speed rises to 101%. We would reduce this to 100% by loosening the speed-changer spring, allowing the steam valve to close a little more. Fig. 3 shows characteristics for speeder spring adjusted to hold 100% speed at 25, 50, 75 and 100% loads.

Relayed governor, Fig. 5, is used where speeder rod doesn't develop enough force to move the steam valve. A *floating lever* links speeder rod to a *pilot valve* and the *servomotor* that actually moves the control valve. Initial speeder-rod movement pivots the lever on the servomotor stem and moves the pilot-valve stem. This admits h-p oil to the spring-loaded servomotor cylinder or drains oil

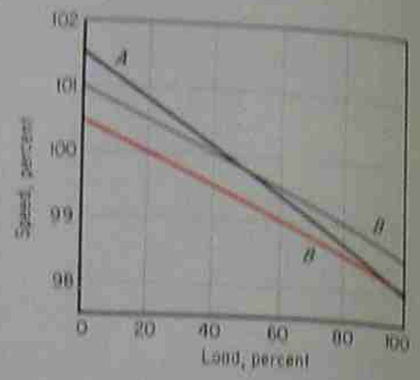
Generator load division depends on governor droop



7 Isochronous governor uses transient speed changes to move to new setting



8 Hydraulic governor has an oil pump as its speed-sensitive measuring element

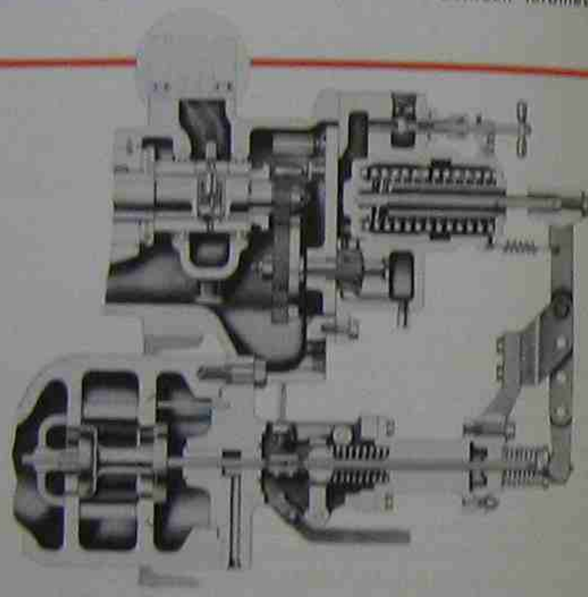


9 Governor-droop characteristics determine load division between turbines

Designs vary with size of unit, shaft speed, needed accuracy



13 Direct-acting mechanical governor has weights mounted on leaf springs, tied to steam-valve stem. It holds steady speed



14 Hydraulic-orifice governor's shaft-driven gear pump supplies oil for governing and lubrication; its speed ratio is 3:1

from it, moving the control valve to its new position. Motion also moves the pilot valve to neutral so it won't overshoot the new position of the control valve.

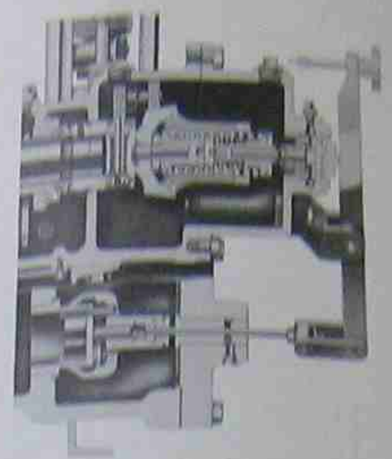
Turbines with large steam valves need a relayed governor for plus amplification, Fig. 6. A cup type pilot valve bleeds h-p oil from the line to control the first-step amplifier piston. This piston controls the pilot valve of the main servomotor. Servomotor is not spring-loaded; to move it, h-p oil is admitted on one side, drained from the other.

Isochronous governor, Fig. 7, holds the same *steady-state* speed on a turbine at all loads without a speed changer. When load first varies it produces a *transient change* in shaft speed, but that's gradually eliminated as load stays constant at its new level. On a change in load the speeder rod moves the receiving piston, and pilot valve in turn unbalances the spring-balanced buffer piston while moving the servomotor to its new position. After the initial correction, buffer piston moves back into balance. It equalizes pressure across the receiving piston, repositioning governor flyweights at rated 100% speed with the new shaft load.

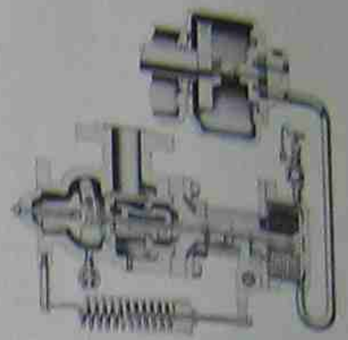
Hydraulic governor, Fig. 8, has a special centrifugal pump instead of flyweights as its speed-sensing element. Oil pressure varies as the square of the shaft speed. Governor pump controls throttled pressure developed by the main oil pump; this acts on the bellows in the speed changer. Bellows controls the cup type valve which is part of the pilot valve, regulating pressure in another bellows which positions the servomotor pilot valve.

Generator load division, Fig. 9, depends directly on the governor droops of the turbines that drive the generators. Paralleled synchronous generators run at the same speed, just as if they were connected mechanically.

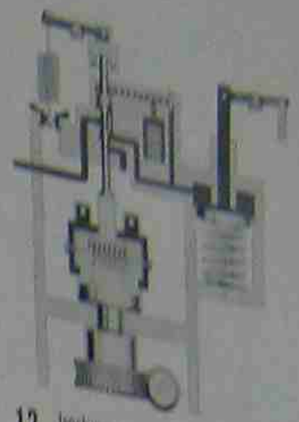
When load rises, speed falls until total output of all



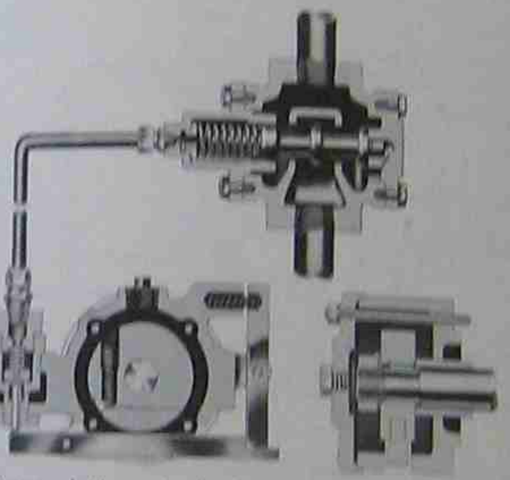
10 Direct-acting flyweight governor for small-size turbine: weight pivots roll



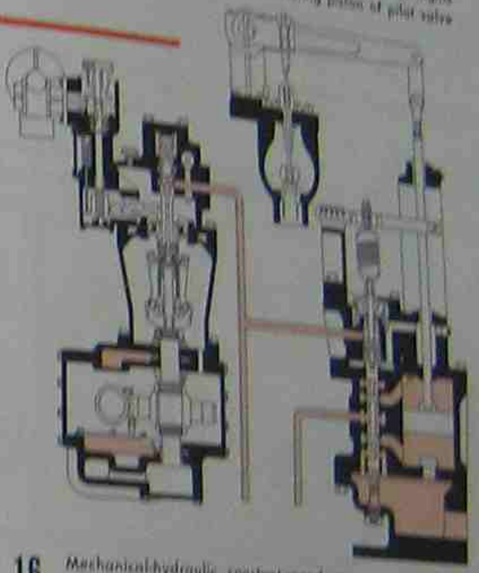
11 Direct-acting hydraulic governor: oil pump moves valve through bellows



12 Isochronous governor's flyweights control rotating piston of pilot valve



15 Overspeed trip: spring-loaded weight on shaft trip lower lever opens pilot valve, left, which then closes main valve



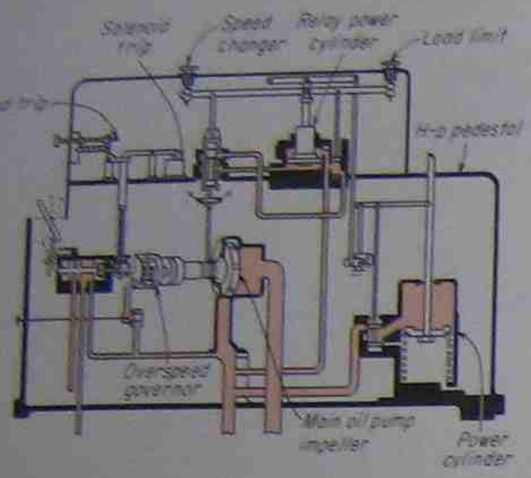
16 Mechanical-hydraulic constant-speed governor head positions rotating pilot. Pilot controls double-relay oil system

units meets the new demand. In Fig. 9, two machines *A* and *B* have the droops shown by the black curves. At 100% speed *A* carries 43% load and *B* 40% load. If load rises until speed falls to 99%, *A* carries 72% load and *B* 80% load. To restore speed to 100% with this same division, speed changers on both units are adjusted to lift both curves the same amount.

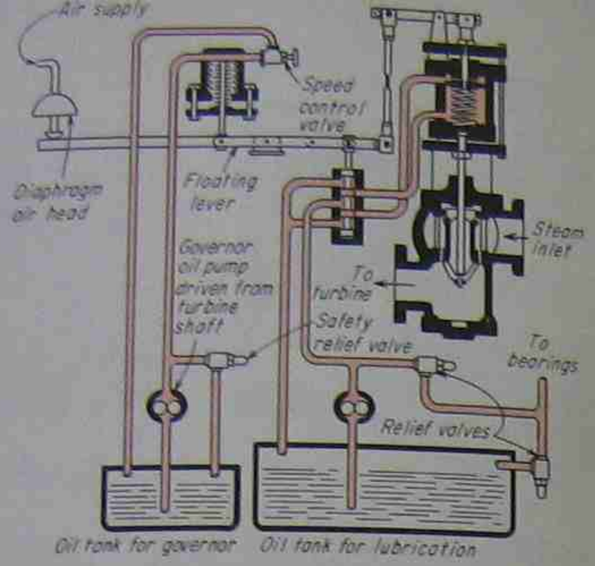
Returning to 100% speed in Fig. 9, suppose we want to drop load from the total 40 + 43% to 63%. If *B* is to take all the reduction, its droop must be lowered to the red curve. In general, unit with least droop will always take largest share of the total load.

Governor-system designs vary with size of turbine, speed of shaft, degree of accuracy—and with the manufacturer. Direct-acting mechanical governor in Fig. 10 links directly to the steam-control valve. To minimize needed force, steam valve is a balanced double-seated design. Both governor weights pivot on rolling surfaces with circular sections. To the left of the governor head a spring-loaded unbalanced pin acts as the overspeed trip. When shaft speed exceeds the safe limit, centrifugal force snaps the pin to an outer position so it trips a lever that closes the turbine stop valve. A speed-changer knob on upper end of governor lever tightens spring (not shown) to shift the unit's droop curve.

Hydraulic governor in Fig. 11 has a 3:1 speed-adjustment ratio. Its gear type positive-displacement oil pump develops a pressure that varies with shaft speed. Pressure acts on the bellows, and this directly positions the balanced double-ported steam-control valve. Needle valve above the bellows bypasses oil back to tank to vary the bellows pressure and hold any desired speed. Turbine stop valve is at left of main governing valve. Fig. 14 shows a hydraulic governing system for a sod turbine.

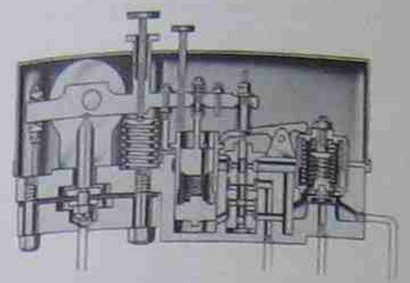


17 Turbine front pedestal houses the mechanical governor, oil pump, relay valves and servomotors for regulating unit

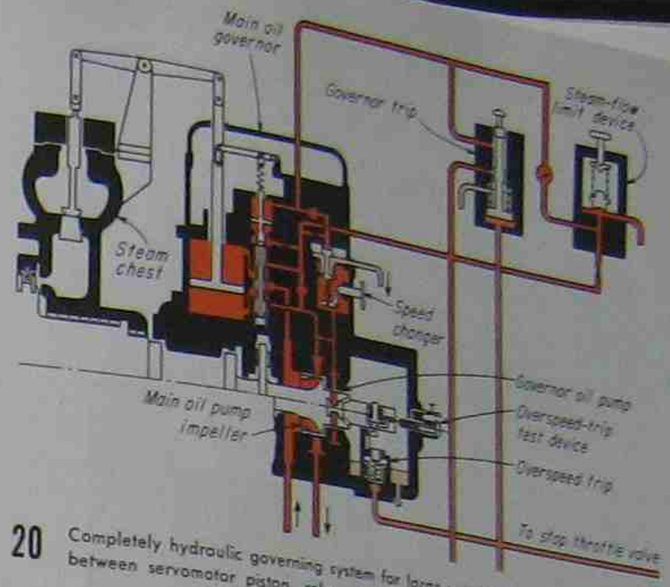


18 Variable-speed oil-relay governor's air motor also acts on floating lever to control the main steam flow into turbine

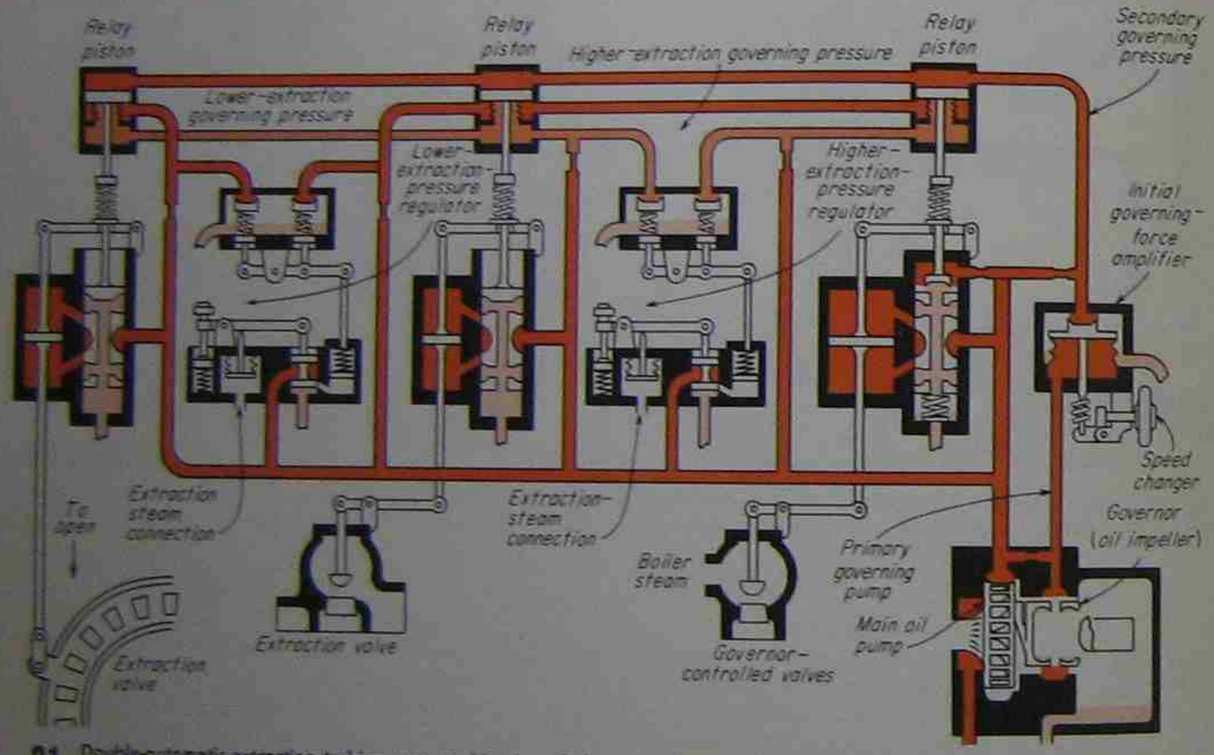
As turbines grow complex, governing systems expand to handle more functions



19 Exhaust-pressure regulator controls oil pressure to turbine's main servomotor



20 Completely hydraulic governing system for large unit needs only mechanical links between servomotor piston, relay and main steam valves; oil serves elsewhere



21 Double-automatic-extraction turbine uses combination of three signals on three relay pistons to hold constant pressure at each of its extraction openings and maintain a constant shaft speed

Isochronous governor, shown schematically in Fig. 12, mounts flyweights on a rotating head at upper ends in torsion bushings. Weights work through strap springs to rotate the pilot valve above. Pilot controls oil pressure to servomotor. Speed changer, upper left, acts on governor through the pilot-valve stem.

In one direct-acting mechanical governor for small turbines, Fig. 13, flyweights mount on flexible springs and directly move the nonrotating steam-control-valve stem which projects through the rotating governor shaft. Fig. 15 shows the same unit's overspeed-trip governor. Spring-loaded weight on the shaft swings out on overspeed to trip the lower lever and open the pilot valve, lower left. This relieves steam pressure in back of the steam stop valve above, slamming it shut.

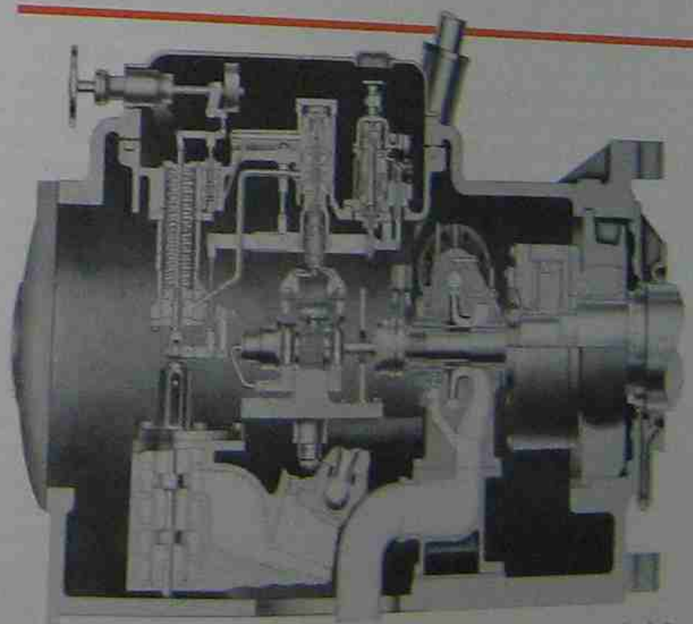
Mechanical-hydraulic governing system for a multi-valved turbine, schematic, Fig. 16, uses rolling-contact flyweights to position the pilot valve above. Speed-changer assembly stands at upper left. Pilot valve controls pressure to the primary servomotor; it controls the secondary pilot valve, lower right. This positions the secondary servomotor or power piston, which opens and closes main steam-control valves.

Fig. 17 diagrams a governing pedestal for a medium-size turbine. Fig. 18 is a schematic for a variable-speed oil-relay governor with an air-motor control on the floating lever. Fig. 19 shows the pressure regulator that controls steam valves on a backpressure unit. Fig. 20 has some details of a hydraulic type governor.

A double-auto-extraction unit's governing system, Fig. 21, combines three signals on three relay pistons to hold constant pressure at each extraction opening and constant shaft speed. Speed changer after governor impeller bleeds relaying-oil pressure, to shift droop characteristics as needed. Pressure regulators modify relaying-oil pressure to control extraction pressures.

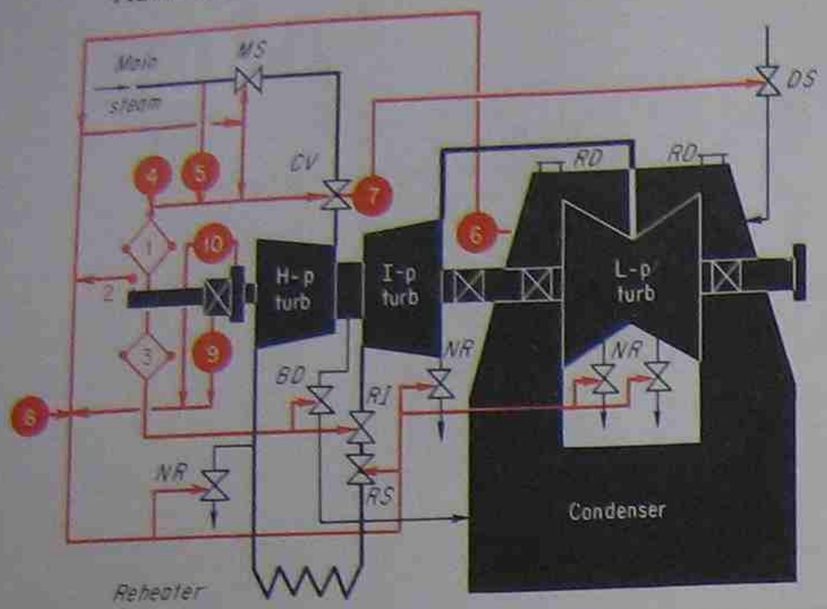
Governing system for a single-automatic-extraction turbine needs fewer elements, Fig. 22; it controls main inlet and extraction valves. Fig. 23 takes a section through front standard of a reheat unit showing the flyweight governor, oil pump, relay valves, servomotors and other elements needed to automatically control this type of a steam turbine.

22 Governing system for a single-automatic-extraction turbine must control main inlet and extraction valves. Links move pilot valves to control servomotors



23 Governing system for reheat turbine also controls intercept valves, partly closing

Automatic load control uses these basic elements



BD — Gland blowdown valve
CV — Turbine control valves
DS — Desuperheating spray valve
MS — Main steam stop valve
NR — Extraction nonreturn valve
RD — Relief diaphragm
RI — Reheat intercept valves
RS — Reheat stop valves

1 — Speed governor
2 — Overspeed governor
3 — Pre-emergency governor
4 — Load-limiting meter
5 — Initial-pressure regulator
6 — Low-vacuum trip
7 — Control-valve position meter
8 — Solenoid trip; hand or relay
9 — Low bearing-oil-pressure trip
10 — Thrust-position trip

CONTROLS AND INSTRUMENTATION

Shaft speed is one of the most important variables in running a turbine. We have seen how some of the many available governing systems control speed in turbines large and small. For safety, the operator must always have on hand certain minimum information about his unit. As turbines grow larger, automatic aids or controllers are required.

Small-turbine needs in controls and instruments represent a minimum: speed governor, overspeed trip, throttle-pressure gage, throttle thermometer, exhaust-pressure gage, tachometer. Where the turbine controls or affects exhaust-header pressure, its speed governor includes an exhaust-pressure regulator to adjust the governor control.

Gland-steam pressures should be known to hold adequate shaft sealing. Turbines that use circulating-oil lubricating systems have pressure gages at pumps, bearing inlets and filters; thermometers are needed at oil-cooler inlets and outlets and at bearing outlets.

List of requisite equipment grows with turbine capacity and rising steam conditions. As an example, let's look at the gear needed by some reheat turbines for automatic control, above left, and instrumentation, right.

To control load automatically we depend on:

Speed governors to measure shaft speed and adjust governor-valve openings to pass the needed steam flow. Valves, in turn, keep speed within governor's regulation range. To hold exact speed, speed-changer spring or bellows tension must be adjusted manually or by an automatic frequency-measuring device. When generators work in parallel, the speed changers are used to divide total load between the turbines on the line.

Load-limiting meter overrides the speed governor to hold maximum load at any point the operator wants. The limiter controls steam flow during startup by setting governor valves as needed.

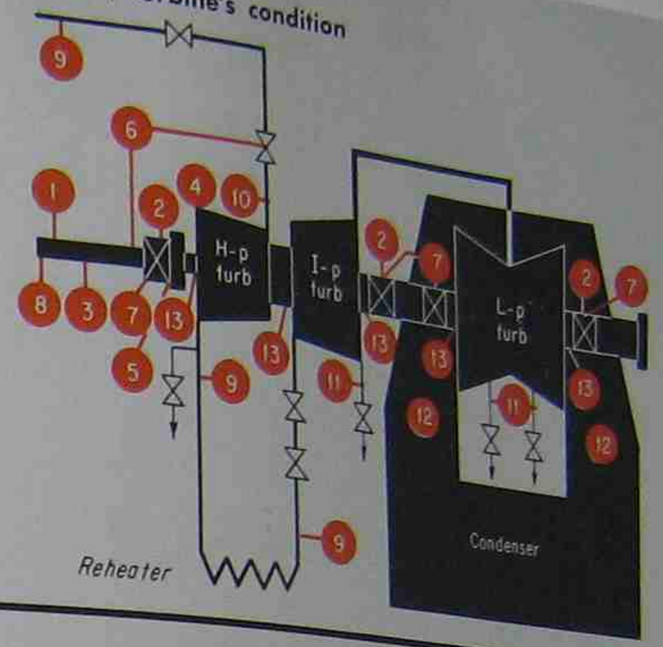
Pre-emergency speed governor controls governor valves or reheat-intercept valve or both during sudden drops in load. When turbine speed exceeds about 101% the governor starts closing the intercept valve; at 105% it shuts the valve completely. At about 104% speed, steam trapped in the reheater is bled down until spent. Speed governor takes control when speed drops below about 101%.

Initial pressure regulator keeps boiler and turbine from running with fast-dropping steam pressure and temperature. When pressure drops to about 90% of rating, regulator closes the control valves to hold the pressure. At about 80% pressure the control valves are in no-load position. As pressure rebuilds, speed control is returned to the governor.

Overspeed trip backs up the normal speed-governing system, including main and pre-emergency speed governors. At about 110% speed the trip goes into action, closing the main stop valve ahead of the control valves to shut off all main steam supply. Simultaneously it: (1) closes the reheat stop valve ahead of the reheat intercept valve to bottle up steam in the reheater (2) closes all check valves in extraction-steam lines, so bleed condensate can't evaporate and flow into the turbine (3) opens the gland-blowdown valve so steam flowing through the gland from h-p to i-p casing can blow down directly to the condenser instead of flowing through i-p and l-p turbines to cause overspeeding.

Low-vacuum trip shuts down every steam valve in the turbine the moment exhaust vacuum falls below about 20-in. Hg. This prevents overheating the exhaust hood and overstressing the last turbine stage. An associated alarm at the hood warns when its temperature exceeds

Instruments give data on steam flow, turbine's condition



1 — Spindle-eccentricity meter
2 — Shaft-vibration meter
3 — Spindle-position meter
4 — Casing-expansion meter
5 — Differential-expansion meter
6 — Speed and governor-valve-position recorder
7 — Bearing-oil pressure, temperature, sight-flow glass, temperature alarm
8 — Tachometer
9 — Steam pressure, temperature, flow
10 — Nozzle-group pressures
11 — Extraction-steam pressure, temperature
12 — Exhaust-hood pressure, temperature
13 — Gland-steam pressure, temperature

provide for safe, efficient operation

safe limits. This may happen when all steam is shut off and the generator motors: last-stage blading churning the l-p steam trapped at exhaust may overheat both exhaust hood and shaft.

Exhaust-pressure relief must be provided when steam pressure in the exhaust hood rises above atmospheric. Rupture diaphragms in the hood burst at about 5 psig. They pass full steam flow so exhaust pressure doesn't exceed about 8 psig.

Desuperheating sprays are needed by some reheat units when their loads drop to less than 5%. A meter on the main-steam control valves or exhaust-hood thermostat operates the desuperheating-spray valve automatically to cool l-p end of the turbine during low-load operation.

Solenoid trip shuts down the turbine by closing all valves. It may be operated by hand or hooked up to control circuits of its boiler and generator.

Low bearing-oil-pressure trip guards against wiping main bearings when lubricating-oil supply fails. This trip activates the emergency shutdown systems, promptly closing all the steam valves.

Thrust trip measures position of the rotor relative to the thrust-bearing cage. If its position deviates from safe limits, trip operates the emergency shutdowns, closing all steam valves.

Other types of controls tie in with various special applications of the turbine. Their use depends on probabilities of emergencies arising, and on an economic balance: cost of guarding against the condition vs cost of possible damage.

Instrumentation on a turbine and its piping tells operator condition of the steam flowing through all parts of the unit and condition of the turbine structure. Available instruments range widely. Some are indicators, others recorders; some may be vital parts of the automatic-control system we just talked about.

Spindle-eccentricity meter checks on rotor's straightness. After an extended shutdown, shaft will bow if it's heated unevenly. Then it would vibrate excessively when brought up to operating speed. This meter tells operator amount of shaft bowing that may be present, before he runs up his rotor speed.

Shaft-vibration meter measures vibration amplitude at several of the turbine bearings. Out-of-balance rotor is quickly detected, as well as any buildup of boiler-steam deposits on the blading. A record of vibration readings taken at regular intervals shows up internal changes.

Spindle-position meter indicates axial position of the turbine spindle relative to stationary parts of the thrust bearing. It's needed because high thrust loads or wear of the bearing shoes may cause excessive movement.

Cylinder-expansion meter measures total elongation of the turbine casings. Instrument usually stands at the governor pedestal, since unit is anchored at its exhaust end.

Speed and governor-valve-position recorder helps operator run the turbine during startups and emergencies. It gives him better basis for judgment when pressure and temperature are off normal.

Bearing-oil condition throughout the lube system must be known to assure continuous smooth operation.

Steam conditions—pressure, temperature, flow—at all major openings in the turbine are informative. They tell the operator a lot about his machine, help him analyze cause of misoperation in an emergency.

Gland-steam conditions must be properly supervised by the operator at all times, if he's to run the turbine at maximum efficiency. Leakage steam that bypasses the turbine stages does no useful work.

LUBRICATION AND HYDRAULIC SYSTEMS

Lubrication is needed to minimize turning friction in main bearings, thrust bearing and reduction gears, cool the journal and other bearing surfaces. Friction heats journals and bearings, and the shaft conducts some heat from hot parts of the turbine to the bearings. Lube oil carries the heat away, keeps bearing temperature at a safe level, prolonging life of bearing and oil.

Smaller steam turbines usually get along with the simplest type of oil system to lubricate their bearings. From this minimum, systems range upward to the complex hydraulic set ups of the larger central-station steam turbines. In these units, oil serves as a power-transmitting fluid for speed- and load-control, high-pressure, overspeed and protective systems as well as a main-bearing lube.

Bearings carry full weight of turbine rotors, let them spin free with minimum friction. Metal-to-metal contact would ruin bearing lining and journal in short order, so an oil film is forced between the two surfaces to separate them. Frictional effects take place between surface and oil, but mainly in the film.

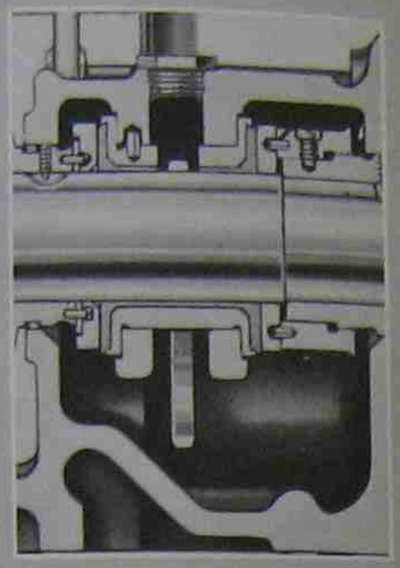
Lube oil must wet the metal surfaces it separates, yet stay cohesive enough to resist being squeezed from area of maximum pressure. Low unit bearing pressures and high shaft speeds help form the needed oil wedge between surfaces. A good lubricating system is designed to prolong life of the oil.

Small bearings need a relatively small amount of oil. In the ring-oiled bearing, Fig. 1, a ring rides loosely on the journal. Lower arc of the ring dips into the oil reservoir below. As the shaft turns the ring revolves; oil from the reservoir clings to the ring and is carried with it to the top of the journal. Here the oil transfers to the journal. Grooves in the bearing surface let the oil flow in an axial direction to fill the space between journal and bearing. The continuously flowing oil drains back to the reservoir after passing through the bearing.

For smaller turbines, the reservoir has enough outer surface area to radiate heat picked up by oil to the room air. Larger turbines using ring-oiled bearings may need cooling coils in their reservoirs.

Larger bearings would not get enough lubrication or good cooling from a simple ring-oiling arrangement. They need forced-circulation oil systems. Since forced circulation requires pumps to produce pressure, economics usually combines the lube system with the fluid-power hydraulic system that actuates turbine controls.

Designs span range



1 Ring-oiled journal bearing: brass ring runs through oil reservoir below

Basic independent oil system, Fig. 2, combines reservoir, pumps, coolers, pressure controls, accumulator, filters and piping. Two pumps are used for service continuity: if one fails in service the other starts fast so oil-pressure won't decay to the point where it trips any of the shutdown controls. Pump capacity, boosted by the accumulator, must supply the high transient oil flow the control system needs during large changes in shaft load.

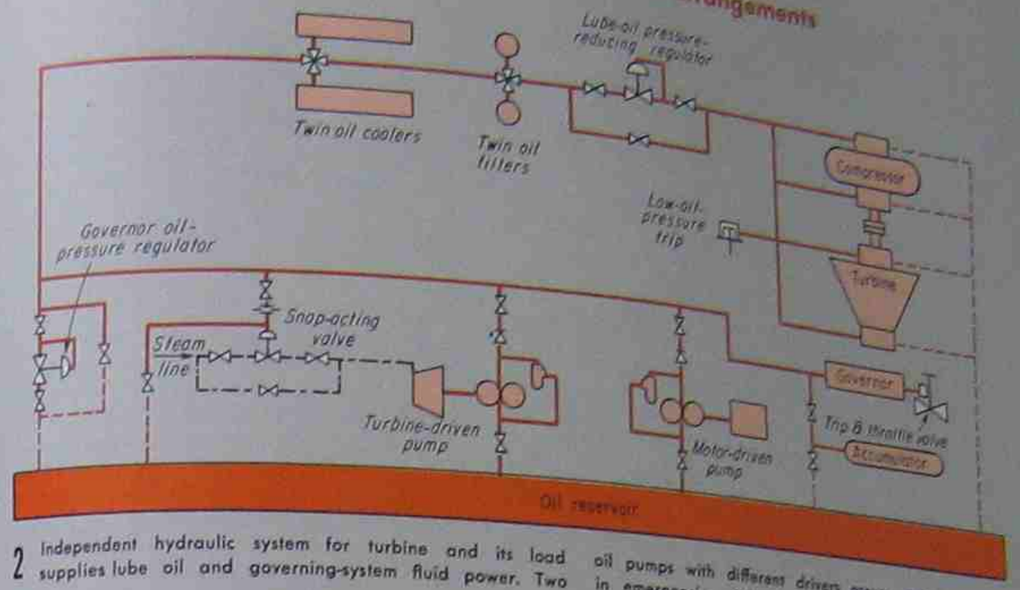
Positive-displacement rotary pumps in Fig. 2 have a flooded suction protected by strainers. The motor-driven pump normally runs with the oil-turbine-driven unit as standby. Bypass relief valves protect pumps and drivers against accidental shutoff of discharge valves. A snap-acting valve automatically brings the turbine-driven standby pump into operation on drop in oil pressure.

Backpressure regulator and reducing valves hold oil-system pressure at operating level. Twin oil coolers and filters in front of the lube-pressure regulator remove heat and clean the oil before it flows to the bearings. At coolers and filters, 4-way valves let one of the elements come out of service so it can be cleaned without shutting down the main turbine.

Oil filters usually are sized to remove dirt particles larger than 3 to 5 mils diameter with a pressure drop of 3 to 5 psi at design temperature and flow. In addition, there's usually auxiliary cleaning and conditioning equipment—either continuous or batch operation.

Various purifying methods may be used. Centrifuging, filtering or settling mechanically separate the contaminants from the oil, but do not cause chemical changes. Adsorbent purifiers using fuller's earth or similar materials and chemical treatments tend to restore neutralization number, but care is needed when using them on oils

from simple oil rings to complex turbine hydraulic arrangements



2 Independent hydraulic system for turbine and its load supplies lube oil and governing-system fluid power. Two oil pumps with different drivers assure continuous oil supply in emergencies. Oil circulates continuously through bearings

containing inhibitors. Heating oil to about 200 F assists in breaking any emulsion. When emulsion persists, oil should be discarded and replaced with fresh lubricant.

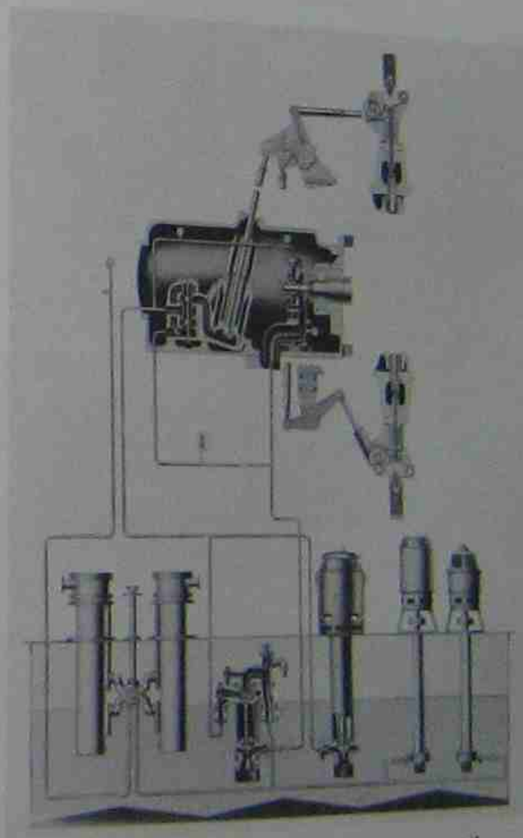
Piping that passes near hot lines or machine parts may be totally enclosed in an outer sheath. If any leak develops in the oil lines, sheath piping drains the leakage back to the oil reservoir. This for safety's sake—most lube oils ignite when sprayed on surfaces at temperatures of 675 F and above.

An alternate solution involves fire-resistant lubricants in the main bearings of large central-station units. Much study has centered on F-R lubes. High cost is one factor, but main deterrent to their adoption by industry has been effect on generator insulation.

Large-turbine hydraulic systems, Fig. 3, have undergone an evolution in the past decade. Their oil reservoirs, usually located in the plant basement, house pumps, regulators, oil coolers and booster pumps or ejectors. Leakage from any of these drains right into the reservoir.

A centrifugal oil pump, directly mounted on the main turbine shaft, is primed by an oil-driven booster pump. Booster mounts below oil level in the reservoir and feeds the shaft-pump suction with oil at 10 to 20 psig. Oil from the shaft pump goes to the small oil-turbine wheel at 200 psig, and that drives the direct-connected booster pump. After discharging from the oil turbine at 30 to 40 psig, oil flows through the coolers on its way to the bearings through a pressure-reducing valve.

This oiling system takes advantage of centrifugal-pump characteristics. Normally it pumps only the bearing's lube needs. Servo mechanism, which needs momentarily large oil flows, goes next to the shaft-mounted pump to reduce size of oil piping between reservoir and turbine.



3 Hydraulic system for large turbine: shaft-driven centrifugal is backed up by motor-driven and booster pumps

These turbine-oil recommendations are typical

Oil properties	Forced circulation: Direct connected	Forced circulation: Gear drive	Ring oiled: Water cooled	Ring oiled: No cooling
Viscosity, ssu, at 100 F	140-170	250-350	250-350	375-525
130 F	76-92	120-165	120-155	180-230
210 F	40-45	47-60	40-45	50-70
Flash point, F	330	350	330	350
Neutralization No.	0.20 max	0.20 max	0.20 max	0.20 max
Oxidation test, hr	1000	1000	1000	1000
Operating conditions				
Min oil temperature before start	50	70	50	—
Bearing inlet temperature, F	110-120	110-120	140-160	140-180
Bearing outlet temperature, F	140-160	140-160	140-160	—

A motor- or steam-driven auxiliary backup pump starts automatically when oil pressure falls below operating level. System in Fig. 3 includes further backup pressure: small ac and dc motor-driven pumps. Ac pump also works as the turning-gear oil pump when the unit coasts down.

Meter orifices in the oil-feed pipe to each bearing divide flow so each bearing gets its adequate share. A basket strainer ahead of each orifice guards against plugging.

As oil drains from bearings and the thrust bearing, some of it flows through an illuminated sight box and over a thermometer. Abnormal operation on any individual bearing can be caught immediately.

Oil should be high quality refined petroleum. It should hold no water, acid, alkali, soap, grit, resin or anything else that might damage it or the turbine parts it contacts. But in case a little water does entrain, the oil should protect ferrous parts of the turbine from rusting. A good turbine oil separates freely from water, has no tendency to emulsify permanently.

Turbine manufacturers usually recommend that the oil vendor undertake responsibility for its conformance to specs, table above. Each manufacturer specifies limits that will satisfy his unit's needs.

Using oils near the upper viscosity limits raises friction losses in the bearings, hence bearing outlet temperatures. Extremely high temperatures speed oil's oxidation rate, abbreviate its useful life. Most satisfactory operation uses the lower-viscosity oils, running with moderate temperatures for longer oil life.

Maintenance of turbine oils means keeping them free of foreign materials that wander into the system. An oil-purification system can be added as accessory to the lube system—it should be checked out with the turbine-oil vendor and turbine manufacturer.

Turbine oil needs a regular analysis to guard against serious lube failure. Analysis reveals progressive changes in oil's properties and possibly system malfunctions.

Water is the frequent oil contaminant; it comes from: (1) steam leakage from shaft glands (2) condensation of moisture in entrained air (3) leaky oil-cooler tubes. Whenever a turbine is idle, its operators should take the opportunity to drain water accumulated in the bottom of the reservoir and other low points of the lube system. Excessive water accumulation should be checked and remedied when found.

Oil foams when it's whipped and mixed with air. Foaming may cause: (1) loss of pressure, which interferes with the control system (2) poor lubrication (3) increased oil oxidation (4) oil overflow and loss. Sometimes just a slight reduction in circulating pressure, or running the oil at a slightly higher temperature, eliminates foaming. Or there may be too much or too little oil in the system.

Additives improve lube performance by inhibiting deteriorating factors. Benefits: longer oil life, cleaner systems, rust prevention and lower wear rates. On the other hand, additives must not affect the oil's base properties.

Grease may be the main bearing lube on a small unit. It's used on many turbine auxiliaries: needle and roller bearings on valve gear, racks and sleeve bearings on control-valve gear, the synchronizing-device gearbox, governor linkage pins and bearings, front pedestal expansion slides and exhaust-hood side feet.

Greases must be high-temperature lubricants, applied by hand, with a pressure gun or by hand-compression cups. They must not separate on standing or when heated below their dropping temperature, must remain solid at operating temperatures, hold together under centrifugal force without separation of soap and oil components. For good operation, grease must resist oxidation, be free of dirt, fillers, abrasives, excess moisture, free acid or lime.

Schedule of oil changes or greasings depends on turbine service and the working environment. Constant vigilance over condition and supply of lube is the price of reliable, continuous steam-turbine operation.

PERFORMANCE varies with turbine cycle

As we've said, turbines convert internal energy of steam into mechanical shaft work, Fig. 1. Amount of energy that steam has available for conversion depends on its initial temperature and pressure and on the way it expands to the lower pressure in the turbine.

A *Mollier chart*, Fig. 2, tells how much energy steam has at each state in terms of enthalpy and how much energy is available for a given expansion. First, the point where the curves for initial pressure and temperature cross tells us enthalpy of the steam h_1 in Btu per lb. Dropping straight down from this point to the curve for the exhaust pressure, we find ideal enthalpy at the exhaust h_{2s}. Then:

Available energy $= h_1 - h_{2s}$

An ideal turbine would convert all this energy to work at 100% *engine efficiency*. Actual turbines can't achieve this high performance. Fig. 2 charts *condition lines* for 100, 75, 50, 25 and 0% engine efficiencies. Energy initially in the steam stays in the steam if it isn't converted to work. We find this by:

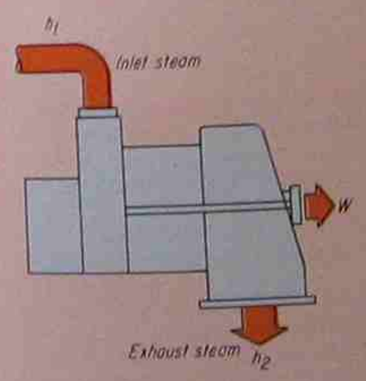
$h_2 = h_1 - (\text{avail energy}) \times (\text{engine efficiency})/100$

Turbine design generally aims for highest engine efficiency compatible with the cost of energy. Engine efficiency also varies for a given turbine with the load it's carrying. Fig. 3 shows the condition line for a single-valve turbine at different loads. As the control valve throttles steam flow with dropping load, steam pressure in the nozzle chest drops. This reduces the available energy and the exhaust enthalpy rises with dropping load.

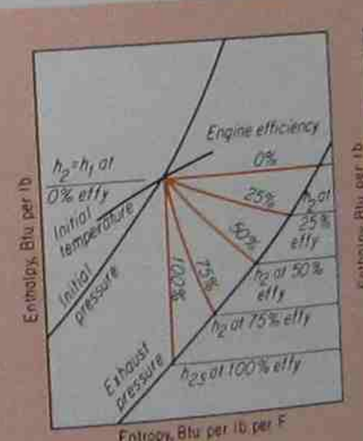
Noncondensing turbines. Fig. 4 shows the variation in available energy in steam used by these units. To find actual work developed, multiply available energy from this graph by engine efficiency. Exhaust moisture will be less than the ideal of Fig. 4.

Fig. 5 shows typical engine efficiencies at rated capacity for single-stage turbines ranging from 30 to 500 shaft hp. Efficiencies rise with both capacity and shaft speed. To find engine efficiencies at half capacity, multiply by the half-load factors.

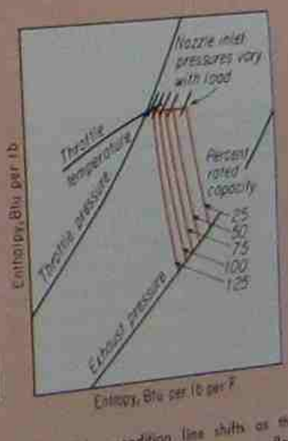
Condensing turbines. Fig. 6 shows the available en-



1 Turbine converts internal energy of steam into useful shaft-work output



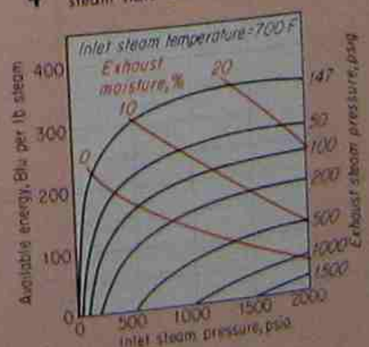
2 Engine efficiency measures available energy changed to shaft-work output



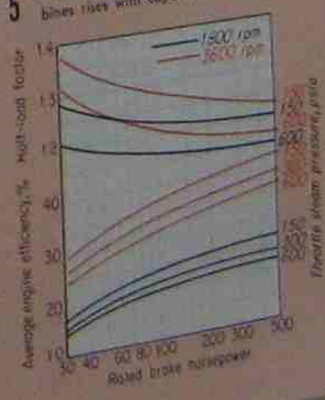
3 Turbine condition line shifts as the governing valve throttles steam flow

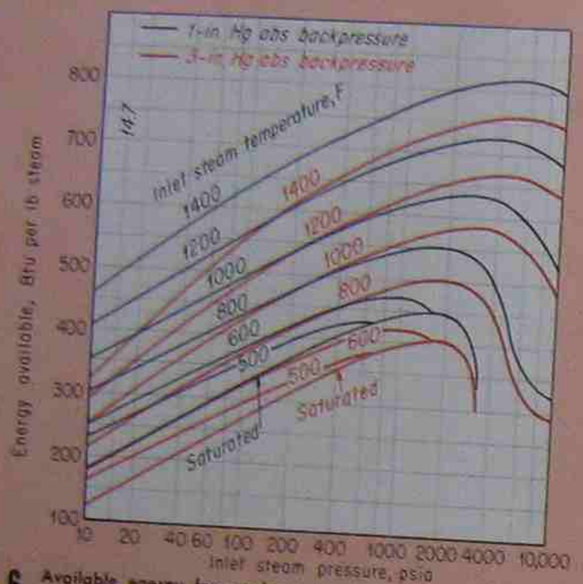
Inlet and exhaust steam conditions fix shaft power generated by a turbine

4 Available energy depends on initial steam state and the exhaust pressure

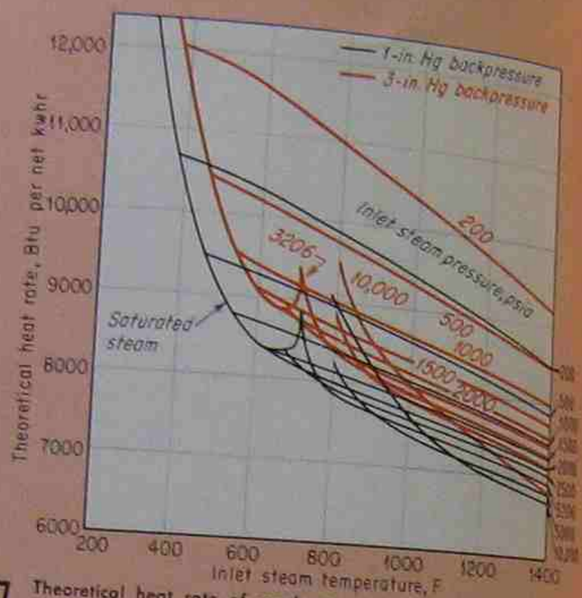


5 Engine efficiency of single-stage turbines rises with capacity, shaft speed





6 Available energy for condensing turbines depends on inlet steam pressure and temperature as well as backpressure



7 Theoretical heat rate of condensing turbines generally improves with rising throttle-steam pressure and temperature

ergy in steam used by these units with 1-in.- and 3-in.-Hg-abs backpressure. The energy generally rises with initial steam temperature and pressure, with some exceptions beyond 5000-psia pressure and around the critical point at 3206 psia and 705 F.

Set of red curves shows that higher backpressure reduces available energy at all inlet-steam levels. In Fig. 6 we see the reason for intensive development of high-pressure high-temperature turbines in the past decade: higher available energy makes better use of expensive materials.

Theoretical heat rates of condensing turbines are charted in Fig. 7, which corresponds to Fig. 6. Theoretical heat rate drops with increasing inlet-steam temperature and pressure. Again, exceptions to this general trend come around the critical-point area. The red curves show that rising backpressure raises the heat rates.

Heat rate relates directly to the overall thermal efficiency of the turbine:

Thermal efficiency = 3413/(*heat rate*)

where heat rate is in Btu per kwhr.

Actual heat rates of condensing turbines can be estimated roughly from Fig. 7: divide theoretical heat rates by the unit's engine efficiency, example on facing page.

Reheat turbines, Fig. 8, have seen wide acceptance in large central stations during the last decade. Here the steam expands in the front end of the turbine. At an intermediate stage, the entire flow passes through a resuperheater in the boiler furnace. Reheated steam then goes back to the turbine at the lower pressure and expands through its remaining stages to the condenser.

Fig. 9 shows effect on ideal-cycle thermal efficiency of reheating at different initial throttle pressures. Throttle and reheated temperatures remain constant at 1000 F at the different pressures. Straight-condensing theoretical efficiency is given at the 1.0 ratio of reheat to throttle pressure (marked *Rankine cycle*).

As reheat pressure drops the thermal efficiency rises until pressure ratio is about 0.3 at 5000 psia, 0.1 at 200 psia. Any further reheat-pressure drop rapidly depresses thermal efficiency. In general, reheating gains about 2% in thermal efficiency. When actual engine efficiencies are considered, relative gain can be larger, about 4 to 5%.

Regenerative cycles, Fig. 10, extract steam from several stages in the turbine to heat feedwater being returned to the boiler. Raising feedwater temperature to highest possible level at h_f means less fuel is needed to evaporate each lb to the throttle-steam state. Amount of heating that the extracted steam can do depends on throttle pressure of the cycle, Fig. 11.

Boiler has to add $(h_t - h_f)$ Btu to each lb of steam. In the straight-condensing cycle, h_f is saturated-liquid enthalpy at the condenser pressure. In the regenerative cycle h_f ideally can be raised to the saturation enthalpy of the throttle pressure (if it's less than the critical pressure of steam, 3206.2 psia).

Fig. 12 shows reduction in straight-condensing-cycle heat rates for a range of throttle pressures and temperatures when feedwater is heated regeneratively to the maximum possible. But these curves assume that heating is done reversibly in an infinite number of heaters. Actual regenerative cycles must be limited to relatively few heaters, so we can't achieve ideal performance. Fig. 13 shows

Estimating turbine performance

Given: 5000-kw turbine, inlet steam at 800 F, 1000 psia; exhaust at 1-in.-Hg abs; engine efficiency of 74%.

Solution: From Fig. 7:

Theoretical heat rate = 8400 Btu per kwhr

Actual heat rate = 8400/0.74 = 11,350 Btu per kwhr

Thermal efficiency = 3413/11,350 = 0.301 or 30.1%

From Fig. 6:

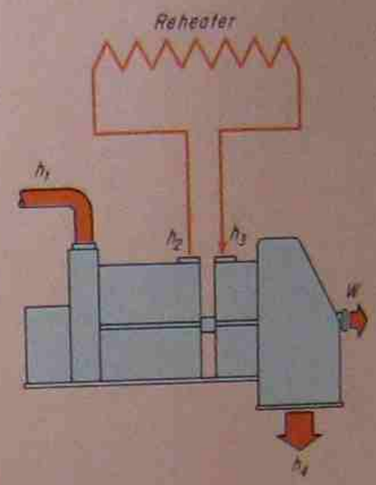
Available energy = 545 Btu per lb

Energy released = 545 × 0.74 = 403 Btu per lb

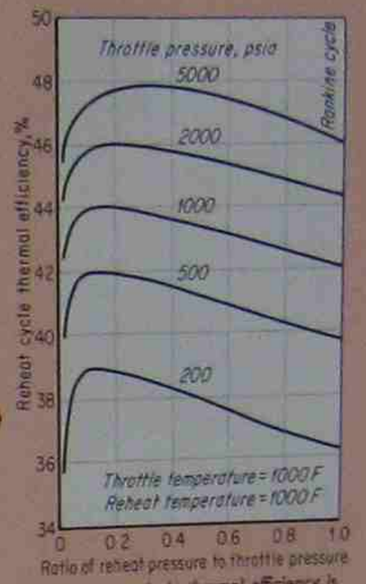
Full-load output = 5000 × 3413 = 17,060,000 Btu per hr

Steam flow = 17,060,000/403 = 42,300 lb per hr

Full-load steam rate of turbine = 42,300/5000 = 8.46 lb per kwhr



8 Reheat turbine has all its steam reheated at an intermediate pressure



9 Maximum gain in thermal efficiency is made with reheats at low pressures

effect of the number of heaters and percentage of possible feedwater enthalpy rise on the actual regenerative-cycle heat rate.

For example, let's assume the 5-mw turbine we were studying, above, has three feedwater heaters. Let's estimate actual heat rate with 1-in.-Hg-abs backpressure in the condenser, feedwater heated to 70% of maximum possible rise.

Straight-condensing heat rate was 11,350 Btu per kwhr. From Fig. 11, maximum possible rise = 495 Btu per lb. Actual enthalpy rise = 495 × 0.7 = 346 Btu per lb. From Fig. 12, theoretical reduction in straight-condensing heat rate = 14.8%. From Fig. 13, reduction for number of heaters and actual enthalpy rise = 0.71. Correction factor for actual regenerative cycle = 1 − 0.148 × 0.71 = 0.895. Then full-load regenerative-cycle heat rate = 11,350 × 0.895 = 10,160 Btu per kwhr.

For any given number of heaters there's a certain enthalpy rise at which economy gain becomes a maximum, as Fig. 13 shows. For higher or lower enthalpy rises the gain will be less. For example, if one heater takes steam from the throttle to produce 100% feedwater enthalpy rise, using main steam gives no economy gain because the heating steam has done no work in the turbine. At the other extreme, a heater tied to the exhaust stage can't do any heating because steam and condensate have the same temperature.

Let's extend our study a little more by finding the heat rate of our 5-mw turbine when it uses ten heaters for feedwater heating to 90% of maximum possible rise. From Fig. 13, heat-rate reduction for number of heaters and actual enthalpy rise = 0.89. Then correction factor for the actual regenerative cycle becomes 1− 0.148 × 0.89 = 0.868. Full-load 10-heater regenerative-cycle heat rate becomes 11,350 × 0.868 = 9850 Btu per kwhr. Adding (10 − 3) = 7 heaters reduces the heat rate by (10,160 − 9850) = 310 Btu per kwhr.

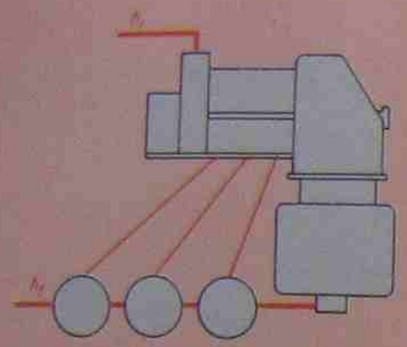
To decide on number of heaters, we would have to compare carrying charges on the extra heaters and piping to the reduction in annual fuel costs. If saving is greater than carrying charges, the larger number of heaters would probably be justified.

Reheat-regenerative cycles combine steam-reheating and regenerative-feedwater-heating principles to achieve high overall thermal efficiencies. Coupling high efficiencies with high throttle pressures and temperatures, these modern turbine cycles appear to be trending to the ultimate in overall thermal performance.

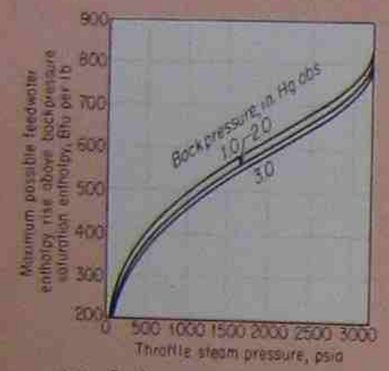
Fig. 14 shows full-load heat rates that can be achieved by turbines ranging in capacity from 100 to 500 mw, with throttle pressures from 1000 to 6000 psig. Initial and reheat temperatures are kept at 1000 F for all units and backpressure is constant at 1.5-in.-Hg abs. All units use six stages of regenerative feedwater heating. Their gross heat rates are figured on generator-terminal outputs. Deducting feedwater-pump energy input from generator output gives net heat rates.

Difference in these curve families shows large work input the feedwater pump needs at high throttle pressures. Taking this into account, we find that optimum net heat rate for the 100-mw unit comes at about 3400-psig throttle pressure. Best pressure for the 500-mw unit: about

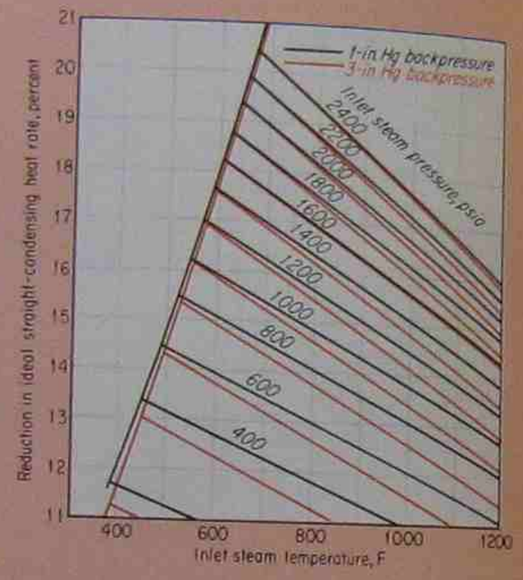
Regenerative cycles conserve energy



10 Regenerative heating cycle extracts steam to heat returning feedwater



11 Feedwater can be heated through higher ranges as steam pressure rises



12 Rising steam pressure improves gain in regenerative-cycle heat rate, but that's offset by rising inlet-steam temperature

4400 psig. Spread of the curves shows performance gain that can be made by going to larger-capacity units at higher throttle-steam pressures. Capacities, steam conditions, cycles, investment and fuel costs—all must be carefully coordinated to arrive at best choice for a central-station generating unit.

Typical large condensing turbines vary in their heat-rate performance with changing load and different backpressures, Fig. 15 to 18. As units become larger and steam conditions higher, heat rates over the range of outputs become lower and lower. This is partly because of larger size, partly because higher steam conditions can be justified for the larger units, Fig. 14. This gives them an inherent thermodynamic advantage.

In Fig. 15 to 18, heat rates are usually minimum near maximum capacity. This follows because throttling isn't needed to control steam flow at full load, Fig. 3. As drawn, these curves are the *mean of valve loops*. The true curve shows a series of concave downward loops that reach a minimum where valves of a nozzle chest are fully open. In contrast, at loads where the valve is just starting to crack open there's a large throttling loss; curve takes a sudden jump upward. Our curves show the overall trend, but true heat rates may be about 2% different from the trend at the valve-opening and mid-valve points.

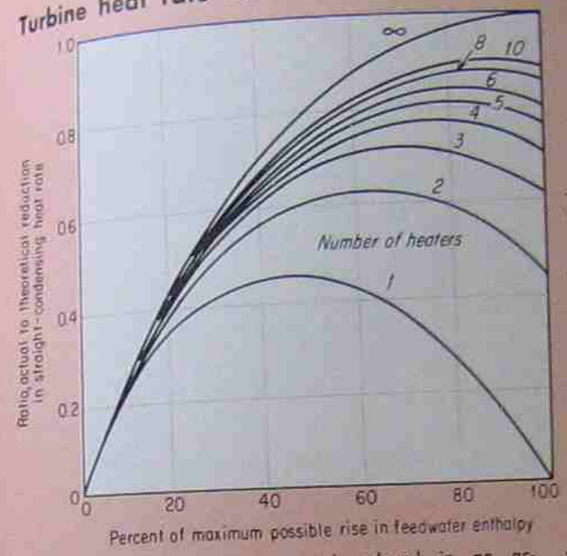
Mechanical-drive turbines often run at variable speed, in contrast to the central-station units running at constant speed. The m-d turbine's shaft output largely depends on shaft speed. Fig. 5 shows engine efficiencies usually achieved by single-stage m-d turbines.

Fig. 19 charts throttle-steam flows for a multistage and a single-stage m-d turbine. Upper scale shows corresponding shaft speed for the shaft output plotted below. Plot of steam flow vs output is called a *Willans line*. For a constant-speed single-valve turbine this line is almost straight. But as we see here, the Willans line becomes curved for variable-speed turbines.

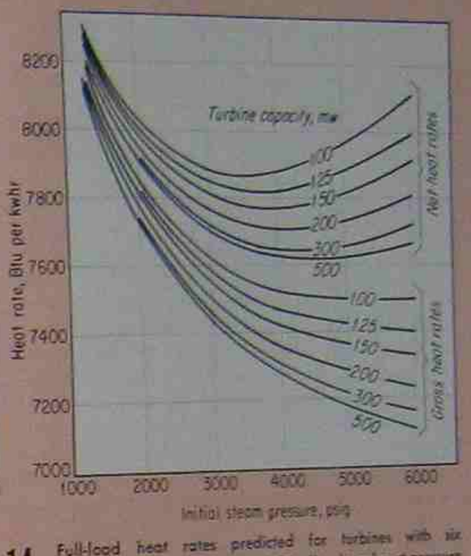
This comparison shows that for the given steam conditions with both turbines exhausting at 150 psig, the single-stage turbine is more efficient at low loads and less efficient at high loads than the multistage unit. Choice between turbines for a given application can only be made after a close study of operating conditions.

Automatic-extraction turbines can be used when both electric power and process steam are needed at the same time. If process steam is needed at two different pressures and electric-energy needs are equal to, or less than, energy available from process-steam flow through a turbine, a noncondensing single-automatic-extraction turbine can be used. However, if electric-energy needs are higher than process-steam flows can generate, a condensing double-automatic-extraction unit should be used.

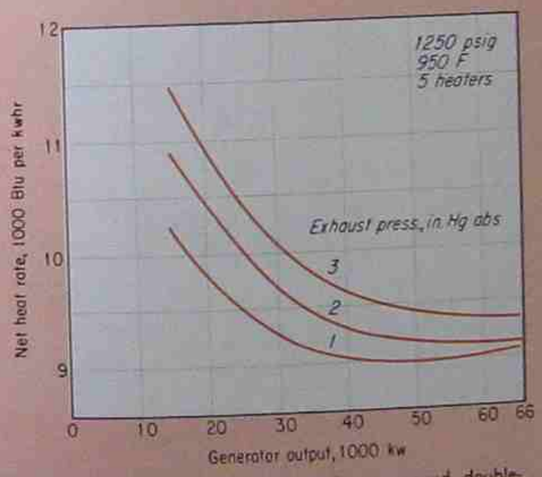
Turbine heat rate varies with load and steam cycle



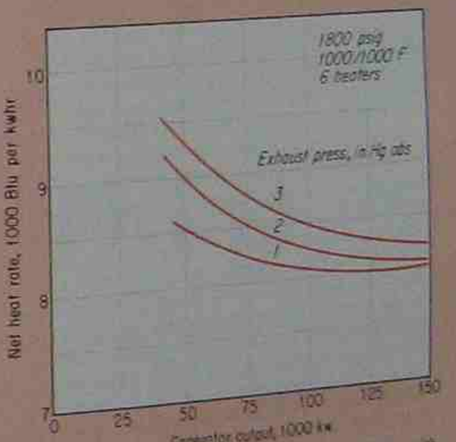
13 More extraction points, properly placed in an actual turbine regenerative cycle, improve the heat rate



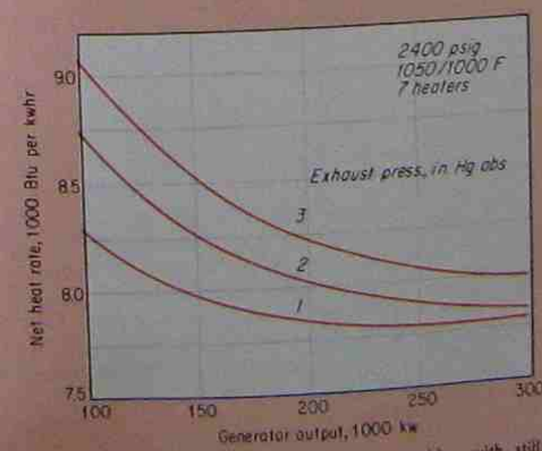
14 Full-load heat rates predicted for turbines with six heaters, 1000/1000-F steam, 1.5-in.-Hg-abs exhaust pressure



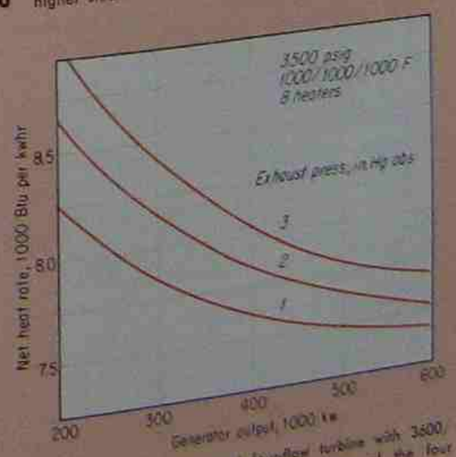
15 Typical heat rates of 66-mw tandem-compound double-flow 3600-rpm unit vary with load and backpressure



16 A 150-mw tandem-compound double-flow turbine with higher steam conditions works at lower overall heat rates



17 A 300-mw tandem-compound four-flow turbine with still higher inlet steam shows more heat-rate improvement



18 A 600-mw cross-compound four-flow turbine with 3600/1800-rpm shafts shows best performance of the four

Performance of automatic-extraction turbines is given in terms of steam flow, both throttle and extraction, versus shaft output in hp or kw. Heat rate of the energy produced by noncondensing automatic-extraction turbines does not vary greatly. Energy chargeable to the turbine is only the relatively small amount "skimmed off" the steam before it flows out through extraction and exhaust openings to the process lines.

Condensed-steam energy of condensing automatic-extraction units is charged to the turbine. So most efficient generating condition comes at maximum-extraction flows (the same as minimum exhaust-section flow). For a given kw output, throttle flow is maximum when extraction is maximum and heat rate minimum; conversely, throttle flow is minimum and heat rate maximum at zero extraction.

In sample performance curve of a condensing single-automatic-extraction turbine, Fig. 20, the family of parallel curves defines required throttle-steam flow at given kw output and extraction flow. Each parallel line is the turbine's Willans line at a constant value of extraction flow. Lower ranges of kw output limit amount of steam that may be extracted.

When output is all produced by extracted steam, exhaust section of the turbine is idle. Then the blades churn steam trapped in these stages and rapidly raise its temperature to a point where the blades may fail. To prevent this, a small "cooling" steam flow is sent through the exhaust section to keep blading temperature at a safe level. Cooling steam carries off windage loss of the idle blades.

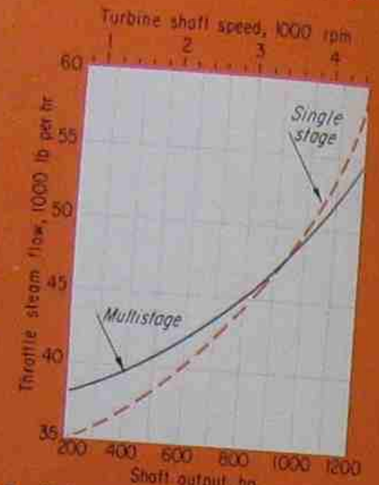
In Fig. 20, the *minimum flow to exhaust* curve shows relation between kw output produced on extracted steam alone and corresponding throttle-steam flow. This curve intersects each of the constant-extraction-flow curves at the throttle flow that equals sum of the cooling steam and extraction steam. In expanding through the first section of the turbine from throttle to extraction stage, the cooling steam does its share of work. But in passing through the exhaust section from extraction stage to exhaust flange it doesn't do any work—only cools last-stage blading.

Exhaust sections often pass just as much exhaust flow as needed to produce rated output at zero extraction. Additional output in the overload range can be generated by admitting more steam at throttle and extracting it. This is the *maximum flow to exhaust* curve. Other limits are *maximum throttle flow* and *maximum generator output*.

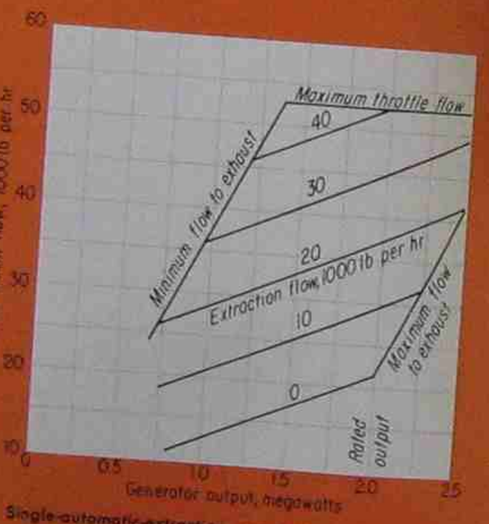
Fig. 21 shows performance curves for a condensing double-automatic-extraction turbine. The second extraction opening needs an additional family of curves on the chart. Two more limits must be considered: *minimum* and *maximum flow to intermediate section*. These depend respectively on cooling-steam-flow need and maximum steam-flow capacity of the intermediate section ahead of the turbine exhaust section.

POWER gratefully acknowledges the willing assistance of engineers of the many steam-turbine manufacturers, who patiently assembled basic data for this report.

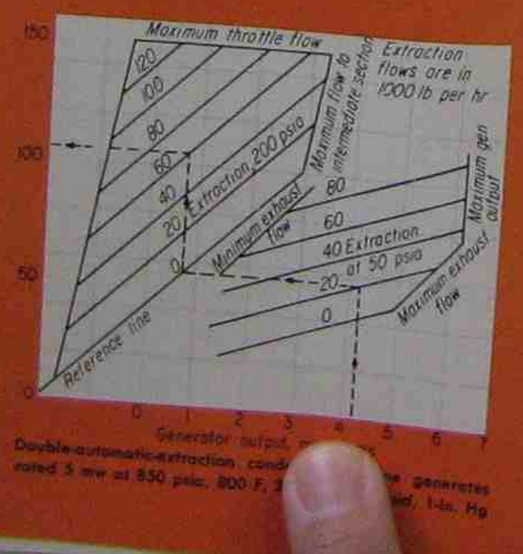
M-d and auto-extraction units show these typical performance curves



19 Performance of single- and multi-stage unit: 400 psig, 650 F, 150 psig



20 Single-automatic-extraction condensing turbine generates rated 2 mw at 600 psia, 800 F, 200 psia, 2-in. Hg abs



21 Double-automatic-extraction, condi... generates rated 5 mw at 850 psia, 800 F, ... id, 1-in. Hg

Fuels and Firing

By L N ROWLEY, *Managing Editor*, J C McCABE and B G A SKROTZKI, *Associate Editors*

From those dawn times when our hairy ancestors squatted about a flame before a cave, fire has been an intimate associate. It gave cozy warmth and kept back the creeping dark. It smelted ores, made metal malleable for forging. In later days it generated steam and pushed mightily on engine pistons.

No wonder the ancients viewed fire as one of the "elements," along with the other cornerstones of their world—earth, air and water. No wonder fire has been and still is worshipped by savage peoples. No wonder traces of that age-old feeling appear in our sentimental appreciation of a glowing hearth.

Down through the centuries, as fire came ever to play a greater part in man's life and work, the nature of "burning" remained secret. Not until the classical experiments of Lavoisier, Priestley and other 18th-century scientists swept aside the mystical ideas of the Middle Ages did the process stand revealed as a reaction with oxygen from the air.

From that time on we have gained steadily in our knowledge of burning. Learned that it is more complex chemically than we first thought. Learned that good combustion is mainly a mechanical problem. Learned many practical things about fuels and efficient firing. Learned above all how little we know.

Today the reaction by which fuel and oxygen combine and give off heat is still the most important single process in our universe. Heat is the power engineer's stock in trade and combustion a process he lives with daily. As fuels become ever more expensive to obtain, and as energy demands skyrocket, nothing is more necessary than an understanding of the manner in which fuels burn and how to put them to work with peak effectiveness.

To aid that understanding is the aim of this special section, POWER's 70th. In 48 practical pages, it tells how fuels burn, gives facts about commercial fuels, describes firing equipment, shows how to select fuels wisely for new plants and old, and outlines short-cut methods for checking efficiency.

How Fuels Burn

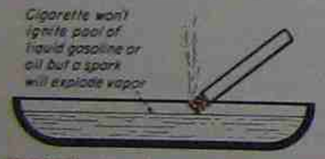
All around us, at all times, oxygen combines with other elements. Iron and oxygen combine to form the *oxide* we know as rust. Silver tarnishes, copper takes on a soft green oxide coat. This general process is *oxidation*. Burning, or *combustion*, is a special form of oxidation. In it, oxygen combines rapidly with materials we call *fuels* and substantial amounts of heat are liberated.

Under some conditions, combustion may be self-starting. For example, coal piled outdoors combines slowly with oxygen in the air, giving off heat. If the heat doesn't get away, temperature rises, the reaction speeds up and eventually becomes rapid enough to be called burning.

How Burning Starts.

Such *spontaneous combustion* is relatively uncommon. We are more familiar with combustion that begins with heat applied from some outside source. A fire laid in the grate will not light itself. Nor, for that matter, will a match. We start the burning process by striking it to generate friction heat enough to set it aflame, then use the flame's heat to light kindling, and the kindling's heat to start the logs. This process of using an easily ignited object to provide heat for ignition of another is common in engineering.

We are all aware that some things burn more readily than others. In general, this depends on how easy it is to turn the particular substance into a gas, because *nothing truly burns unless or until it is a gas*. This, in turn,

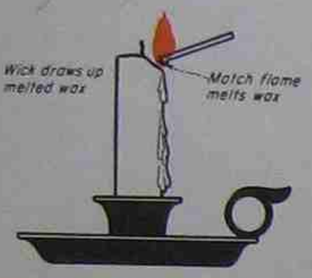


Nothing burns unless or until it is a gas

depends on the nature of the substance and on its amount compared with the amount of heat available to start the process. It's easier to start wood burning than coal, and easier to ignite a twig than a log.

A candle illustrates the point well. To make wax burn, we turn it into a gas. With a wick, heat from a match flame does the trick easily; without a wick it can't be done. Why? Without a wick, the match's heat is so small in comparison with the mass of wax that it can do no more than melt a little. None is vaporized, because there just isn't heat enough. Adding a wick changes the picture.

The wick draws up, by capillary action, an amount of melted wax so small in relation to the match flame that enough heat is available to raise the wax to the temperature needed for vaporization. Once wax is vaporized,



Wick draws up melted wax by capillarity

or made like a gas, burning is relatively easy to start. Burning the wax gives off enough heat to continue the process of melting, vaporizing and igniting.

Although the wick is eventually consumed, it contributes nothing to the burning. It is a purely mechanical device to create conditions needed to start and maintain combustion. It finds its counterpart in burners, stokers and furnaces, for while combustion is essentially a chemical reaction, most practical problems of fuel burning are mechanical.

Combustion of Gases.

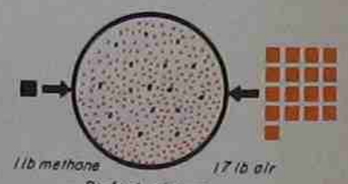
Since our fuels burn as gases, or as if they were gases, we need some acquaintance with the rules governing combustion of gases. Assume we have a gas, either a fuel that is normally gaseous, or a gas given off from a solid or a liquid fuel. In burning this gas, or any gas, it is first necessary to have a gas-air mixture that will ignite and then to raise this mixture to the ignition temperature and hold it there. Let's look first at this business of combustible mixtures.

To start with, we are working with two basic fuel elements—hydrogen and carbon. Sulphur and some other elements burn and give off heat, but common practice considers the reactions negligible and the elements impurities. Hydrogen is normally a gas and can only be liquified at an extremely low temperature—more than 400 F below zero. On the other hand, carbon is a solid that cannot be completely vaporized at temperatures much under 6300 F. Heating values are high: 62,000 Btu per lb for hydrogen and 14,500 Btu per lb for carbon.

Carbon and hydrogen exist in almost innumerable combinations called *hydrocarbons*. Many of these compounds, like methane (CH_4), are normally gaseous and form a major part of most important fuel gases.

Air Required.

Although the form in which these two elements appear in any actual fuel is vastly important to its burning, as we will see later, it makes no difference from the chemical balance-sheet angle. The important thing here is that each element or compound needs a certain amount of oxygen for complete combustion. It thus becomes easy (see p 114) to figure exactly how much oxygen we must have to burn a given amount of gas and, further, just how much air we need. If we mix exactly this much air with the gas we have a *perfect* or *theoretical* mixture. The relation be-



Perfect-mixture amounts for air, methane

tween gas and air is called the *fuel-air ratio*. This is usually expressed by weight. For any particular fuel, this ratio can be figured from the chemical analysis.

Ignition Temperature.

Now we have a combustible gas and the exact amount of air to burn it completely. We need still another element—heat. If such a perfect mixture is heated gradually, rate of chemical combination increases until a point is reached where the reaction no longer depends on heat from an outside source and practically instantaneous combustion occurs. Lowest temperature at which this happens is the *ignition temperature*. It may be defined as the temperature at which heat is generated by the reaction faster than it is lost to the surroundings, and combustion thus becomes self-propelling. Below this point the gas-air mixture will not burn freely and continuously unless heat is supplied to it.

Actual ignition temperature depends to some extent on surrounding conditions, and the term usually refers to

combustion in ordinary air. Among other factors, pressure affects ignition temperature, which is lower at high pressures.

These statements apply equally to mixtures that are not perfect, that is, to mixtures a little leaner or a little richer than perfect. But for each gas there is a point where the mixture becomes too lean or too rich for ignition and continued burning. Almost every automobile owner has cussed a flooded carburetor that produced too rich a mixture and made starting difficult. Most of us have also seen the same engine miss fire when the carburetor is adjusted for too lean a mixture. Thus, for each gas there is a range of mixtures that will ignite and continue to burn. These are called *inflammable mixtures*. Limits of this range are known as limits of inflammability.

Practical Mixing.

Thus far we have looked at this business of mixtures and burning as if the right amount of gas was mixed with the right amount of air, and the entire mixture heated and burned in one operation. In actual practice this happens only rarely. Nearest approach is in the cylinder of a gas engine. In



Gas engine has near-perfect mixture

boiler firing, and other furnace work, we meet not with a single mass of ready-made gas-air mixture but rather with air and gas streams, which must be brought together and heated somehow to start and maintain ignition. The way this mixing is accomplished, and its effectiveness, makes all the difference in the nature of combustion and its completeness.

The familiar Bunsen burner of the laboratory and the fishtail burner once used in gas-lighting systems show up these differences clearly. The Bunsen burner displays a relatively small, blue, *nonluminous* flame, while the fishtail burner shows a larger, yellow, *luminous* flame. With the same gas, why the difference?

Yellow-Flame Burning.

The answer lies in the way air and gas mix, and shows clearly how the time and place of this mixing affect the process by which the fuel elements, particularly the hydrocarbons, burn. In the fishtail burner, gas flows through a slotted opening in a thin flat stream. The dark area near the burner tip is



Fishtail gas burner shows yellow flame

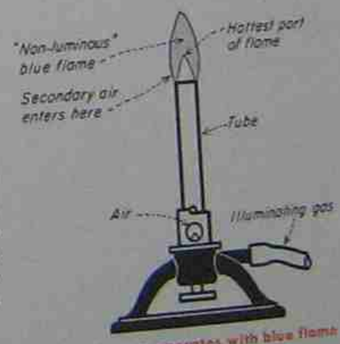
cold gas in the process of picking up and mixing slightly with air. Suddenly the mixture reaches correct proportion and starts to burn rapidly only a few hundredths of an inch from relatively cold, too-rich mixture.

Here we run into an action commonly known as "cracking" or, more fully, *thermal decomposition*. When hydrocarbons are subjected to high temperature they crack or break down chemically into other carbon and hydrogen combinations and eventually into the basic ingredients, carbon and hydrogen. This is what happens to some of the gas near the edge of the flame where heat is intense. The cracking action sets free hydrogen, which burns in the flame, and carbon particles, which glow to incandescence and make the flame yellow and highly visible.

Normally carbon burns out pretty well by the time it reaches the flame edge. But if we put any cold object in the flame, the carbon particles are chilled and the burning stops. Resulting deposit of lamp-black or soot is identical with similar deposits in boilers. If these microscopic particles of carbon "that didn't finish burning" stay suspended in the products of combustion, we have *smoke*.

Blue-Flame Burning.

In the Bunsen burner, gas issues from a small jet at the base of a mix-



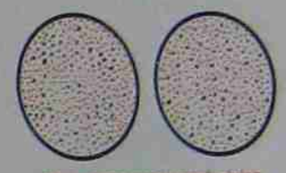
Bunsen burner operates with blue flame

ing tube. Air is drawn in through a side opening. Gas and air mix before reaching the flame area and the result is a nearly colorless "blue" flame.

The secret lies in the fact that gas and air mix before reaching the combustion zone and are heated more slowly than in the fishtail burner. This gives oxygen a chance to penetrate the hydrocarbon molecules and form oxygenated compounds. The process by which oxygen associates with hydrocarbons is known as *hydroxylation*. As will be explained more fully later, the new compounds thus formed burn with an entirely different flame. There is no cracking and no carbon is formed. Thus a change in the point of mixing, and rate of applying heat, produces an entirely different burning process.

Good Mixing Vital.

This simple example yields several ideas of great importance in this combustion business. First is the key part played by mixing. In actual flames and combustion spaces we have widely different mixtures side by side. In one area the mixture may be too rich to burn, as it was close to the tip in the fishtail burner. In other areas we may



Poor mixing versus good mixing

have almost all air and hardly any fuel. This unsatisfactory situation may prevail even though the average relation of fuel to air over the entire space may be correct for good burning. By evening out these inequalities, thorough mixing makes the actual furnace condition more nearly like the "statistical" average.

The example also shows what happens when carbon breaks away from its compounds. Microscopic particles formed are carried along in the stream with little or no motion relative to the air. This makes them extremely difficult to burn even if the process is not stopped, as by chilling.

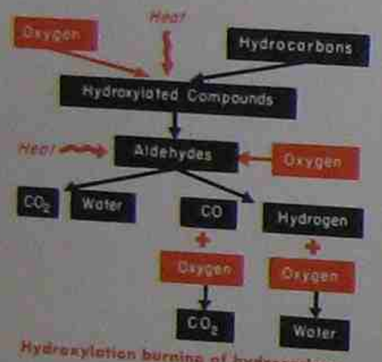
Finally, and perhaps most important, we see that combustion is not quite so simple as it seems. It is true that we start with only two fuel elements, and that by simple equations we can show that they combine with oxygen to form water, carbon dioxide and, under some conditions, carbon monoxide. This is much like saying that two men traveling from New York to Chicago have identical journeys. Their experiences would depend on how they went, and by what route, and only by knowing these could we tell something about their trips.

Burning Hydrocarbons.

Burning of gaseous hydrocarbons is a good case in point. Complete analysis

of flue gas from gas- and oil-fired furnaces often reveals presence of chemical compounds known as *aldehydes*. Formaldehyde is a fairly familiar member of this group. Nothing in our simple carbon-to-carbon-dioxide and hydrogen-to-water reaction explains the presence of these compounds. How did these strangers get into the parade?

Part of the answer lies in our comparison of two types of gas burners. Under one set of conditions, as we have seen, oxygen associates with the hydrocarbon molecules, producing *hydroxylated* compounds that are unstable. These form aldehydes which, in turn, break down or oxidize until formaldehyde is produced. What happens next depends on how much oxygen is present. Formaldehyde may break down with heat to form carbon monoxide and hydrogen, or it may burn to water and carbon dioxide or carbon monoxide. Any carbon monoxide and hydrogen formed burns in the normal way.

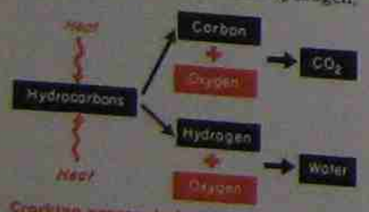


Hydroxylation burning of hydrocarbons

So it is clear that quite a few changes occur between the beginning and end of the burning operation and that many intermediate products form and disappear. If combustion is incomplete, some of these compounds remain and show up in the flue gas. The faint acrid odor sometimes observed indicates the presence of one group of intermediate compounds, aldehydes.

Cracking Process.

From our gas-burner example, we also saw that under different conditions, hydrocarbons are cracked instead of hydroxylated. Such cracking breaks them down into carbon and hydrogen.



Cracking process in hydrocarbon burning

which burn to carbon dioxide and water. We have seen that it is the incandescent carbon which gives such a flame its characteristic yellow color, and it is the carbon which gives it soot-and-smoke-forming propensities.

We have talked about these two ways hydrocarbons burn as if they were entirely separate. In virtually all practical burning of hydrocarbons, however, both processes go on simultaneously and the general character of the flame depends on which predominates. This, in turn, depends on surrounding conditions. Early mixing and preheating of hydrocarbons and air, plus time for the oxygen molecules to enter the hydrocarbon molecules, favor hydroxylation. Rapid heating, and lack of mixing time, favor thermal decomposition.



What fixes nature of hydrocarbon flame?

We've belabored this business of hydrocarbons for two reasons: (1) Biggest part of practical combustion work involves them; natural gas and oil are hydrocarbon fuels, so is the volatile matter of coal. (2) It shows clearly that while our familiar chemical equations for combustion are useful in calculating air requirements, etc, we must know more about what happens between the starting point and the finish if we are to design and operate successful firing equipment and furnaces. *The actual combustion process may consist of several reactions and their nature depends on the form in which the basic elements carbon and hydrogen appear in the fuel, and the way burning takes place.*

Elementary Fuels.

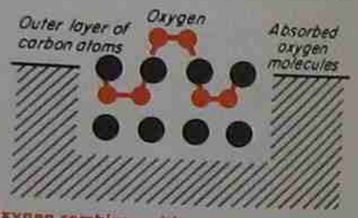
Thus, to understand practical combustion problems we must take a look at each of the forms in which carbon and hydrogen appear in commercial fuels and the steps through which they pass in burning. This isn't as tough as it sounds, since for our purposes we can consider all complex fuels as combinations of three simple or elementary fuels: (1) gaseous hydrocarbons (2) solid carbon and (3) mixture of carbon monoxide and hydrogen. Each of these general groups contains a variety of fuel substances which differ in minor respects (charcoal and coke in the solid-carbon class, for example), but each group displays a generally similar pattern of combustion.

Some commercial fuels are simple mixtures of these elementary fuels. For example, coal gas is essentially a mixture of gaseous hydrocarbons and carbon monoxide plus hydrogen. With other familiar fuels, our elementary fuels come into being during the burning process; fuel oil volatilizes into gaseous hydrocarbons before actual combustion. Some cracking may also occur, yielding solid carbon and hydrogen.

Coal is another fuel that decomposes into elementary fuels before actual combustion starts. When first exposed to the fire's heat gaseous hydrocarbons, carbon monoxide and hydrogen are distilled off, leaving solid carbon behind. Hence to know what actually happens when coal burns we must know the individual burning processes of all three elementary fuels.

How Carbon Burns.

We've got the toughest of these under our belts, having already seen how gaseous hydrocarbons burn. The way carbon burns has puzzled the experts for many years but careful experiments seem to back up the current theory. This assumes that oxygen penetrates the carbon surface to break away atoms which hook up with the oxygen



Oxygen combines with outer carbon atoms

in a loose sort of carbon-oxygen compound that is unstable. It is not a true chemical compound because proportions of carbon and oxygen atoms are not fixed, nor is it entirely a mixture, since the oxygen cannot be driven off. Depending on temperature and other conditions, this *physiochemical* compound breaks up into carbon dioxide and carbon monoxide. If there is an excess of oxygen, carbon monoxide is oxidized to carbon dioxide. If carbon is in excess, dioxide is reduced to monoxide.

Burning H_2 and CO.

Hydrogen and carbon monoxide are grouped together as an elementary fuel because they commonly occur together and their burning processes are alike. In ordinary combustion work, conditions are such that both burn according to the familiar simple reactions:

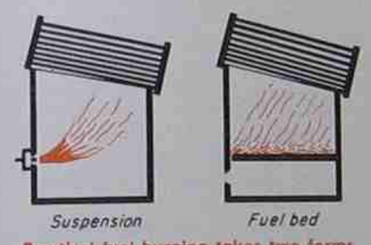
$$2H_2+O_2=2H_2O$$
$$2CO+O_2=2CO_2$$

Hydrogen burns more than 2.5 times as fast as carbon monoxide when they burn together with excess oxygen.

Actual Firing Job.

Now, with these fundamentals out of the way, we're primed to tackle the job of burning commercial fuels in actual furnaces. Just what is this job? In broadest terms, it includes: (1) preparing the fuel and air (2) converting the complex fuel into elementary fuels (3) bringing these fuels and air together in the right proportions and at the proper temperature for ignition and combustion, and (4) transferring heat from the products of combustion to the boiler or other surfaces while retaining enough heat in the combustion zone to maintain volatilization and ignition. All these actions are going on at the same time in any furnace, and each particle of fuel traces the entire sequence, in order, in its brief passage through the furnace.

Broadly speaking, there are two ways to handle this job: (1) in *suspension* or (2) on a *fuel bed*. Let's look at both



Practical fuel burning takes two forms

to see how they differ and, more important, in what ways they are alike.

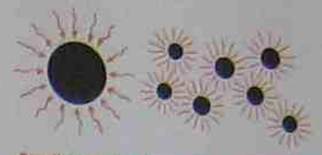
Suspension Firing.

When we think of suspension, or *burner firing*, gas comes immediately to mind as the simplest example. Here we have a fuel already in the gaseous state, ripe for quick mixing with air. Gas burners thus need only proportion the volume of air and gas to insure thorough mixing. As we shall see later when examining actual burner designs, they differ mainly in how and when this mixing occurs.

Burners for oil and coal, in addition to proportioning fuel and air, and mixing them, must *prepare* the fuel. For oil, this means making it ready for conversion from liquid to gaseous hydrocarbons. For coal, it involves distilling off the volatile matter (gaseous hydrocarbons again, plus hydrogen and carbon monoxide). This must be done in the instant after the fuel enters the furnace.

Preparing Fuel.

It is the furnace heat that does the conversion; job of the firing equipment is to put fuel into shape that makes best use of this heat. For suspension firing of both oil and coal the answer is the same—it must be broken up into many small particles to expose as


Small particles show more area to heat

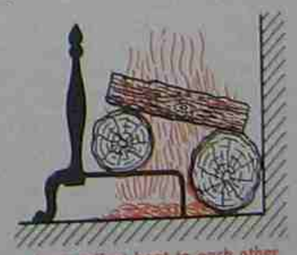
much surface as possible. With oil, *atomization* is obtained in a variety of ways by the burner; with coal *pulverization* is handled in a separate unit, the burner merely mixing the finely ground particles with air and injecting them into the furnace.

In addition to small particles, we need fast motion between particles and air to strip away the microscopic "coats" of gas that form on the particles and thus expose fresh surfaces to heat and air.

Furnace's Job.

The furnace takes over where the burner leaves off, providing the conditions for continuous complete combustion. Within the combustion zone, fuel must be vaporized or distilled, mixed with air, ignited, and the resulting reactions between fuel and oxygen carried to a finish. Chief responsibility for bringing fuel and air together rests with the burner; the furnace can do little to correct failure of the burner in this respect. On the other hand, the heating and igniting job is predominantly the furnace's.

The difficulty met in trying to burn a single log in a fireplace illustrates the part played by good furnace design. As anyone who has tried will testify, a single log is one of the hardest things in the world to keep burning, while a number of logs will blaze merrily. The answer lies in the fact that

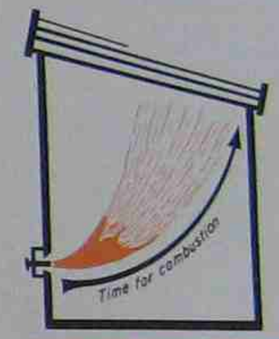

Logs reflect heat to each other

when there are several logs, each reflects heat to the others, for distillation of volatile matter and ignition. In the same way a furnace must maintain a heat supply to prepare and ignite incoming fuel.

Soot and Smoke.

With either coal or oil, some carbon formerly associated in hydrocarbon compounds breaks away as free carbon and, of course, a substantial part of almost coal is solid carbon. Thus we always have the problem of burning carbon particles, which, as we have seen, proves extremely difficult even with ample time. Here is the germ of smoke and soot. Naturally, if the furnace is small and cold areas (boiler tubes and the like) are badly located, carbon cannot possibly burn to completion.

All these steps—bringing air and fuel together, raising mixture to ignition temperature, sweeping away successive layers of gas from fuel particles, burning carbon as far as possible – occur while fuel and air travel from burner to furnace outlet, an extremely short



In combustion, time equals distance

time. Just how much depends on the distance traveled and the speed, and whether or not flow is *turbulent*.

Turbulent Mixing.

By turbulence, we mean a condition in which fuel and air whirl and eddy in irregular paths instead of flowing in streamlines from burner to furnace outlet. This has several beneficial effects: (1) There is an increase in the time available for combustion. (2) Better mixing of fuel and air results. (3) Fuel and air move past each other at higher velocity, thus helping to sweep away combustion products and expose fresh surfaces. It has been well said that successful combustion depends on three "T's"—Temperature, Time and Turbulence.

Ash and Slag.

So far, we have ducked the question of mineral impurities (ash) found in many fuels and particularly in coal. These, of course, do not burn. In suspension firing, if nothing else happened, some particles would be carried out of the furnace with the gas stream (*flyash*) while others would drop out of suspension in furnace or boiler passes. This simple picture is complicated by the fact that, depending on the nature of the ash, and to some extent on surrounding conditions, ash becomes plastic and sticky. If it comes in contact with relatively cold surfaces while in this plastic state it forms *slag* coatings, reducing rate of heat trans-

fer, hindering flow of gases through boiler passes, and creating a maintenance problem. Later, in pulverized-coal firing, we'll see some practical steps to avoid such slagging difficulties.

Fuel-Bed Firing.

After this quick run-through of suspension-firing fundamentals we're ready to take an equally quick look at fuel beds. In this kind of firing, fuel is pushed, dropped or thrown on a grate in a high-temperature region within the furnace. Air flows upward through the grate and through the fuel bed that forms on it. The "green" coal is heated, volatile matter distills off and coke is left on the grate. Coke burns to a mixture of carbon dioxide and carbon monoxide, and ash remains.

The volatile matter of the coal, and the carbon monoxide from the coke burn over the fuel bed with air that has come up through it and, usually, secondary air admitted to the furnace over the grate. Thus anywhere from 40 to 60% of the coal's heat is liberated over the fuel bed. We thus see that burning gases is still a big part of the job even with fuel-bed firing.

To help understand what happens in the fuel bed, divide it into four zones, one above the other. In actual beds, location and shape of these zones varies depending on grate construction and how the fuel reaches it. For simplicity, we can visualize the beds as more or less uniform layers extending across the grate. From top down, these zones are: distillation, reduction, oxidation and ash.

Fuel-Bed Zones.

At the top, green coal receives furnace heat, volatile matter distills off, and the coke thus formed works down through the bed as lower layers burn out and new coal is added. In the oxidation zone, coke is burned to carbon dioxide with the primary air rising through the bed. This carbon dioxide travels up through the zone above and is partly reduced to carbon monoxide by contact with hot coke. The layer of ash at the bottom protects the grate from excessive heat.

Oxygen in the primary air is pretty much used up a few inches above the grate, this being the oxidation zone. If it were not for air that rises rapidly through blowholes and leaks around edges, there would be little oxygen above this point except that brought in with secondary air. Increasing amount and velocity of primary air speeds up burning but does not alter the fact that oxygen is largely consumed a short distance above the grate.

Only a little carbon monoxide is formed until all oxygen is gone, but rate of CO formation becomes rapid immediately this point is reached, that is, at the beginning of the reduction zone. As distance from the grate increases, CO continues to form, but at a slower rate. Thus the thicker the fuel bed, the more CO is formed. Because reduction of CO_2 to CO depends on time of contact between gas and coke, higher air velocities mean less CO.

Fuel-bed temperature depends largely on rate of firing, being higher at high rates. Usually temperature within the bed is somewhat greater than at the surface. If this temperature is above that at which ash fuses, clinker may form. More about this later.

Overfire Burning.

As we have seen, about half the burning job must be done in the space above the fuel bed. How successfully this is done determines largely the efficiency of the entire operation. The job is complicated by the fact that composition of the combustible gases above the fuel bed varies from point to point and uniform distribution of air is hard to obtain. *Stratification* is likely to result, that is, there will be separate streams of gas and air leaving the furnace without mixing. As in all forms of firing, excess air, above the amount required for theoretically complete combustion, is supplied. This increases the chances for air and gas to meet and mix.

Furnace Size.

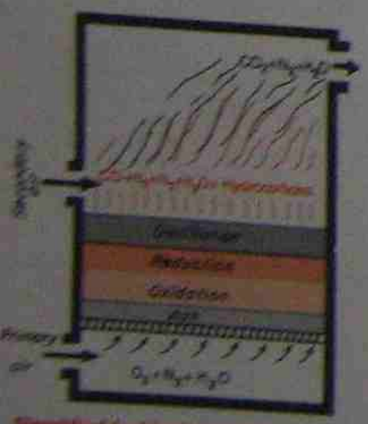
Size of combustion space is of utmost importance. In general, the less excess air, the larger must be the space. Naturally, more space is needed for higher burning rates. For any given set of conditions, size of combustion space largely determines completeness of combustion. Of the "given conditions", mixing is perhaps most important. With poor mixing, combustion is likely to be incomplete no matter how large the space, while with good mixing combustion may be completed quickly and added space would be of no value. Incomplete combustion means heat loss in the form of unburned CO and carbon. Likewise, high excess air means loss of sensible heat in the flue gas.

Turbulence Again.

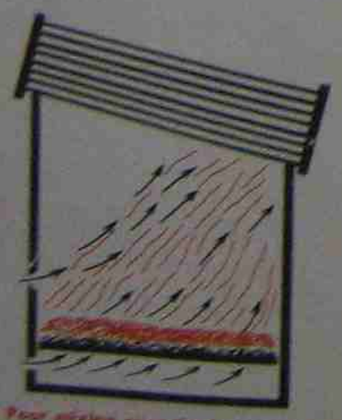
Best all-round balance of these factors results from a furnace design that makes maximum use of space. Here again turbulence proves the vital factor. Modern practice leans strongly to devices such as high-velocity jets to obtain good penetration, high turbulence and thorough mixing. By this means, the furnace "size" may be increased without actually enlarging its dimensions.

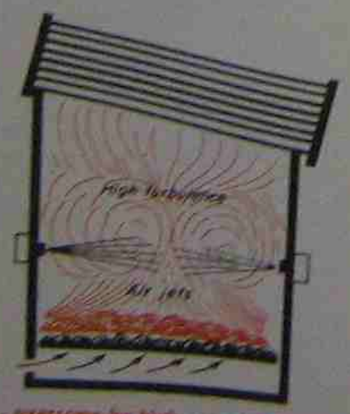
In an existing furnace, burning a given coal, there is a certain percentage of excess air that gives most economical operation. For a furnace having high stack temperature, best excess-air percentage is lower than for a furnace with low stack temperature. For the majority of furnaces, best results follow setting excess air to give a trace of CO in flue gas.

Here we have given some of the fundamentals of fuel burning. Following pages will cover the sources and properties of commercial fuels, practical aspects of their firing in various kinds of equipment, and something of the problem of selecting them.



Simplified fuel bed shows four zones


Poor mixing over the fire may be . . .



. . . overcome by high-velocity jets

TABLE I — PROPERTIES OF FUEL GASES

Fuel	Source	Average composition	High heat value, btu per ft	Remarks
Blast-furnace gas	Byproduct of iron making	58% N_2, 27% CO, 12% CO_2, 3% H_2, some CH_4	90-100	Good fuel when cleaned — used mainly at source
Butane	Byproduct of gasoline making, also in casing-head gas	C_4H_{10}; usually has some butylene C_4H_8 and propane C_3H_8	3200-3260	Liquefies under slight pressure, sold as liquid (bottled gas)
Casing-head gas	Oil wells	Varies, mostly butane, propane	1200-3000	Used mostly in oil fields
Carburetted water gas	Manufactured from coal, enriched with oil vapor	34% H_2, 32% CO, 16% CH_4, 7% N_2, 5% C_2H_4, 4% CO_2, 2% C_6H_6	500-600	Good fuel, but usually costly. Part of most city gas
Coke-oven gas	Byproduct coke ovens	48% H_2, 32% CH_4, 8% N_2, 6% CO, 3% C_2H_4, 2% CO_2, 1% O_2	500-600	Good fuel when cleaned, often used at source
Natural gas	Gas wells	Varies, mostly CH_4, C_2H_6, C_3H_8	950-1150	Ideal fuel, piped to point of use
Oil gas	Manufactured from petroleum	54% H_2, 27% CH_4, 10% CO, 3% N_2, 3% CO_2, 3% C_2H_4	500-550	Used on West Coast, often mixed with coke-oven gas
Producer gas	Manufactured from coal, coke, wood, etc.	51% N_2, 25% CO, 16% H_2, 6% CO_2, 2% CH_4	135-165	Requires cleaning
Propane	Byproduct of gasoline	C_3H_8	2500	Similar to butane
Refinery gas	Byproduct of petroleum processing	Varies, mostly butane, and propane	1200-3000	Used mainly at refineries
Sewage gas	Sewage-disposal plants	65% CH_4, 30% CO_2, 2% H_2, 3% N_2, traces of O_2, CO, H_2S	600-750	Many disposal plants meet all power needs with this fuel

TABLE II — OIL MEASUREMENTS AT 60 F

Gravity, deg API	Specific gravity	lb per gal	Btu per lb	Btu per gal	Lb per 42-gal barrel	Weight, lb per cu ft
3	1.0526					
4	1.0449	8.76	18,190	159,340		
5	1.0443	8.69	18,340	158,900	364.98	65.54
6	1.0366	8.63	18,390	158,550	365.31	65.29
7	1.0291	8.57	18,340	157,840	360.60	64.59
	1.0217	8.50	18,390	157,170	359.98	64.12
8				156,220	357.37	63.63
9	1.0143	8.44	18,440	155,540	354.81	
10	1.0071	8.39	18,490	155,120	353.46	63.14
11	1.0000	8.33	18,540	154,420	350.13	62.78
12	0.9861	8.22	18,590	152,740	347.71	62.36
			18,640	153,220	349.28	61.93
13	0.9795	8.16	18,690	152,510	347.68	61.59
14	0.9725	8.10	18,740	151,790	346.23	60.65
15	0.9659	8.05	18,790	151,290	344.55	60.46
16	0.9593	7.99	18,840	150,530	343.81	60.24
17	0.9529	7.94	18,890	149,980	342.64	59.83
					340.64	59.47
18	0.9465	7.89	18,930	149,360	339.45	59.05
19	0.9403	7.83	18,980	148,610	339.23	58.64
20	0.9340	7.78	19,030	147,980	337.55	58.25
21	0.9279	7.73	19,060	147,320	334.91	57.87
22	0.9218	7.68	19,110	146,760	333.83	57.48
23	0.9159	7.63	19,150	146,110	330.71	57.13
24	0.9100	7.58	19,190	145,460	331.63	56.75
25	0.9042	7.53	19,230	144,850	329.59	56.39
26	0.8984	7.49	19,275	144,330	314.58	56.03
27	0.8927	7.44	19,310	143,670	312.60	55.68
28	0.8871	7.39	19,350	143,090	310.63	55.32
29	0.8816	7.35	19,380	142,440	308.75	54.98
30	0.8763	7.30	19,420	141,770	306.81	54.64
31	0.8708	7.26	19,450	141,210	304.92	54.31
32	0.8654	7.21	19,490	140,550	303.03	53.97
33	0.8602	7.17	19,520	139,960	301.14	53.64
34	0.8550	7.13	19,560	139,370	299.27	53.32
35	0.8498	7.08	19,590	138,690	297.37	52.98
36	0.8448	7.04	19,630	138,120	295.80	52.68
37	0.8398	7.00	19,660	137,590	294.04	52.37
38	0.8348	6.96	19,680	136,970	293.22	52.06
39	0.8299	6.92	19,720	136,460	290.64	51.76
40	0.8251	6.87	19,750	135,680	288.91	51.46
41	0.8203	6.83	19,780	135,090	287.23	51.16
42	0.8156	6.79	19,810	134,510	285.55	50.86

Facts About Fuels

With the fundamentals of combustion under our belts, we now need to know more about commercial fuels: where they come from, what their characteristics are, how their properties are measured. Let's take gases first.

GAS

Of many gaseous fuels, only natural gas has any commercial importance in steam generation because manufactured gases run too high in cost. Usually byproduct gases have low heating values and are produced in relatively minor quantities. So they are ordinarily used at the production point and not distributed.

Natural Gas. The origin is not known but it is often found associated with oil, and the two fuels are believed to have a common source. Natural gas is produced in more than 30 states and widespread pipeline networks make it available in some part of nearly every state (see map, next page).

Natural gas is colorless and odorless. Composition varies with source, but methane (CH_4) is always the major constituent. Most natural gas contains some ethane (C_2H_6) and a small amount of nitrogen. Gas from some areas, often called "sour" gas, contains hydrogen sulphide and organic sulphur vapors. Heating value averages about 1000 Btu per cu ft (20,000 Btu per lb) but may run considerably higher. Natural gas is usually sold by the cu ft, but may be sold by the *therm*, which is 100,000 Btu.

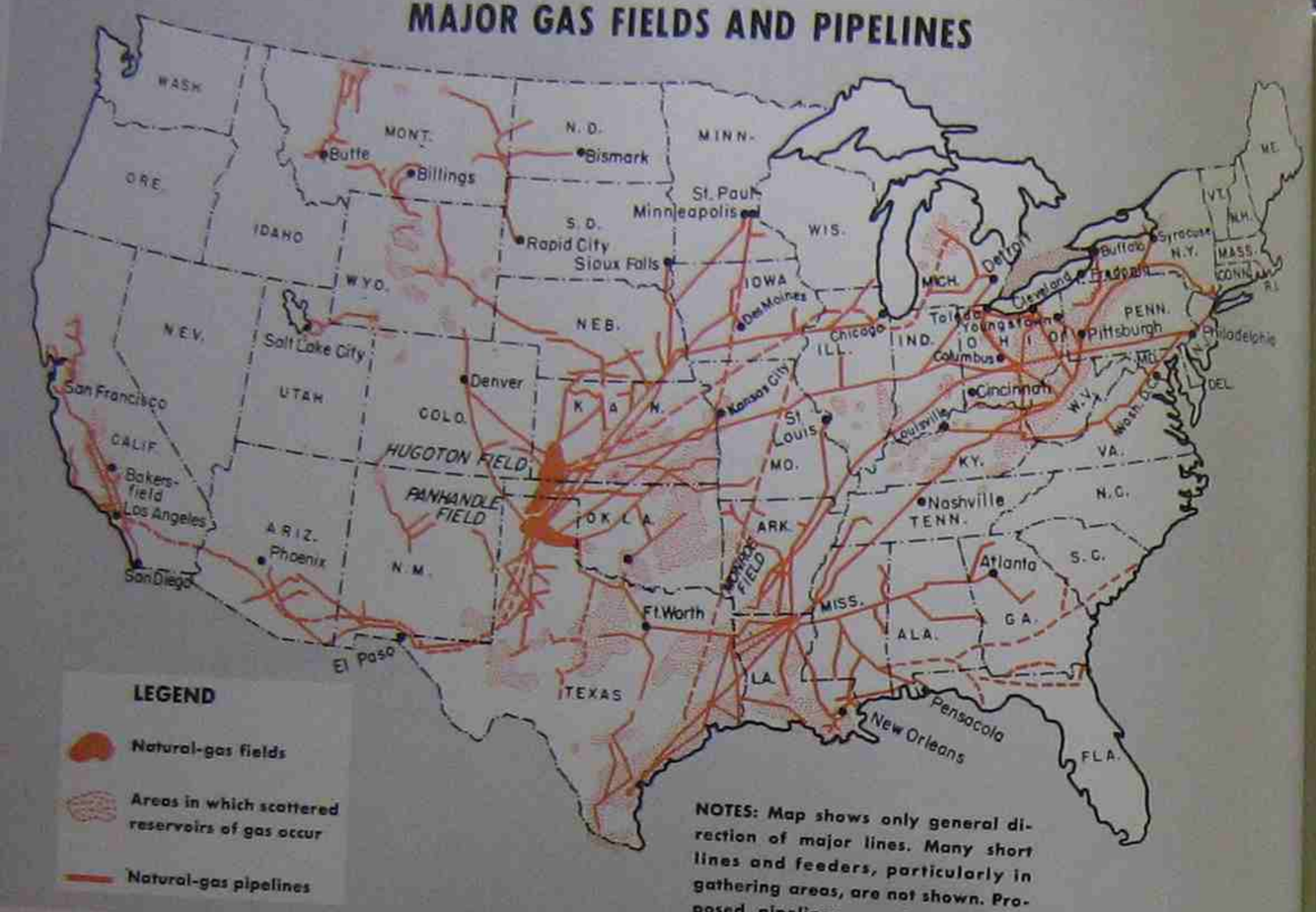
Manufactured Gases. *Coal gas* and *coke-oven gas* are produced by carbonizing high-volatile bituminous coal in retorts that exclude air and are heated externally by producer gas. Usually a number of byproducts result. Cleaned of impurities, these gases are roughly one-half hydrogen and one-third methane, plus small amounts of carbon monoxide, carbon dioxide, nitrogen, oxygen and illuminants (C_2H_4 and C_6H_6). Heating value runs around 550 Btu per cu ft.

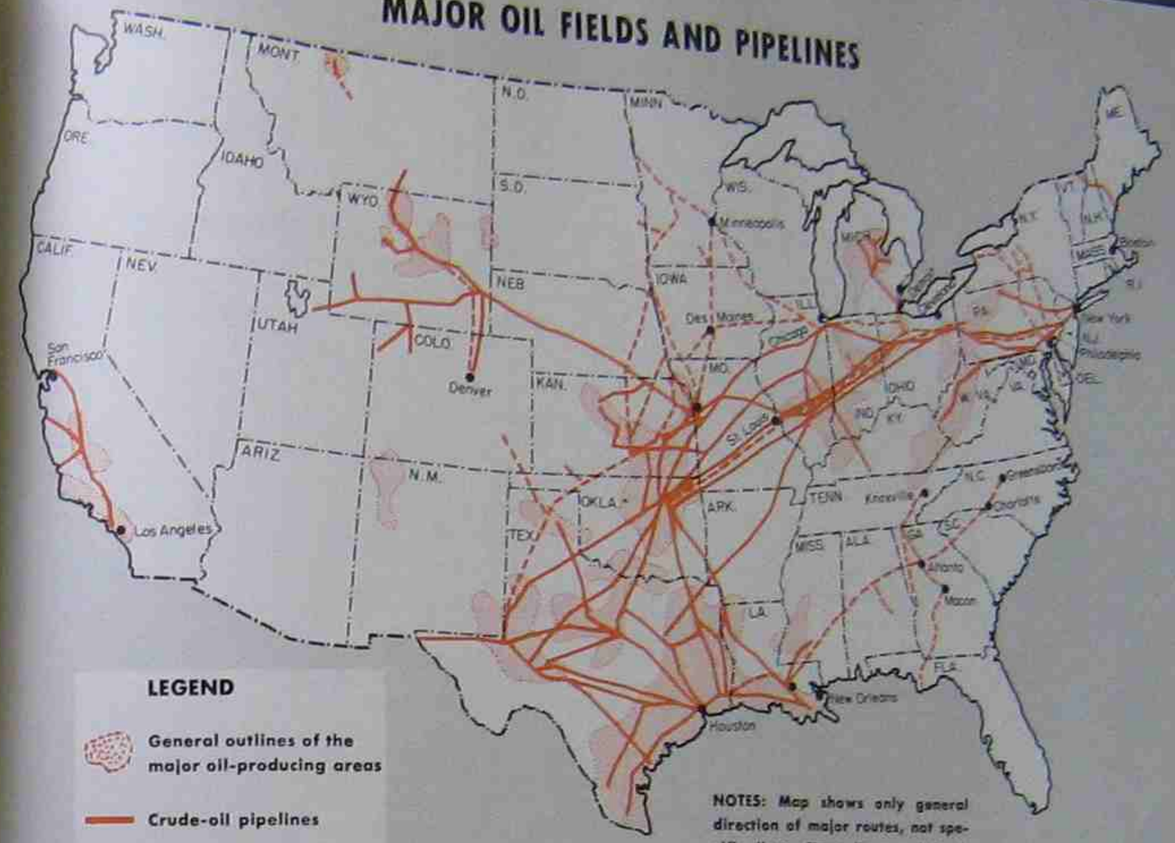
The term *water gas* generally refers to a mixture of carbon monoxide, hydrogen and nitrogen obtained by passing steam and air alternately through a bed of incandescent carbon. Heating value averages less than 300 Btu per cu ft. This gas may be enriched by carburetting with oil, which is converted into a permanent gas and mixed with the water gas. This increases heating value to about 550 Btu per cu ft.

Where oil is cheap, *oil gas* may be made. Like coal gas, this runs about one-half hydrogen and one-third methane for about 550 Btu.

The manufactured gases described are those commonly distributed. The gas served in a given area may be a mixture of two or more of them, or a mixture of natural and manufactured gas. Heating value, usually held to 525-550 Btu per cu ft, is often fixed by state or local ordinance.

Although it is a manufactured gas, the low heating value of producer gas (135-150 Btu per cu ft) makes it uneconomical to distribute it. It is made by firing coal with an air supply insufficient for complete combustion, either with or without admixture of steam. It runs about one-half nitrogen, one-quarter carbon monoxide, and one-





sixth hydrogen. Fuels other than coal may be used; in many parts of the world producer gas is made from waste.

Byproduct Gases. Commercial *butane* and *propane* are essentially byproducts of manufacture of natural gasoline and of certain refinery operations. As supplied, propane (C_3H_8) is essentially pure, while butane (C_4H_{10}) usually contains a small amount of propane. Both have high heating values, are easily liquefied at low pressure. They are widely used as "bottled" fuels.

Blast-furnace gas, a byproduct of iron-making, has the lowest heating value of any commercial gas, about 90 Btu per cu ft. It is close to three-quarters nitrogen and carbon dioxide, the only important combustible constituent being carbon monoxide. Raw gas, which usually contains a high concentration of solid impurities, is normally washed before use. Unwashed gas, however, has been successfully burned in boiler furnaces (POWER, Nov 1938, pp 588-591).

In recent years, use of gas produced by digesting sewage sludge has become common practice in disposal plants. *Sewage gas, or sewage-sludge gas,* runs about two-thirds methane and one-third carbon dioxide, with small amounts of hydrogen, nitrogen and usually some hydrogen sulphide. Heating value is about 650 Btu per cu ft. Although mostly used in engines, this gas is also burner fired.

OIL

Petroleum and its byproducts furnish practically all commercially used liquid fuels. Geologists believe decomposition of minute marine growths or possibly, at times, of vegetable matter formed the oil that lies trapped in pools between layers of the earth's crust. This *crude oil* consists of 83-87% carbon and 10-14% hydrogen, plus traces of oxygen, nitrogen and sulphur. The hydrogen and carbon are combined as *hydrocarbons*.

Crude oil moves from well to refinery mainly by pipeline and tanker. Although virtually every state boasts some refining capacity, ten have almost 90% of the nation's total. Fuel oils move from refineries to nearby markets by truck, tank car and barge, with tankers serving seaboard areas.

Refining Processes. Since practically all liquid fuels are either products or byproducts of refining, the way they are made has more to do with their fuel qualities than the source of the crude. Refining consists of separating and, usually, recombining the hydrocarbons of the fuel oil into specialized products like gasoline, fuel oil, etc. Basic process is simple distillation, which separates the hydrocarbons into groups or "fractions" having the same range of boiling points. From light to heavy, typical fractions are: (1) naphtha (2) gasoline (3) kerosene, and (4) gas oil. These are the *distillates;* the remainder, or *residual,* is a heavy fuel oil. Products of simple distillation are called *straight-run.*

Simple distillation is sometimes the whole story, but in modern refining it is only the beginning. To secure greater gasoline yields, fractions heavier than gasoline are usually *cracked,* that is, decomposed by heat and pressure, with or without a catalyst. Of the new hydrocarbons resulting, some are lighter and some heavier; these are likewise separated according to boiling range. Cracking, unlike simple distillation, actually changes the hydrocarbon structure so crude oil yields more valuable lighter hydrocarbons (gasoline) and proportionately less heavy ones.

Commercial Fuel Oils. Fuel oils used commercially may be either distillates or residuals, and either straight run or cracked. Straight-run products become increasingly less common as refinery practice leans more heavily on cracking, and are, in general, premium grades. Thus the great bulk of commercial fuel oils are cracked products; distillates form the source for lighter grades used in domestic and some commercial and industrial burners, whereas residuals supply the heavy oils for larger commercial and industrial units.

Refinery wastes, which have little or no commercial value, are usually burned at the refinery or in adjacent plants. They include acid sludge, tars and tank cleanings or "bottoms."

Specific Gravity. Since hydrogen has a much higher heating value and lower atomic weight than the other principal element in fuel oil, it's easy to see that the proportions of carbon and hydrogen affect both specific gravity and heating value. Because of this, specific gravity forms a reliable guide to an oil's heating value (see table on p 77).

Specific gravity in *degrees API* (American Petroleum Institute) is found by dividing *specific gravity with respect to water* (at 60 F) into 141.5 and subtracting 131.5 from the answer. Gravity in *degrees Baume* is found in the same way except the numbers are 140 and 130, respectively. For practical engineering work, the two gravity scales may be considered the same.

Viscosity. The relative ease or difficulty with which an oil flows is its *viscosity*. It is measured by the time in seconds a standard amount of oil takes to flow through a standard orifice in a device called a viscosimeter. The usual standard in this country is the *Saybolt Universal,* or the *Saybolt Furol,* for oils of high viscosity. Since viscosity changes with temperature, tests must be made at a standard temperature, usually 100 F for Saybolt Universal and 122 F for Furol.

Viscosity indicates how oil behaves when pumped and, more particularly, shows when preheating is required and what temperature must be held.

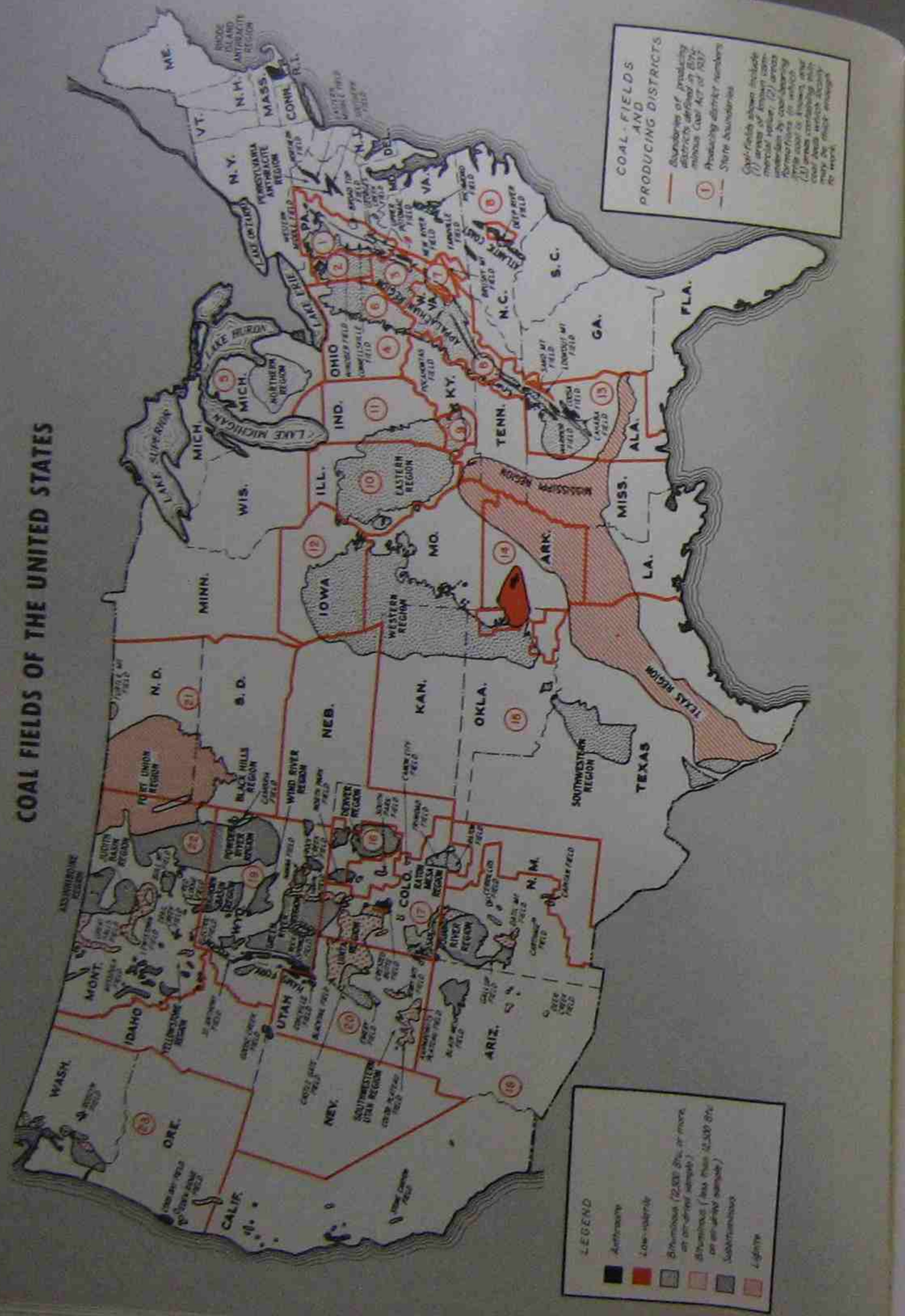
Flash and Pour. *Flashpoint* represents the temperature at which an oil gives off enough vapor to make an inflammable mixture with air. Results of a flashpoint test depend on the apparatus, so this is specified as well as temperature. Flashpoint measures oil's volatility and indicates maximum temperature for safe handling.

Pour point represents lowest temperature at which an oil flows under standard conditions. Including pour point in a specification insures that an oil will not give handling trouble at expected low temperature.

By centrifuging a sample of oil, amount of *water and sediment* can be found. These are impurities and while it is not economical to eliminate them, they should not occur in excessive quantities (not more than 2%). Incombustible impurities in oil, from natural salts, from chemicals in refining operations, or from rust and scale picked up in transit, show up as *ash*. Some ash-producing impurities cause rapid wear of refractories and some are abrasive to pumps, valves and burner parts. In the furnace, they may form slag coatings.

All tests above are covered by ASTM standards, which should be consulted for details of apparatus and methods (*ASTM Standards on Petroleum Products and Lubricants,* American Society for Testing Materials, 1916 Race St, Philadelphia 3, Pa.).

Fuel oils have a tendency to deposit



sludge in storage; this may be aggravated by mixing oils of different character as when deliveries from two sources go into the same tank. These simple rules avoid trouble when oils are mixed: (1) Straight-run residuals can be mixed with any straight-run product, and cracked residuals with straight-run residual (2) cracked distillate can be added as a third constituent, but (3) cracked residual *cannot* be added to straight-run distillate.

COAL

Three-hundred-million years ago, in swamp forests of the Carboniferous Age, the foundation of our present reserves was laid. For 50 million years, giant trees and ferns grew and fell, to decay and form rich peat bogs. Floods buried the bogs under layers of sediment, only to subside and permit the growth-and-decay cycle to begin again. As millions of years passed, pressure, heat and time worked to drive off some volatile matter, to harden the mass, and to turn it into the carbon-substance we call coal.

Different kinds contain different amounts of carbon substance depending on the age of the deposit and the conditions under which it formed. Next to the original peat, the "youngest" form is *lignite*, high in moisture and low in fixed carbon. Older coals, higher in "rank," contain more fixed carbon.

Analyses. Various tests and methods of analysis express coal qualities in figures instead of words. Principal characteristics are expressed in what is known as a *proximate analysis*, as distinguished from an *ultimate analysis*, which shows the exact chemical composition of a fuel, without paying any attention to the physical form in which the compounds appear. As we have seen, this gives data needed for combustion calculations.

For a better picture of coal's behavior in a furnace, the proximate analysis determines the percentage of (1) *moisture* (2) *ash* (3) *volatile matter* and (4) *fixed carbon*. These percentages add up to 100. In addition, it is customary to determine: (1) total amount of *sulphur*, as a separate percentage (2) *ash-fusion temperature*, and (3) heating value.

Reporting Analyses. There are five ways to report an analysis, although only the first three are likely to be met in power-plant work: (1) as received (2) air dried (3) moisture free (4) moisture and ash free, and (5) moisture and mineral free. As the name implies, the as-received analysis reports the condition of coal as delivered to the laboratory. This comes closest to giving the conditions *as shipped* or *as fired*, the values desired in practical work. Loss or gain of moisture between time of sampling and analysis depends on the kind of coal, size, weather conditions, and method of handling sample.

Following paragraphs discuss the various characteristics of coal (those reported in proximate analyses and others) and how they affect the value of coal in power-plant operation. For details on equipment and procedures for testing coal, consult *ASTM Standards on Coal and Coke* (1948).

Moisture. All coal contains some natural moisture (1 to 5% in Eastern coals and up to 40% in some lignites). This *inherent* moisture lies in the pores and forms a true part of the coal, being retained when it is air dried. Surface moisture depends on conditions in the mine, and during transit.

Moisture must be transported, handled and stored; its presence in large amounts increases cost and difficulty of these operations. Looked at another way, moisture replaces an equal amount of combustible material and thus decreases the heat content per lb. In addition, some heat liberated in the furnace goes to evaporating moisture in the fuel and superheating the vapor; this *moisture* loss can be figured from the chart on page 117.

MINERAL IMPURITIES

Ash. This incombustible mineral matter, left behind when coal burns completely, differs from "ashes," as the power-plant man knows them, because ashes taken from a furnace always contain some unburned coal.

Like moisture, ash is an impurity that increases shipping and handling costs. It must be removed from the furnace and the plant, usually requiring additional equipment and expense. Recent research shows that amount and character of ash constitutes the biggest single factor in fuel-bed and furnace problems like clinkering and slagging. An increase in ash content usually means an increase in carbon carried to the ashpit.

Volatile Matter. In a way not yet clearly known, coal holds combustible gases such as methane and other hydrocarbons, hydrogen and carbon monoxide, and incombustible gases like carbon dioxide and nitrogen. Heat releases these gases.

Percentage of volatile matter indicates the amount of gaseous fuel present and thus bears a direct relationship to firing mechanics. It affects furnace volume and arrangement of heating surfaces.

Fixed Carbon. When the volatile matter distills off, a solid fuel is left, consisting, in the main, of carbon, but containing some hydrogen, oxygen, sulphur and nitrogen not driven off with the gases. Subtracting percentage of moisture, ash and volatile matter from 100% yields a percentage called fixed carbon.

Sulphur. Although it burns, sulphur in coal is an undesirable element for power-plant use. It plays a part in clinkering and slagging, in corrosion of air heaters, economizers, breeching and stacks, and in spontaneous combustion of stored coal. It occurs mainly as iron sulphide (commonly known as pyrites), as organic sulphur, and in small amounts as sulphates. Only total sulphur is measured, although it is known that iron combined with the sulphur shares the blame for troubles laid to sulphur.

Ash Fusion. Temperature at which ash fuses is measured by heating cones of ash in a furnace arranged to produce a reducing atmosphere. Temperature at which the cone fuses down to a round lump is called softening or ash-fusion temperature. Other temperatures sometimes observed include that at which (1) cone tip starts to bend (initial deformation temperature) and (2) cone spreads out in a flat layer (fluid).

Ash-fusion temperature (and sometimes the spread between initial and softening, or softening and fluid temperatures) serves as the best single indicator of clinkering and slagging tendencies under given fuel-bed and furnace conditions.

Heating Value. If a coal sample is burned in a "bomb" calorimeter filled with oxygen under pressure, the higher heating value is measured. The consumer buys energy units when he buys fuel, and so the heating value plays a basic part in judging fuel values. Sometimes heating value of fuel may affect maximum capacity of a plant.

PULVERIZING QUALITIES

Grindability. Wide use of pulverized-fuel firing brought a need for tests to show the relative ease or difficulty of grinding different kinds of coal. ASTM tentatively approves two methods, *ball-mill* and *Hardgrove*. The first measures relative amounts of energy needed to pulverize different coals by finding the number of ball-mill revolutions needed to grind a sample so 80% passes a 200-mesh sieve (74 microns). The *ball-mill grindability* index, in percent, is found by dividing number of revolutions into 50,000.

In the Hardgrove test, a prepared sample receives a definite amount of grinding energy in a miniature pulverizer; results are measured by weighing amount passing a 200-mesh sieve. Multiplying weight passing the sieve by 6.93 and adding 13 to the product gives *Hardgrove grindability*.

Grindability values do not give a direct comparison of pulverizer capac-

SPECIMEN ANALYSES OF TYPICAL COALS

Bed or Seam	State	County	%M	%V	% FC	% Ash	% S	Htg val, Btu/lb	Ash-fusion temp, F	HG
District 1:										
Barton	Md.	Allegany	2.5	15.8	68.3	13.4	2.1	13,020	.....	
Brookville	Pa.	Somerset	4.3	18.0	69.0	8.7	1.2	13,340	.....	
		Jefferson	2.6	34.4	52.1	10.7	3.1	13,040	.....	
Clarion	Pa.	Fulton	1.5	15.2	74.8	8.5	1.2	14,100	.....	
		Clarion	3.7	38.5	49.2	8.5	3.6	13,140	.....	
Elk Lick	W. Va.	Mineral	1.6	18.7	66.6	13.1	3.4	12,820	.....	
L Freeport	Pa.	Somerset	3.2	17.4	70.6	8.6	1.1	13,790	2500–2900	
		Elk	2.8	32.8	58.4	6.0	2.0	14,120	.....	
L Kittanning	Md.	Garrett	2.7	22.3	63.5	11.5	3.4	13,370	.....	
L Kittanning	Pa.	Lycoming	4.1	15.9	66.3	14.7	0.5	12,320	.....	
		Clarion	3.3	37.1	51.5	8.1	3.2	13,330	.....	
L Sewickley	Md.	Allegany	2.8	19.6	69.8	7.6	1.1	13,810	2700–2900	47
M Kittanning	Pa.	Somerset	4.2	16.1	68.9	10.8	1.7	13,250	.....	
		Elk	2.4	29.6	51.1	16.7	1.9	12,170	.....	
Mahoning	W. Va.	Mineral	3.0	14.2	70.8	12.0	1.6	13,230	.....	
Pittsburgh	Md.	Allegany	2.5	16.2	70.5	8.6	0.9	13,860	2700–3000	
Sewickley	Pa.	Somerset	3.0	20.7	67.0	9.3	1.4	13,700	.....	
U Freeport	Md.	Allegany	2.3	19.3	68.2	12.2	2.6	13,250	.....	
U Freeport	Pa.	Bedford	1.1	16.4	70.8	11.7	2.1	13,630	.....	
		Armstrong	2.1	33.9	54.5	9.5	2.2	13,360	2100–2800	57
U Freeport	W. Va.	Mineral	2.0	15.2	70.6	12.2	3.6	13,270	.....	
		Tucker	2.8	24.0	65.3	7.9	1.2	13,960	.....	
U Kittanning	Md.	Allegany	3.0	14.4	69.6	13.0	1.3	13,090	.....	
		Clarion	3.0	38.1	50.0	8.9	5.5	13,230	.....	
District 2:										
Brookville	Pa.	Butler	3.7	37.0	52.4	6.9	1.6	13,550	.....	
L Freeport	Pa.	Butler	3.1	35.0	55.2	6.7	1.1	13,710	.....	
L Kittanning	Pa.	Armstrong	2.3	38.6	51.7	7.4	2.9	13,570	.....	
Pittsburgh	Pa.	E. Westmoral'd.	3.0	24.2	61.6	11.2	1.3	13,340	2600–2900	
		Washington	3.0	35.7	54.4	6.9	1.2	13,710	2100–2600	60
Redstone	Pa.	Allegheny	2.5	32.6	52.9	11.0	1.6	12,840	.....	
Sewickley	Pa.	Fayette	2.5	34.0	52.1	11.4	3.1	13,020	2200–2500	
U Freeport	Pa.	Butler	3.0	34.2	53.5	9.3	1.5	13,250	2100–2700	
U Kittanning	Pa.	Butler	3.4	34.7	54.8	7.1	2.0	13,510	.....	
Waynesburg	Pa.	Greene	3.4	34.1	48.9	15.6	3.2	12,030	.....	
District 3:										
Bakerstown	W. Va.	Preston	2.0	26.9	61.4	7.7	1.8	14,010	2200–2500	
L Kittanning	W. Va.	Randolph	2.6	29.5	57.4	10.6	1.3	13,410	2600–3000	51
		Preston	2.5	22.8	64.2	10.3	1.8	13,458	2400–2700	101
Pearless	W. Va.	Webster	2.1	36.3	59.1	2.5	0.7	14,800	.....	
Pittsburgh	W. Va.	Taylor	2.0	37.8	52.8	7.4	2.5	13,890	2000–2200	71
Redstone	W. Va.	Upshur	2.6	36.3	54.1	7.0	1.7	13,650	.....	
Sewell	W. Va.	Randolph	3.3	29.8	61.9	6.0	0.8	14,060	2500–2900	
Sewickley	W. Va.	Monongalia	2.0	35.6	57.0	11.4	2.5	13,080	2100–2400	
U Freeport	W. Va.	Preston	2.5	29.1	57.9	10.5	1.6	13,410	2200–2800	63
	W. Va.	Upshur	1.5	38.0	50.7	9.8	1.4	13,550	.....	
District 4:										
Clarion	Ohio	Vinton	5.5	39.6	41.9	13.0	3.7	11,690	.....	
L Freeport	Ohio	Jefferson	3.8	37.6	49.8	8.8	2.8	13,050	.....	
L Kittanning	Ohio	Lawrence	7.3	37.8	45.1	9.6	1.6	11,880	.....	51
M Kittanning	Ohio	Perry	7.8	36.0	47.3	8.5	2.0	11,900	2200–2700	
		Coshocton	5.9	41.6	44.2	8.3	3.0	12,470	.....	
Pittsburgh	Ohio	Jefferson	4.5	36.8	49.6	9.1	3.0	12,740	2100–2200	58
		Belmont	3.8	40.3	47.2	8.7	3.9	12,940	1900–2100	
Sharon	Ohio	Jackson	12.0	35.1	43.3	14.6	0.4	10,280	.....	
U Freeport	Ohio	Athens	5.1	37.3	50.8	6.8	2.8	12,580	.....	
District 5:										
	Mich.	Bay	12.1	34.0	47.5	6.4	1.2	11,930	.....	
		Calhoun	11.2	40.1	40.2	8.5	6.3	11,510	.....	
		Midland	13.1	33.3	46.6	7.0	2.2	11,510	.....	
		Saginaw	11.1	34.9	46.2	5.8	1.8	12,140	.....	
		Shiawassee	11.7	36.3	42.5	9.5	2.7	11,540	.....	50–60
District 6:										
Pittsburgh	W. Va.	Brooke	4.0	36.9	50.6	8.5	2.7	12,920	2000–2200	
		Hancock	5.8	35.5	49.6	9.0	2.3	12,550	.....	
		Marshall	2.9	40.5	47.2	8.5	4.4	13,160	.....	
		Ohio	3.5	39.5	48.7	8.3	4.2	13,030	2000–2200	
District 7:										
Beckley	W. Va.	Raleigh	2.7	17.1	74.8	5.4	0.7	14,390	2500–3000	107
Big Eagle	W. Va.	McDowell	3.0	29.2	62.0	5.8	0.8	14,150	.....	
Campbell Creek	W. Va.	Fayette	2.8	33.6	59.4	5.4	1.2	14,070	2400–2600	69
Coalburg	W. Va.	Fayette	1.6	34.4	58.0	5.8	0.7	14,050	.....	
Eagle	W. Va.	Fayette	2.5	28.7	62.3	5.5	0.6	14,380	2400–3000	
Fire Creek	W. Va.	Raleigh	2.7	16.4	74.7	6.2	1.0	14,260	2400–2800	75
Jewell	Va.	Buchanan	2.6	20.8	73.2	3.4	0.5	14,970	.....	
Merrimac	Va.	Montgomery	2.4	11.5	66.7	19.4	0.6	12,000	2400–3000	
Pocahontas No. 3	Va.	Tazewell	3.2	18.9	72.5	4.4	0.6	14,570	2200–2600	103
Pocahontas No. 3	W. Va.	McDowell	2.7	17.5	73.7	6.0	0.7	14,440	2200–2700	103
	W. Va.	Raleigh	2.6	16.4	74.1	6.9	0.7	14,210	2600–2900	
Pocahontas No. 4	W. Va.	McDowell	1.9	15.9	75.4	6.8	0.5	14,370	2100–2400	91
Pocahontas No. 5	Va.	Tazewell	3.4	21.0	69.4	6.2	0.5	14,260	.....	99
Pocahontas No. 6	W. Va.	Wyoming	2.0	17.5	74.6	5.9	0.6	14,520	2500–2900	101
		Greenbrier	2.6	22.6	68.6	5.8	0.6	14,350	.....	
Powellton	W. Va.	Fayette	0.3	32.0	59.4	8.3	0.7	14,120	.....	61–67
Red Ash	W. Va.	McDowell	1.5	23.6	70.0	4.7	0.8	14,890	.....	
Sewell	W. Va.	McDowell	3.0	16.1	72.9	6.0	0.6	14,300	2400–2600	
		Greenbrier	3.1	25.6	66.8	5.1	1.3	14,290	2200–2500	87–98
Welch	W. Va.	McDowell	2.5	18.2	72.2	7.1	0.5	14,160	2500–2900	

Bed or Seam	State	County	%M	%V	% FC	% Ash	% S	Htg val, Btu/lb	Ash-fusion temp, F	HG
District 8:										
Big Eagle	W. Va.	McDowell	2.9	31.2	59.6	6.3	1.8	14,050	.....	
Big Mary	Tenn.	Anderson	2.5	36.8	51.6	9.1	3.3	13,230	2200–2500	69
Blair	Va.	Wise	2.9	32.7	58.7	5.7	0.9	14,060	.....	
Campbell Creek	W. Va.	Fayette	2.5	34.7	56.5	6.3	1.0	14,000	2400–2600	79
Cedar Grove	W. Va.	Logan	2.0	35.7	56.0	6.3	1.6	13,950	2300–2800	
Chilton	W. Va.	Logan	2.5	34.4	56.9	6.2	0.7	13,910	2500–2900	
Clintwood	Va.	Buchanan	2.5	31.3	59.6	6.6	1.1	14,110	2600–3000	59
Coalburg	W. Va.	Kanawha	3.5	34.2	54.9	7.4	0.8	13,470	.....	56–63
Coal Creek	Tenn.	Anderson	2.0	36.3	55.3	6.4	1.2	13,910	.....	39–47
		Morgan	2.0	39.0	51.9	7.1	3.9	13,860	2200–2500	
Dean	Ky.	Knox	4.0	36.0	52.7	7.3	0.9	13,150	2000–2200	
Deep River	N. C.	Lee	2.0	32.1	58.3	7.6	2.5	13,750	2600–2900	
		Moore	3.7	15.9	57.9	22.5	3.0	11,280	.....	
Eagle	W. Va.	Logan	2.5	32.7	58.6	6.2	0.8	13,980	2600–2900	45–57
Elkhorn	Ky.	Letcher	3.0	36.4	57.3	3.3	0.5	14,170	2200–2600	46–53
Fire Clay No. 4	Ky.	Perry	3.5	37.3	54.8	4.4	0.8	13,820	2300–2800	
Harlan	Ky.	Harlan	2.5	37.1	55.8	4.6	0.8	14,000	2300–2800	48–58
Hazard No. 4	Ky.	Breathitt	5.6	34.0	53.3	7.1	1.0	12,960	.....	
Hazard No. 6	Ky.	Perry	4.8	35.2	53.0	7.0	0.6	13,090	2900–	43–53
Hazard No. 7	Ky.	Perry	4.3	35.7	54.1	5.9	0.6	13,430	2800–3000	44–54
Hernshaw	W. Va.	Boone	3.0	34.6	57.3	5.1	0.9	14,160	.....	51
High Splint	Ky.	Harlan	4.0	37.6	53.7	4.7	0.7	13,500	2300–2700	31
Hooper	Tenn.	Morgan	2.6	37.4	56.5	3.5	1.5	14,020	.....	
Imboden	Va.	Wise	2.5	34.3	58.7	6.5	0.8	13,820	2500–2900	62
Jellico	Tenn.	Campbell	4.0	36.5	54.8	4.7	1.0	13,760	2300–2800	
Keokee	Ky.	Harlan	3.0	36.9	56.6	3.5	0.7	14,120	2200–2500	
L Banner	Va.	Buchanan	2.3	22.3	67.8	7.6	1.3	14,150	2600–2800	
		Russell	2.1	36.3	55.3	6.3	0.7	14,090	.....	
L Elkhorn	Ky.	Pike	3.0	33.2	57.3	6.5	0.6	13,880	2600–3000	
L Kittanning	W. Va.	Kanawha	3.0	35.2	53.7	8.1	0.8	13,330	2500–2900	
L Sewanee	Tenn.	Cumberland	2.3	28.3	62.1	7.3	0.7	13,750	.....	
Low Splint	Va.	Lee	2.9	36.4	53.7	7.0	0.7	13,630	.....	
Mason	Ky.	Bell	3.0	37.4	55.4	4.2	1.2	13,920	2400–2600	
Norton	Va.	Wise	2.9	32.9	57.6	6.6	1.1	13,910	.....	
No. 1	Ky.	McCreary	3.1	36.3	53.0	7.6	2.6	13,300	.....	
No. 1½	Ky.	McCreary	4.0	35.6	54.1	6.3	0.6	13,330	.....	
No. 7	Ky.	Boyd	5.0	37.3	51.8	5.9	1.0	12,790	.....	
Poplar Creek	Tenn.	Campbell	3.0	36.9	55.3	4.8	1.4	13,780	.....	
Poplar Lick	Ky.	Bell	3.4	37.9	49.7	9.0	2.6	13,120	.....	
Powellton	W. Va.	Fayette	2.9	32.7	60.3	4.5	0.8	14,290	2600–2900	
Raven	Va.	Tazewell	2.8	31.7	59.7	5.8	0.5	14,240	.....	
Red Ash	Tenn.	Campbell	3.4	38.5	52.2	5.9	1.1	13,510	.....	
Sterling	Ky.	Bell	2.2	37.9	50.5	9.4	3.0	13,060	.....	
Straight Creek	Ky.	Bell	3.0	37.9	54.6	4.5	0.8	13,930	2100–2300	53
Taggart	Va.	Lee	3.3	35.7	56.6	4.4	0.6	13,960	2100–2500	
U Banner	Va.	Dickenson	2.0	30.0	62.0	6.0	0.8	14,400	2400–2800	
		Russell	2.7	35.0	55.3	7.0	0.6	13,670	2200–2500	
U Elkhorn No. 1	Ky.	Floyd	4.0	36.8	54.2	5.0	0.9	13,580	2300–2700	
U Elkhorn No. 2	Ky.	Floyd	4.4	35.9	54.6	5.1	1.1	13,530	2200–2700	51
U Elkhorn No. 3	Ky.	Pike	3.3	33.4	58.4	4.9	0.7	13,900	.....	
Wallins	Ky.	Harlan	3.1	38.1	54.3	4.8	0.7	13,840	.....	58–68
Wilder	Tenn.	Overton	3.3	35.8	50.5	10.4	2.5	12,880	2100–2400	
Windrock	Tenn.	Anderson	2.5	38.0	52.7	6.8	0.9	13,620	.....	
Winifrede	W. Va.	Mingo	3.5	36.1	53.8	6.6	0.6	13,550	2600–3000	
District No. 9:										
No. 6 (Raw)	W. Ky.	Various	6.4	36.4	51.9	5.3	1.7	12,900	2220	
No. 9 (Washed)	W. Ky.	Various	5.1	36.8	51.3	6.8	2.5	12,749	2215	65
No. 11 (Washed)	W. Ky.	Various	7.0	39.6	47.7	5.7	3.0	12,625	2210	54
No. 12 (Washed)	W. Ky.	Various	10.5	33.9	44.6	11.0	2.9	11,230	2310	56
No. 14 (Washed)	W. Ky.	Hopkins	8.0	37.6	48.0	6.4	3.0	12,400	2200–2400	
District No. 10:										
Herrin No. 6	Ill.	Christian	13.5	35.6	39.3	11.6	4.2	10,610	2000	57
		Franklin	9.5	33.0	49.0	8.5	0.8	11,900	2100–2500	56
		Fulton	17.0	34.0	42.2	6.8	2.6	10,960	.....	
		Bond	12.4	32.9	42.9	11.8	4.0	10,730	.....	
LaSalle No. 2	Ill.	Bureau	13.7	35.0	38.9	10.4	3.8	10,580	.....	
Springfield No. 5	Ill.	Peoria	14.5	34.1	39.0	12.4	3.0	10,530	.....	66
Harrisburg No. 5	Ill.	Saline	6.5	33.9	51.2	8.4	2.2	12,490	2000–2100	59
Colchester No. 2	Ill.	Henry	14.5	37.1	38.7	9.7	3.3	10,750	.....	62
Rock Island No. 1	Ill.	Knox	14.5	37.2	38.6	9.7	5.1	10,970	.....	
Danville No. 7	Ill.	Vermilion	13.3	36.8	39.0	11.1	3.6	10,940	.....	
District No. 11:										
III	Ind.	Greene	11.2	36.7	43.7	8.4	4.0	11,570	.....	
IV	Ind.	Clay	11.9	34.7	44.1	9.3	1.7	11,440	.....	
V	Ind.	Sullivan	11.6	34.1	47.6	6.5	1.3	11,850	.....	
		Warrick	10.0	37.4	43.1	9.5	3.9	11,570	2000–2200	
VI	Ind.	Sullivan	11.3	36.8	43.7	8.8	2.2	11,580	.....	
VII	Ind.	Sullivan	15.2	31.7	44.8	8.3	0.6	11,150	.....	
Brazil Block	Ind.	Clay	16.0	31.3	46.5	6.2	1.0	11,460	.....	
Semi-Block	Ind.	Greene	10.9	40.3	41.3	7.5	2.9	12,010	.....	
Minshall	Ind.	Vermilion	12.3	37.6	39.0	11.1	4.6	11,010	.....	
District No. 12:										
Clark	Ala.	Bibb	2.9	34.6	56.1	6.2	0.8	13,830	2100–2400	59
Jagger	Ala.	Fayette	3.1	33.9	52.5	10.5	0.7	12,780	.....	
Black Creek	Ala.	Jefferson	2.9	31.8	61.5	3.8	0.7	14,416	2500–2800	64–70
Black Creek	Ala.	Marion	3.1	37.3	54.4	3.2	1.4	13,640	.....	49
Helena	Ala.	St. Clair	3.9	34.2	56.0	5.9	1.0	13,580	.....	
Montevallo	Ala.	Shelby	2.9	38.4	52.8	5.9	0.9	13,700	.....	50–53
Blue Creek	Ala.	Tuscaloosa	4.7	24.4	61.7	9.2	0.6	13,360	.....	
Mary Lee	Ala.	Walker	3.0	30.9	52.0	12.5	0.8	12,320	2600–2900	51–65
Corona	Ala.	Walker	2.6	38.1	49.4	9.9	2.3	12,550	.....	
Etna	Ga.	Dade	3.5	27.2	64.0	5.3	1.0	14,230	.....	51
Durham No. 5	Ga.	Walker	3.1	20.0	70.5	6.4	1.0	14,190	.....	
Durham No. 4	Ga.	Walker	3.2	16.5	67.6	12.7	0.8	13,610	.....	
Sewanee	Tenn.	Grundy	3.3	28.7	58.0	9.0	0.8	13,260	2300–2700	50–61
U Clifty	Tenn.	Hamilton	2.6	29.7	57.6	8.9	2.5	12,430	.....	

Average or specimen analyses can only be broadly representative and hence must be used with caution. Analyses above, with exception of those for District No. 9, and all grindability figures, are condensed from a comprehensive Bureau of Mines survey covering each bed or seam in each county, state and district. It must be remembered that preparation changes coal characteristics. Bureau of Mines figures are from run-of-mine samples. Screenings would probably show slightly more ash. Prepared coals would show slightly less ash and sulphur, higher heating value and probably higher fusion temperatures. Grindability data (Hardgrove) are from Babcock & Wilcox Co. Bulletin No. 3-241. Being based on different samples, they do not relate directly to the analyses, but serve to give a general picture.

ity or power requirements. The latter are affected by size and type of pulverizer, and by feed size, moisture and fineness. The operator should check behavior of coals in his pulverizer against standard indices to establish a relation between pulverizer performance and grindability.

Coking, Coking. Considerable confusion exists regarding proper use of these two terms. Heating coal drives off volatile matter, leaving behind practically pure carbon. This is *coke*. It may take the form of small powdery particles or may fuse into lumps of varying size and strength. Swelling may occur. In commercial coke-making, "coke" generally refers to lumps of marketable size; *coking* coals make them.

Coke formation, in one shape or another, represents an intermediate combustion stage in any fuel bed; the difference lies in whether a plastic stage occurs and lumps of coke form. Coals that become plastic and form lumps or masses of coke are called *caking* coals while those that show little or no fusing action are *free-burning*.

Caking properties of a coal and the nature of the coke masses formed (size, strength, etc.) are valuable indicators of behavior in fuel beds. A recently adopted test measures *free-swelling index* and a proposed test determines *agglutinating value*, an approximate measure of that material in coal that fuses and becomes plastic.

SIZING OF COAL

Size Stability. Ability of coal to resist breakage is *size stability;* its opposite is *friability*, the tendency to break or crumble into smaller pieces. Where plant conditions make size an important factor, friability must be considered to get a rough idea of the difference likely to exist between size as shipped and as fired. ASTM has two tentative tests for these complementary properties: (1) *drop-shatter* test indicates resistance to breakage from ordinary handling (2) *tumbler* test, the effect of rougher handling in mechanical conveyors, feeders, etc.

Anthracite Sizes. Standard sizes are: *broken*, passing a 4⅜-in. screen, retained on 3¼-in.; *egg*, 3¼ to 2⅞6; *stove*, 2⅞6 to 1⅝; *chestnut*, 1⅝ to 13⁄16; *pea*, 13⁄16 to 9⁄16; *No. 1 buckwheat*, 9⁄16 to 5⁄16; *No. 2 buckwheat rice*, 5⁄16 to 3⁄16; *No. 3 buckwheat (barley)*, 3⁄16 to 3⁄32. *Culm* or *river coal* is refuse from screening anthracite into prepared sizes. It is now often dredged from rivers into which it was originally dumped.

Bituminous Sizes. There is little standardization of either screen openings or names given to sizes. *Run of mine* is unscreened coal as it comes from the mine; a steadily decreasing amount is shipped today because of demand for prepared sizes for domestic stokers, etc. Screen openings usually designate sizes. A "2-in. nut-and-slack" normally means all coal passing a 2-in. screen; amount of different sizes present may vary widely. Occasionally a limitation is placed on percentage of fines. So-called *between-screen* sizes (everything passing one screen and retained on another) give a closer idea unless spread between screens is large.

Coal size affects fuel-bed nature, draft required, density of coke formed, amount of unburned-carbon loss.

PREPARATION, STORAGE

Coal Preparation. Many producers now offer cleaned or washed coals as products having a higher value to users. Cleaning or washing removes impurities and so lowers ash content; it also tends to reduce sulphur in the form of pyrites and raise ash fusion.

Treating coal with refined petroleum oils of 100-600 ssu, or blends of petroleum products, allays dust nuisance in handling by eliminating most of the fine dust and much of the coarse. Treatment remains effective more than a year, even in outdoor storage. Experience seems to show that oil treatment reduces both moisture absorption of coal and freezing troubles. Tests show it does not increase spontaneous heating, nor appreciably affect burning.

Storing. Coal exposed to atmosphere combines with oxygen, liberating heat. Such slow oxidation is called *weathering*. It dulls the appearance of coal, causes reduction in size, impairs firing and coking qualities, and lowers heating value. These changes are practically unnoticeable for anthracite, and slight for most bituminous coals. Low-rank bituminous coals and lignite suffer more markedly. Loss of heating value over a 5-year period might run 1-3% for West Virginia and Pennsylvania coals, 4-6% for Illinois.

If heat liberated by oxidation is confined to a small area, temperature rises, increasing reaction rate. This cycle of rising temperature and faster oxidation continues until "hot spots" form and *spontaneous* combustion occurs.

To guard against such troubles: (1) Remember that small sizes pack tighter and present more surface, making them likelier to heat. (2) Avoid piling coal in hot weather or in a heated space. (3) Don't crush before piling, and watch pile closely during first three months since fresh surfaces oxidize more readily. (4) Avoid segregation of sizes by building the pile up in layers, leveling off and compacting each. (5) Check pile regularly, especially 5 to 8 ft below the surface of the flanks—temperature over 140-150 F means danger point is reached at which coal must be withdrawn. For storage details, see POWER, Sept. 1942, p 643.

Sampling. Coal composition varies within a given seam or mine and even between points several feet apart on the face. Although shipped from one point, coal composition varies from car to car and from one part of a car to another. Understanding the nature of all these variations makes it possible to use laboratory tests intelligently.

To begin with, a laboratory analysis, according to approved standards, represents within an extremely small margin of error characteristics of the sample on which it is made. How well the analysis represents the lot of coal involved depends on sampling methods. Until recently, size of gross sample was thought to be of major importance for accurate sampling.

Recent research shows accuracy of sample depends on number and size of increments composing it rather than on its weight. Proof of this point makes possible use of much smaller samples and simplifies reduction of gross sample to laboratory dimensions.

SAMPLING PROCEDURE

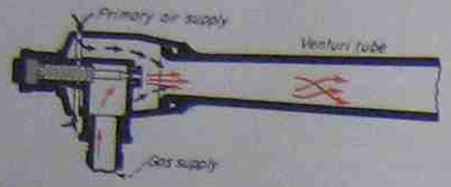
New ASTM standard distinguishes between "commercial" and "special-purpose" sampling and bases sample size and number of increments on coal size and expected ash content. Note that *increment* refers to quantity of coal obtained by a single sweep of the sampling instrument; where possible coal should be sampled while in motion.

The standard provides for mechanical sample preparation and subdivision by large and small *riffle samplers* like those used in the laboratory. Commercial procedure is designed so 95% of test results fall within plus or minus 10% of ash content of coal sampled. Correct determination of ash value indicates accuracy of other results.

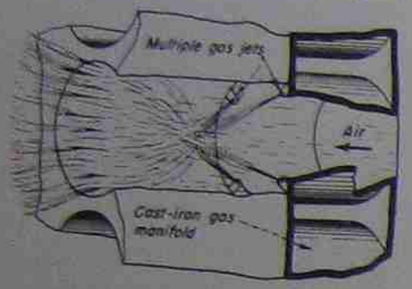
Knowing how closely a given analysis represents a given sample and lot of coal, we need also to know how reliable one test may be in predicting the average for a series of shipments, or, if average quality is known, what variation might be expected in individual shipments. Recent research shows that for bituminous coals of less than 9% ash, one-half of ash determinations depart from the average by no more than 0.5%; for coals of more than 10% ash, deviation is about twice as much.

Common sense indicates that one test from one sample from one shipment is a poor guide. Statistical studies show that an average of ten shipments is three times as accurate as a single test while an average of 20 tests is 4.5 times as accurate. Beyond 20 tests, gain in accuracy is small.

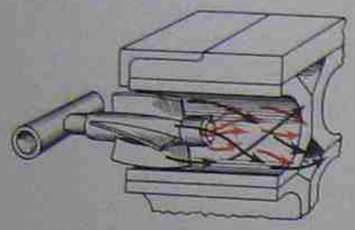
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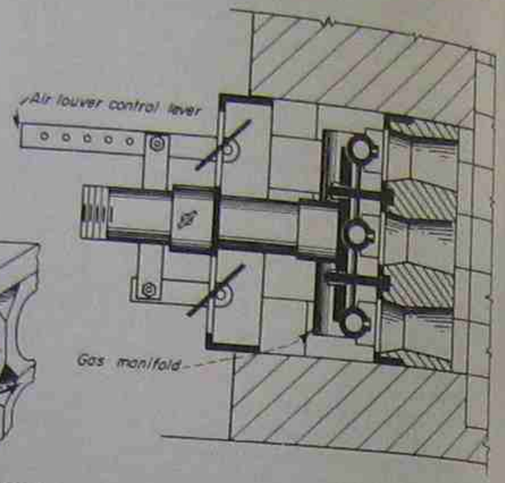
1 Atmospheric gas burners pull in their primary air for combustion by the action of a stream of low-pressure gas expanding through an orifice



2 Premixing of fuel gas and air needed for combustion takes place in a mixing chamber outside the furnace proper



3 Vanes placed in the path of incoming air to this tunnel burner act to impart swirling motion to stream



4 Gas issues from a number of spuds connecting to vertical and horizontal manifolds. Primary air enters around the spuds

Burning Gas

Knowing something about the general process of combustion and the various fuels met in power-plant practice, we're now ready to tackle the next element—firing equipment. Its job is to prepare the fuel, bring fuel and air together in proper proportions and, with the help of the furnace, ignite and burn the fuel-air mixture continuously.

GAS

On the face of it, burning gas is simple, because the fuel is ready for combustion and requires no preparation in the strict sense of the word. Nevertheless, the remaining parts of the job—proportioning, mixing and burning—can be handled in a variety of ways and their characteristics need to be known for sound selection of equipment and successful operation.

Atmospheric Burners. Gas burners differ mainly in the way air and fuel mix. Perhaps most familiar is the so-called *atmospheric* burner. One form appears quite generally in the ordinary household gas range. In it the momentum of the incoming low-pressure gas stream is used to draw in, or *aspirate*, part of the air needed for combustion. A shutter or similar device regulates amount of air so induced. Gas and air together pass through a tube leading to the burner ports, mixing in the process. The mixture burns at the ports or openings in the burner head (with a blue, nonluminous flame. Secondary air is drawn into the flame from the surrounding atmosphere. Larger counterparts of this general burner type, having ring or sectional burner heads with many ports, are used to fire small boilers and industrial equipment.

A single-port atmospheric burner is shown in Fig. 1. Needle valve controls gas flow through the spud; air is drawn in around the shutter at the end. The resulting mixture passes through the tube and burns at its end. Single-port burners may be grouped, several banks high and wide, to serve larger furnaces.

Although physically simple, such a burner must be proportioned with considerable skill to conserve the relatively small amount of energy in the low-pressure gas stream. It is this energy which entrains the primary air. How well this is done depends on primary-air percentage, gas-orifice size, ratio of mixer throat to burner port area and, in boilers especially, furnace draft.

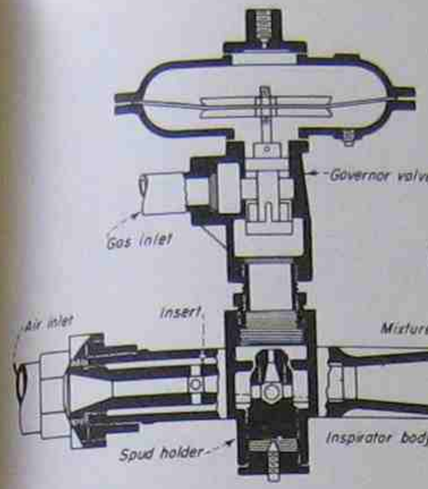
Premix Percentage. With burner-port size and shape fixed, nature of burning depends largely on amount of primary air, or *premix*. With premix low, flame is long and pale blue. It may have a yellow tip, indicating, as we have seen, some cracking and presence of free carbon. Increasing primary air shortens the flame as burning becomes more rapid, and a greenish inner cone appears. When speed of burning, or *flame propagation*, exceeds that of gas issuing from the port, flame flashes back into mixing tube.

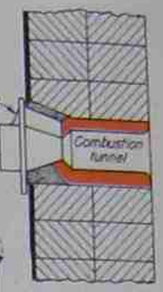
Operation is generally satisfactory with 30 to 70% premix; in some special designs 100% primary air is used. This premix range gives a turn down, or capacity range, of about 4 to 1. Usually premix and capacity ranges are somewhat narrower.

Secondary air is usually drawn in around the burner and the amount thus depends on the area of the opening and the draft. Control may be effected by varying draft or, sometimes, by adjusting opening area by shutters.

The so-called atmospheric burner is one example of a general class, in which the energy of one fluid is used to aspirate the other and in which part or all primary air mixes with the fuel in the burner body. The "high-pressure" burner uses gas at about 20 to 30 psig and air at atmospheric pressure. Another type uses compressed air, and the gas is at atmospheric pressure. The burner of Fig. 6 expands high-pressure gas through two venturi-sections in series to obtain thorough mixing in a short distance.

Refractory Burners. For boiler firing, a somewhat different type of burner finds wide use. It depends on natural or fan draft to draw in all air required for combustion; hence draft conditions are most important. Design of Fig. 2



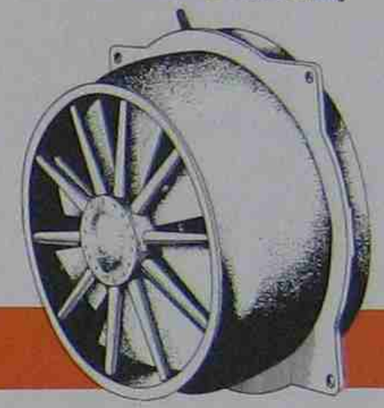




6 Two-stage burner operates on high-pressure gas; passes it through two venturi sections in series. Primary air enters shutter, at left, under induction

7 High-pressure gas issues from jets in the spider and reaction spins the spider to rotate the fan. Resulting turbulence gives prompt, thorough mixing

5 So called low-pressure gas-burner systems work with air under pressure and gas at atmospheric conditions. An inspirator governor, left above, delivers gas-air mixture at proper pressure to burner blocks, right above



and Oil

employs multiple gas jets, which discharge into the air stream in such a way that violent agitation results in a short mixing tube or tunnel of refractory. In the burner of Fig. 3, turbulence vanes impart a swirling motion to the air entering the tunnel. Each of the small jets of gas issuing from the multiple-jet orifice entrains with the air and impinges it outward against the tunnel walls. This action gives turbulent, thorough mixing.

In the burner shown completely assembled, Fig. 4, vertical manifolds connect horizontal tubes, which contain individual gas orifices for the 15 tunnel blocks forming the complete burner (3 high, 5 wide). Louvers in front of the burner assembly control air admission. Each orifice discharges into a refractory mixing tube or tunnel.

In burners of this type the refractory tunnel aids in heating the mixture for ignition and protects metal burner parts from high temperature. The flame can be made relatively luminous, for high radiant-heat transfer.

Large steam-generating units often employ a high-pressure (2 to 25 psi) gas burner of the gas-ring, Fig. 20, center-diffusion tube, or turbulent, Fig. 7, design. The gas-ring, Fig. 20, has an annular manifold located between air register and furnace wall surrounding burner opening. Orifices drilled in this ring spray gas angularly across an incoming air stream controlled in quantity, velocity and rotation by the registers.

Fan-Mix Burner. In the burner of Fig. 7, gas issues from jets drilled at an angle in a rotating spider. Resulting reaction spins the spider and with it the connected fan. A shutter controls air drawn in, to maintain desired fuel-air ratio. Thorough mixing of gas and air result from the turbulent interaction of jets and air stream; combustion is completed close to the burner.

Thus far we have talked of designs in which fuel and air mix in or at the individual burner. Higher burner head pressure to overcome variable furnace draft, high overload capacity, uniform air-gas mix at all loads, and single-valve control may be had in a system in which mixture is made at one point and supplied to several burners. Such a system is shown in Fig. 5. This is the low-pressure type; gas is at atmospheric pressure while air is at 1 to 2 psi.

Inspirator Governor. Heart of the system is the inspirator governor, left, Fig. 5. Air passes through the venturi tube at high velocity to create a low-pressure region at the end of the straight run where gas ports are located. This pulls atmospheric-pressure gas through the ports into the throat and produces mixing. As the mixture expands through the inspirator body its velocity is converted to pressure.

Gas enters the governor under pressure and flows through the governor valve. A passage through the governor valve keeps pressure at governor outlet and on the under side of the diaphragm the same. With atmospheric pressure on the other side of the diaphragm, governor delivers gas at atmospheric pressure.

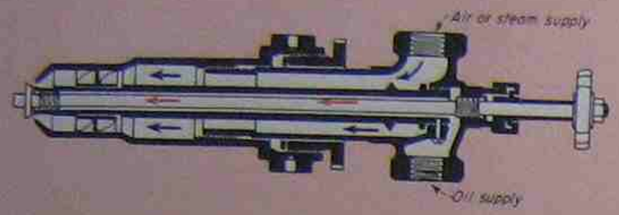
The mixture leaving the inspirator governor contains all air needed for combustion. An air valve controls the burning rate. The complete gas-air mixture goes from the inspirator-governor to a number of individual burners, usually the tunnel type shown at the right in Fig. 5. This principle of supplying a complete mixture to a number of burner units is also found in systems operating with high-pressure gas and atmospheric air.

OIL

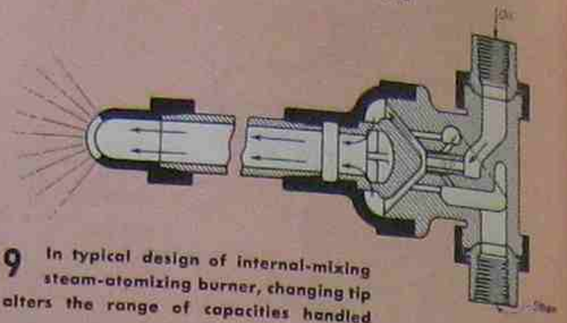
In addition to proportioning fuel and air, and mixing them, oil burners must prepare the fuel for combustion. There are two ways of doing this, with many variations of each: (1) The oil may be vaporized or gasified by heating within the burner, or (2) it may be *atomized* by the burner so vaporization can occur in the combustion space.

Designs of the first group, usually called *vaporizing burners*, are necessarily limited in range of fuels they can handle and find little power use.

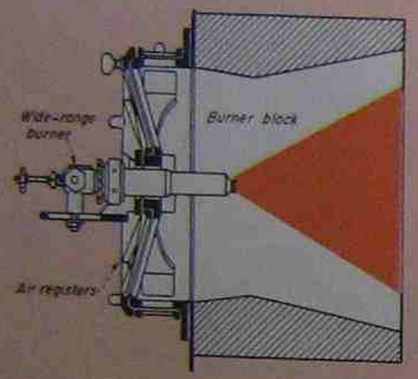
THESE BURNERS ATOMIZE FUEL OIL BY ACTION OF STEAM OR AIR

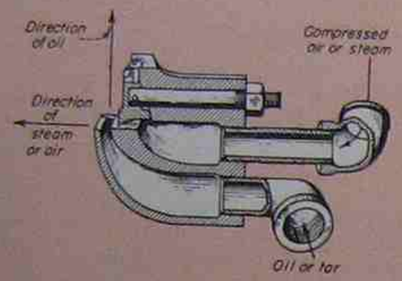


8 Steam-atomizing burner of external-mixing type, above, brings oil and atomizing medium, steam, together at the burner tip. Register, below, has damper vanes to regulate the air supplied

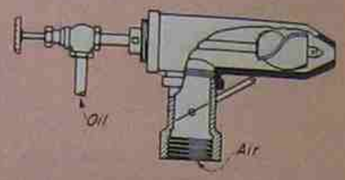


9 In typical design of internal-mixing steam-atomizing burner, changing tip alters the range of capacities handled





10 In this external-mix oil burner a steam jet hits the emerging oil at right angles as the oil leaves the burner; gives turbulent mixing action



11 Low-pressure air serves as atomizing medium for this burner, meeting oil at the tip and breaking it up. Air atomization finds relatively little use because cost is often high

If oil is to be vaporized in the combustion space in the instant of time available, it must be broken up into many small particles to expose as much surface as possible to the heat. This atomization may be effected in three basic ways by: (1) using steam or air under pressure to break the oil into droplets (2) forcing oil under pressure through a suitable nozzle, and (3) tearing an oil film into drops by centrifugal force. All three methods find use in practical burners.

Turbulence Necessary. In addition to breaking the oil into small particles for fast vaporization, the burner must provide motion between oil droplets and air, so vapor "coats" are stripped off as fast as they form and fresh surfaces exposed. This calls for penetration of the oil particles in the proper direction and for a high degree of turbulence in the air. Such relative motion of oil and air helps to produce more uniform mixture conditions over the combustion zone.

Hydrocarbons, as we have seen, burn by hydroxylation and by cracking. In practice, both forms are present, although the usual oil-burner flame is predominantly the latter type. This characteristic short yellow flame has good radiating characteristics and fits usual combustion spaces well. It carries, however, solid carbon particles, which, if their burning is stopped by any chilling action, form soot. Depending on the nature of the chilling, the soot may deposit on heating surfaces or may be carried out the stack as a major constituent of smoke.

Pure hydroxylative burning, while free from soot and smoke possibilities, yields a less radiative flame and can be produced only in certain types of burners. Thus, as in many engineering matters, we compromise and strive to introduce enough hydroxylation into a predominantly cracking process to keep the flame clean and reduce smoking tendencies. Hydroxylation is encouraged by thorough atomization, suitable preheating of both oil and air, and exposing the mixture to a gradually increasing temperature over not too short a time.

Steam-Atomizing Burners. Let's look now at practical oil-burning equipment. Oldest form is the steam- or air-atomizing burner. Installation is relatively inexpensive and simple, especially where no attempt is made to control steam and oil supply simultaneously. Steam-atomizing burners, as a class, possess ability to burn almost any fuel oil, of any viscosity, at almost any temperature. Air is less extensively used as an atomizing medium because its operating cost is apt to be high.

These burners can be divided into two types: (1) internal-mixing or premixing—oil and steam or air mix inside the body or tip of the burner before being sprayed into the furnace, Fig. 9, 11, and (2) external-mixing—oil emerging from the burner is caught by a jet of steam or air, Fig. 8, 10.

Steam consumption for atomizing runs from 1 to 5% of steam produced, usually averaging around 2%. Pressure required varies from about 75 to 150 psi, and steam can be taken from: (1) a low-pressure line (2) a desuperheater with a pressure reducer, or (3) a drum vent, through an orifice and regulating valve. Oil pressure need only be enough (usually 10 to 15 psi) to carry oil to the burner tip.

External Mixing. In the burner of Fig. 8, oil reaches the tip through a central passage, flow being regulated by the screw spindle, right. Oil whirls out against a sprayer plate to break up at right angles to the stream of steam, or air, coming out behind it. The atomizing stream surrounds the oil chamber and receives a whirling motion from vanes in its path. When air is used as the atomizing medium in this burner, it should be at 10 psi for lighter oils and 20 psi for heavier. Combustion air enters through a register, shown below in Fig. 8. Vanes or shutters are adjustable to give control of excess air.

Fig. 10 shows another external-mixing design. Oil and steam discharge through separate nozzles at right angles to each other, the steam breaking up the oil stream.

Internal Mixing. Fig. 9 and 11 give examples of the premixing principle. In Fig. 9, steam and oil meet and mix well within the burner body. Energy in the steam serves to force the steam-oil mixture through the nozzle for atomization. Burner of Fig. 11 brings oil and air under pressure together at the burner tip for mixing before discharge into the furnace.

Mechanical Atomizing. Now let's look at another major burner class, mechanical atomizers, Fig. 12 to 15. Good atomization results when oil under high pressure (75 to 200 psi or higher) is discharged through a small orifice, often aided by a slotted disk. The disk gives the oil a whirling motion before it passes on through a hole drilled in the nozzle, where atomization occurs. For a given nozzle opening, atomization depends on pressure and, since pressure and flow are related, best atomization occurs over a fairly narrow range of burner capacities (about 40%).

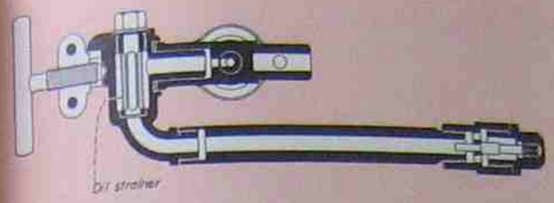
To follow a fluctuating boiler load, a number of burners may be installed and turned on or off as steam demand varies; or burner tips with different nozzle openings can be applied to a single burner body.

Wide-Range Designs. Oil-burner manufacturers have developed many designs to extend the usual 1.4 to 1 capacity range of the mechanical-atomizing nozzle. One, for example, features a plunger that opens additional tangential holes in the nozzle as oil pressure increases. This gives a 4 to 1 range. Another design, Fig. 13, employs a movable control rod, which, through a regulating pin, varies the area of tangential slots in the sprayer plate and the volume of oil passing the orifice.

Still another variable-capacity design, Fig. 14, delivers oil at high pressure (350 psi) at a constant rate, but discharges through the nozzle only the quantity needed to meet steam demand. The remainder recirculates.

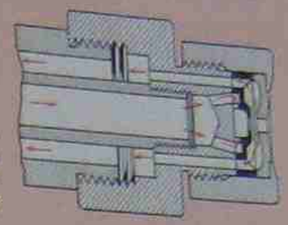
Fig. 15 shows a wide-range mechanical atomizer which, when combined with either of the pumping systems shown in Fig. 16, will give a capacity range of about 15 to 1, and considerably higher if needed. By use of either a constant-differential valve or pump, as shown, difference in pressure between supply and return is held constant. This maintains a uniform pressure drop across the tangential slots in the burner tip and creates a constant atomizing force. The valve system is simple to install and maintain, but the pump system offers advantages in many plants: (1) No hot oil is returned

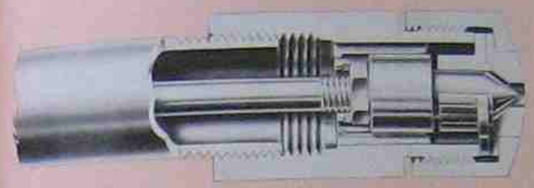
THESE BURNERS ATOMIZE OIL UNDER PRESSURE BY MECHANICAL MEANS



12 Mechanical-atomizing burner receives the oil under pressure, about 225 to 300 psi, and at an optimum viscosity of about 150 ssu. Orifice atomizes the fuel

14 With fixed orifice size, best atomization occurs in narrow flow range. Design at right obtains wide capacity range by supplying oil to burner tip at a constant rate in excess of demand. Oil burned varies with the load, rest is returned



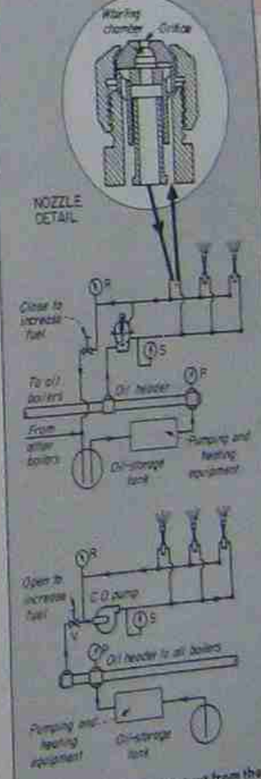


13 Movable control rod, center, through a regulating pin, varies the area of tangential slots in sprayer plate and volume of oil passing through orifice, right. With oil kept at 300 psi and 200 ssu, range is 10 to 1



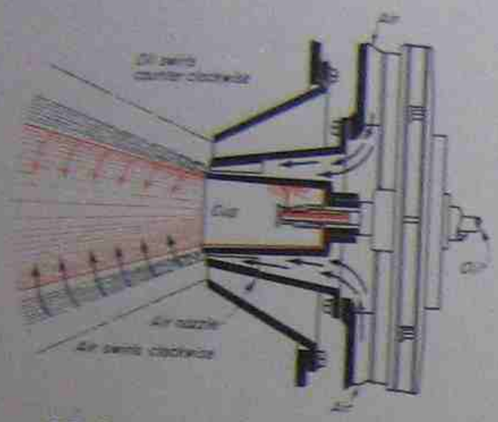
15 Wide-range burner above operates on constant-differential systems shown, Fig. 16

HOW ONE WIDE-RANGE SYSTEM OPERATES

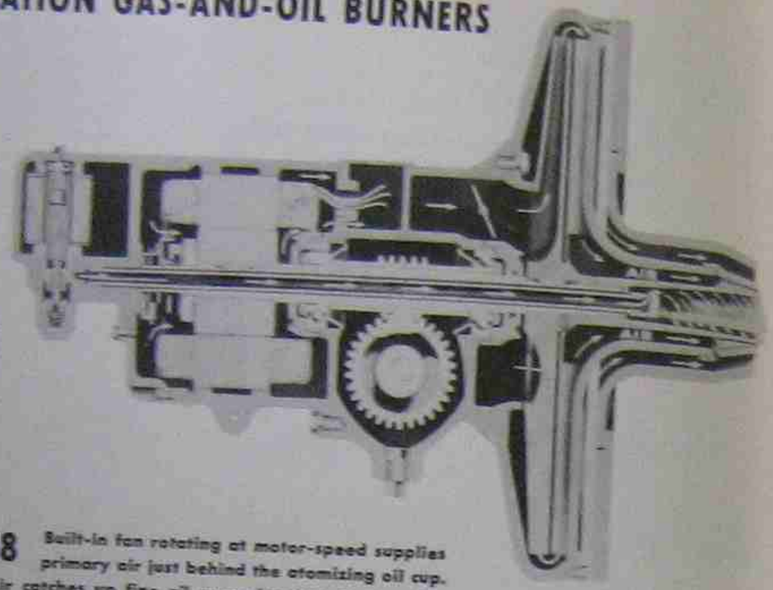


16 Regulation of output from the wide-range burner of Fig. 15, whose atomizing and whirling end shows above, can come from either a constant-differential valve or a constant-differential pump to hold pressure across supply and return

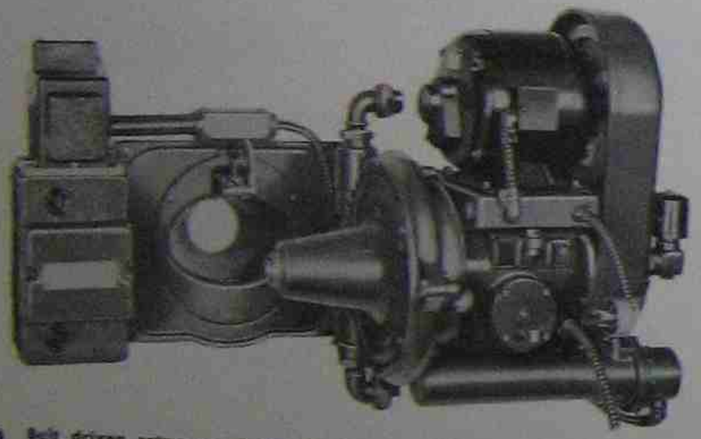
ROTARY-CUP AND COMBINATION GAS-AND-OIL BURNERS



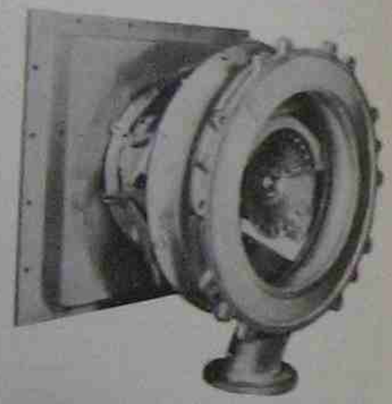
17 Cup revolving counterclockwise breaks up oil film at rim by centrifugal force and discharges into a clockwise air stream



18 Built-in fan rotating at motor-speed supplies primary air just behind the atomizing oil cup. Air catches up fine oil spray leaving at cup edge



19 Belt driven rotary-cup burner carries a fuel-oil reservoir to insure positive feed, and a submerged electric heater to hold oil at correct temperature. Gas pilot mounted overhead, together with low-voltage system, serves to ignite the oil



20 Combination gas and oil burner uses either fuel or both together; some register regulates primary air supplied

to storage tank or pump suction. (2) Fuel enters the closed circuit at the same rate it is burned, simplifying fuel metering and combustion control. (3) Pump may be used to boost pressure on existing oil-burner systems.

Rotary-Cup Burners. Third major class of oil burners, the horizontal rotary cup, atomizes fuel oil by literally tearing it into tiny droplets. A conical or cylindrical cup rotates at high speed (usually about 3500 rpm if motor-driven). Oil moving along this cup reaches the rim where centrifugal force flings it into an air stream, Fig. 17.

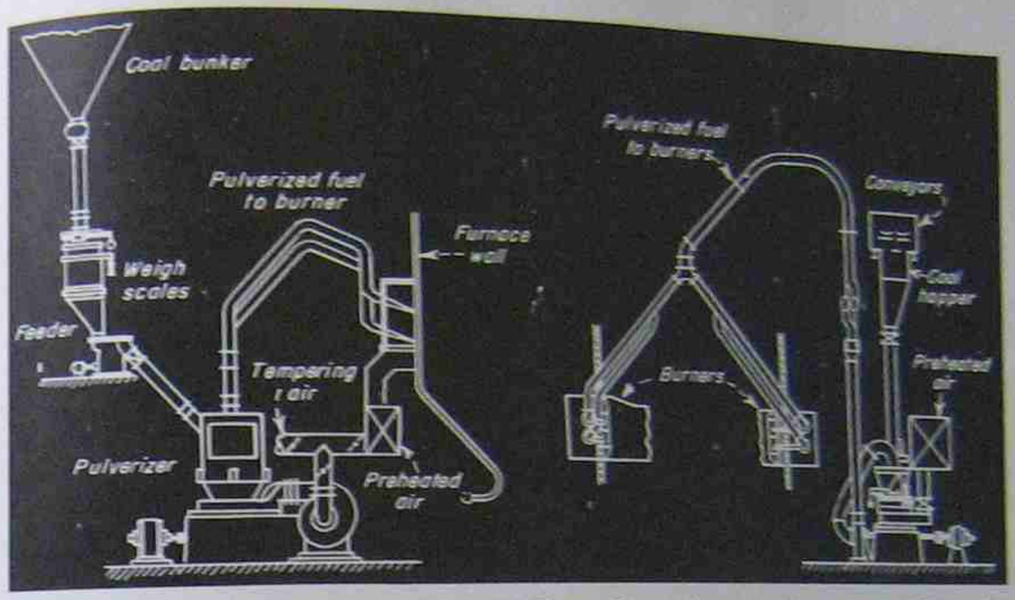
This system of atomizing requires no oil pressure beyond that needed to bring oil to the cup, and proves attractive in installations where only low-pressure steam is available. High oil preheat temperatures must be avoided since gasification may develop. The rotary cup can satisfactorily atomize oils of high viscosity (300 ssu), however, and has a wide range, about 16 to 1.

Fig. 18 shows a burner with a built-in driving motor, while Fig. 19 shows one with a belt drive. It also indicates provision for swinging the burner out of the furnace.

Gas and oil burners are often combined, as in Fig. 20. Designs of such combinations vary widely, both in nature of oil unit and gas unit. Their ability to handle either of the two fuels, or both at once, proves desirable in locations where both are available.

Burner Maintenance. Properly maintained, modern oil burners give highly satisfactory service. For peak performance, make sure that the burner gets uniformly free-flowing oil, clear of sediment that clogs burner nozzles. This means avoiding sludge buildup in storage tanks and keeping strainers in good condition. Preheat temperature must be right for fuel and burner type, and must be uniform.

Keep burners in good condition by watching for wear caused by abrasion of ash in fuel, and for carbon buildup. In rotary-cup burners, worn rims cause poor atomization. If cups are not properly protected after being turned off, carbon forms on the rim. When burner is shut down always take out the cup and insert a flame shield. Worn or carbonized mechanical-atomizing nozzles play hob; replace worn nozzles and keep them clean.



1 In this pulverized-coal firing system, pulverizer is held under positive pressure by forced-draft fan, must be tight

2 Exhauster fan puts negative pressure on mill but requires that special precautions be taken against severe fan wear

Burning Pulverized Coal

Ground to the fineness of flour, coal flows in pipes and handles in a furnace much as does oil. The job requires equipment for drying and pulverizing the coal, transporting it to the furnace in an air stream and injecting it along with the air needed for combustion.

Suspension Burning. Within a fraction of a second after one of these minute particles enters the furnace and is exposed to radiant heat, its temperature rises and the volatile matter distills off. Enough air (*primary air*) is introduced at the burner, intimately mixed with the stream of coal particles, to burn gas resulting from separate distillation of each particle in the stream. The volatiles, mostly hydrocarbons, ignite more easily than the carbon remaining in the particle and heat the latter to incandescence. *Secondary air*, introduced around the burner, sweeps past the hot carbon particles and gradually burns with them in a flame several feet long.

This job of grinding, transporting and injecting coal into the furnace may be handled in a number of ways. Originally the preparation phase was entirely separate. In the so-called *bin* system, coal was dried, pulverized, separated from the air used in the pulverizing mill, and stored to await demand. Being divorced from furnace operation, this system could operate at best capacity with constant fineness. Storage reduced need for spare pulverizer capacity. Burners could be controlled separately with ease.

Unit System. The *direct-firing* or *unit* system is now almost universally used in new plants. In it, pulverizers feed burners directly. There is no storage; pulverizer operation thus fluctuates with steam demand. This system is not only simpler, involving less equipment, but it avoids storage-bin fire hazard as quantity of pulverized coal never exceeds that in the mill and in the short lengths of piping to the burners. Elimination of a separate mill house, pulverized-coal storage, conveyors and feeders reduces capital outlay. Built into today's systems is the flexibility needed to handle various functions under a wide range of load and coal conditions.

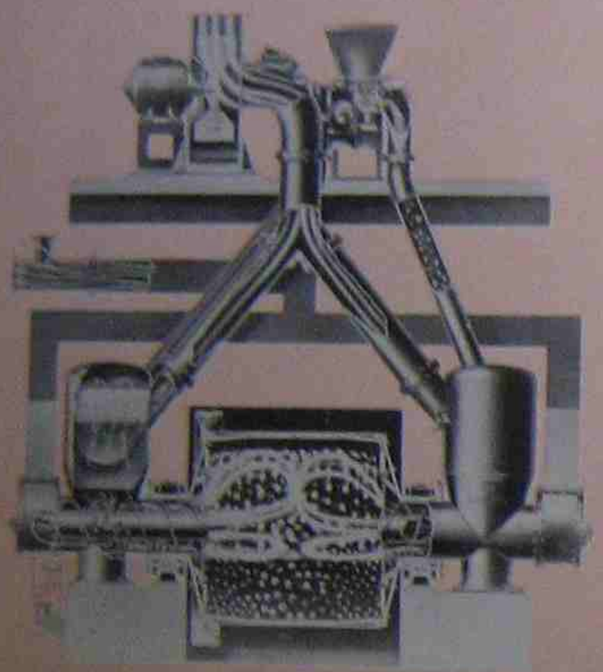
Heart of the unit system is the pulverizer, with its equipment for feeding raw coal at the proper rate, grinding the coal to desired fineness, classifying the finished product so oversized particles are returned to the mill and delivering the coal in its transport air.

Basic Arrangements. In most mills, air performs three functions. It dries the coal, classifies the pulverized fuel leaving the grinding elements and transports the finished product to the burners. The mill and its associated fan can be arranged in either of two basic ways. In one, a forced-draft fan outside the mill supplies it with air under enough pressure to carry out the jobs to be done in the mill and to transport the coal to the furnace. The fan handles air only, which is an advantage, but the pulverizer must be kept tight.

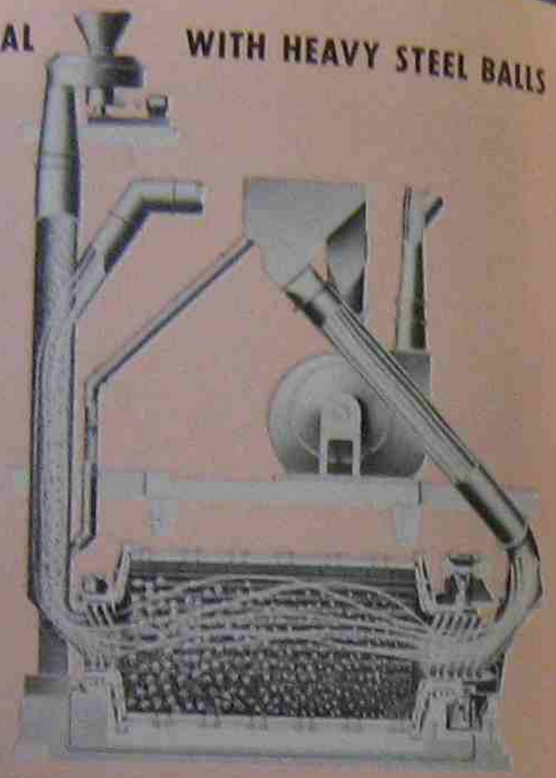
In the second scheme, the mill is under negative pressure developed by an exhauster fan, which may be combined with the pulverizer proper, or mounted externally. Since it handles air laden with coal, it must be designed to resist wear. Fig. 1 and 2 show typical layouts of each type.

Coal Preparation. Before taking a look at pulverizer construction, let's consider some factors that affect operation. First comes the matter of raw-coal size. Many plants receive, either regularly or occasionally, run-of-mine coal. While the usual feeder provides for rejecting oversized pieces, it is well to take as much load off the mill as possible. Thus some form of coal-crushing equipment represents a good investment. A further precaution for an

THESE PULVERIZERS TUMBLE COAL WITH HEAVY STEEL BALLS



3 Ball-mill pulverizer resembles a tumbling barrel with its rotating drum filled with coal and many heavy steel balls



4 Coal enters air-swept tube mill through feeder, upper left; leaves at right end of mill under pull of exhauster, above

uninterrupted and uniform supply of raw coal is a magnetic separator somewhere ahead of the pulverizer feeder. It removes tramp iron, which might block the feeder.

Usually a pulverizer does its job best when supplied with raw coal having definite size limits. These vary somewhat with mill size. In general, small mills do best on coals up to about ¾ in. top size. For medium and large mills, best top size goes up to about 1 in. and 1¼ in., respectively. For any specific mill the manufacturer's recommendations should govern.

Fineness. Quality of mill output, or *fineness*, is a highly important factor. It is normally expressed as the percentage of pulverized coal passing through a sieve with openings of a specific size. Commonest sizes for pulverized-coal testing are 50-mesh for determining oversize, and 200-mesh for powdered dust. Number of openings per lineal inch fixes the mesh of a screen. The 50-mesh sieve, for instance, has 50 openings to the inch, or 2500 to the square inch.

Fineness of pulverization obtained from a mill depends on a number of factors: Grindability, ash content and moisture of the coal may be some of these. The fineness desired likewise depends to a great extent on coal characteristics and the way they affect behavior in the furnace. For example, coking coals, when exposed to furnace temperature, swell and form lightweight, porous coke particles. These can easily float out of the furnace before they are burned. As a result, carbon loss can run high unless pulverization is very fine. Free-burning coals do not have the same swelling characteristic and hence do not require the same fineness.

Effect of Volatile. Again, high-volatile coals ignite more readily than low-volatile. And since ease of ignition dictates somewhat the degree to which fineness is carried, it follows that high-volatile coals as a class need less-fine pulverization than do low-volatile coals. On the other hand, low-volatile coals, with the single exception of anthracite, have higher grindabilities, because they are softer. The balance of these compensating factors determines results in any given case.

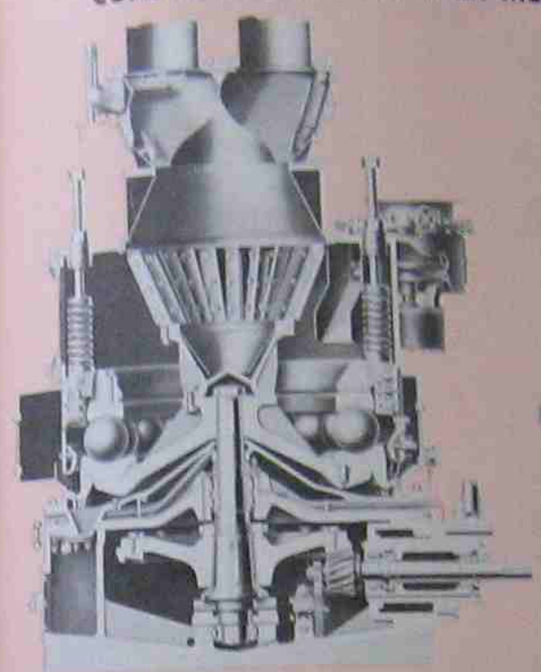
Before turning to any consideration of fineness specifications, it would pay to see more exactly what the term means. Coal from a pulverizer consists of a continuous band of particle sizes from coarsest to infinitely fine, distributed according to laws of probability. Plotting amount of each size yields a typical frequency curve, with a peak at some particular size. Shape of the curve and size occurring in greatest amount depends on the coal and the pulverizer.

In power plants, prime purpose of pulverizing is to eliminate oversize. No matter what the percentage of coal that will pass 200-mesh, as little as 5% over the 50-mesh limit may result in slagging and increased combustible loss. That is why most specifications call for at least 98% through 50-mesh.

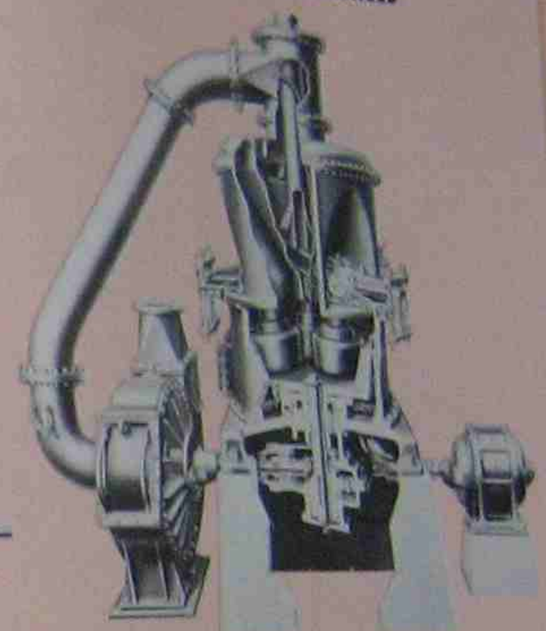
Economical fineness may be defined as the point where total cost per lb of steam, including fuel, operating and capital costs, becomes a minimum irrespective of boiler efficiency. This recognizes the fact that reduction of a small percentage of coarse particles, to obtain complete combustion in the furnace, may require an increase in operating and capital cost that is out of proportion to the value of the gain in efficiency.

Mill Capacity. What about factors affecting mill capacity? Just as with fineness there are several. Mill capacity does not vary in direct proportion to

COAL IS GROUND BETWEEN MOVING SURFACES IN THESE MILLS



5 Pulverization takes place between balls and grinding rings. Adjustable springs maintain grinding pressure and fineness



6 Whirling bowl and rollers mounted on pivoted axes reduce to a powder coal thrown between them by centrifugal force

grindability. Ash and moisture content of the coal, and fineness desired, may play important parts.

A basic premise in setting mill capacity is the assumption that enough heated air will be available to dry the coal. If this is not the case, it is the drying operation that limits mill output, not grinding. Thus it may be possible to obtain more capacity with a dry coal of lower grindability than with a wet high grindability coal.

Nevertheless, a knowledge of grindability properties is helpful information in rating a pulverizer. In recent years manufacturers have developed correction factors that take into account influence of coal properties.

Drying Coal. Let's look at one more problem common to all pulverizing before examining specific mills. That common problem is moisture and specifically *surface* moisture. *Inherent* moisture, that is, moisture actually held within the coal, does not greatly affect pulverization. Drying of coal undergoing pulverization, then, need only be enough to remove objectionable surface moisture.

The extent of drying that can be done within a given mill depends somewhat on its design. For example, most mills are arranged so incoming wet coal mixes immediately with the drier coal inside. Without this quick mixing mill feed end may plug with wet coal.

Primarily, though, the amount of heat that can be introduced measures the success or failure of the drying step. Where air flow acts as the drying medium (the most usual arrangement) the mill must be able to handle fairly large volumes of high-temperature air. Conditions within the mill should be held at a relative humidity below that of saturation at mill outlet temperature, roughly 150-160 F.

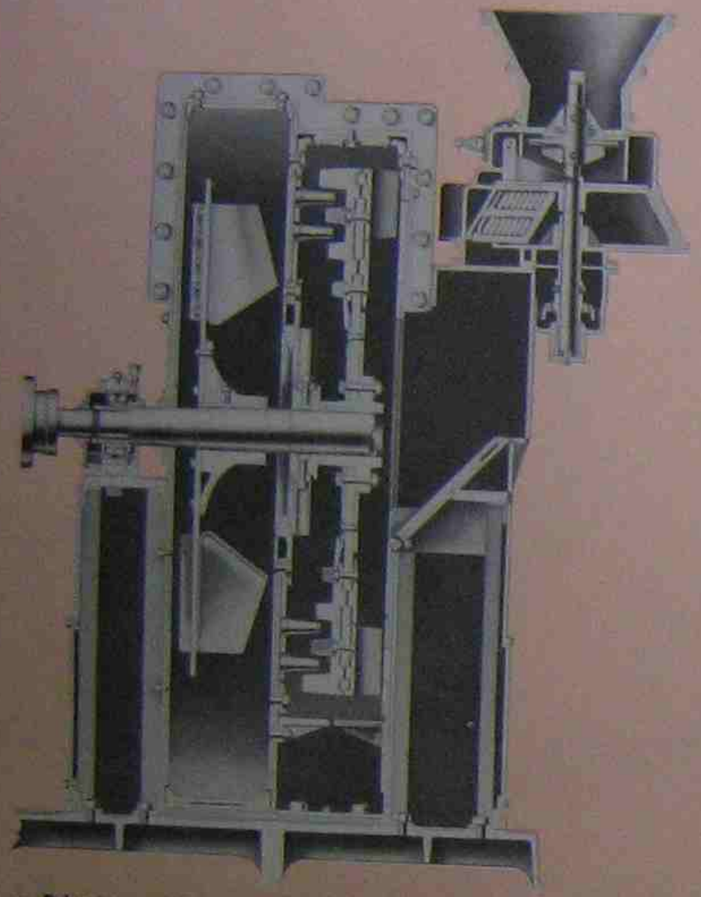
Air Supply. With today's steam-generating units, a supply of preheated air at about 500 F or higher, depending on coal moisture, can be obtained readily. The mill should be so constructed that it can handle air at this temperature without need for tempering to avoid preignition with dry coals.

We are now ready to look at typical current pulverizer designs. These employ three basic forces, singly or in combination: (1) impact (2) attrition, and (3) crushing. The nature of these forces becomes apparent when their application is seen.

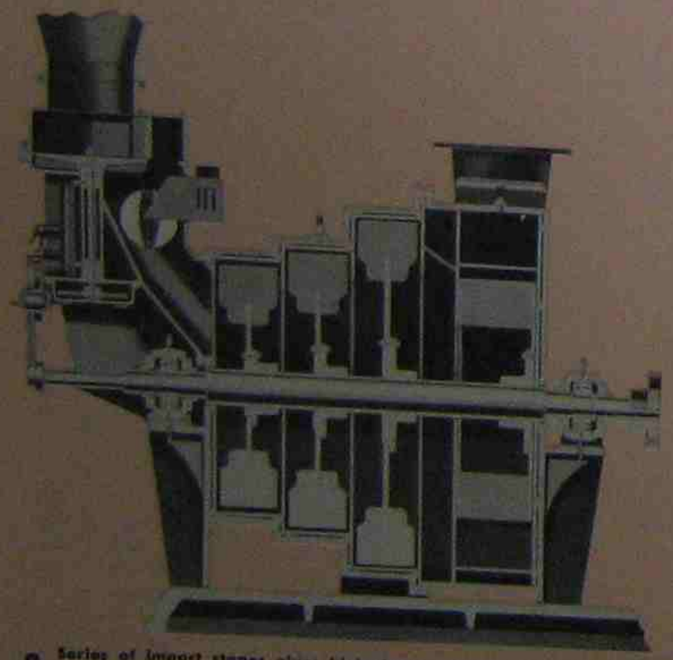
Ball Mills. The ball mills of Fig. 3 and 4 are essentially horizontal rotating cylinders somewhat longer than they are round. This physical shape leads some to describe them as tube mills. Usual design employs cast liners for the interior. Steel or special alloy balls, ranging from 1 to 2 in. in diameter, are dumped into the drum and fill it to just under half full. The mill rotates slowly, depending on tube diameter, but speed is of the order of 20 rpm. The balls carry part way around the cylinder circumference, then slide back toward the bottom. Coal, intermingled with the balls, undergoes impact from falling balls and attrition and crushing from the sliding mass.

Classifying Action. Hot air passes through the mill to dry coal, classify it after grinding, and transport finished product to burners. Operation of a typical classifying arrangement can be seen in Fig. 3. Passing through main vertical body of classifier, coal-air stream undergoes sharp change in direction, which throws out oversized particles. These *tailings* reenter the mill with incoming raw coal. Coal-air stream leaving classifier carries only coal that meets desired fineness limits. Opening the bypass damper in the scroll of the classifier increases coal output and reduces fineness.

IMPACT IS THE MAJOR FACTOR HERE



7 Pulverizer combines impact, attrition forces to powder coal in two steps. Hammers in first stage supply impact and pegs in second furnish attrition



8 Series of impact stages gives high degree of coal fineness at pulverizer outlet. Preheated air dries coal. Exhauster fan can be seen at right end

Returning oversized particles, which have already been dried, helps general operation by reducing average moisture content of coal entering the pulverizer and cuts down any tendency of incoming coal to plug at the inlet.

Crushing Action. Fig. 5 and 6 show pulverizers that grind coal between two surfaces moving in relation to each other, with crushing as the principal pulverizing force. One design, Fig. 5, employs as the moving elements balls that are held between two races. Grinding pressure is adjusted by controlled tension of springs shown in cutaway.

Coal in the raceway between and around the balls is subject to various pulverizing forces as the balls rotate. The entire mill operates under pressure. An outside fan blows a stream of preheated air through it to dry, classify and transport pulverized coal.

The mill of Fig. 6 has a grinding ring carried by a revolving bowl whose rim speed is about 1200 fpm. Stationary rolls, preloaded by springs, are set so they do not contact the ring. When incoming coal reaches the spinning bowl, centrifugal force throws it against the slant-faced grinding rim and into contact with the rolls. Ground coal is thrown from rim into annular passage surrounding it. Here partial classification takes place with heavy particles rejected back to the grinding ring by deflecting plates.

Remaining coal particles carry along on the exhauster-induced air stream into the classifier, where the stream undergoes a whirling motion to dislodge heavier particles. To a large extent, adjustable vanes on the classifier set the fineness of output.

Impact, Attrition. Fig. 7 illustrates a mill combining impact and attrition forces, working under suction. A series of hammers make up the primary pulverizing stage into which flows a stream of hot air pulled in by fan action of the hammers. Partly ground coal passes around the outside of the rotor into the final pulverizing stage, which consists of pegs on a rotating disk that travel between stationary pegs. Coal in the turbulent air stream rubs against pegs and other coal particles to be reduced by attrition. A fan pulls out the fines; rejector arms in the path of this coal-air stream return heavy particles.

Impact Pulverizer. The pulverizer of Fig. 8 consists of a series of impact stages with an exhauster fan at the mill outlet. As coal-air mix proceeds from stage to stage, individual particles become progressively finer. Preheated air enters at the left to perform its usual functions of drying and transporting.

A rather different treatment of the

basic pulverizing forces shows in Fig. 9. Here raw coal from a supply hopper is pushed by a feeder shoe into the grinding chamber below the rotating element. Incoming fuel particles do not come in contact with the rotor on entering the chamber. Instead, the coal adds to a dormant body of fuel lying on the pulverizer bottom.

Into this atmosphere, under pull of the rotor, in effect a closed-end fan, comes the preheated air stream. This stream whips across the dormant fuel bed and sets up a scouring, sandblasting action between coal particles pulled up in the stream as well as those on the surface of the fuel bed.

The pulverized product passes on with the air stream into the separator above. There the mixture goes through a spinner cone, where the coal-air stream experiences several sharp changes in direction to dislodge heavier particles from the stream. These fall back for further attrition.

Fluid Pulverization. The unit of Fig. 10, introduced recently, contains no moving parts; the expansive force of steam or air is employed to create strong attrition action.

Raw coal not exceeding ⅜ in., either wet or dry, enters the mill through a venturi. For wet coal, steam superheated to a total temperature of 750 F serves as the working medium, drying and pulverizing the coal simultaneously. As the coal enters the venturi it comes into the steam jet's path and is forced down into the pulverizer onto a protection cover. It falls through this cover to the pulverization zone in the bottom steam-jet block, where it is pulverized by steam issuing from several jets.

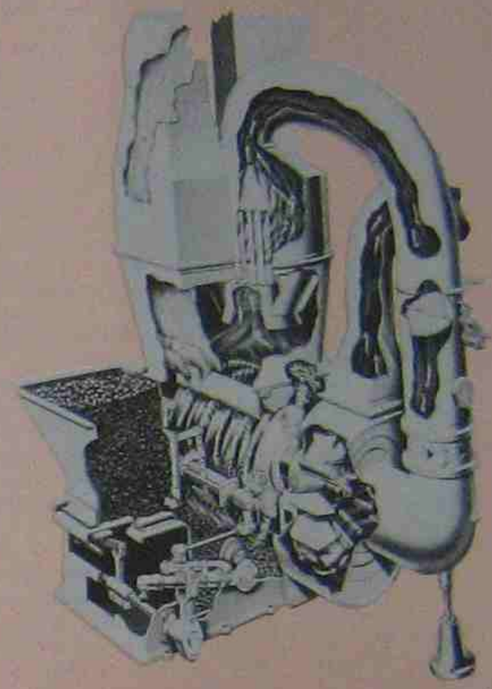
From this pulverization zone the fuel particles are carried with the steam through the uptake leg, back through the classifier where the heavier particles drop back for further pulverization. There is enough energy left in steam-coal mix for delivery to burners. No fan is needed for transport.

Fluid forces are also employed in the pulverizer of Fig. 11, which is designed for ultra-fine grinding. Raw material—minus 4-mesh or less—enters under inspirator action to be broken down still finer. Such fine pulverization goes beyond present power-field requirements, but for gas-turbine applications, and other uses such as grinding coal for colloidal fuel, it may well be the answer.

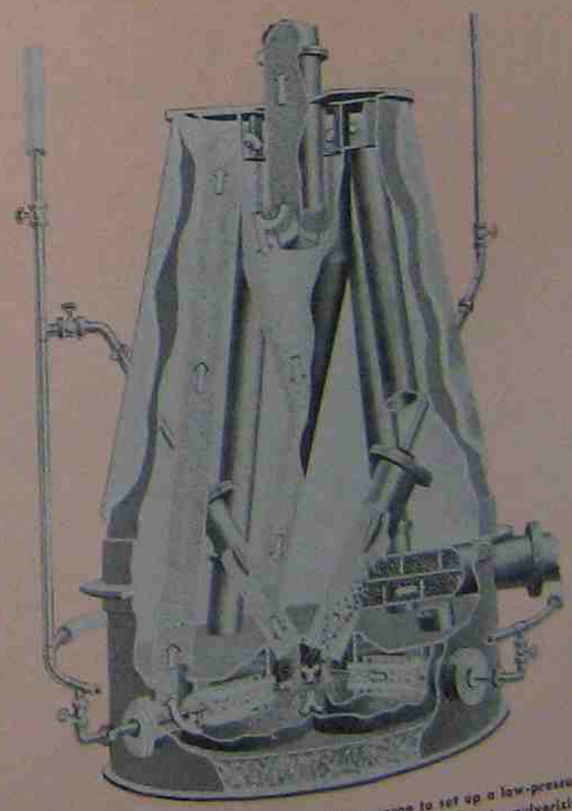
Disk Feeder. The job of delivering an uninterrupted flow of coal to the pulverizer, at the rate set by steam demand, falls to the feeder. Although details vary, feeders fall into two broad classes—disk or plate, and drum or roll.

Fig. 12 shows a totally enclosed disk feeder made in sizes for feeding from

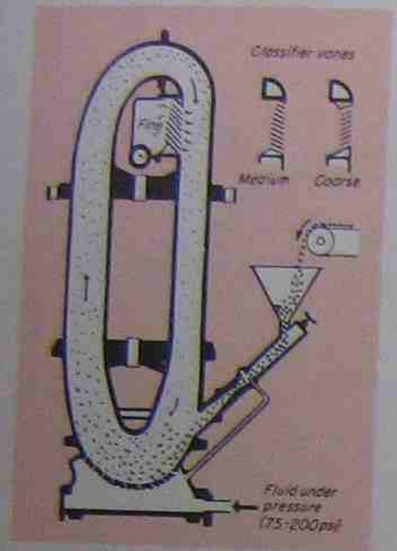
ATTRITION DOES THE WORK HERE



9 Size reduction results from attrition produced when incoming coal, under pull of a high-speed rotor, sweeps across fuel on the pulverizer bottom



10 Four jets of steam (or compressed air) converge to set up a low-pressure area where coal enters. Attrition between particles does the pulverizing



11 Fluid expansion sets up attrition action for an ultra-fine pulverization

a few pounds to 50 tons per hr. It consists of a rotating disk, usually direct-connected to a variable-speed motor. An adjustable sleeve in the downspout from the supply bin terminates a sufficient distance above the disk to form a cone over the center of the disk. An adjustable knife or plow cuts into the rim of the cone and plows or scrapes coal over the disk edge into feed chute. Feed rate can be varied by changing knife position or disk speed.

Drum Feeder. Illustrative of the second general class of feeder, the drum type, is Fig. 13. A slowly revolving 8-pocket drum feeds coal from the hopper. A spring-loaded leveling apron measures out equal quantities for each pocket. Rate of feed is controlled by a variable-speed transmission driving the feeder drum. A revolving wiper removes any coal that adheres to the bottoms of the pockets.

Burner Functions. So far we have concentrated on the preparation phase of pulverized-coal firing. Next we come to the burners themselves. These must supply air and fuel to the furnace in a manner that permits (1) stable ignition (2) effective control of flame shape and travel, and (3) thorough and complete mixing of fuel and air.

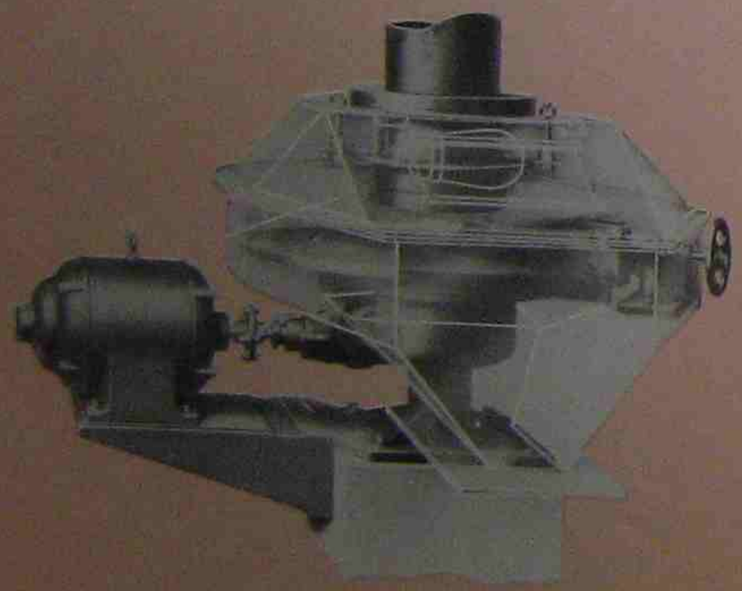
The air used to transport the coal to the burner forms the primary air; secondary air may be introduced in the burner (so called *turbulent* burners) or around or near the burner (so called *nozzle* burners). The turbulent burners of Fig. 14-17 impart a rotary motion to (1) the coal-air mixture in a central nozzle and (2) the secondary air issuing from a chamber around that nozzle —all within the burner. This gives some premixing for coal and air, and considerable turbulence.

In the burners of Fig. 18, 20, the coal-air mixture issues from a series of nozzles to mix within the furnace with secondary air admitted through separate openings.

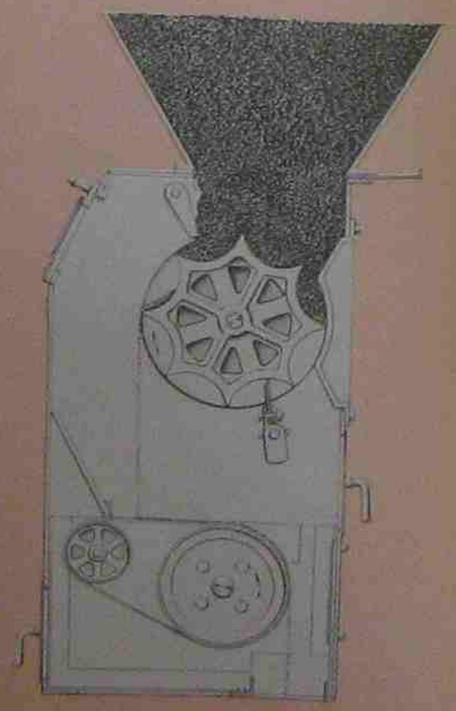
Burner Location. The great majority of burners fire into the furnace horizontally, usually from only one wall. In the customary arrangement, a burner block of refractory surrounds the burner opening. If the wall carrying the burners is watercooled the tubes bend around the burner opening. Fig. 18 shows a type of burner designed to fire between waterwall tubes with minimum disturbance of the spacing.

Vertical burners are also employed. Early designs had the primary-air and coal nozzle at the top of the furnace chamber pointing downward, more or less vertically. Secondary-air nozzles directed air into the furnace horizontally, for flame control and turbulence. A typical vertical burner of today, Fig. 20, leads secondary air around the burner nozzles in baffled streams.

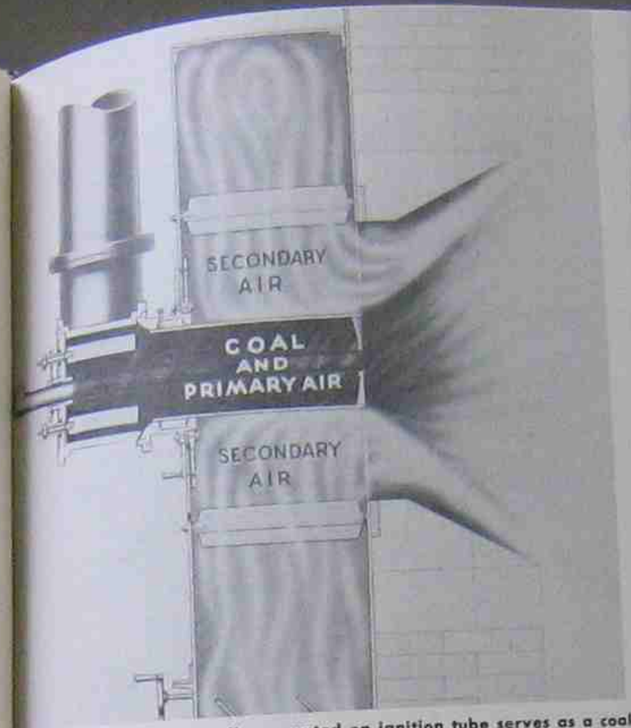
TYPICAL COAL FEEDERS FOR PULVERIZERS



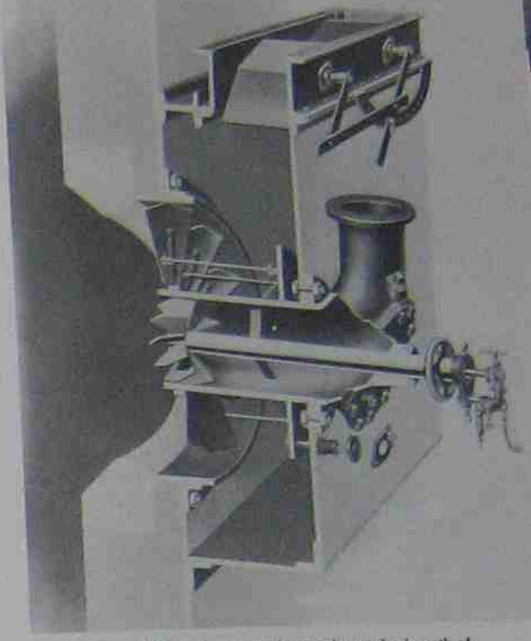
12 Downspout piles up coal in a cone on disk feeder; adjustable blade scrapes coal from rim of cone into feed chute



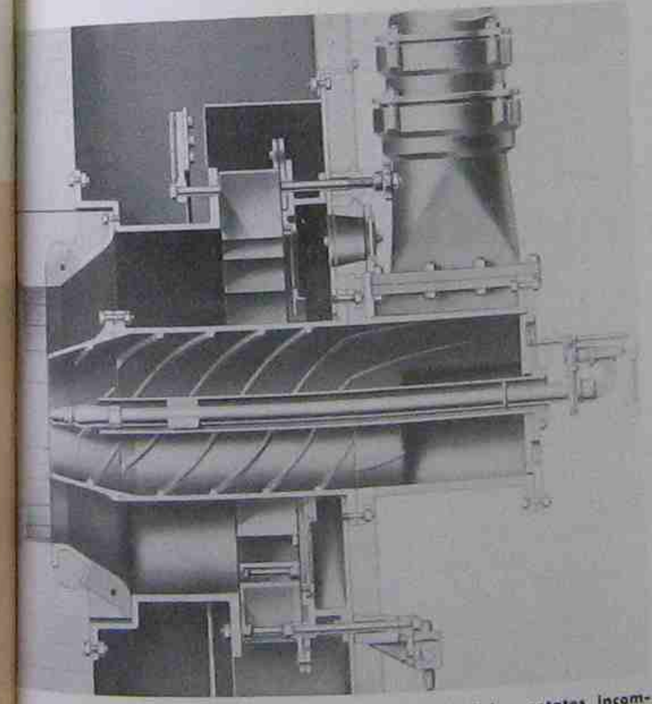
13 Rotating drum operating at variable speed carries coal to magnetic separator; revolving wiper removes sticky coal



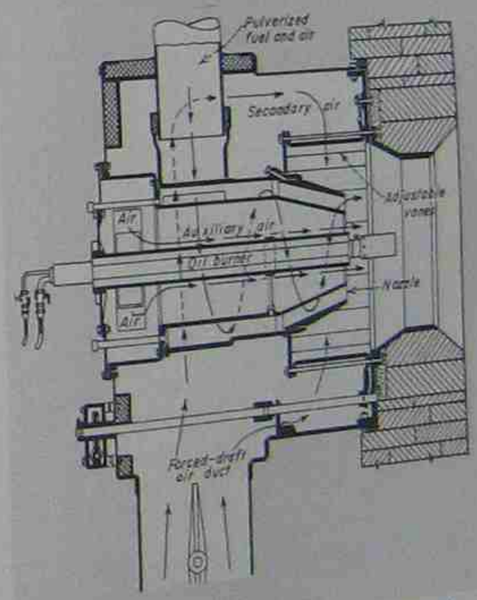
14 Rotary impeller mounted on ignition tube serves as a coal spreader to insure a good fuel-air mixture leaving burner



15 Horizontal flare burner employs coal spreader in path of primary air and coal; secondary air surrounds the outlet



16 Turbulent burner for coal and oil firing rotates incoming fuel-and-air mixture, center, also adds secondary air



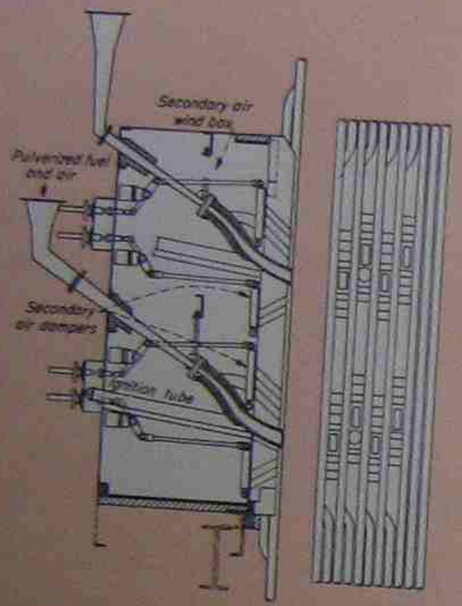
17 Intervane burner has primary air and coal whirling around a cylinder enclosing auxiliary air passage and oil burner

Horizontal burners may be located in such relation to each other as to promote turbulence. In *opposed* firing, burners in opposite walls of the furnace play their flames against each other.

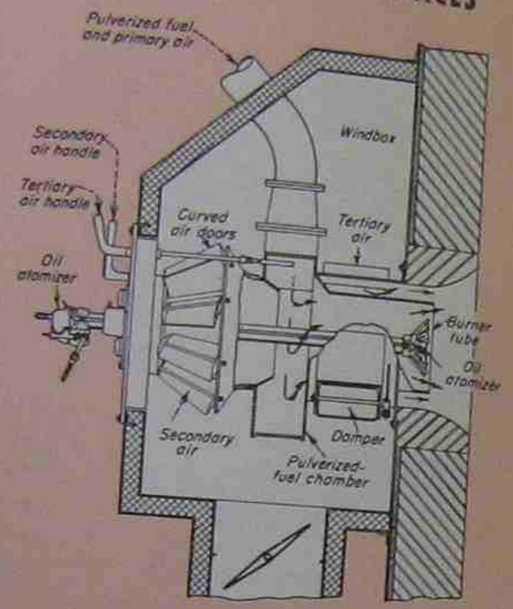
Tangential Firing. Here, burners in furnace corners direct their flames tangent to an imaginary circle in the furnace space. Pronounced turbulence can be set up in this fashion and there is a tendency for unburned combustible in the "tail" of one flame to be caught up in the second. A special form of tangential firing appears in Fig. 22; burners are adjustable to shift flame zone vertically and so regulate temperature of furnace exit gas according to load. This, in turn, controls superheat over a wide load range. Later installations of this type employ fully automatic control of burner inclination.

Combination Firing. Fuel problems of the past war emphasized the value of fuel flexibility and of burners capable

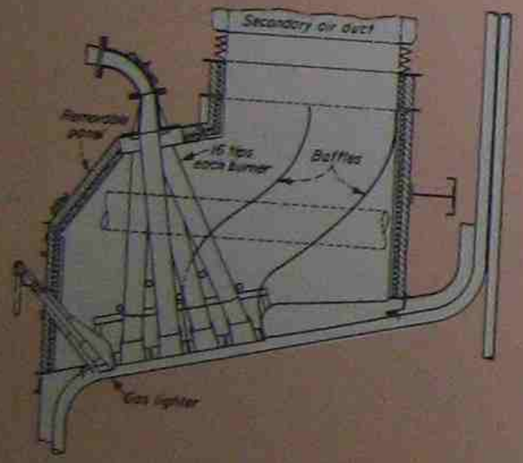
TYPICAL BURNERS, IGNITION DEVICES AND SPECIAL FURNACES



18 Intertube burner consists of a wide fantail distributor to spread coal in broad stream; nozzles form it into jets



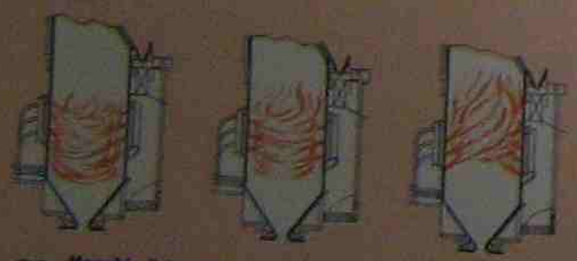
19 Combination coal and oil burner handles primary, secondary and tertiary air; gives fuel flexibility often needed



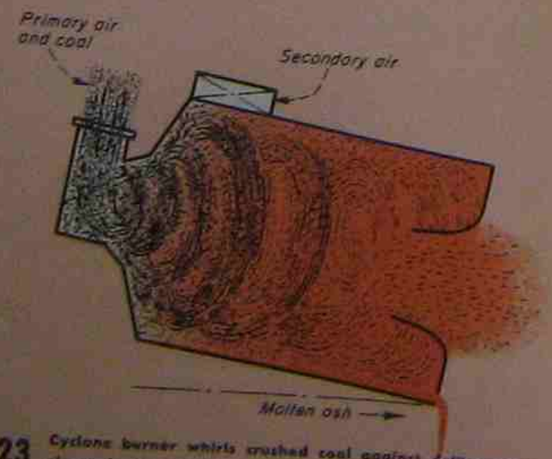
20 Vertical burners direct coal-and-air mix toward furnace bottom; help to increase travel and thus combustion time



21 This electric ignition unit with mechanical-atomizer oil burner has retractable electrodes and atomizing element



22 Movable firing nozzles aimed tangent to imaginary circle give turbulence; shifting flame area controls superheat



23 Cyclone burner whirls crushed coal against deliberately slagged walls, thereby removing a high percentage of ash

of handling more than one fuel. Many designs have been developed. Fig. 19 shows a unit for coal and oil in which primary, secondary and tertiary air, under separate control, are used for efficient firing. Many other combinations are available.

Ignition Equipment. Because these burners are designed to give peak performance at or near rated burning capacities and fall off at low loads, the problem of lighting off is a major one. Usually, an auxiliary oil or gas burner, electrically ignited, is employed for this purpose. The unit of Fig. 21 has a mechanical-atomizing oil burner. Both burner and igniting electrodes are retractable. In addition, a safety interlocking system prevents oil flow until burner and electrodes are extended.

AIR REQUIREMENTS

Having seen something of the form that pulverized-coal burners take, we're now ready to look at some of the relations between burner and preparation system, and between burner and furnace. Remember that today's unit system depends on air for drying, classifying and transporting the pulverized coal. When that transport air reaches the burner it becomes, willy-nilly, primary air unless it can be tempered or a portion bled off.

Air Supply. If amount of air needed for operations in the mill and that needed at the burner were the same, all would be simple. Each function performed by the air, however, has a ratio of air to coal that is best for that function. Hence some compromise is necessary. For example, amount of primary air for best ignition varies with the amount of volatile matter in the coal. Rule of thumb puts the percentage of primary air equal to the percentage of volatiles. With coals having a low-volatile content, volume of air needed for other jobs in unit systems may exceed that for ignition.

This, for example, is the case with anthracite. Successful unit-system burning of anthracite hinges on removing excess air from the transport system before it enters the burner to become primary air. Modern direct-fired anthracite designs thus *bleed* air.

Let's assume now that the burner delivers fuel and air in proper proportions for ignition. Here the furnace enters the picture, since it must supply heat sufficient to evaporate all moisture, distill all volatiles, and raise the entire mixture to ignition temperature. And it must do all this in as short a time as possible, so as not to take up too large a fraction of the available transit time, or furnace volume.

Heat for Ignition. With most coals, heat for ignition is no problem. Usually, the task is to remove effectively the large amounts of heat liberated and to handle the high temperatures resulting from radiation of incandescent fuel particles. Extensive watercooling is the answer. But with low-volatile fuels, particularly anthracite, the balance between heat removal and heat "reflection" must be carefully maintained. In furnaces for such fuels, it is customary to provide some refractory surface, strategically located to insure stable ignition.

Where does the burner figure in all this? In two ways: first in point of ignition and second in speed and completeness of mixing. Point of ignition depends on mixture velocity. As a lower limit, this must be greater than speed of flame propagation or, as we learned earlier in gas firing, flash-back may develop. As an upper limit, velocity cannot be so great that incoming mixture has time to become so lean or diffused with secondary air that furnace heat is not enough to ignite it.

Control of Mixing. The requirement of thorough, complete and rapid mixing of fuel and air is fundamental. But even beyond this is control of the mixing elements that affect flame travel. This control of flame travel touches on an inherent weakness in pulverized-coal firing—the difficulty of influencing the "tail" of combustion, as can be done in fuel-bed firing. It is for this reason that considerable attention is given to the problem of creating turbulence and aiding this turbulence by burner arrangement.

Combustible Loss. Even under the best of conditions, as combustion progresses unburned combustibles experience greater difficulty in finding available oxygen. For this reason, a high degree of turbulence becomes of prime importance where air and fuel keep constantly changing in physical relationship to each other. There is always a certain amount of combustible loss, the majority of which, in pulverized firing, goes up the stack. Its amount varies with percentage of excess air and ash content of the fuel. As ash percentage increases, percentage of excess air must also increase to hold combustible loss at a fixed level. Eventually it becomes a question of balancing loss in combustibles against dry-gas loss.

Ash and Slag. Ash enters the furnace picture in another way. Temperatures realized in burning of most coals are well above those at which ash fuses. Coal burned in suspension, then, has its ash content at one time or another in a molten state. It is highly desirable for the ash to be dry before it enters the gas passages of the steam generator. Transfer of heat from the suspended particles by radiation to the furnace surfaces is the only way of cooling the ash, and it takes time. Can it be speeded up?

Yes, fully watercooled furnaces absorb heat faster. But time for absorbing heat usually exceeds combustion time. This time, in suspension firing, is roughly equivalent to distance. So the distance between the burner and entrance to the boiler surface is a function of the time required for heat absorption. The magnitude of this time, or distance, is largely determined by ash content of the fuel.

DRY-BOTTOM AND SLAG-TAP

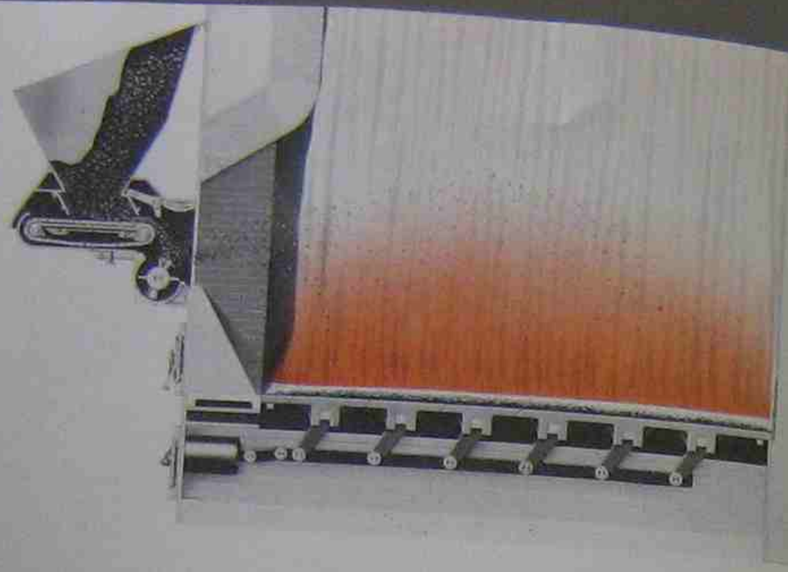
Ash formed under good combustion conditions contains iron in a highly oxidized form and has a higher fusing-temperature range than indicated by laboratory conditions. Fineness of pulverization and good combustion reduce carbon content of ash and so tend toward higher oxidation of iron, thus helping to keep ash from slagging walls and tubes of dry-bottom furnaces.

Slag-Tap Furnaces. We may, however, elect to keep ash molten by use of a slag-tap furnace. Part of ash is removed from the combustion zone by directing burner flame generally downward over a pool of molten slag. These furnaces are suitable for high-heat releases, and tend to remove the low-fusion-temperature elements of the ash, so less slagging occurs on walls and tubes proper. Slag pool must be kept hot enough to remain molten so slag flows continuously over a water-cooled weir or ring into a quenching pit, where it is broken up by water.

Cyclone Burner. In this new furnace design, what might be termed "deliberate" slagging is employed. This burner, Fig. 23, receives crushed, not pulverized, coal in a stream of high-velocity air tangent to the circular burner housing, which forms a primary water-cooled furnace. Coal thrown to the rim of the furnace by centrifugal force and held by a coating of molten ash receives a vigorous scrubbing from fast-moving air. Secondary air enters at high velocity also, and parallel to the path of primary coal-air mixture.

It might be said that the coal in the sticky slag film burns as if it were in a fuel bed—volatiles are distilled off and carbon is burned out to leave ash. Combustion of volatile matter begins in the burner chamber, and is completed in the secondary furnace into which the burner chamber discharges. Molten ash, under centrifugal force, clings to the burner-chamber walls. Slight inclination causes slag to discharge continuously. Nature of this burning tends to reduce substantially amount of ash carried in suspension, hence flyash emission is negligible.

(91) 97



1 In spreader-stoker firing part of fuel is burned in suspension, part on a grate. Coal is projected across the furnace; fine particles burn during travel but the larger pieces fall to grate, forming an overfeed fuel bed on it. The stoker shown feeds coal by a chain to an overthrow distributing rotor, to be propelled into the furnace. The grate is arranged for dumping by steam, air or hydraulic operating devices

Burning Coal on Overfeed Stokers

In terms of number of applications, fuel-bed firing takes the lead over suspension firing, the method of burning solid fuels we have just discussed. In modern practice, this means *stoker* firing, as mechanical methods have made obsolete less-efficient hand firing. Stoker operation, we have seen, consists of: (1) pushing, dropping or throwing coal on a grate within a high-temperature region of the furnace (2) distilling off part of the coal as a combustible gas (mostly hydrocarbons and CO), which burns above the fuel bed just like gaseous fuels (3) exposing the remaining red-hot solid, coke, to vigorous scrubbing by air coming up through the fuel bed until it is burned, and (4) removing the resulting ash from the furnace zone.

Stoker Types. Stokers accomplish these steps in a variety of ways, and the nature of the fuel bed may differ considerably in actual fact from the simplified bed with clearly defined zones illustrated on page 76. Stokers may be divided into two general classes, depending on the direction from which raw coal reaches the fuel bed: (1) *overfeeds*, in which the fuel comes from above, and (2) *underfeeds*, in which it comes from below. In turn, current overfeed designs may be divided into two broad groups: (1) *spreader* stokers, and (2) *chain-grate* or *traveling-grate* stokers. Let's look at the spreaders first, because their combination of suspension and fuel-bed firing forms a logical bridge from the pulverized-coal firing just discussed, and also because their fuel beds most closely resemble the idealized fuel bed set up for earlier basic consideration.

Spreader Operation. These stokers take raw coal (within definite size limits) and whirl it into suspension within the furnace by paddles or wheels, Fig. 1-7, or by air or steam jets, Fig. 8-10. The fines in the incoming stream of coal tend to burn in suspension during their travel across the furnace, while the larger pieces fall to the grate to form a fuel bed there. To a limited extent, then, spreader firing partakes of the characteristics of pulverized-fuel burning.

The fuel bed is normally rather thin but, since raw coal is distributed over it relatively evenly, it is not unlike the idealized fuel bed, with distillation, reduction, oxidation and ash zones one on top of the other. Actual thickness of the bed varies with steam demand and class of coal. Usually there is never more than a few minutes' supply of fuel on the grate. Underlying the thin, active fuel bed is a layer of ash. This, together with flow of air up through the grate, serves to keep metal parts to safe operating temperature. Air can usually be preheated to 300-350 F without creating a maintenance problem.

Underfire Draft. The characteristically thin fuel bed offers relatively light resistance to underfire air flow. Keeping resistance of the grates themselves fairly high and holding windbox pressure relatively low avoids heavy fluctuations as fuel-bed thickness changes, and also avoids heavy cinder carryover or, in extreme cases, blowholes.

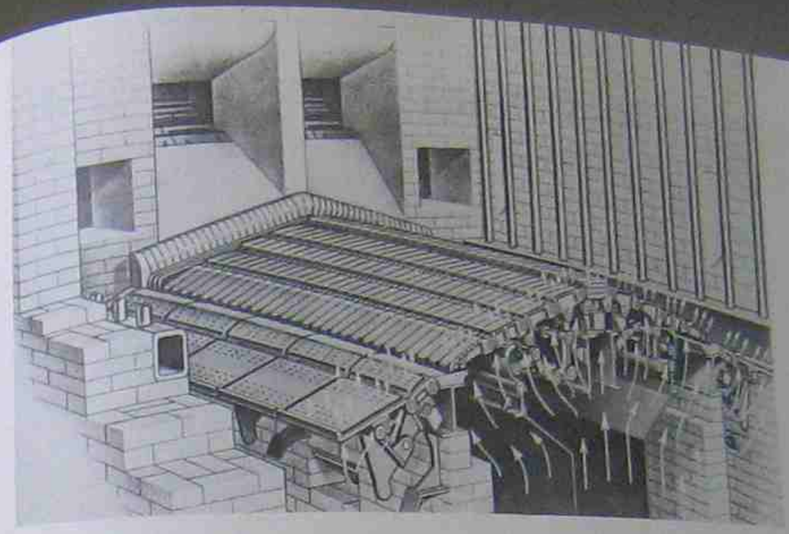
Normal operation calls for relatively low overfire draft and gas velocity. This precaution becomes doubly important when it is realized that an estimated 30 to 50% of the coal's ash content may go off with the furnace gas.

As much as half of this carryover may be unburned combustible. Hence, installation of a cinder reinjection system often proves desirable. Such a system comprises settling chambers somewhere in the boiler setting and, usually, a cinder collector ahead of the induced-draft fan to save wear and tear on fan blades. Particles collected are fed to the furnace for reignition and burning. Returned cinder usually enters at a point above the fuel bed, but not too close to boiler tubes, under impulse of a jet. The jet gives added overfire turbulence and helps promote good combustion.

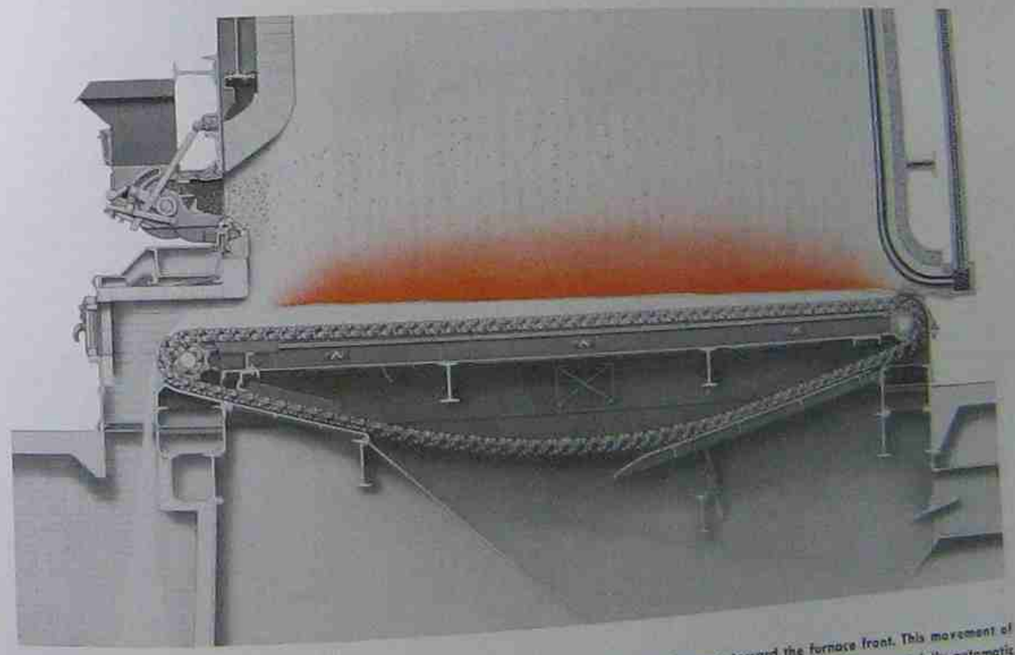
Furnace Design. Usual furnace arrangement follows simple lines with little or no arch construction. As with all fuel beds, composition of the gas released varies somewhat from point to point, and there is a tendency for gas, and secondary air, to take the most direct way to the furnace exit. High-velocity overfire jets prove effective in combating possible stratification. The turbulence they create not only improves mixing and increases time for combustion, it helps to reduce cinder carryover as well. Location of these jets should be worked out carefully, giving due consideration to relation to the coal's travel path.

Grate Arrangements. A variety of grate constructions are available and, by and large, plant operating conditions determine the most suitable one for any given installation. Simplest form is the stationary grate, which is cleaned manually. For dumping operation, grates are sectionalized so that one part of the fuel bed may be cleaned without affecting the others. In both, fuel feed stops during the cleaning operation. But the dumping arrangement minimizes the interruption by the sectionalizing feature and by the greater ease with which fire-cleaning may be carried out. Stationary grates prove entirely satisfactory in small plants, particularly where low-ash coal is used. Dumping grates find wide acceptance in somewhat larger installations.

In the stoker of Fig. 2, coal is thrown evenly over the entire central portion of the grate. This is constructed to give a wavelike motion to the fuel bed, keeping it active and porous as it slowly moves toward the ash-cleaving discharge grates at either side. The hydraulically operated discharge breaks off the burned-out refuse and drops it to the ashpit. With this central firing and moving grate, there is no need to interrupt fuel feed during ash discharge.

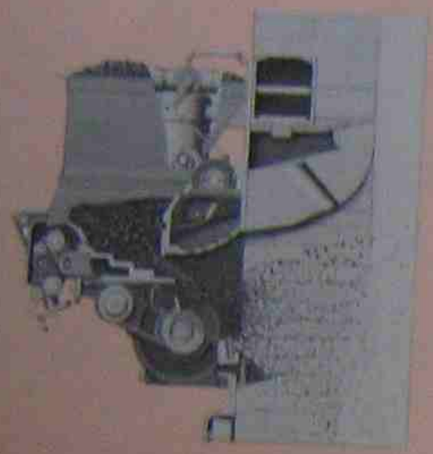


2 In this design, feeder rams supply coal to a spill plate where spring-loaded equalizer plate reciprocates at a right angle to it, shredding off fuel. Overthrow rotor spreads coal over central portion of grate, which has link construction to give a wave-like motion that keeps the fuel bed active and moving to ash-discharge grates. Dumping doesn't interrupt feeding



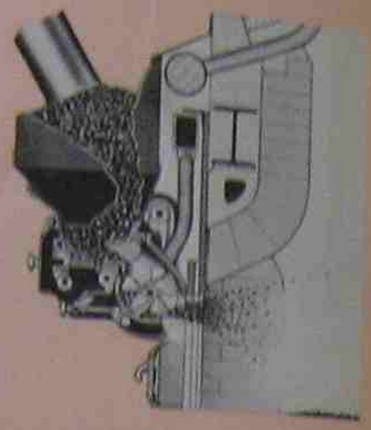
3 Revolving rotor takes coal fed from a hopper over a spill plate. This overthrow rotor hurls coal back over a chain grate which moves toward the furnace front. This movement of the grate makes ash-discharge continuous and fully automatic

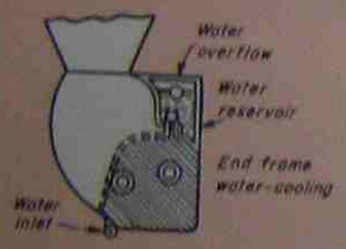
TYPICAL CONSTRUCTION DETAILS OF MECHANICAL SPREADER STOKERS



4 Sectional coal-feeder pushers, hydraulically driven, alternate in movement to deliver coal to overthrow-type rotor

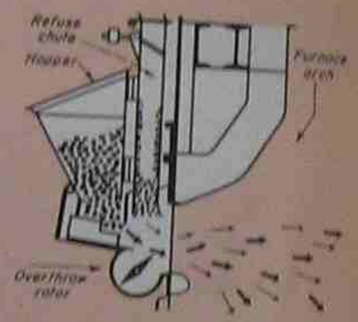
5 In this design, rotor has curved blades and projects coal into furnace by underthrow action





6 Detail shows a watercooled feeder. At top, reservoir extends across width; end frames have a cooled area

7 For firing waste fuels, this unit has separate hinged spout feeding refuse directly to an overthrow rotor



Unit of Fig. 3 has a traveling grate that moves forward slowly toward the front, or coal-feeding end, of the furnace. It discharges ash continuously. Such designs prove well suited to large installations, and have been applied to boilers with steaming capacities of 250,000 lb per hr. Some engineers believe much larger units can be built.

Coal Feeders. Spreader stokers can handle a wide range of coal types, including lignite. As to size, they do best on coals under about 1¼ in., with preferred size of the order of ¾x0-in. nut and slack. Coarse coal tends to wear the feeders and may form clinker.

Coal is usually withdrawn from a hopper by a mechanical feeding device whose role is to insure an even, uninterrupted supply to the distributing system. A variety of means is employed: a chain feeder does the job in Fig. 1; a set of feeder rams, Fig. 2; a double-acting ratchet mechanism and rotary feeder in Fig. 6; a hydraulic reciprocating drive working sectional pushers in Fig. 4; a series of reciprocating plates working off the main lineshaft, Fig. 5. Still another example, Fig. 10, uses a worm. All have positive uniform feed as their objective.

Rotors. In mechanical spreader units, coal feeds down from the hopper to paddle or wheel-shaped distributing rotors. These move at high speed to throw the coal out into the furnace. There are two methods in common use, both of which claim advantages—overthrow and underthrow. They are so named from the point on rotor travel where incoming coal meets blades.

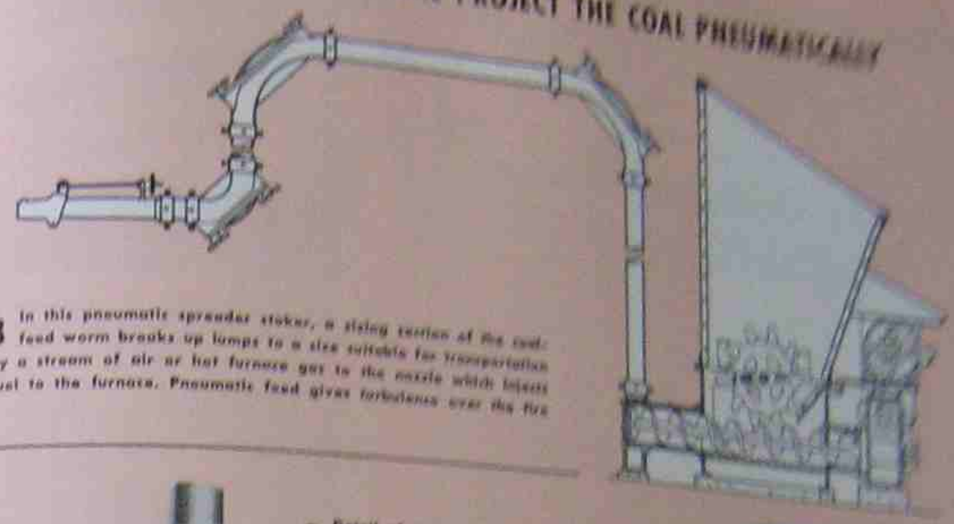
Overthrow. Fig. 1-4, and 7, show various designs employing the overthrow principle. Rotors, spaced to give desired coverage, are usually designed so individual paddles or elements can be readily removed and replaced. Feeder assembly provides means to correct for change in coal size to maintain desired distribution pattern. For example, the unit of Fig. 3 has a spill plate. When moved forward, it causes the rotor to throw more of the fuel toward the rear of the furnace, and when moved backward does the opposite.

Underthrow. Fig. 5 shows an underthrow rotor, which consists of small blades of special curvature, suspended loosely on shafts concentric to the main impeller shaft. Blades are designed to give a hammer-mill effect, breaking up any wet coal that tends to lump. In another design, the rotor is divided into sections, each having four blades at a slight angle to the shaft. Angles are such that one blade throws coal to the right, while the next throws to the left. This crisscrossing feed is designed to give uniform fuel distribution.

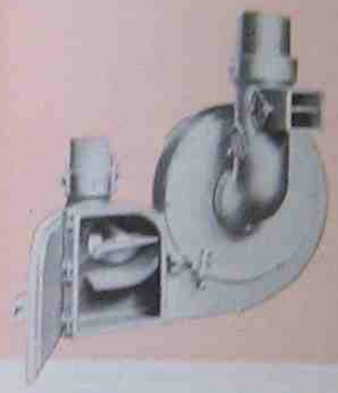
Watercooling is provided on many feeding and distributing assemblies. The detail of Fig. 6 shows one arrangement, with a reservoir at the top extending across the unit and cooled sections in each end frame. In many designs, the feeding machine and the grate section covered by it work together with an individually controlled air supply. The number of sections depends on furnace width.

An indication of the versatility of the spreader method of firing can be seen in Fig. 7. Here firing of waste fuels is provided for by the addition of a hinged chute, down which the refuse flows, under control of a gate. Both coal and refuse are distributed over the grate by an overthrow rotor. A series of stepped shoes set on a sharp slope, and moved by rocker action, feeds the coal.

THESE SPREADER STOKERS PROJECT THE COAL PNEUMATICALLY



8 In this pneumatic spreader stoker, a sizing section of the coal-feed worm breaks up lumps to a size suitable for transportation by a stream of air or hot furnace gas to the nozzle which injects fuel to the furnace. Pneumatic feed gives turbulence over the fire



9 Detail of stoker above shows the transfer housing where feed worm discharges into outlet of radial-vane fan which gives high velocity to the transporting air (or hot furnace gas)

10 In this pneumatic stoker, agitator wheel in hopper prevents piling up of coal on screw feeder. Coal from feeder falls into path of air stream which projects it into furnace



coal and refuse are distributed over the grate by an overthrow rotor. A series of stepped shoes set on a sharp slope, and moved by rocker action, feeds the coal.

Pneumatic Spreader. A different method of spreader firing is shown in Fig. 8 and 10. These units employ a jet of steam or air to project the coal into the furnace. The unit of Fig. 8, which features a remotely located feeding mechanism and hopper, can readily be arranged to feed directly from a bin or bunker. Coal in the hopper moves slowly down to a feed worm, which has a sizing section to break up lumps too large for transport by pneumatic means. The worm carries the coal in a loose state to the transfer housing, Fig. 9. Here a stream of air from a high-pressure radial-vane fan picks it up and conveys it through a pipe to the burner nozzle. Hot gas from the furnace may be used as the transporting medium, if so desired.

The spreader nozzle is wedge shaped; front and back distribution is regulated by elevating or depressing the nozzle tip, and side distribution by movable wedge blocks in the tip. A low-pressure fan supplies air for combustion. Separate motors drive feed screw, conveying-air fan and combustion-air fan. Variable speed transmission adjusts rate of fuel feed and an air-volume regulator maintains desired air supply.

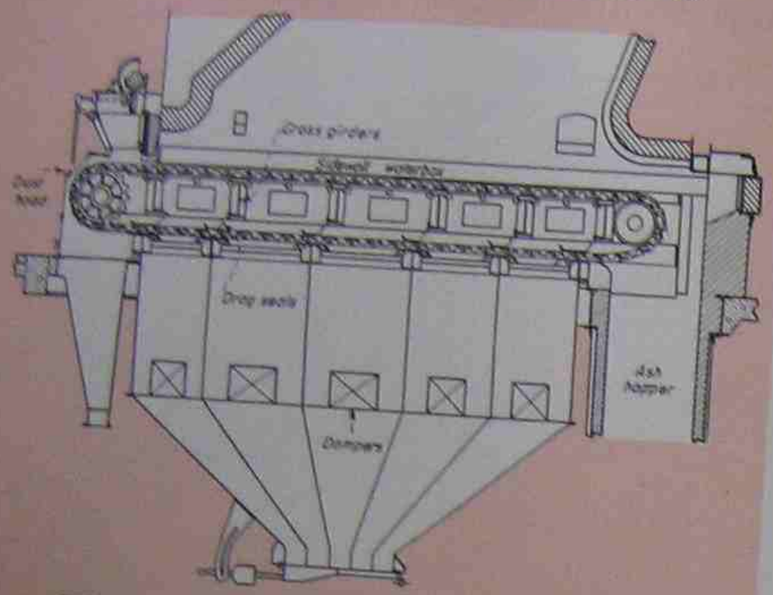
Another Pneumatic. In the design of Fig. 10, feed screws spaced across the width of the stoker move coal from the hopper to the point of injection. An agitator wheel in the hopper prevents coal piling up on the screw. An air jet set just below the end of the screw catches up the coal as it falls and spreads it over the grate. At the same time, this air jet provides an ample air stream.

Spreader Drives. Many feeder mechanisms are motor driven, with some form of variable-speed transmission to control rate of fuel feed. Usually a steam-turbine drive, and sometimes a hydraulic drive, can be applied. Dumping grates may be hand operated or powered by steam, air or hydraulic cylinders. Moving grates used for continuous ash discharge are powered by motor with variable speed transmission, and by hydraulic drives with a constant speed variable displacement pump supplying fluid to a constant-stroke cylinder, variable speed by double stroke.

The stoker of Fig. 4 has an integrated hydraulic drive that drives all parts, and provides automatic fuel-air ratio control. A single pump driven by a constant speed motor (or motors) supplies oil to a hydraulic motor driving the rotors, and hydraulic cylinders actuating moving grates and discharge gates and feed rams. Fuel-air ratio control acts on proportioning valves in the discharge from the pump, regulating flow to the various drives and relief to the oil tank.

The spreader stoker has come into use in recent years because it is relatively simple, low in first cost, and maintains its coal-burning abilities with proper controls and provisions for banking under capacity to an overnight level it gives high efficiency, service under a wide variety of conditions. It has a reputation for quick response to load changes when it

CHAIN GRATE: BOTTOM AIR DISTRIBUTION



11 Chain-grate stoker with bottom air distribution; dampers in individual compartments regulate air flow to each grate section from front to rear



12 Rear of traveling grate shows grate-clip overlap to reduce the siftings



13 Detail of chain-grate construction shows how it differs from one above

however, dependent on maintenance of a thin, level fuel bed.

Chain and Traveling Grates. The grate in these stokers resembles nothing so much as a wide belt conveyor, moving slowly from the feed end of the furnace to the ash-discharge end. Coal feeds from a hopper under control of a gate, which establishes fuel-bed thickness. Furnace heat ignites coal and distillation begins. As the fuel bed moves along slowly, the coke formed is burned and the bed gets progressively thinner. By the time the far end is reached, nothing remains but ash, which falls off the grate as it goes around the end sprocket to begin its return journey underneath.

Grate Construction. Chain grates were originally developed for bituminous coal, and traveling grates for small sizes of anthracite. Structural details differ, but these units perform the same functions, often side by side. As the name implies, the chain grate is in reality a wide chain, with grate bars forming the links. Links are staggered, Fig. 13, and connected by rods extending across the stoker width. In the traveling grate there is a drive chain at each side with crossbars at intervals. The fingers, keys or clips that form the grate surface are attached to these crossbars. They overlap, Fig. 12, to prevent ash sifting through.

It can be seen that stokers of this type are true overfeeds, but the fuel bed differs considerably in appearance from the idealized one shown on p 76. At the feed end, we have virtually all raw coal, with ignition beginning in the top layer. Further along the stoker, distillation has progressed and we have active burning. Then, as distillation is completed, we come to an area where carbon is being burned out and, at the end, we have nothing but ash. Thus, although the steps in the burning process are the same, the location and shape of the various zones differs markedly from the idealized version with clear-cut zones one above the other.

Ignition. With this method of firing on a moving fuel bed, rate of ignition tends to control grate speed and fuel-bed thickness. Otherwise, available time within the furnace may be too short for complete combustion, or too long to permit full use of the grate.

It is radiation, in the main, that ignites incoming fuel. Once the surface layer ignites it warms coal beneath by contact. If the rate of air flow through this part of the fuel bed is about right, surrounding coal ignites in short order. If air flow, including leakage, is far more than needed, overall result is cooling of the fuel bed and a slower ignition rate.

It can be seen that for best results air-flow rate will differ along the grate, as the burning progresses, and that the gas coming off the bed will differ markedly in composition from feed end to ash discharge. From this point of view, there are three broadly different sections: (1) The part where most volatile matter is distilled off, usually early in the grate's travel. Furnace atmosphere in this region is a reducing one—the gas is rich in combustible volatiles but poor in air. (2) The active burning area, where mixture of air and combustibles comes closest to the ideal. (3) The rear zone where the last chance for burning carbon occurs. Gas from this is usually lean—heavy with excess air.

Air Distribution. Amount and control of air is highly important. So, too, is control of leakage around the grate. Should this occur at the combustion-chamber level it breaks down the pressure difference across the fuel bed. This drop in "pull" through the bed lowers the ignition rate. In units with forced or induced draft, such leakage puts a heavier load on the fans. For this reason, considerable attention is given to sealing arrangements.

To take care of differing air requirements and fuel-bed resistances along the grate length, the stoker is zoned or sectionalized, with a damper in each section to regulate air pressure. Air for combustion can enter from the bottom through both grates, Fig. 11, or from

the side between top and bottom grates, Fig. 14. In the latter, three typical damper and seal arrangements in side-admission units are illustrated.

The difference in composition of the gas coming off the fuel bed calls for definite measures to avoid stratification and insure thorough mixing.

Arches. Earliest and still commonest device for mixing is the furnace arch. Furnace layouts have traced a long pattern of development. Early designs featured a long front arch to reflect heat to the incoming fuel for quick ignition and to direct rich gas from the front end toward the rear. The rear arch has gradually become more prominent, and the front arch shorter. A typical arch design of today, Fig. 15, has a modest front arch, a long rear one, and a relatively narrow "throat" between them. The rear arch directs the lean gas forward and the narrow throat promotes mixing. The excess air from the rear end thus helps to supply the air deficiency of the rich gas from the front end and thereby reduces over-all excess air.

Overfire Jets. Some designers prefer a relatively open furnace with only a short front arch, and depend on high-velocity overfire jets to produce the turbulence and mixing required. They reason that arches as mixing agents give best results at design rating, whereas the jets give positive mixing over the entire load range. A number of such "open" furnaces have been installed and results seem favorable.

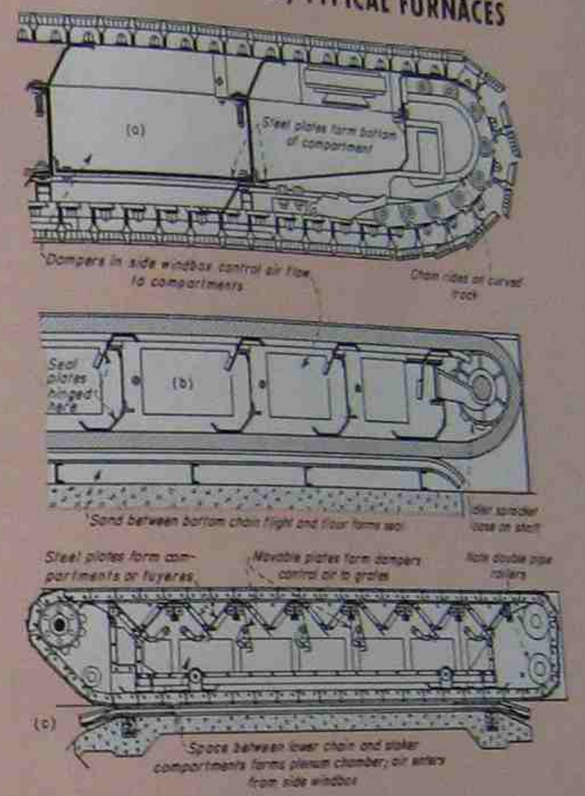
Stoker Drives. Drive can be applied at either front or rear end. A worm and wheel or gear and pinion provide the necessary speed reduction. Power unit can be a constant-speed motor with variable-speed transmission, a turbine or a steam engine.

Chain- and traveling-grate stokers, as a class, have long been considered well suited for high-ash free-burning coals. The reasoning behind this is that the fuel moves in one plane, relatively free from agitation. Coking coals, it is felt, tend to mat over, cut off air supply, and increase fuel-bed resistance.

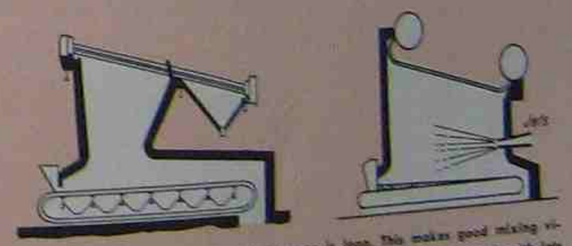
Proper selection of coal size and size consist goes a long way toward assuring satisfactory operation. With natural furnace draft of about 0.1 to 0.15 in., coal having a top size of 1¼ in. and little fines below ½ in. gives good results. Heavier draft permits coals of 1½-in. top size, having the range of fines naturally occurring in crushing.

Forced-draft chain grates have about 7 to 10% air space in the grate as contrasted to about 20% for natural-draft units. So coals with an increased percentage of fines and a smaller top size (¾ to 1 in.) can be burned satisfactorily with forced draft.

SEALING OF GRATES, TYPICAL FURNACES



14 Air requirements differ as fire moves from front to rear. Where air is admitted at sides, various methods are used to zone air flow accordingly. At top, cross members and steel bottom plates form flight compartments. Middle design has seal plates hinged from cross members and resting on lower grate. In bottom unit, space between grates forms plenum chamber with dampers above



15 Gas at stoker front is rich, at rear is lean. This makes good mixing vital. Arches may be used to direct flow or furnace may be open, with jets

Compensating Feed. One overfeed stoker employing a moving grate operates on what is known as the compensating-feed principle. The grate is made up of alternate moving and stationary sections that run the full length. Grate is inclined. Moving sections occupy the greater area. Over the grate surface at the rear are cover plates designed to retard ash flow and give a tight rear-end draft seal. As coal moves progressively down the grate, impelled by the moving sections, the stationary sections retard movement and build up a compression force. When cracks and fissures develop this force relieves itself by shifting coal into the open areas of the fuel bed.



1 Single-retort underfeed stoker has screw feed; the retort is surrounded by dead plates, with tuyeres recessed below



2 Air-cooled side-dump grates afford final air supply for any unburned coal, and cut down losses from this source

Burning Coal on

As the name implies, in *underfeed* stokers raw coal comes to the fuel bed from below. It is pushed along in a feed trough, or *retort*, and, under pressure of fresh coal behind, it rises in the retort to spill over onto the fuel bed at either side of it. No air is supplied in the retort proper; it comes through openings called *tuyeres* in the grate sections adjoining the retort. At the retort top, raw coal is exposed to some drying action from incoming air, and to furnace heat. Ignition occurs and distillation begins as the coal moves from the retort area to the active burning area around it. Either under pressure of incoming coal, or as a result of grate motion, burning coke moves slowly to ash-discharge area.

Underfeed Types. *Single-retort* units can handle up to about 25,000 lb per hr steaming capacity, occasionally as high as 40,000. Fig. 1-4 illustrate stokers of this type. *Twin-retorts*, Fig. 5, are also employed. For capacities from about 30,000 lb per hr up to more than 500,000, *multiple-retort* designs, Fig. 6-12, may be employed.

Single-retort stokers differ in method of feeding coal and in the grate arrangement. In the smaller size ranges, coal is propelled into the retort by a worm or screw, while in larger units a ram, possibly aided by pusher blocks or a sliding retort bottom, does the job. Simplest grate design employs stationary sections which are cleaned manually. When no air is admitted through them, these are called *dead plates*; when air is admitted they are sometimes called *live plates*. In either case, main air flow comes through tuyeres around the retort top.

Screw Feed. Fig. 1 shows a screw-feed unit with dead plates surrounding the roughly square retort area. The tuyeres are recessed below the dead plate level. In other designs, tuyere blocks are high and slope away from the retort. Sectional tuyere blocks allow for expansion and make replacement easy. Screw-feed stokers with stationary grates find application for coal-feeding rates from as low as 100 lb per hr and up to about 1200. Stoker, draft fan and controls may be designed and sold as a unit.

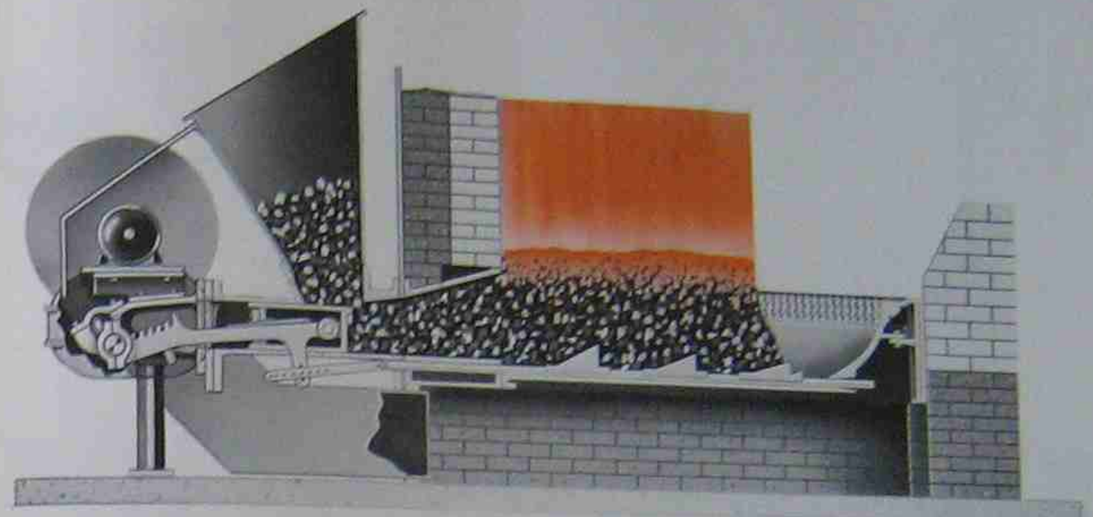
Dumping Grates. In larger units, retorts are longer and dumping grates are applied at the sides. Fig. 2 shows such a design looking toward the front end. Extended tuyere sections form live grate areas at the sides of the retort. The ash grates dump into collecting pits from which ash is removed manually at intervals.

Many screw-feed stokers are powered by constant-speed motors, usually with a mechanical transmission for speed reduction and adjustment. Hydraulic transmissions are sometimes used. Where automatic control is applied it is frequently of the "on-off" type, with a hold-fire arrangement.

Ram Feed. The ram-feed single-retort stoker overlaps the screw feed at the lower end of its size range. But, as mentioned before, some designs serve boilers of 25,000 lb per steaming capacity, and higher.

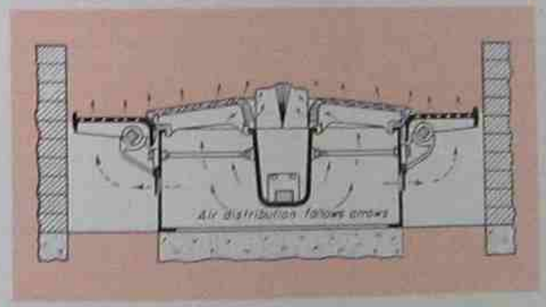
The ram, piston, or plunger, as it is variously known, connects by a crank to a driving mechanism or to a steam, air, or hydraulic cylinder in some designs. Ram stroke usually stays constant; change in timing varies fuel feed. The ram pushes the coal to the retort area. For distribution in longer retorts a variety of means are employed. Some units have sliding retort bottoms while others have pusher blocks that reciprocate slowly. These devices usually drive from the same mechanism as the main plunger. Ram and pusher strokes are usually adjustable. In addition to distributing coal in the retort, auxiliary pushers provide an additional measure of fuel-bed agitation. Fig. 3 shows a typical ram-feed stoker with pusher blocks.

Grate Motion. Many single-retort units have moving grates to provide fuel-bed agitation and to assist move-

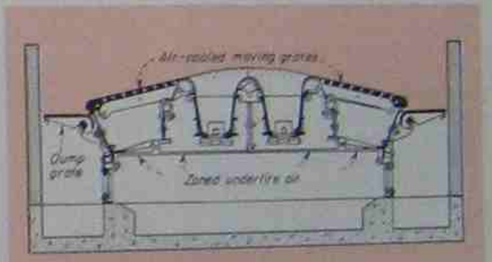


3 Gravity-fed coal from hopper reaches a reciprocating ram, moving under action of crank. Ram feeds coal into retort where pusher blocks help distribute it to the fuel bed. Burning coal moves out over tuyere section to ash grates at sides

Underfeed Stokers



4 Section through single-retort unit with side-dump grates; arrows show how air flows through tuyeres and grate areas



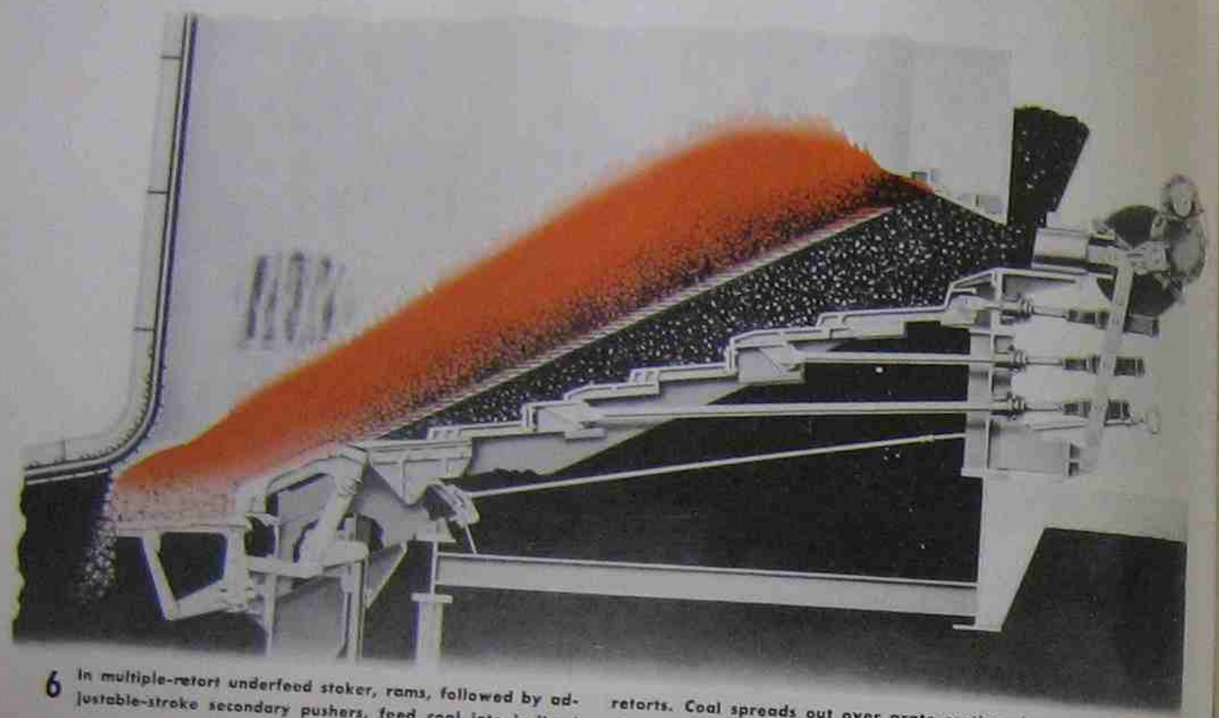
5 Section through an underfeed stoker with twin retorts; an air-cooled oscillating grate provides fuel-bed agitation

ment of the coal to the dump grates at the sides. Methods of providing this motion vary. In some units, alternate grate bars move laterally, actuated by a rocker arm or camshaft driven from the main drive mechanism. In one design, Fig. 5, side grates consist of a series of bars grouped along the long axis of the retort. Two or more rows of bars may form the grate area, depending on furnace width. An oscillating shaft imparts motion directly to these grates, with maximum movement near the retort.

Air Distribution. Side grates and dumping grates are usually provided with air holes to extend the active burning area. Air in quantities and at pressures suitable to fuel-bed conditions is supplied from a main air chamber with dampers providing control of distribution to various grate sections. Some units have hollow grate bars through which air passes from the main chamber to auxiliary chambers. This cools grate castings and provides some air preheating.

Having seen some of the construction features, we can now form a better picture of single-retort operation. Under action of the feed screw or ram, coal enters the retort, being pushed rearward and upward. It moves slowly over the retort edges and spreads out over the active grate area. It is first exposed to air and furnace heat at the top of the retort zone. Here some drying occurs and ignition and distillation begin. Normally, ignition occurs about as the coal reaches the boundaries of the retort area and, except in narrow stokers, the only active burning occurs on the side grate sections.

As the coal moves slowly to the sides (and rear in many small units) all volatiles distill off to leave coke, which is burned out as the edges of the unit are approached. Most of the incoming



6 In multiple-retort underfeed stoker, rams, followed by adjustable-stroke secondary pushers, feed coal into inclined retorts. Coal spreads out over grate sections between retorts; air comes through tuyeres in them. Final section is overfeed

air goes up through the fuel bed close to the retort area, Fig. 4. At this point it serves the useful purpose of promoting rapid ignition and maximum mixing between air and volatiles released from heated raw coal. In some installations, overfire jets are employed to give high turbulence.

It is characteristic of this type of firing that some clinkering should occur and fuel-bed agitation breaks up such clinkers and coke masses as form. Use of a coal having a lower ash fusion than that suitable for the design of a given unit may lead to clinkering difficulties, especially along the sidewalls at the grate level. Watercooled sidewalls reduce such tendencies and thus help to extend range of coals burned satisfactorily and also the continuous capacity rating.

Coal Characteristics. Single-retort underfeed stokers handle most bituminous coals, and anthracite. Size is not too critical, but preferred choice limits top size to from ¾ to 2 in. Usual specifications call for 2-in. nut and slack with no more than 50% through a ¾-in. round-hole screen. Reduction of the percentage of fines promotes flexibility by extending possible choice of coals. The desired aim is, of course, to get a coal size-consist that gives rapid ignition and a porous and uniform fuel bed. Where single-retort stokers equipped with stationary grates are used, a double-screened coal is advisable to reduce percentage of fines.

The fuel-bed agitation of underfeed firing makes it suitable for caking coals. Amount of agitation varies with stoker design; hence selection of coals with caking characteristics suited to the degree of agitation obtained is important. Also to be considered is the matter of ash-fusion temperature previously mentioned.

Multiple-Retort Stokers. The multiple-retort underfeed stoker is a logical development of the single-retort idea. There are many special provisions and practices that apply, however, only to multiple-retort designs.

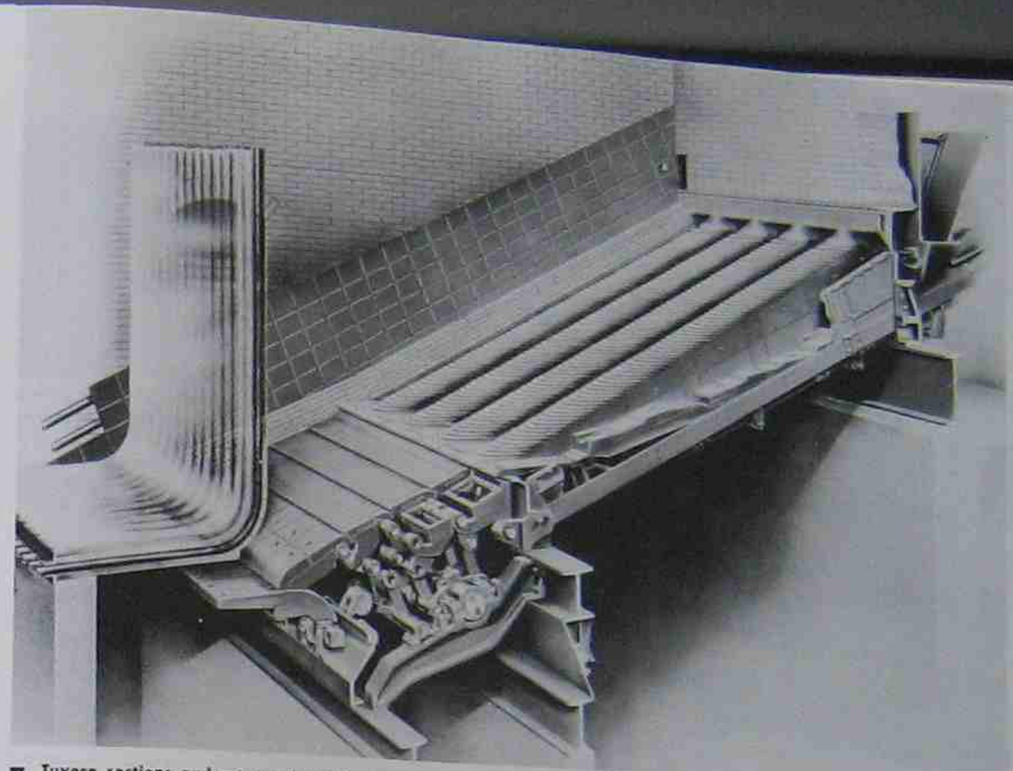
As the name implies, multiple-retort stokers consist of a series of inclined feeding retorts extending from front to rear of the stoker, with tuyere sections between them, Fig. 7. Rams push coal into the front end of the retorts, below the point of air supply, which is through tuyeres in the grate sections between and at the top of the retorts. Incoming green coal gradually forces its way up under the fire. Secondary pushers move the whole mass slowly to the rear. Usually there is an overfeed section where burning is completed before ash discharges.

Fuel-Bed Contour. In the underfeed section, a sort of hill-and-valley contour characterizes the fuel bed. The slight hills are directly over the retorts, which are the supply channels for the incoming coal and have virtually no flow of air through them. The tuyere sections display an opposite condition. Almost all incoming air passes through them and only lateral flow from neighboring retorts feeds coal over their surfaces. The relatively thin sections of fuel bed over the tuyere zones form a series of parallel active burning lanes down the stoker length.

The hill-and-valley contour becomes less marked at the lower end of the bed and the active burning lanes tend to widen until on the overfeed section the active area extends more or less uniformly across the entire stoker.

Overfeed Action. In the underfeed part of the bed, the early coking and plastic stage occurs, by and large, over the retorts. High combustion rates on a thin and active fuel bed characterize the action over the tuyeres. Because of this difference in fuel-bed thickness and character over retorts and tuyeres, the overfeed extension-grate section is important for shaking down and leveling out the fire to give a uniform bed in which the final stage of burning out the coke can be completed. As we will see later, a variety of means are employed to achieve desired action in the overfeed section.

Air Distribution. As previously mentioned, air for the underfeed section comes through the tuyere blocks. Quantities and pressures needed along this section differ somewhat and those required for the overfeed section, where



7 Tuyere sections and retorts alternating across stoker show clearly here. Cutaway reveals feeding-ram action. The rear end of this stoker is an overfeed link grate, having a wave-like action that is synchronized to rate of feeding the fuel

fuel-bed resistance is generally less, are also different. Windbox dampers are used to take care of these differences. In some large units, extensive zoning of air supply, with gages for measuring pressure in each zone, has been provided so air supply and pressure can be controlled to meet variations in fuel-bed resistance across the width and along the length. Such complete control of air distribution is reported to give: (1) higher practical burning rates (2) lower maintenance of grate castings (3) increased efficiency because of lower excess air, and (4) elimination of smoking tendencies.

Air Preheat. Modern practice generally accepts preheated underfire air as desirable. It permits higher ratings, and a moderate preheat materially increases the output range. On the other hand, excessive preheat causes burning back into the retorts with consequent greater maintenance of the grate castings. Holding preheat temperature to about 250-300 F represents conservative practice.

Having seen some of the general characteristics of multiple-retort firing, we can turn now to constructions.

Stoker Drives. Looking first at the drive mechanism, we find that type employed depends to some extent on load conditions. These fix peak and low-load firing rates and rapidity of fluctuations, hence the type of drive and control to give desired flexibility. Where only a narrow speed range, with few intermediate speed points, is needed, multi-speed motors find acceptance. Variable-speed transmissions extend the speed range and number of intermediate positions. Steam engines and turbines give flexible speed characteristics and are often employed because of heat-balance conditions.

Hydraulic Systems. Two basic types of hydraulic drive have found general use. In one a constant-speed motor drives a variable-displacement oil pump which delivers varying quantities of oil to a constant-displacement oil motor. This variable-speed unit drives the stoker. In the other type, oil from a pump acts directly on hydraulically actuated coal-feeding rams. Hydraulic systems give wide speed range with infinitely variable adjustment.

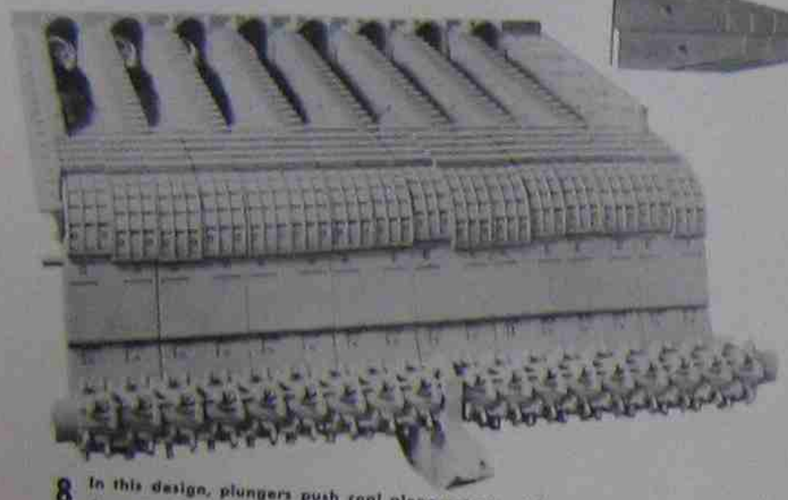
The stoker of Fig. 6 has different drives for the front end and the overfeed extension grate. Front-end drive employs a planetary spur-gear power box for transmission from a constant-speed motor to the coal-feeding mechanism. Connection between drive and rams and between secondary pushers and pusher-actuating levers is designed to give essentially straight-line action. Both ram and pusher strokes are adjustable. The extension grate and ash-discharge plates of this design move as a unit, independent of the main drive. An automatically timed hydraulic cylinder moves grates up and forward to push ash onto the discharge plate.

Turbine Drive. The stoker of Fig. 7 can be driven by either a turbo-gearbox, designed for steam service, or an adjustable-speed ac motor drive, where electricity is the choice. The turbo-gearbox is a small turbine built integral with the stoker gearbox. A single turbo unit serves the stoker, with standard gearboxes serving each ram and pusher group. Under control of an oil governor, this turbine drive operates over a 10 to 1 speed range.

The electric drive employs a self-excited series-wound dc generator driven by an ac motor to furnish power to a standard series-wound dc motor. This unit mg set can be mounted in any position and gives simple, reliable speed adjustment over a 10 to 1 range. With both types of main drive, link-grate overfeed section is separately driven, in most cases by a hydraulic cylinder.

Gearboxes. In usual practice, coal-feed rams operate from crankshafts driven through gearboxes. One such box may drive three or more rams. Wide stokers thus may have two or more gearboxes, which permits changing coal-feeding rate over part of the width. Usual arrangement has two speeds and neutral. Mechanism may be a spur-gear planetary drive without a clutch, or a spur-gear train or worm-and-wheel with a clutch.

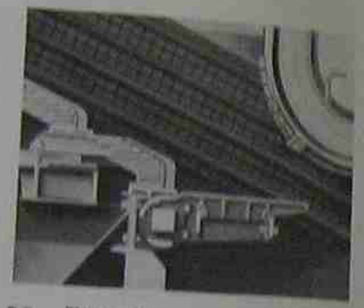
ASH-DISCHARGE METHODS



8 In this design, plungers push coal along retorts; sides of retorts also reciprocate (see detail, upper right). Clinker grinder can be seen at the discharge end



9 Rocker dump plates discharge part of ash steadily; lengthen dump interval



10 These dump grates are normally horizontal. Overfeed bars move ash

Rams and Ram Boxes. These may be horizontal or inclined at the angle of the grate surfaces. Most rams are cylindrical; some are tapered. In most units, construction of ram box and plunger is such that wearing parts can be renewed readily. This usually means replaceable liners for the ram boxes.

Rams and secondary pushers (1) move the fuel bed at the proper rate from front to rear, and (2) provide for changing rate of feed and motion at different parts of the fuel bed as thick or thin spots develop.

Fuel-Bed Motion. These functions may be accomplished in a variety of ways. A common solution depends on secondary rams or pushers in the retorts, driven from the main rams or directly from the stoker drive. Stroke of pushers may be adjusted individually or in groups to control local fuel-bed conditions.

A variation of this arrangement features sliding retort bottoms with auxiliary pushers mounted in them. Adjusting the motion of the sliding bottoms controls fuel distribution. Fig. 8 shows a different method. Here the retort sides, made up of half the tuyere stack split lengthwise, reciprocate. Tuyere blocks, overfeed grate sections and rocker dump plates work together from common sidebars, two to a retort. These sidebars are, in turn, connected to the main plungers and move with them. This reciprocating surface gives a decided agitation to the fuel bed. Changing sidebar travel controls general fuel-bed conditions.

Extension Grates. Only ash and coke remain when the underfeed section has completed its work. To burn this coke efficiently and thoroughly requires uniform air distribution at lower pressures. Extension overfeed grates meet this requirement. The extension section usually has a reciprocating action and may be driven separately or from the pushers. Moving and stationary surfaces are variously disposed and may be flat or stepped.

Overfeed section of Fig. 7 consists of three or more links of narrow bars set in frames that correspond in width to the center-to-center distance between tuyere rows. Upper link pivots on lower end of the underfeed section. Rocking motion of the drive shaft imparts an undulating motion across the grate width that keeps the fuel bed active and porous as it moves down to the dumping grates.

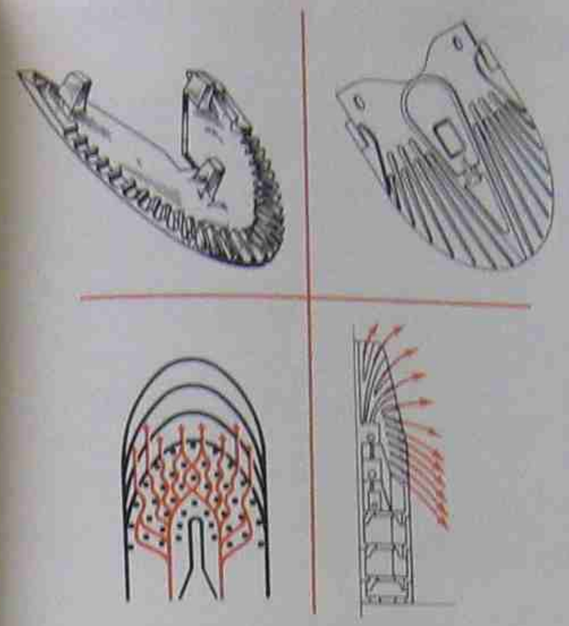
In the design of Fig. 8, the extension grates work from the sidebars previously mentioned. Since adjacent halves of each grate section reciprocate in opposite directions, a shearing action is set up that tends to break up any clinker formations.

Ash Discharge. In the majority of multiple-retort stokers, some form of dumping grate is employed for ash removal, often designed for continuous discharge. For continuous discharge with refuse sizing, clinker grinders are employed. Character of coal, stoker size, and nature of load influence selection of ash-discharge method. The simpler dumping grate installation is commonly found in small or medium-size units burning relatively low-ash coal. In large installations meeting continued high-capacity steam demands, and particularly where ash-content of coal runs high, continuous-discharge designs and clinker grinders are used.

Dump grates are usually pivoted at the ends of the overfeed section and arranged so they may be lowered at intervals to dump accumulated ash and clinker into a pit. They may be operated by hand, or steam, air or hydraulic cylinders. Some have openings for admitting air.

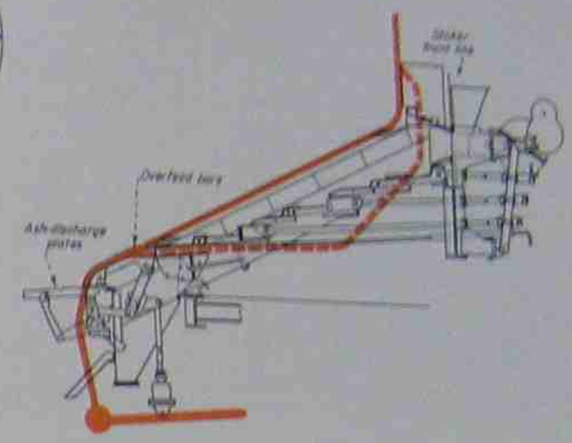
To approach continuous ash discharge while maintaining the relative simplicity of the dumping grates, a number of modifications are employed. The rocker dumping plate of Fig. 9 is hinged at one end and supported by a linkage. Hinged end moves with the extension grate, the action breaking up ash and clinker so part of refuse is continuously discharged.

Another design, Fig. 6, employs ash-discharge plates that move as a unit with the extension grate. These plates are counterweighted and together with a resistance to ash movement, maintain a seal between ash plates and rear



11 Details of typical tuyere blocks show how the incoming air is distributed to the stoker fuel bed

TUYERE DETAILS, WATERCOOLING



12 Watercooling may be used to handle coals of low fusion temperature. Cooling tubes connect into main boiler circulation system

wall. The hydraulic driving mechanism for these plates is timed by a solenoid-operated 4-way valve which sets the frequency with which ash-discharge plates recede. As they recede, resistance to ash movement is lowered. Once plates return to normal position they carry ash forward through the discharge opening. Removal of ash is continuous and plates do not dump.

In the stoker of Fig. 7, the position of the ash-discharge grate is adjusted according to load and ash-content of the coal so action of link-grate pushes ash through space between ash grate and watercooled bridgewall. Discharge is continuous.

Clinker-grinder rolls, Fig. 8, increase stoker length and require a deep ash pit to permit all combustible to burn out. But grinding helps to reduce carbon loss, tends to improve furnace conditions because of better air control and, where heavy ash quantities are to be handled, may prove a necessity.

Usually the front ashpit wall is ventilated for cooling and to help burn out combustible. Waterwalls with protective armor coating at the back of the pit assist in cooling and help to reduce maintenance. Where double rolls are employed they usually rotate outward, against adjustable breaker plates. To facilitate maintenance of wearing parts, rolls are usually built with renewable teeth. Clinker grinders are normally driven separately.

Tuyere Construction. As we have seen, the tuyeres constitute the principal source of air for the early stages of the combustion process. Secondary air may be admitted over the fire, usually through the front wall. In a number of installations, overfire jets, at relatively high pressures and velocities, have been found helpful as a means of producing turbulence and hence better mixing of air and volatiles.

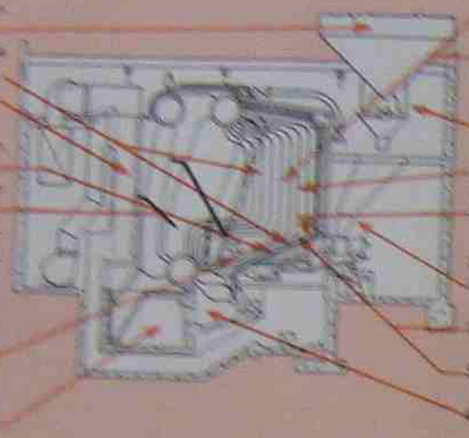
Most units employ flat tuyere blocks, Fig. 11, grooved or vaned to split the air into a large number of small streams for good distribution through the fuel bed. A primary consideration in design is the problem of holding tuyere-block temperature down. Many use some form of extended surface to increase heat-dissipating area. Height of the individual tuyere blocks may be reduced to give a greater number of blocks per foot of stoker length and thus increase air-swept surface and decrease heat-absorbing surface. Still another stoker has tuyere blocks laid out vertically, with air moving around and out sides and top. Most units employ high sidewall tuyere-block construction. The air from this side source cuts down clinker adhesion in this area. In other cases, an armored watercooled section is installed along stoker sides.

Coal Characteristics. Multiple-retort underfeeds handle a range of bituminous coals. In many cases, run-of-mine coal is received and burned after crushing to a top size of about 2 in. Best results are usually found with caking coals having a relatively high ash-fusion temperature. Free-burning coals have a tendency to drift and avalanche. In general, the lower the fusion temperature, the more likely that clinker troubles will be met, although iron-oxide content of the ash exerts a marked influence on clinkering tendencies and furnace conditions, particularly temperature, can change the picture radically.

Perhaps the most important consideration in fuel selection is the caking characteristics of the coal. Different stoker designs impart varying degrees of agitation to the fuel bed and hence can handle coals of different caking qualities. There is, as yet, no clear-cut way of correlating caking qualities and stoker characteristics, hence the operator must learn by carefully noting the behavior of various coals on his particular unit.

Watercooling. Cooling tubes may be run under retorts and along the tuyeres, Fig. 12. They tie into the main boiler circulation system. This arrangement tends to increase radiant-heat absorption, lower fuel-bed temperature and chill ash to help prevent closing of air ports by slag. The over-all objective is to permit higher fuel-burning rates and to extend the range of coals that may be handled satisfactorily, particularly in regard to fusion temperature.

HOW FUEL PROPERTIES AFFECT STOKER-PLANT DESIGN AND OPERATION



HOW FUEL PROPERTIES AFFECT PULVERIZED-COAL DESIGN AND OPERATION



Selecting Fuel for New Plants and Old

A fuel is a package of energy plus other qualities, good and bad, that affect the way it behaves in use and so influence the equipment needed to handle and burn it. Normally, the package can't be taken apart, and we have to take it as it comes. This means shopping around for the one that offers the best all-round bargain. The way the bargain-hunting is done depends on the situation — if we're trying to find the best fuel for an existing plant we work differently from the way we do if we're looking over the situation for a plant still on the drawing boards.

For the existing plant, the problem is easy to visualize. We have certain equipment. It handles some kinds of fuel better than others. Then we first find exactly what kinds of fuel it can do a satisfactory job with, and then decide which of these proves most economical. Where is the problem with the new plant?

Fuel Survey Work. Designing a plant without first making a careful analysis of the fuel situation is like deciding to buy a railroad ticket without first deciding where you are going, but it's done all too often. A thoroughgoing fuel survey should precede everything but the decision to build the plant, since choice of fuel affects practically everything in the boiler house. What's more, each design decision made as details are worked out may prove a later limitation in buying fuel for the plant.

Purpose of a fuel survey is threefold: (1) to find out what fuels are available to the plant; (2) to establish the relative value of these fuels, and (3) to attempt to predict, or at least allow for, changes in relative value in future years. It would be wrong to say this is a simple job, except where only a few fuels are available, but there is no part of the design that pays bigger dividends over the life of the plant. In many cases, it pays to bring in a fuel consultant to make the survey.

Sources of Data. Where gaseous and liquid fuels are available the survey tends to be relatively simple because differences in type and grade play little part with these fuels. Where coal is involved the story is likely to be different; here the job is often skimped, just where thoroughness pays the biggest dividends. In many areas, a wide range of kinds and sizes is available; how to get to know about them?

Much information about coal is available in publications of the Bureau of Mines and in directories such as the *Keystone Coal Buyer's Manual*. In recent years, coal producers in various areas have formed associations to disseminate information about the coals mined in these areas. Large individual producers offer similar fuel-engineering services. Independent fuel consultants keep up-to-date files on coal characteristics, availability and price trends.

From sources such as these it should be possible to set up a list of the fuels available to the proposed plant, complete with characteristics and costs. This should be arranged on a cost-per-delivered-Btu basis. If allowance didn't have to be made for differences in the properties of the fuels and, therefore, in the kind and amount of equipment necessary for burning and handling them, this list would give the answer. As it is, it's just a starter toward a more complete study that takes into consideration plant design and cost.

Preliminary Analysis. It is impracticable to make a complete study for each fuel involved, showing estimated operating costs (including labor and maintenance) and estimated investment. Luckily, this is rarely necessary. Usually it is possible to estimate operating costs for, let's say, oil and the most likely of the bituminous coals available, and then to prepare rough investment figures for each kind of plant.

If the results of this preliminary analysis come out closely enough to be affected by differences in operating cost or investment for various kinds of coal, the comparison can be made on a more accurate basis. As a practical matter, in such cases it might be wiser to decide on coal, since a later change to oil or gas would require only minor plant changes and modest investment. On the other hand, shifting an oil- or gas-fired plant to coal may prove expensive and even impossible unless suitable provision has been made for storage and handling. Combination firing often proves a practical solution where several fuels are competitive.

What's Ahead? At this stage, consideration should be given to possible future shifts in the fuel situation, for both price and supply. In general, coal prices tend to change fairly slowly. Large supplies, relatively consistent production costs and regulated freight rates all contribute to this stability. On the other hand, oil and gas prices tend to show more variation, with the local supply situation playing a greater part than with coal. A study of past performances of each fuel in the given area will shed some light on what may be expected. Where the outlook is doubtful, either for price or supply, it may pay to add slightly to the investment and provide for combination firing, or incorporate, in the design, space and layout features that make a future fuel shift possible and less expensive.

An interesting example of the effect of fuel-situation changes can be seen now on the West Coast. There, for many years, hydro power has been a major energy source and the relatively few steam plants have been fired by oil or gas. Continued load growth and lack of remaining good hydro sites, except on the far reaches of the Columbia River, mean heavy steam-plant construction during a period when demand on petroleum products is high. In view of doubts of the final outcome of this situation, far-sighted designers of new utility plants are providing space for coal-handling and pulverizing equipment, and dust collectors, in the event a shift to coal may be necessary later.

The important consideration in all this is that a power plant represents a long-term investment. It is only prudent to protect this investment against future changes as far as it is possible to foresee them.

Choice Between Coals. Assuming that the preliminary analysis shows some form of coal to be the best fuel, what happens next? This depends somewhat on the coals involved, and also on the kind of firing equipment contemplated. A few examples will show how.

Assume the plant in question is, for controlling reasons, to be stoker fired. If the comparison lies between free-burning and caking coals, nature of stoker selected depends on type of coal chosen. If, for example, the free-burning coal and an unagitated-bed stoker proves the best combination, such a choice more or less rules out caking coals from later consideration. Where the decision carries this limiting effect, it should be made with extreme care, and assurance as to continuance of the supply and price situation is necessary.

Fuel Flexibility. The other common situation can be illustrated by considering a large plant where pulverized-coal firing is contemplated. Here the choice is likely to be between setups varying largely in degree, rather than in type, as in the previous example. Specifically, such a case is likely to boil down to a comparison between a minimum-investment plant, which can handle only a limited range of coals, or a similar but more generously designed layout capable of handling a wide range. This latter layout will probably feature greater furnace volume for lower heat release, and more pulverizer capacity.

Keeping first cost down weighs heavily both with plant owners and the manufacturers who supply equipment for their plants. At such a time, possible future savings from cheaper fuels and from greater latitude in fuel buying, are likely to look small. More and more, experience indicates that this is shortsighted; sound practice requires that plant design be such as to permit handling the entire range of coals that may now be available or may come into the picture in the future.

Watch Design Details. Even after a wise choice of fuel and general plant layout is made, the question of fuel must be kept in the foreground at every

stage of the actual design. Fuel properties and plant design tie-in at many points, as diagrams on pages 110 and 111 show. Attention to this angle at the drafting-board stage keeps some small limitation from creeping into the plans. Such a restriction might look big when the time comes to operate the plant.

SPENDING THE FUEL DOLLAR

So much for fuel selection as a factor in plant design. Let's turn now to the problem of buying fuel for an existing plant—one that was, in all probability, designed without benefit of a fuel survey. "Needle-in-the-hay-stack" purchasing leads to high steam cost and operating headaches. Responsibility for proper selection rests squarely on the shoulders of the power engineer. He is the only man, aside from the independent fuel consultant, who understands all the facts needed to spend the fuel dollar wisely. The purchasing agent can help with his knowledge of market conditions and buying procedure, the salesman and fuel-service engineer can supply facts about their fuels, but the power engineer must coordinate these with plant requirements and make the choice.

Because coal is a complex substance, selection cannot be reduced to a simple formula. What follows is an outline of a sound procedure which can be followed in most plants. Because it involves a minimum of testing and a maximum of "horse-sense," it comes closest to meeting small-plant needs.

The right coal for any plant is the one that will carry the load, meet all reasonable operating requirements and produce lowest over-all steam cost. While any coal can be burned in any plant, after a fashion, every practical engineer knows that many plants have design and equipment limitations that bar certain coals, either because they will not carry the load, because reliability will be seriously impaired, or because intolerable operating difficulties will be encountered.

To eliminate a lot of unorganized trial-and-error testing, the power engineer must examine every part of his plant from coal pile to ashpit and stack, with but one thought in mind, to locate and evaluate every factor affecting coal selection. Even the engineer familiar with his plant will find such a fuel-engineering analysis reveals limitations he wasn't aware of or puts the finger on the exact cause for some limitation only vaguely recognized.

Of equal importance, he will find that some limitations thought to exist will disappear on close examination. By removing false restrictions on coal choice, the analysis may actually lead to savings from wider buying latitudes.

The check list on this page gives some idea of the questions the power engineer must ask and answer. Experience and records will furnish some of the answers definitely and easily; others will have to be determined by trial. For example, a low boiler setting causes smoke trouble at high burning rates with high-volatile coals. The engineer knows this but has no records that would indicate the maximum amount of volatile matter that will permit operation at high rates without exceeding the smoke requirements. A few tests with sample shipments of coal will give the answer.

Limiting factors on coal use will take various shapes in different plants; in many cases the limitation will occur outside the furnace. For example, inadequate ash-handling equipment may require putting a limit on the ash content of fuels burned. A plant equipped with considerable air-heater surface, which produces low exit-gas temperature, may find it necessary to limit sulphur content to avoid rapid and expensive corrosion.

In considering furnace and firing equipment, it will be found that each factor of the design must be considered in relation to burning rates encountered and nature of load; that is, whether it is steady or fluctuating. For example, minimum ash-fusion temperature for clinker-free operation on an underfeed stoker depends largely on combustion rate. Likewise, nature of load affects importance of caking qualities of coals; a fluctuating load may bar a strongly caking coal from use on a stoker with inadequate agitation of the fuel bed, or from a hand-fired grate.

The engineer must also remember that one property of a coal may modify another. Thus presence of excessive fines may aggravate clinkering tendencies, producing trouble with a coal having apparently satisfactory ash-fusion characteristics.

Finally, in making the fuel analysis of his plant, the engineer must distinguish between limitations and preferences. For example, in a plant with barely enough pulverizer capacity, if grindability drops below a definite point, the load can't be carried; coals with lower grindabilities are worthless. However, if pulverizer capacity is ample, the engineer may still prefer high-grindability coals since grinding costs will be somewhat less. Saving in power consumption and cost of replacing wearing parts will indicate how much can be paid for higher grindability.

TYPICAL QUESTIONS FOR PLANT FUEL SURVEY

FUEL AND ASH HANDLING

Is coal stored long enough to make its weathering characteristics important?
Need to watch heating tendencies?
Would wet coal cause handling troubles?
Would dust from excessive fines constitute a nuisance?
Does rough handling bar friable coals?
Do segregation difficulties put premium on close sizing?
Does inadequate handling limit ash?
What is coal- and ash-handling cost per ton, including labor?
How much does ash disposal cost?

LOAD CONDITIONS

What burning rate results from maximum load? What is duration of peak?
What is lowest load to be carried for any length of time?
Is load fluctuating or fairly steady?
Is spare boiler capacity available?

SMOKE AND DUST EMISSION

Is smoke restricted by law? How?
Is there any specific restriction on fly-ash? If so, what?
Does plant have effective dust collectors?

OPERATION

To what extent is combustion controlled automatically?
Are operators experienced, competent?
Does plant have adequate metering and facilities for testing?

FURNACE

Volume ample, heat release conservative?
Is setting height adequate?
Does lack of refractory surface make ignition difficult?
What is furnace temperature just ahead of first tube row?
What is temperature in combustion zone?
Does furnace promote turbulence, mixing?
How much air preheat, if any?

STOKER SYSTEMS

How much agitation does fuel bed get?
How well can underfire air be distributed and controlled?
Is there enough overfire air, at the right places, with enough velocity?
How much do coal size and caking qualities affect fuel-bed structure?
What is limit on ash-fusion temperature to avoid clinkering troubles?

PULVERIZED-FUEL SYSTEMS

Is mill capacity ample for low grindability coals?
What is grinding cost per ton, including parts replacement?
Does inadequate drying limit moisture?
Does amount and location of watercooled surface restrict volatile content?
Is furnace dry-bottom or slag-tap? What range of ash fusion can be handled?
Does furnace bar high-ash fuels requiring long flame travel?

Some properties of coal have importance only as limits, never as preferences. For example, once the minimum ash-fusion temperature for trouble-free operation has been determined, any increase has no actual value.

The completed plant analysis boils down primarily to a set of limitations expressed as far as possible in coal properties that can be measured (ash content, fusion temperature, sulphur content, etc.) with properties that still defy exact expression (caking quality, weathering properties) stated as clearly as possible. Armed with this analysis, the power engineer can tackle the list of coals available, eliminating immediately those that fail to meet minimum requirements.

At this point relative prices enter the picture. The list of coals remaining after the first elimination should be set up on the basis of delivered-cost-per-Btu. This will immediately permit a second elimination, divided into two parts. (1) of the coals meeting all requirements, eliminate all but the best two or three from the delivered cost standpoint, and (2) from the coals exhibiting one or more undesirable qualities, eliminate those where low cost seems insufficient to compensate for undesirable properties.

Note that up to this point the only testing required has been of a simple sort and that even such trials as mentioned for setting the upper limit of volatility are only needed where plant records and observations are lacking on a particular point. Elimination can be carried even further without need for full-fledged evaporation tests. Each of the coals whose cost per Btu is low should be studied to determine how much weight must be given to the undesirable properties which pull its price down. High ash content may make no difference in a plant where ash can be sold; in a plant where removal must be paid for every increase in ash content involves a definite cash outlay. Thus, more coals may be eliminated.

For the small plant without test instruments, this may be enough. What looks like the best value among the remaining coals can be used for a short period. If it behaves satisfactorily and there is no apparent increase in operating troubles or maintenance it can be used with a fair degree of confidence.

If the plant has equipment for evaporation testing, plant trials will help verify the analysis up to this point and further sort out the remaining coals. By avoiding hit-or-miss plant testing, a large number of coals can be given consideration and the necessary careful testing can be given those worthy of it, all without excessive expense.

To be worthwhile, plant tests must be carefully made and the results must be analyzed properly. The errors involved in casual tests will often exceed the differences in coal quality. Every effort must be made to keep load conditions the same from test to test. Boiler surfaces should be equally clean. Finally, each coal should get equal attention and skill from the operating force. This does not mean each should be fired the same way; it means each should be fired to get best results, allowing for its peculiarities on the given equipment. This, in turn, means that each test should be preceded by a "warm-up" period to give the operating force a chance to get acquainted with the coal and its behavior. During this warm-up and the test itself, everything connected with the coal's performance should be studied and checked against the plant analysis.

LOWEST-COST COAL

If none of the coals display any markedly unsatisfactory operating characteristics, final selection will depend on over-all steam cost indicated for each. This will be made up of fuel cost, as calculated from the evaporation results, and maintenance and labor costs as estimated from observation.

Differences in evaporation results must be taken with a grain of salt since relative coal values are not the only factors affecting evaporation. Operation of other factors can often be determined and allowed for by calculating a boiler heat balance.

Unless plant testing extends over a fairly long period, it is difficult to estimate any differences in operating costs due to different coals. Items like increased power cost for handling or pulverizing can be measured but differences in maintenance costs will not show up for some time and then must be analyzed carefully to be sure they result from some property of the coal.

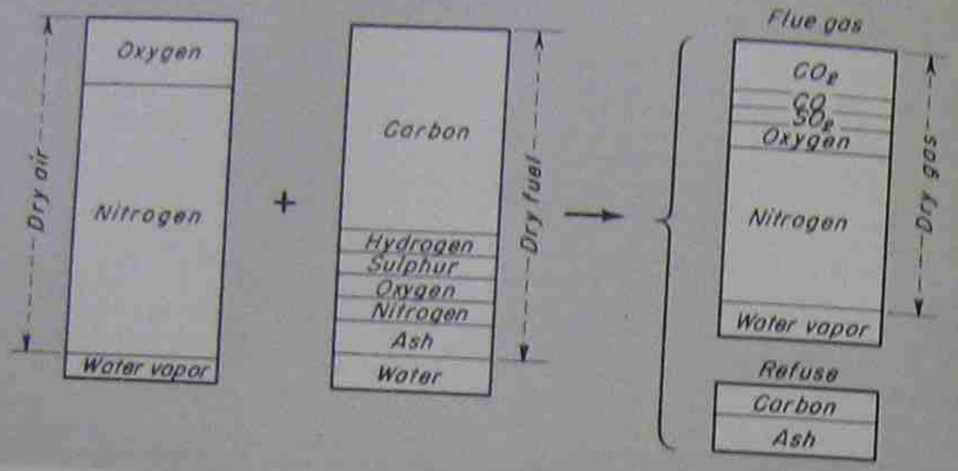
Normally analysis and testing will yield several coals having nearly the same value, any one of which will prove economical.

Once the job is done, the engineer must stay with it, for fuel values change and so do plant conditions. For example, improved preparation has raised ash-fusion temperature of West Kentucky coals enough to make them "available" to many midwestern plants formerly unable to use them. The vigilant engineer will keep his eyes open for such changes. He will also constantly revise his fuel specifications as changes in equipment and amount and nature of plant load so require.

ACKNOWLEDGMENTS

The editors wish to express their sincere appreciation to the many engineers who helped to insure the completeness and accuracy of this material by making technical data available and offering constructive comments. Power is also indebted to the following manufacturers of firing equipment who furnished information used in preparation of this special section:

American Coal Burner Co
American Engineering Co
Babcock & Wilcox Co
W N Best Combustion Equip Co
Blaw-Knox Co, Power Piping Div
Wm Bros Boiler & Mfg Co
Brownell Co
Canton Stoker Corp
Combustion Engineering Co
Combustion Equipment Co
Coppus Engineering Corp
Denver Fire Clay Co
Detroit Stoker Co
C H Dutton Co
Eclipse Fuel Engrg Co
Engineer Co
Enterprise Engine & Fdry Co
Erie City Iron Works
Faber Engineering Co
Fairbanks, Morse & Co
Fisher Industrial Co
Flynn & Emrich Co
Foster Wheeler Corp
Hammel Oil Burner Co
Hammel Oil Burning Equip Co
Hoffman Combustion Engrg Co
Illinois Stoker Co
Iron Fireman Mfg Co
Johnston & Jennings Co
Kennedy-Van Saun Mfg & Engrg Corp
Laclede Stoker Co
James Leffel & Co
Lee B Mettler Co
National Airoil Burner Co
Peabody Engineering Corp
Petroleum Heat & Power Co
Preferred Utilities Mfg Co
Ray Oil Burner Co
Riley Stoker Corp
W S Rockwell Co
Schutte & Koerting Co
Simplex Oil Heating Corp
Staples & Pfeiffer
David Stout & Sons
Strong-Scott Mfg Co
Superior Combustion Industries
Surface Combustion Co
Timken Silent Automatic Div, Timken-Detroit Axle Co.
Todd Shipyards Corp, Combustion Equipment Div
Webster Engineering Co
Westinghouse Electric Corp
C H Wheeler Mfg Co
Whiting Stoker Co
York-Shipley Inc, Industrial Div
John Zink Co



How to Figure Combustion

First part of this special section outlines the chemical and mechanical basis of combustion. By an understanding of the chemical changes between air supply and fuel, and the final flue-gas or combustion products, the plant engineer can tell whether he has made best use of his fuel and air. In other words, all chemical elements entering a fire must equal the elements leaving; hence, we can set up a chemical balance sheet as a basis for analysis.

The bar chart above shows in a very general way what substances are in both air and fuel before burning, and what substances appear in the combustion products. Heights of the bar-chart areas should not be regarded as proportional, but merely as indicating whether the amount of substance is relatively large or small.

Large amount of nitrogen in the air supply performs no useful duty in the burning process. It does not combine with any of the other elements and simply passes on to form the major bulk of the flue gas in the combustion products. Nitrogen moderates the fire temperature; if it were eliminated flame temperature would be much higher.

Oxygen, the only active element in air, combines with the so-called combustible elements of the fuel to produce heat. While pure oxygen would produce much higher temperatures, it proves more economical to use air, of which only 21% by volume is oxygen.

Air invariably contains a certain amount of humidity. This water vapor ordinarily does not perform any useful function. Its amount is very small and it passes on in the same form as part of the flue gas.

Most commercial fuels consist principally of carbon or some form of carbon associated with hydrogen. Hydrogen amounts vary according to the fuel, very small in anthracite coal, relatively large in natural gas. Sulphur, found in small amounts in most fuels, combines with oxygen releasing heat, but the product, sulphur dioxide, corrodes metals. Thus sulphur is considered an impurity. Carbon and hydrogen are the important burnable elements; all others play no part with the exception of the small amount of oxygen usually present in many fuels. Small amounts of nitrogen will also be found in fuels.

Ash quantities vary with the fuel nature, being large to small in coals, and very small to zero in oil and gas. Ash consists largely of minerals and in some coals may have a large proportion of iron.

Water in fuels tends to be higher for coals than for oil and gas. During burning this water evaporates and appears as steam in the combustion products.

Upon completing the burning process and giving up most of the heat generated the combustion products take two forms, flue gas and solid refuse. The carbon dioxide, CO_2, results from the complete combustion of carbon with oxygen from the air (and with the small amount in the fuel). In a properly controlled fire, carbon monoxide, CO, does not appear in the flue gas since it forms from incomplete burning of carbon. If it does appear, the amount is generally small.

Sulphur dioxide, SO_2, never proves to be large because the initial amount of sulphur in the fuel is slight. As the flue gas cools on its way to the stack, sulphur dioxide dissolved in water may be formed under certain conditions. It produces a corrosive acid.

If fires could be burned under perfect conditions no oxygen would appear in the flue gas. But more than the theoretical air need must be introduced to effect adequate mixing of oxygen with carbon and hydrogen, and thus insure complete burning of all combustible elements. When this mixing is done all the oxygen will not be used up.

Largest part of nitrogen in the flue gas comes from the air, a relatively minute portion was originally in the fuel combined with the other elements.

Water vapor in the flue gas comes from (1) air humidity (2) water in fuel (3) burning of hydrogen.

Solid refuse may be in the form of flyash going up the stack or in heavier masses collecting in the boiler ash hopper and on heating surfaces. This refuse consists largely of ash originating in the fuel, but sometimes there is a small amount of carbon caused by poor burning conditions.

Not shown in the bar chart are hydrocarbons that may appear in the flue gas when proper mixing has not taken place in the furnace. These fuel elements are in the gaseous form and represent important efficiency losses.

COMBUSTION EQUATIONS

Because air and fuel elements always combine in exact proportions the results of proper combustion can be predicted. Comparing actual results with predicted, a measure of performance can be established. Table above gives chemical data on the elements from which calculations can be made.

First let's consider the burning of carbon to CO_2. The number of atoms before and after the reaction must balance, and hence weights of the elements entering the reaction must equal weight of the product. In the equations below, the first one is the chemical reaction, the second the respective atomic or molecular weights taken from the table above, and the third the proportioning of these molecular weights referring to 1 lb of carbon as the base:

$$C + O_2 = CO_2$$
$$12 + 32 = 44$$
$$1\text{ lb} + 2.67 = 3.67\text{ lb}$$

or it takes 2.67 lb of oxygen to burn one pound of carbon to produce 3.67 lb of CO_2. Carbon originally is a solid, oxygen a gas, and the product is a gas.

Incomplete burning of carbon to CO is figured by:

$$2C + O_2 = 2CO$$
$$24 + 32 = 56$$
$$1\text{ lb} + 1.33\text{ lb} = 2.33\text{ lb}$$

When burning hydrogen:

$$2H_2 + O_2 = 2H_2O$$
$$4 + 32 = 36$$
$$1\text{ lb} + 8\text{ lb} = 9\text{ lb}$$

Here the combustion product is in the form of vapor, which condenses when flue gas cools to near atmospheric temperature.

Sulphur burns to sulphur dioxide as follows:

$$S + O_2 = SO_2$$
$$32 + 32 = 64$$
$$1\text{ lb} + 1\text{ lb} = 2\text{ lb}$$

Gas fuels are primarily composed of hydrocarbons which, when burned completely, produce carbon dioxide and steam. Two of the more common hydrocarbon fuels are as follows:

Methane:

$$CH_4 + 2O_2 = CO_2 + 2H_2O$$
$$16 + 64 = 44 + 36$$
$$1\text{ lb} + 4\text{ lb} = 2.75\text{ lb} + 2.25\text{ lb}$$

Acetylene:

$$2C_2H_2 + 5O_2 = 4CO_2 + 2H_2O$$
$$52 + 160 = 176 + 36$$
$$1\text{ lb} + 3.08\text{ lb} = 3.39\text{ lb} + 0.69\text{ lb}$$

Equation Application. Above equations, with data on fuel analysis, form the basis of computing combustion performance. From the quantitative standpoint the most important factor is the air supplied. Ultimate analyses of fuels give the percentage of each element present. When figuring the amount of air needed to burn the fuel, the above equations can be used to find the oxygen. Since air contains 23.1% by weight of oxygen the pounds of air needed are the oxygen weight divided by 0.232. Letting C, H, O and S represent the pounds of element per lb of fuel, the weight of air theoretically needed is:

$$W = 11.5C + 34.5\left(H - \frac{O}{8}\right) + 4.3S$$

Combustion Products. Flue-gas analysis by orsat or similar apparatus is useful in checking on combustion efficiency. Knowing air components by volume to be 21% oxygen and 79% nitrogen, the following example shows how to figure back from the flue-gas components to find out how much air was initially supplied:

Flue-gas analysis (volume):

CO_2	8.86%
O_2	10.70%
CO	0%
N_2	80.44%
Total	100.0%

Assuming that there is zero nitrogen in the fuel, then all of this component must have come from the air. For every 100 cu ft of flue gas, the amount of air supplied = 80.44 ÷ 0.79 = 101.9 cu ft. In this air was (101.9 × 0.21 =) 21.4 cu ft of O_2 per 100 cu ft of flue gas. Actually, there are 10.7 cu ft of O_2 per 100 cu ft of gas left, which means 21.4 − 10.7 = 10.7 cu ft were used to burn the combustible elements of the fuel. The remainder was excess to insure complete combustion. On a percentage basis the excess air is (10.7 ÷ 10.7) 100 = 100%.

The amount of oxygen used to burn the fuel's carbon is 8.86 (2.67 =) 23.7 cu ft per 100 cu ft of flue gas. The remaining oxygen, 10.7 − 6.44 = 4.33 cu ft per 100 cu ft of gas, was used to burn hydrogen in the fuel. Since most gas analyses are made at room temperature, the H_2O product of H_2 has condensed and therefore does not appear in the analysis.

PROPERTIES OF COMBUSTION ELEMENTS

Element or Compound	Formula	Molecular weight	At 14.7 psia, 60F: Weight, lb per cu ft	At 14.7 psia, 60F: Volume, cu ft per lb	Gas or solid	Heats: Combustible	Heat value, Btu: Per pound	Heat value, Btu: Per cu ft at 14.7 psia, 60F	Heat value, Btu: Per mol
Carbon	C	12	—	—	S	C	14,540	—	174,500
Hydrogen	H_2	2.03	.0053	188	G	C	61,000	325	123,100
Sulphur	S	32	—	—	S	C	4,050	—	129,600
Carbon monoxide	CO	28	.0739	13.54	G	C	4,340	321	121,600
Methane	CH_4	16	.0423	23.69	G	C	24,000	1013	384,000
Acetylene	C_2H_2	26	.0686	14.58	G	C	21,500	1483	563,000
Ethylene	C_2H_4	28	.0739	13.54	G	C	22,300	1641	623,400
Ethane	C_2H_6	30	.0792	12.63	G	C	22,300	1763	668,300
Oxygen	O_2	32	.0844	11.84	G	—	—	—	—
Nitrogen	N_2	28	.0739	13.52	G	—	—	—	—
Air*	—	29	.0765	13.07	G	—	—	—	—
Carbon dioxide	CO_2	44	.1161	8.61	G	—	—	—	—
Water	H_2O	18	.0475	21.06	G	—	—	—	—

*By volume, air is 79 parts nitrogen and 21 parts oxygen. The "molecular weight" of 29 is merely the weighted average of the molecular weight of the constituents.

HOW TO FIGURE BITUMINOUS-COAL COMBUSTION QUICKLY

1. Kind of fuel ..... Bituminous coal
2. Heating value as fired ..... 13,800 Btu per lb
3. Room temperature ..... 80 F
4. Flue-gas temperature ..... 520 F
5. Flue-gas analysis:
   a. CO_2 ..... 10.2%
   b. CO 0.6%
   c. O_2 ..... 9.2%
6. Boiler efficiency (from test) 74.4%

COMPUTATIONS:

7. Theoretical air, from scale 1 ..... 10.2 lb per lb fuel
8. Water produced by burning available hydrogen (scale 2) 0.35 lb per lb fuel
9. Total water from burning of coal = 0.35 + 0.05 = 0.40 lb per lb fuel
10. Actual air = 175% of theoretical = 1.75×10.2 = 17.9 lb per lb fuel
11. Total flue gas = air + coal − ashes = 17.9 + 1 − 0.2 = 18.7 lb per lb fuel
12. Dry flue gas = total flue gas − water produced = 18.7 − 0.40 = 18.3 lb per lb fuel
13. Sensible heat loss in dry gas = Dry gas weight × temperature rise × specific heat = 18.3 × (520−80) × 0.24 = 1930 Btu per lb fuel
14. Moisture heat loss per lb water = 1060 + ½ flue gas temperature = 1060 + 260 = 1320 Btu
15. Moisture heat loss = loss per lb water × lb water per lb coal = 1320 × 0.4 = 500 Btu per lb fuel
16. Incomplete-combustion loss, from chart 4 ..... 3.1%
17. Heat balance

	Btu per lb fuel	%
a. Dry-gas loss	1,930	14.0
b. Moisture loss	500	3.6
c. Incomplete-combustion loss	440	3.1
d. Unaccounted-for losses	660	4.8
e. Total losses	3,530	25.6
f. Useful heat	10,270	74.4
g. Heating value, Btu per lb fuel	13,800	100.0

18. Calculation of heat balance items:
   a. Dry-gas loss = 1930/13,800 = 14.0%
   b. Moisture loss = 500/13,800 = 3.6%
   c. Incomplete combustion loss = 13,800×0.032 = 440 Btu per lb fuel
   d. Unaccounted losses = 3530−440−500−1930 = 660 Btu per lb fuel
   e. Useful heat = 13,800×0.744 = 10,270 Btu per lb

Short-cut Combustion Calculations

Every textbook on steam power plants has a complete demonstration on the calculation of fuel combustion. Such an exhibit usually assumes that complete fuel, flue-gas and refuse analyses are available. But many plants, especially in the smaller capacities, do not have such complete information and cannot justify the money needed to determine it. Nevertheless, to operate economically these plants should closely follow their combustion performance because it is at this point that efficiency can be made or broken.

Assuming that such a plant has instruments for analyzing flue-gas composition and measuring flue-gas temperature the method described here suffices to tell the operator whether his combustion conditions are proceeding satisfactorily or not. While the method is approximate, numerous checks have shown the results to be within 2% of those found by using the longer, complete methods. The operator must know his fuel type and its heating value in Btu per pound *as fired*. The fuel supplier can normally give this information with satisfactory accuracy.

Scales and charts forming the basis of this computing method are given on the facing page. Their use is demonstrated in the table above for a given set of data using bituminous coal as the fuel. Let's follow through on this table, item by item, to find out how the calculations are made.

Items 1 to 6 are the data that must be known as mentioned above. The boiler efficiency should preferably be known by test, but a guaranteed efficiency using the same fuel will do if test results are not available.

Item 7. Scale 1 under the appropriate fuel classification on the facing page gives the theoretical air requirement when the fuel heating value is known. In this computation method, note that all weights are given in pounds per pound of fuel as fired.

Item 8. Water in the flue gas originates from three sources: (1) water originally in the coal (2) water produced by the burning of available hydrogen in the fuel (3) moisture in the air supplied for combustion. Of these we shall figure only (2), which is five to ten times as much as the amount appearing in (1). We do not attempt to figure the value of (3) because it is very small and its variation unimportant from the angle of everyday operation. *Item* is found by using Scale 2 for the appropriate fuel.

Item 9. Since original moisture in coal is unknown we assume it to be 0.05 lb per lb of fuel. Any error in this assumption will be of little practical importance in figuring moisture heat loss later, except with lignite, wood and very wet coals.

Item 10. First add CO_2 and ½CO to find 10.2 + ½(0.6) = 10.5. Use this value with Scale 3 for bituminous coal and read 75% excess air. On the lower scale it will be found that 9.0% O_2 corresponds to 75% excess air. This figure should be close to the O_2 value found by flue-gas analysis, which in this case was 9.2%. This is close enough to indicate a consistent gas analysis. If the CO_2 only should be known and the CO believed to be zero or negligible, enter Scale 3 with the CO_2 value to get the excess air magnitude.

Item 11. Practically speaking, everything fed to the furnace ultimately goes up the stack or into the ashpit. Then, to get the total weight of flue gas (per lb of coal fired) add 1 lb (of coal) to the air supplied and subtract the refuse produced per lb of coal. The refuse generally contains the original ash in the coal and perhaps some unburned carbon. Hence the amount of refuse is always greater or at least equal to the original ash weight in the coal, unless some ash is lost up the stack. Fortunately the refuse correction for the flue gas is not important. An error of 50% in the refuse allowance usually affects the total flue gas less than 1%. For practical purposes it is close enough (for any bituminous or anthracite coal) to assume 0.2 lb refuse *for this calculation*.

Item 12. Dry gas and water vapor in the flue gas must be separated to calculate the amount of heat energy carried off by each.

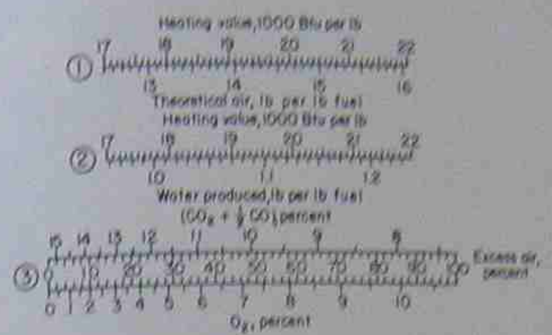
Item 13. Largest loss in boiler furnaces is the heat energy carried off by the dry gas. It is proportional to the amount of dry gas and the number of degrees above room temperature to which it is heated. These Btu loss figures are rounded off to the nearest 10 Btu. The method does not warrant closer figuring.

Item 14. Water in the coal as fired and the water produced by burning the fuel's available hydrogen must be heated to the boiling point, evaporated and then superheated to the flue-gas temperature. The formula given calculates the heat approximately needed to put 1 lb of water through these heating steps, starting with room temperature of 80 F. The formula is also suitable for room temperature ranging from 60 to 100 F.

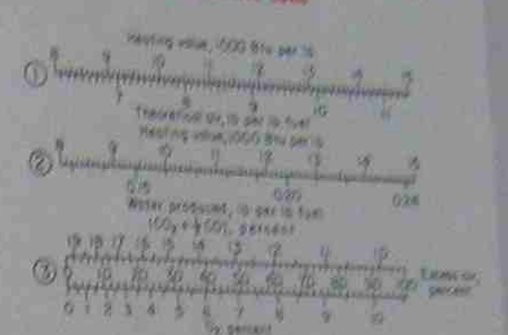
Item 15. The previous step calculated the heat energy per lb of water; this formula corrects this figure to heat

SCALES AND CHART FOR COMBUSTION PERFORMANCE ESTIMATE

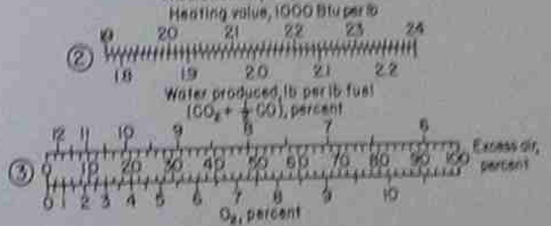
FUEL OIL



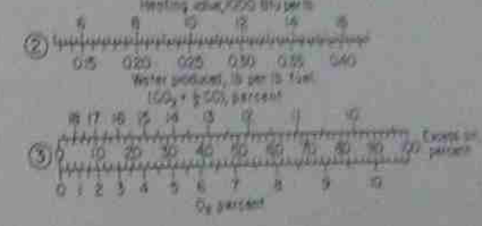
ANTHRACITE COAL

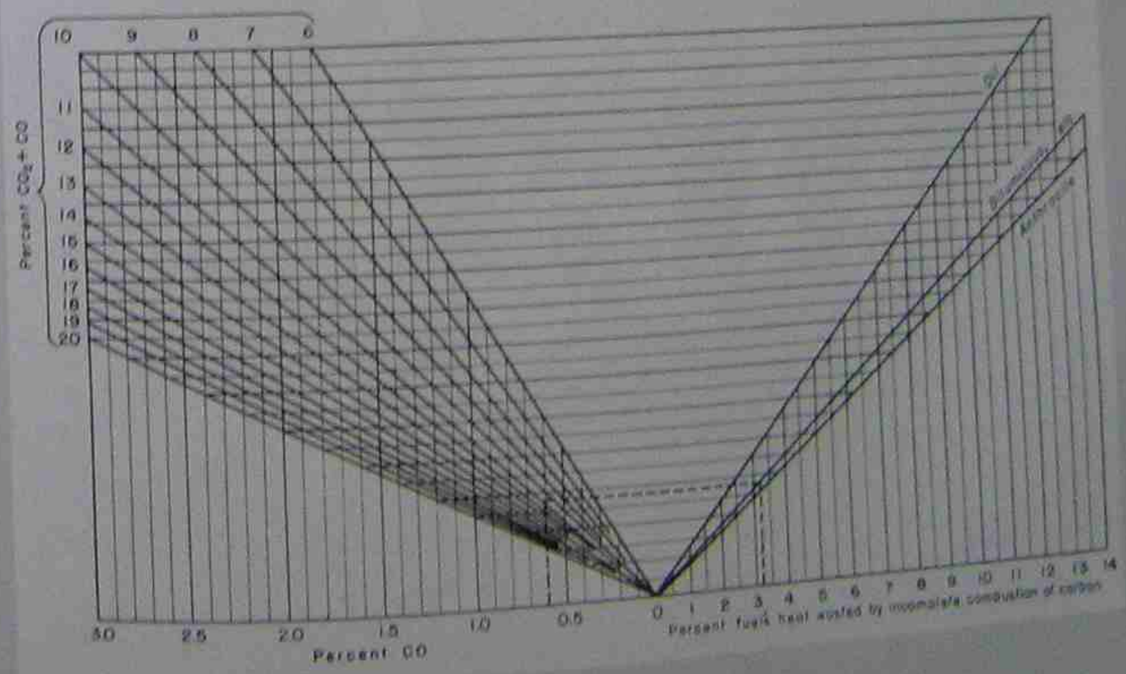


NATURAL GAS



ALL RANKS OF BITUMINOUS, LIGNITE, WOOD





AIR REQUIRED FOR AND PRODUCTS OF COMBUSTION

Gives required combustion air and products for common combustibles burned with theoretical air requirements. Air and products are given in mols, cu ft and lb (see right-hand column) for 1 mol, 1 cu ft and 1 lb of fuel

Fuel	For 1 mol of fuel					For 1 cu ft of fuel					For 1 pound of fuel					
	Air		Other products (than N_2)			Air		Other products (than N_2)			Air		Other products (than N_2)			
	O_2	N_2	CO_2	H_2O	SO_2	O_2	N_2	CO_2	H_2O	SO_2	O_2	N_2	CO_2	H_2O	SO_2	
C	1.0 379 32.0	3.76 1425 105	1.0 379 44.0	— — —	— — —	— — —	— — —	— — —	— — —	— — —	.0833 31.6 2.67	.313 118.8 8.78	.0833 31.6 3.67	— — —	— — —	Mols Cu ft Pounds
H_2*	0.5 189.5 16.0	1.88 712 25.6	— — —	1.0 — 18	— — —	.00132 0.5 .0422	.00496 1.88 .139	— — —	.00264 — .0475	— — —	.250 94.8 8.0	.940 356 26.3	— — —	0.5 — 9.0	— — —	Mols Cu ft Pounds
S	1.0 379 32.0	3.76 1425 105	— — —	— — —	1.0 379 64	— — —	— — —	— — —	— — —	— — —	.0312 11.84 1.0	.1176 44.6 3.29	— — —	— — —	.0312 11.84 2.0	Mols Cu ft Pounds
CO	0.5 189.5 16.0	1.88 712 52.6	1.0 379 44.0	— — —	— — —	.00132 0.5 .0422	.00496 1.88 .139	.00264 1.0 .116	— — —	— — —	.179 6.77 .571	.0672 25.4 1.88	.0257 13.53 1.57	— — —	— — —	Mols Cu ft Pounds
CH_4	2.0 758 64.0	7.52 7850 210	1.0 379 44.0	2.0 — 36.0	— — —	.00528 2.0 .169	.0198 7.52 .556	.00264 1.0 .116	.00528 — .0950	— — —	.125 47.4 4.0	.470 178 13.17	.0625 23.7 2.75	.125 — 2.25	— — —	Mols Cu ft Pounds
C_2H_2	2.5 947 80.0	9.40 3560 263	2.0 758 88.0	1.0 — 18.0	— — —	.0066 2.5 .211	.0248 9.40 .694	.00528 2.0 .232	.00264 — .0475	— — —	.0962 36.4 3.08	.362 137 10.13	.0769 29.15 3.38	.0385 — .692	— — —	Mols Cu ft Pounds
C_2H_4	3.0 1137 96.0	11.29 4280 316	2.0 758 88.0	2.0 — 36.0	— — —	.00792 3.0 .253	.0298 11.29 .834	.00528 2.0 .232	.00528 — .0950	— — —	.1071 40.6 3.43	.403 153 11.29	.0714 27.1 3.14	.0714 — 1.786	— — —	Mols Cu ft Pounds
C_2H_6	3.5 1326 112.0	13.17 4990 369	2.0 758 88.0	3.0 — 54.0	— — —	.00923 3.5 .296	.0347 13.17 .972	.00528 2.0 .232	.0079 — .1425	— — —	.1167 44.2 3.73	.439 166.3 12.29	.0667 25.3 2.93	.10 — 1.8	— — —	Mols Cu ft Pounds

*Varying assumptions for molecular weight introduce a slight inconsistency in the values of air and combustion products from the burning of hydrogen. True molecular weight of hydrogen is 2.02, but the approximate value of 2 is used in figuring the air and combustion products.

energy per lb of fuel to be consistent.

Item 16. Loss due to incomplete combustion of the carbon to CO is found directly from the chart at the bottom of page 117. Enter chart with 0.6% CO and move vertically up to slanting line equaling sum of CO_2 and CO, which is 10.8%. From this intersection move horizontally to right to line marked *Bituminous*, then down to lower right-hand scale showing percent of fuel's heating value wasted.

Item 17. By setting up the table shown with lines *a* to *g* all the foregoing calculations may be summarized by entering them in the proper spaces as shown in color. The calculations needed to fill the rest of the table are given in *Item 18* in correspondingly lettered lines.

The unaccounted losses as shown in *Item 18, line d*, are found by difference and here include chiefly: (1) loss of carbon to ashpit (2) radiation from boiler and furnace (3) cumulative error (plus or minus) of all data and computations. Any marked variation in this quantity should be cause for an operator to look for trouble in his steam generator unless he can account for it directly by known factors.

Carbon loss in refuse to the ashpit is usually figured from analyses of the coal and the refuse. The foregoing method assumes that no analyses are available. If the coal-ash content is known, the carbon loss can be calculated from measurements of coal fired and refuse produced. To illustrate let's assume the following data:

Ash in coal as fired, 7.4%; refuse produced per lb of coal, 0.096 lb. Then the refuse from each pound of coal fired must contain 0.096-0.074=0.022 lb of combustible material. Since this material will be pretty well "cooked" or heated to drive off the volatile gases, we can figure it as pure carbon with a heating value of 14,600 Btu per lb. Then carbon loss=0.022×14,600=320 Btu per lb fuel fired.

This method cannot be used where substantial amounts of carbon are lost up the stack, as in certain cases of pulverized fuel and stokers operating with heavy forced draft. Where carbon loss is figured it should, of course, be inserted in the heat balance, reducing the unaccounted losses by that amount.

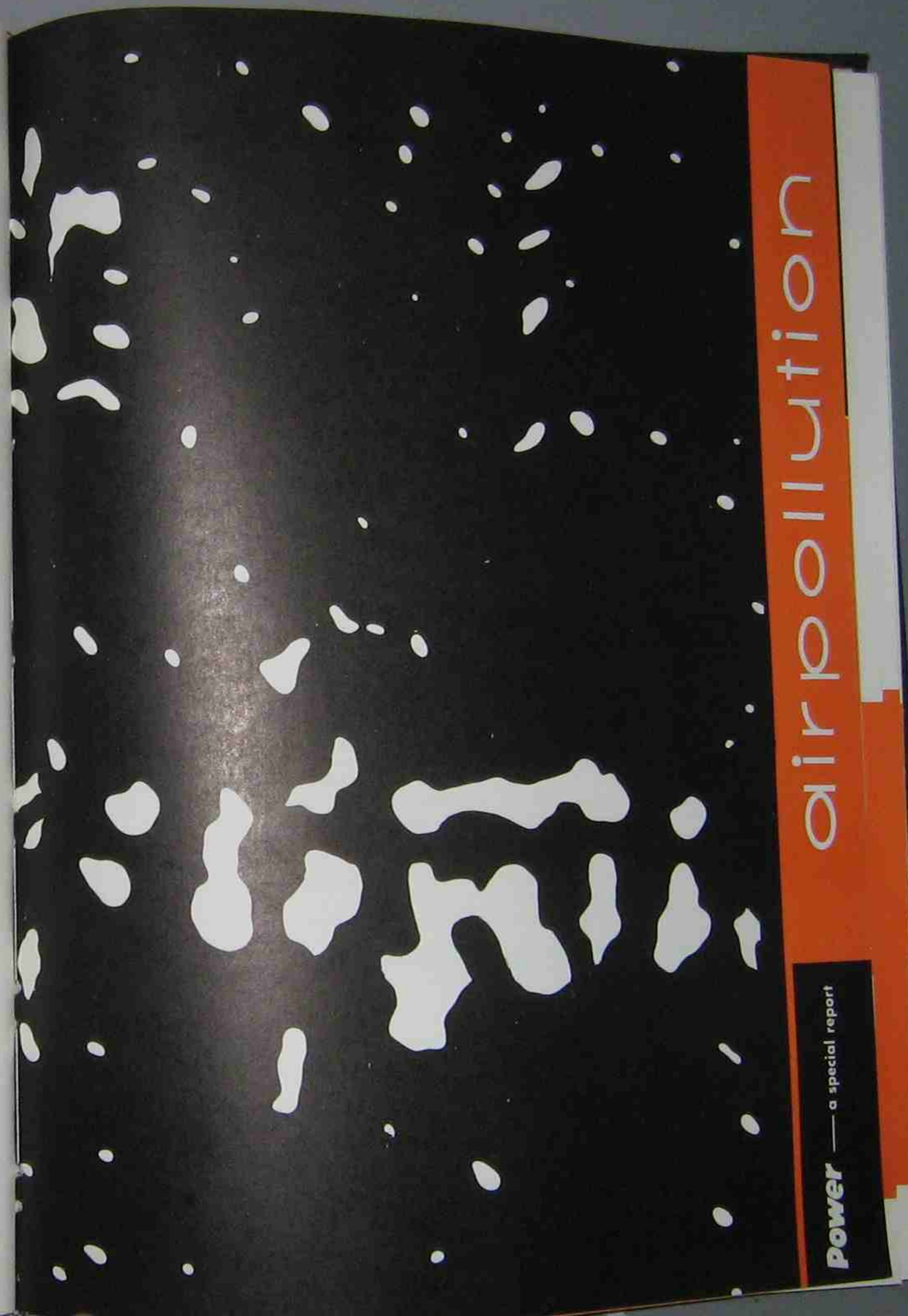
As-fired vs Dry. The heating value and analysis of fuel as fired varies with the amount of moisture associated with it. The moisture, in turn, constantly changes in amount during mining, shipping and storing. Hence, chemists and coal men sometimes prefer to quote the analysis of dry coal and give the moisture separately.

But all the foregoing computation and charts in this section are based on fuel as fired. If coal data are given on the dry basis they must be converted to the as-fired basis. For instance, let's assume that coal on the dry basis has 12,700 Btu per lb and 12.4% ash. If the as-fired coal has a moisture content of 4.5%, the conversion constant is 1.00−0.045=0.955. Then multiply the dry-basis figure by 0.955 to get the as-fired figure, or 12,700×0.955=12,130 Btu per lb as-fired coal.

This shortcut method was designed for the engineer who wants his answer quickly though his technical resources are limited. Combustion technicians in large power plants and others who make elaborate boiler tests and studies have all the paraphernalia for a complete analysis based on chemical relations. This method is not intended for their use.

Calculation Data. Above table is compiled for the engineer who must deal with many fuels and their combustion. It gives basic data on relation between elements in the combustion process on (1) the mol basis (2) the volumetric basis and (3) the weight basis. Study of the table will show that it enables the rapid conversion of any calculation from one base to any of the two other bases with a minimum of both time and error.

Each of the three groups of columns refers to one of the calculating bases. For example, the first group of columns refers to the mol basis, that is, one mol of the fuel element shown in the first column. The first line in each box gives the corresponding mols of oxygen and nitrogen in air needed for burning this element or the number of mols of combustion products resulting from the completed reaction.



Air pollution is by no means a new problem: records show efforts at control as early as the 14th century. But where this once was a matter of concern in a few unusual situations, population growth and concentration now give pollution control importance and urgency in many communities. Nor is the answer any longer a simple one. While our technical resources for diagnosis and prescription are greater than ever, the multiplying diversity and complexity of human activities make both vastly more difficult.

Thus, while pollution affects more and more people, it becomes increasingly a problem for the specialized skills of the engineer. It demands these skills in two areas. One is a responsibility engineers have recognized and accepted for many years—the application of their know-how to the direct and practical task of designing and operating plants and facilities that, taken individually, are good citizens from the pollution standpoint.

Now, as never before, engineers must recognize and accept another kind of responsibility—as individual citizens of their communities. Compared to the job of cleaning up a single stack, the task of cleaning up a region's air is infinitely complex and full of pitfalls for the technically unwary. Only too often it is approached in an atmosphere where emotion and ignorance outweigh judgment and knowledge. To this situation the engineer-citizen can bring the leaven of logical, informed thinking, a dispassionate desire for the right answer rather than the expedient one.

If community efforts to achieve clean air are to reach fruition, the engineer needs to raise his sights from his own plant to encompass all aspects of pollution, while the enlightened citizen needs some technical understanding of the nuisances he seeks to limit. As an aid to both, POWER editors began more than a year ago to research each phase of air pollution. From their digging into source materials, interviews with authorities, on-the-spot investigations, comes the special report that follows.

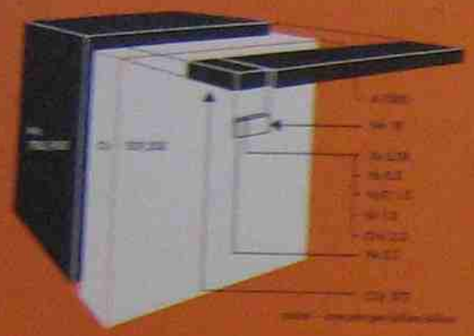
To put the manifold aspects of the pollution situation into perspective, the report deals first with the great ocean of air in which man lives and works. Then it takes a wide-ranging look at the many ways that living and working produce pollutants. With the elements of the problem identified and their interplay explored, the report then presents constructive approaches to solutions for the community and for the individual plant.

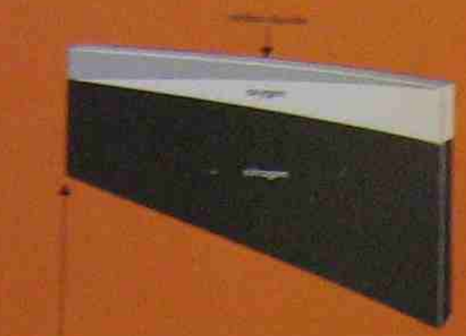
We hope that engineers accustomed to daily concern with plant pollution control will welcome this broader view. And we hope that civic leaders and public-spirited citizens of America's communities will find here the essentials for acting with wisdom in a matter of ever-increasing urgency.



Our ocean of air: Stretching toward outer space, earth's atmosphere displays ever-changing facets of composition and behavior. Most important to us is the restless troposphere, that thin layer, only 5 to 11 miles deep, next to our planet's surface. This region of seething activity, from storm to balmy day, has for an overlay the austere and serene stratosphere, never-changing and weatherless. Then comes the incredibly thin air of the ionosphere. Cosmic-ray bombardment gives its atomic particles electric charges, making it a useful reflector of radio waves from the earth. Far out, the ionosphere merges into the exosphere. Some believe this may be the sun's outer atmosphere.

As we rise through the earth's atmosphere, pressure steadily lessens until it all but vanishes in the exosphere. Temperature gyrates fantastically with altitude as the endless spinning of the earth and its surrounding air changes the energy balance.





The troposphere, in which we live, is made up of many elements...

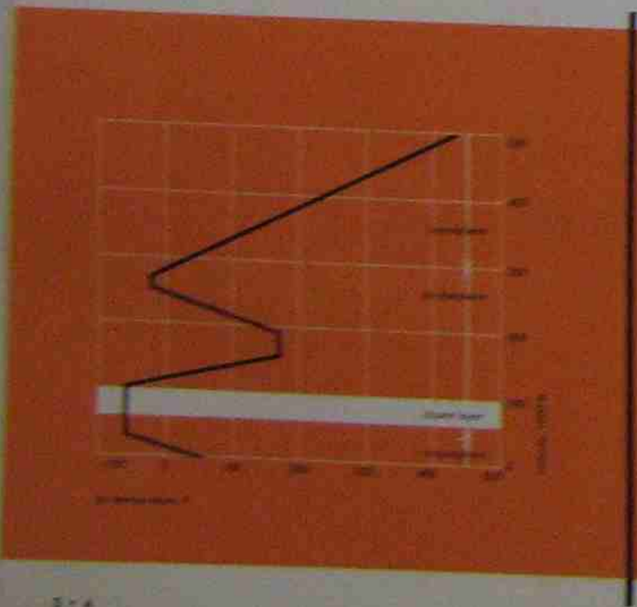
Of air's many elements, the most important are nitrogen and oxygen. Diagrams above show the present makeup of the troposphere and the change believed to have occurred during eons of geological history. There was probably no free oxygen present during earth's creative convulsions; it was most likely formed by plant life.

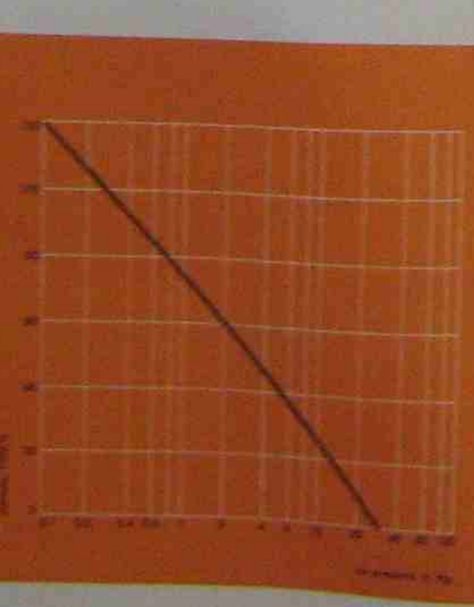
As we rise through the troposphere the air thins rapidly —pressure falls to microscopic levels as fewer and fewer molecules rise to high altitudes. But the air holds surprises. As we first ascend, it drops to frigid temperatures, and then oscillates back and forth until finally it gains soaring levels in the upper reaches of the exosphere. Below left, we have the trend of temperature change with rising altitude, but this is no fixed relation.

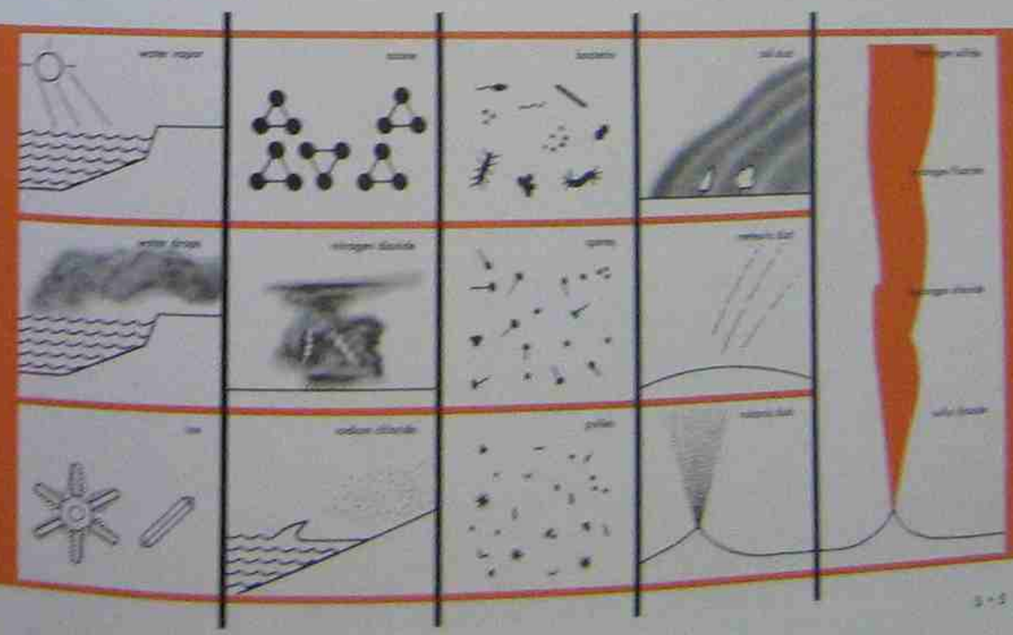
In the habitat of living things, temperature changes continuously. In the lower layers of the "thick" atmosphere we find that air cools with rising altitude, above left. But its rate of change depends on the entrained water vapor (humidity) and momentary gain or loss of thermal energy at all altitudes.

The change in temperature we call the *lapse rate*. Dry still air cools at 5.5 F per 1000 ft, while moist air cools at 3.2 F only. Sometimes the air has a constant temperature at all altitudes, and then again temperature may rise with altitude. The flow of energy through the universe persistently changes the lapse rate of a locality during a 24-hr daily cycle as typified at upper right.

The restless darting molecules of air carry with them many particles and gases flung up by the forces of nature. These natural pollutants, some of which are diagramed below, would exist in the atmosphere even if man had never set foot on this ancient planet of ours.





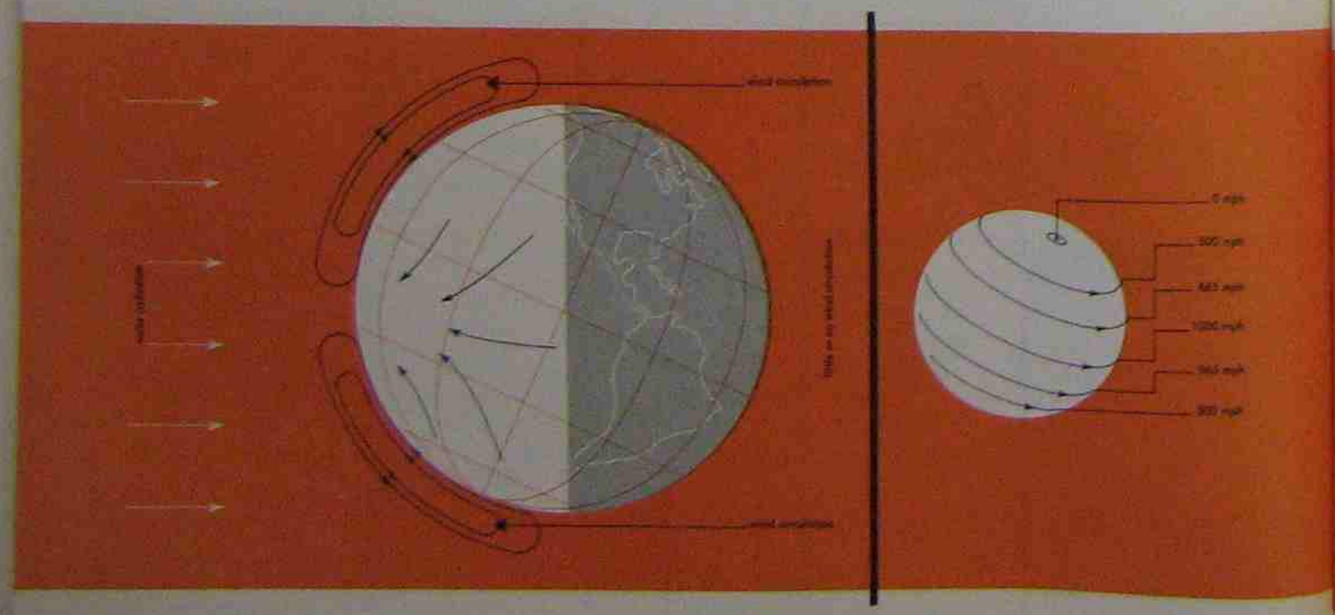


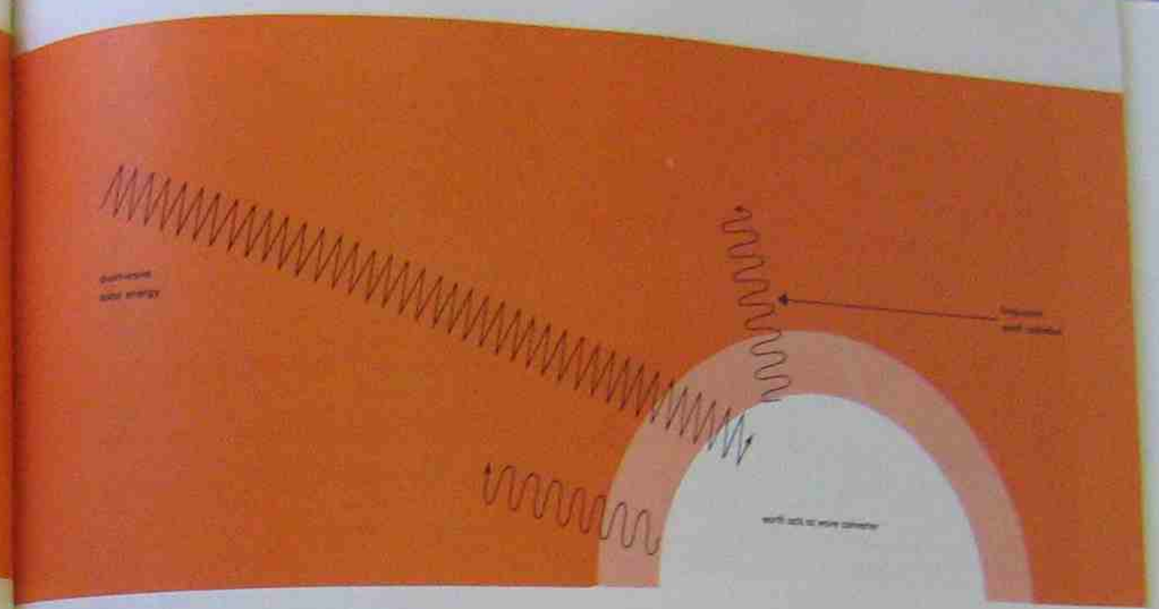


Solar energy conversion, the earth's inclination and rotation...

The earth's share of the sun's nuclear-generated radiant energy is paltry, but it runs our weather system. In terms of averages the atmosphere directly absorbs only about 15% of the energy received; 42% reflects back to outer space and 43% is absorbed by the earth's varied surface. The earth acts as an energy converter; it receives short-wave light energy and changes it to long-wave heat energy. This warms our airy envelope and makes it move; ultimately the heat energy radiates to outer space. The air acts like a greenhouse, passing short-wave radiant energy but absorbing long-wave heat energy.

If the earth did not rotate to produce alternating day and night we would have a fixed wind pattern, lower left. Surface winds would blow to the hottest part of the globe and there rise as they heated by conduction from the warm earth. Welling up toward the stratosphere, the air

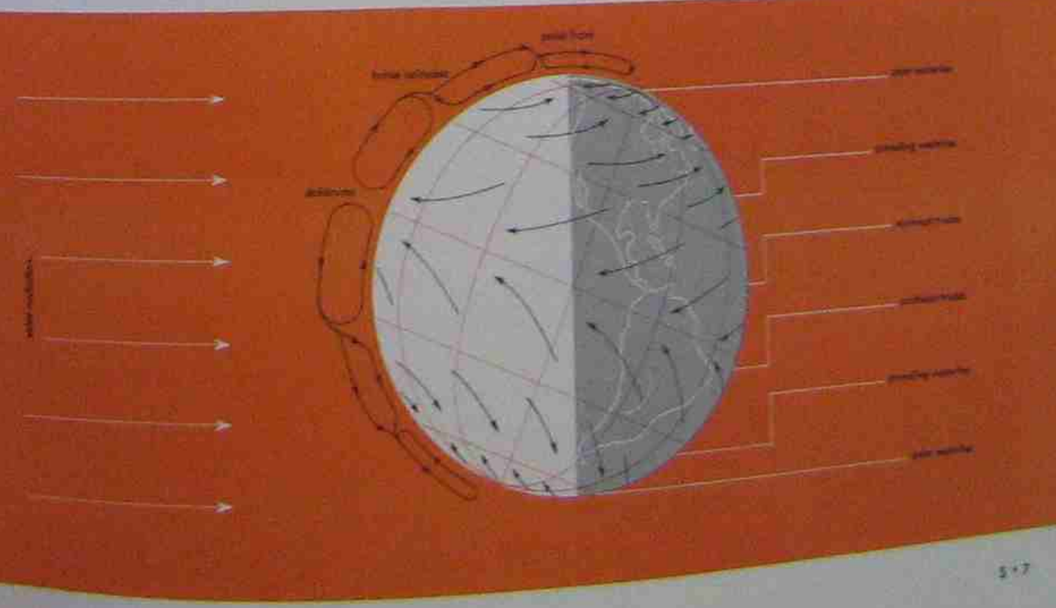


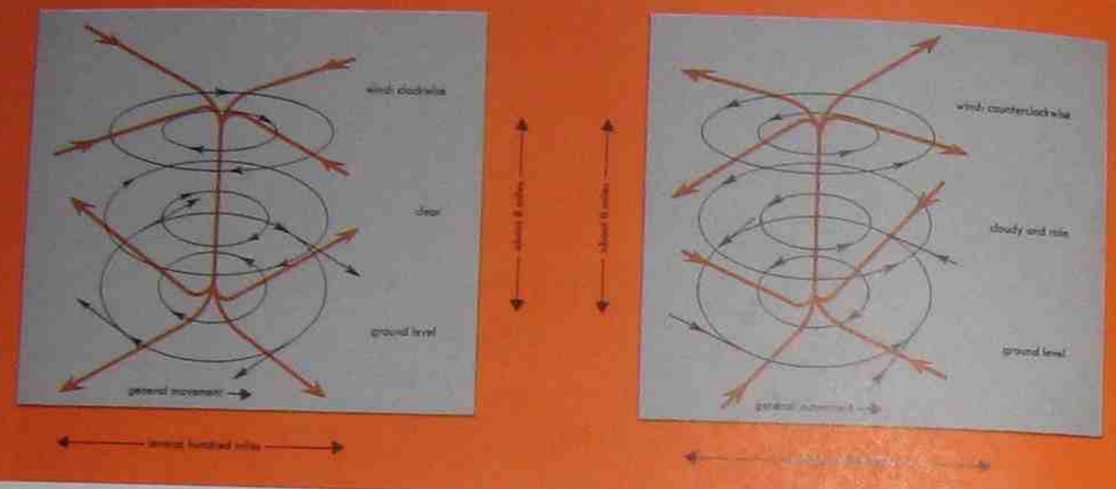


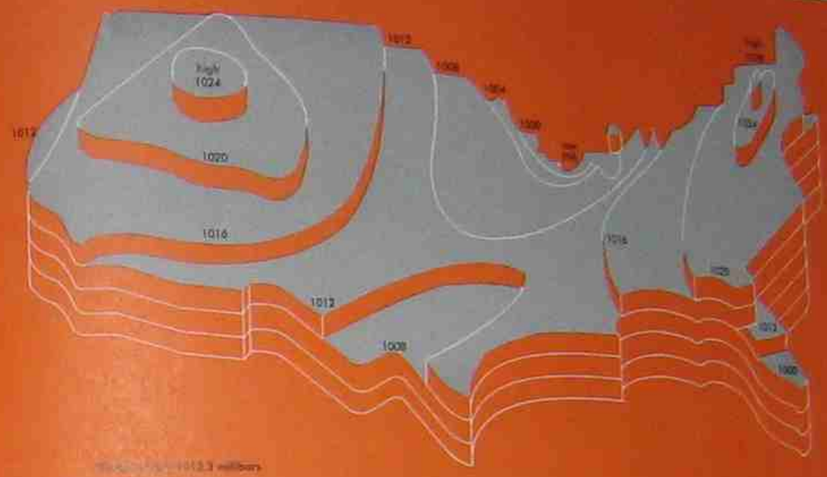
...are among factors causing general atmospheric motion patterns...

would cool as it worked against gravity. In the upper troposphere it would sweep out in all directions toward the wide-flung dark, cold parts of the globe. Here the upper winds would sink as they cooled and again head for the hot spot on the surface directly under the sun.

But the earth turns on its polar axis, and its linear speed varies from about 1000 mph at the equator to zero at the poles. This motion continuously changes the hot spot on the earth and churns the troposphere in six major zones, each with its prevailing wind motion. The height of the troposphere varies from about 11 miles in the tropics to about 5 miles at the poles. Zone widths vary with the season and the day. Churning through this complex pattern the air displays such dramatic effects as vicious tornadoes and the lofty 300-mph jet streams periodically girdling the earth in sinuous paths.







...and erratic, eddying movements in earth's thin skin of air...

Air, being a gas, can move independently of the solid earth. When it moves with the earth we have a calm; when it moves in any other direction we have a wind. But the air has many unpredictable complex motions.

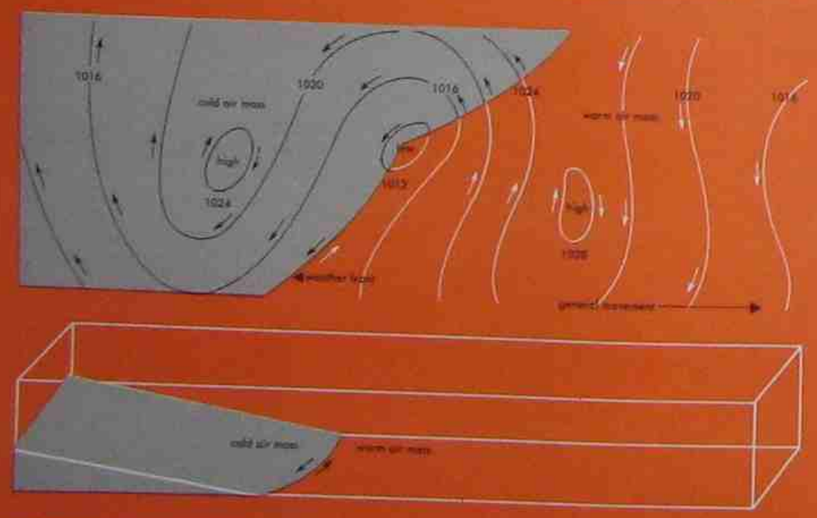
Great masses of air tend to move independently of each other—polar continental and maritime masses from the ends of the earth, tropical continental and maritime masses from the steaming torrid zone. As the accumulation of solar energy on the earth waxes and wanes these hot and cold masses battle for domination of the temperate latitudes. This gives us alternating fair and foul weather, while the occasional stalemates produce our enervating droughts or long dreary rains.

All weather depends on these world-wide forces, but local topography can sharply affect the prevailing climate, mitigating or worsening the general weather pattern.

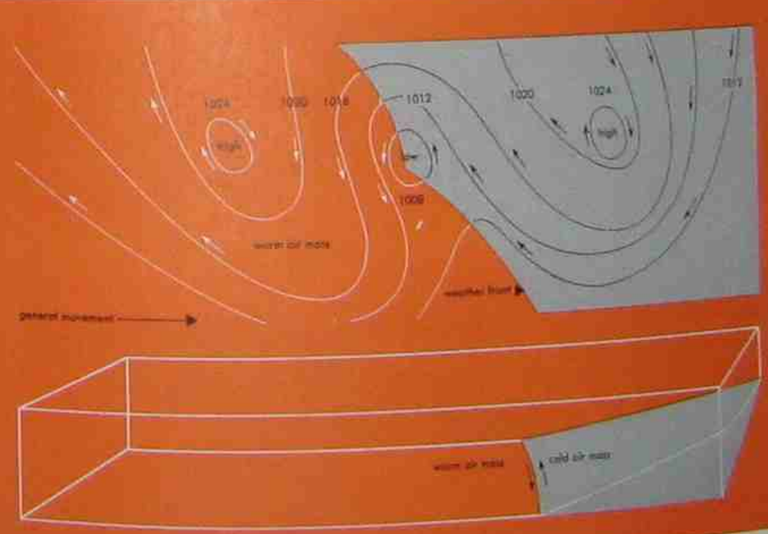
...whose manifold effects we feel and recognize as "weather"

Battle lines of the air masses are set along the weather fronts. The results range from violent storms to just a mild change in temperature. Along the front will be a cyclone or low-pressure area with winds rotating counterclockwise around the center in the northern hemisphere. These winds generally rise at a much slower velocity. They bring in moisture, and rainy, windy weather prevails as the rising air cools and its vapor condenses.

On each side of the weather front will be high-pressure areas or anticyclones with winds moving clockwise about the center. The subsiding air brings welcome fair weather because the cold upper troposphere carries little water vapor, and the air warms as it slowly flows groundward, superheating any vapor that is entrained. Winds flow along lines of constant pressure at altitude, but at an angle along the ground because of frictional contact.



Advancing cold front has cold air mass from left wedging under warm air mass and lifting it. Above ground the wind flows around a low-pressure area, but on the ground the wind angles into the area and generally rises. Condensing moisture produces clouds and rain. Fronts form at margins of high-pressure areas or cells. Technically, air masses are high-pressure cells and they may be either warm or cold. They change their character as they travel world wide.



Advancing warm front has warm air mass from left overriding retreating cold air mass. Warm air being forced upward is cooled and its water vapor condenses to clouds and rain. Warm fronts usually move at about 15 mph, half the speed of cold fronts. Clouds may form as much as 1000 miles in advance of the ground position of a warm front. Sloping boundaries between warm and cold air masses form angles of less than two degrees with the surface of the earth.

As air sweeps across a vast ocean expanse it heats or cools and picks up a load of water vapor. As the wind sweeps on shore the sloping mountain side forces it to rise; the air cools and sheds most of its moisture load as rain. Tumbling down the far side, the dried wind heats faster than it initially cooled. Descending mountain winds rise and fall in waves in the valley and may form standing turbulent eddies. This depends on the changes in slope of the leeward side.



Land shapes and water expanses interplay with solar energy...

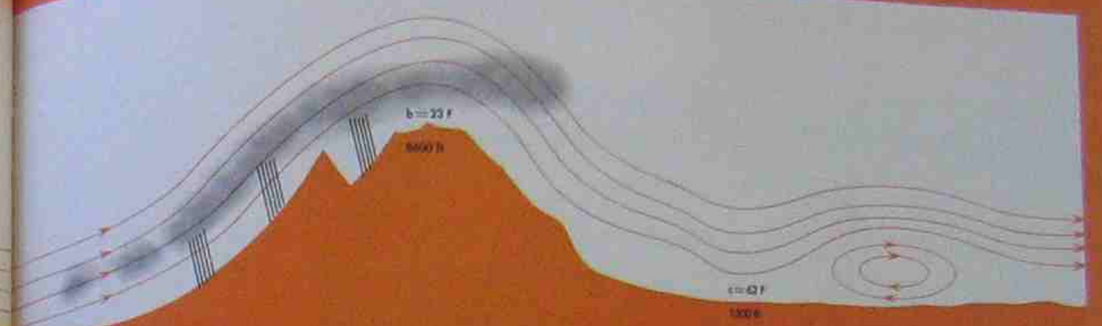
Widely varying water expanses over the face of our globe and topography of our land surfaces play important parts in forming regional climates. For instance, snow absorbs only 25% of incident solar energy, plowed fields about 80% and grassy fields and forests up to about 95%. Regions favoring cloud formation will stay warmer at night because the clouds absorb heat radiated by the ground. Clear nights are colder because heat radiates to outer space more easily with less vapor in the way.

Mountains and barren ground bordering on green fertile fields or seas breed local winds moving contrary to the overall wind system of the globe. When these situations have broad enough geographic scope they can fix the climates of whole states.

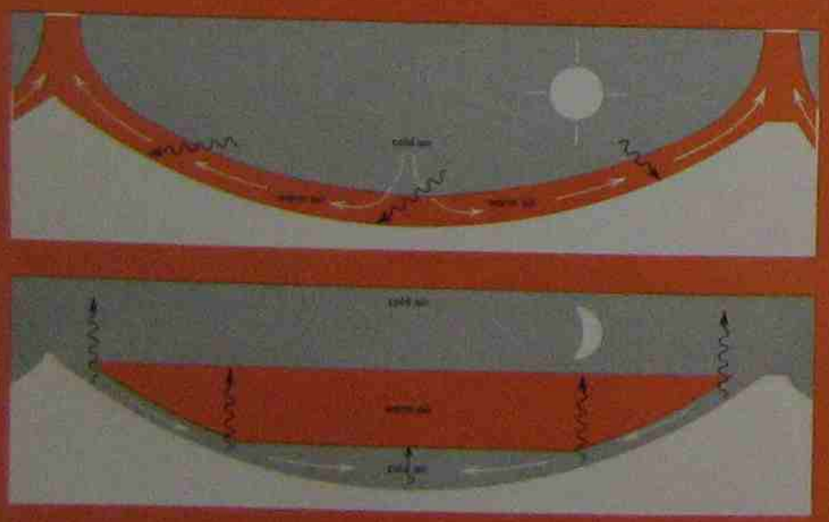
Limited local situations are called *microclimates*—they show marked differences from the general regional climate. For example, Milwaukee on the windward shore of Lake Michigan has an average temperature 3.6-F lower than Grand Haven on the leeward shore during January, but 2-F higher in August. Milwaukee has 2-in. less rain from December to February but ½-in. more from June to August during the warm summer.

Forests stay warmer in winter than open lands but cooler in summer; winds don't blow as fast in forests, relative humidities and water storage are higher than in open land. Plants change microclimates by their varying use of water, the shade they cast, their effects on winds.

Coastal mountains, as above, control climates of the terrain they dominate. At *a*, we have sea winds at 50 F. They rise to 8600 ft at *b*, cool to 23 F. The falling wind then heats to 62 F at *c*, 1500 ft. (See lapse-rate diagram, fifth page of this report, for technical explanation.)

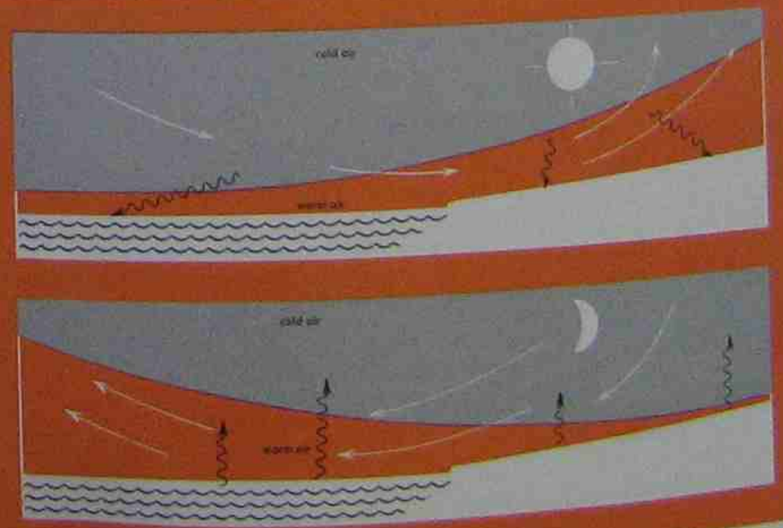


...to influence short-time changes in local weather conditions



On clear days the earth's surface heats rapidly and promptly warms the adjacent layer of air. Strong convection currents then flow up sloping surfaces. They induce colder upper air to subside into the valley, giving strong air circulation over the terrain.

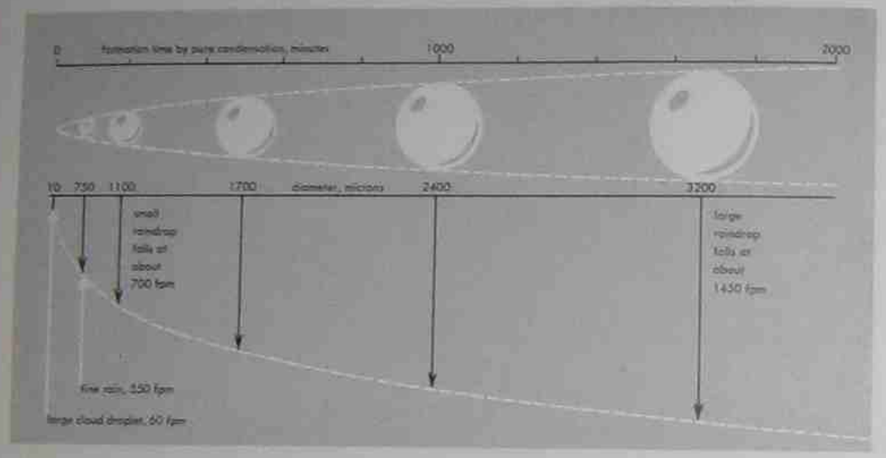
On clear nights the earth's surface cools faster than the upper air and cools the lower air first. Cooled air flows downward and accumulates in valleys, causing stagnant inversions by trapping warm air above.

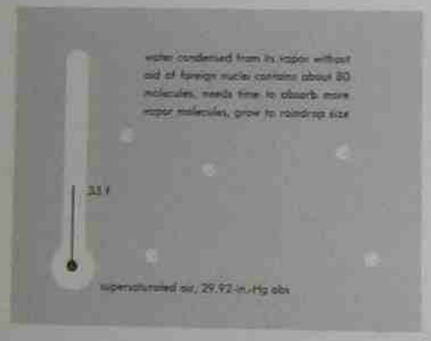


At the seashore on clear days the land usually heats faster than the water. The lowest air layer on land warms quickly, making the air unstable so that it rises. This induces an inland flow of cooler air from the sea and sets up the well-known cooling sea breeze.

On clear nights the land cools faster than the water and so cools the low air layer on the land quickly. The heavier land air spills seaward where the lower air stays warmer longer, setting up a land breeze.

Airborne particles speed the rate of rain formation





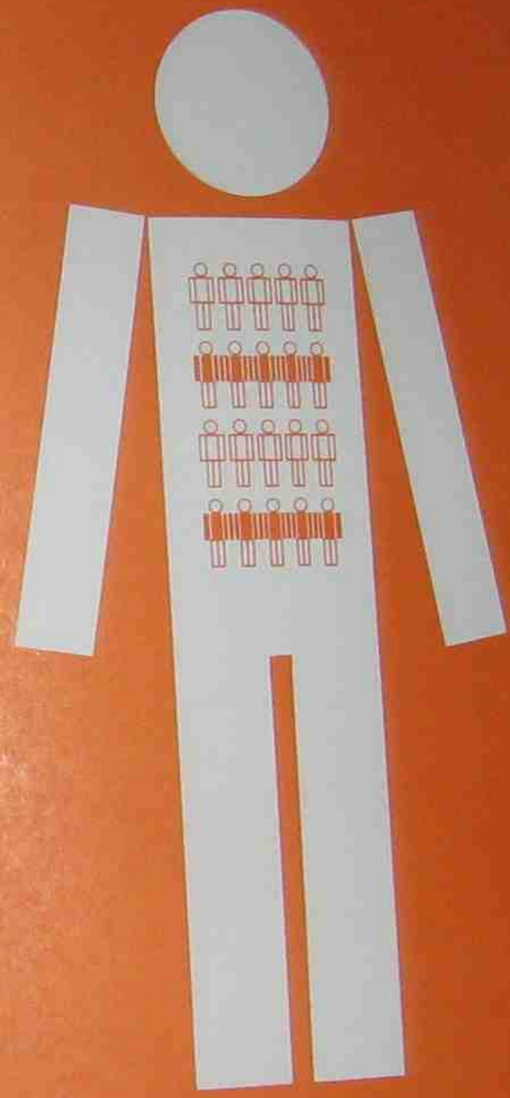


It takes time for raindrops to be born in the misty swirling interiors of the lofty clouds. Mixed air and water molecules dart about swiftly and collide with each other. Air molecules far outnumber the water molecules, tend to keep them apart, prevent them from agglomerating to grow to full-fledged raindrops. But when molecular motion slows down in the process we call "cooling," chances of vapor molecules agglomerating increase. Then condensation takes place at supersaturation, at temperatures lower than the normal level, left, to form water.

Polluting particles are much bigger than the individual vapor molecules. They move more slowly and form ideal gathering places that quickly adsorb water, lower left. They speed rain formation from the pedestrian pace shown in the graph above, and at much-higher temperatures, at or near 100% humidity.

Cloud droplets are tiny. They fall freely at about 60 fpm, above. But prevailing updrafts of air molecules keep them suspended. Large raindrops may stay suspended in violent updrafts; then a sudden change in air motion causes a cloudburst. So we see that nature makes use of various pollutants in its vast thirst-quenching water cycle.

b



Man and pollution: The day John Doe is born he starts polluting the air with every breath, cough, sneeze, even with the valeric acid found in human odors. As the years roll by his puffs of tobacco smoke, simple acts of cooking food, keeping warm, driving a car feed pollutants into our fresh-air supply. If John were a hermit this would be of little concern. Problems arise when many Does gather in communities to carry on the day-to-day chores of living, playing, working.

This concentration of Does increases pollution volume by sheer growth in numbers while, in effect, it creates a widely varying pollution pattern across the country. Then atop these joint offerings of man and plant being sent skyward the sun steps in, converting the base pollutants into still other and often more-harmful materials. This is the picture as it stands today, with the seriousness varying from region to region.

Pollution problems begin when activities become complex...

During the 1959 World Series a heavy cloud hung over the Los Angeles Coliseum—a cloud created in part by smoke from cigarettes, pipes and cigars being puffed by some 100,000 fans watching the Chicago White Sox battle the Los Angeles Dodgers. Perhaps many more smokers in number were watching and listening to the same game in their homes, without any observable effect on countryside air pollution. This is but one example of how John Doe's day-to-day pollution offerings to the air above us go unnoticed until he joins his fellows in community living.

In the larger urban areas of our country we find millions of people crammed onto relatively few acres. Even our once sparsely settled suburban sections are taking on a closer-knit appearance. Sum effect of this trend toward group living is further multiplication and concentration of the polluted outpourings of a single John Doe.

Home heating can be a major pollutant source. Products of combustion from the home furnace will vary widely in their effect on the pollutant tally, depending on fuel used, the design and condition of firing equipment.

Gas as a fuel for domestic space and water heating generally produces little significant air contamination. But oil burning adds oxides of nitrogen and sulfur in sizeable doses in addition to some organic materials. Coal-burning home and apartment-house heating furnaces can be a major source of air pollution, even in an industrial city. Solids, oxides of nitrogen and sulfur, organic materials are high in the exhaust from bituminous-coal fires. And the finger of control points to all these components as air pollution continues to increase in severity.

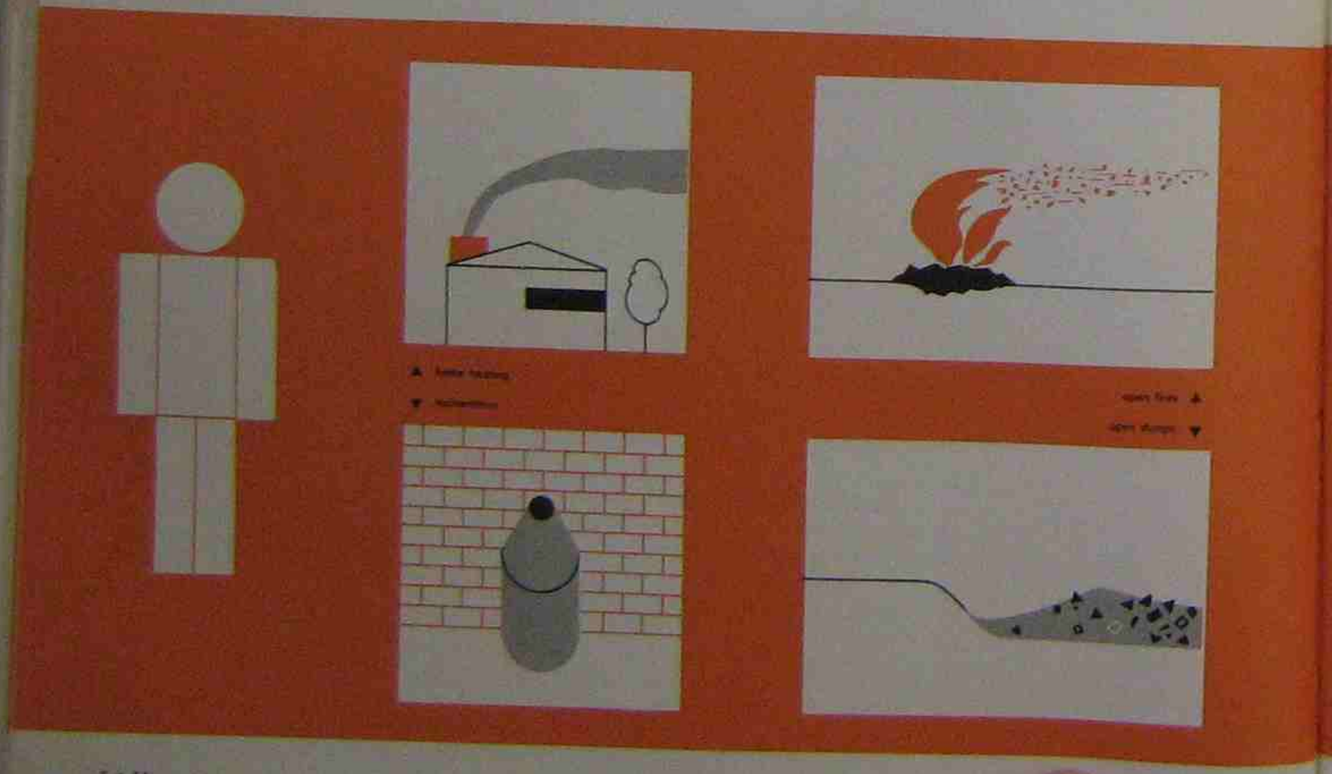
To get some idea of relative quantities, let's look at the chimney exhausts from 100,000 homes. If all burned an average grade of bituminous coal, some 307,000 lb per day of pollutants would be formed. Of this total about 200,000 lb would be solids, 42,000 lb in the form of SO_2 and SO_3; organics would account for 20,000 lb and about 30,000 lb would be organic acids.

If the same 100,000 homes burned oil you could expect 42,000 lb of combustion products to be given off. This total would consist of 17,000 lb of SO_2 and SO_3 and 12,000 lb of organic acids along with lesser amounts of still other pollutants. If gas were the fuel, these same 100,000 homes would produce a mere 10 lb per day. Electric home heating, with its zero pollutant output, may be one answer for polluted regions where gas isn't available.

Domestic incineration by household units may be another big offender. For a time all household incinerators were banned in Los Angeles, Detroit, Pittsburgh and Philadelphia because of NO and other solids spewed forth.

Older units, made up of a single furnace with gas-fired grate, were a serious problem. Heat of combustion cooked off moisture and vapors from unburned garbage above the main flame. These, plus solid material carried over in the exiting flue gas, presented a significant problem.

Using our same 100,000 homes as a yardstick, domestic incinerators of the single-furnace design could produce



...and when men live and work together in concentrated groups

daily 12,000 lb of organics, 16,500 lb of solids, 8400 lb of aldehydes, 1900 lb of organic acids—a total of 40,000 lb every day for the housing group.

Newer version of the home incinerator has two chambers in series; the second completes combustion of the gaseous material while trapping solid particles.

Open burning, including backyard burning rigs, often represents the second-largest pollutant source in an area. Many communities just do not have adequate refuse collection, forcing residents to burn paper, leaves and assorted debris in backyard bonfires, again pouring forth sizeable quantities of organics and solids.

Open dumps are a nuisance primarily, since the main output is methane, not looked upon as a serious pollutant. But decaying vegetable matter poses an odor problem.

Exhaust fumes from the ever-swelling hordes of autos, buses and trucks have certainly become a major headache to several metropolitan areas—perhaps John Doe's biggest contribution. Recent survey of air conditions at several busy points in New York City showed 50-ppm CO—toxic threshold for continued exposure.

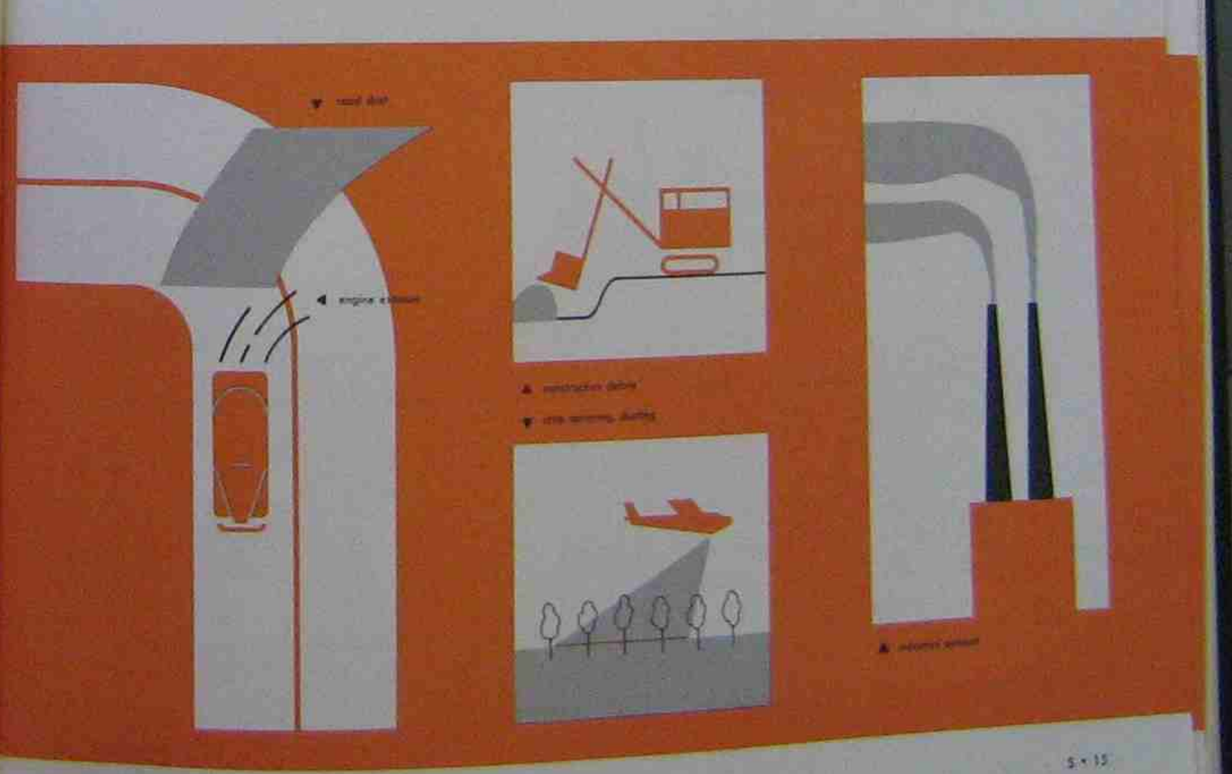
Striking example of serious exhaust pollution is found in Los Angeles County. Every day about 7-million residents drive 3-million cars and trucks, consuming 6-million gallons of gasoline and diesel fuel. Combustion of the gigantic volume of petroleum creates 9600 tons of CO, hydrocarbons weighing 1000 tons, 300 tons of NO plus smaller quantities of aldehydes, SO_2 and other products.

Road dust kicked up by man and his vehicles is another contributor to the pollution total. Each year tons of rubber particles are deposited on highways along with pulverized concrete, cinders, sand and dirt. Usually most of this material stays close by, remaining a localized source of pollution. Solution to this problem will be a long time coming since any wheeled vehicle will abrade rubber and crush other solid particles into dust. Perhaps tomorrow's levacars—those windy vehicles riding on a cushion of air —will cut back highway pulverizing. Since road dust is classed by many as a secondary source of pollution, it will get little serious attention in the immediate future.

Construction of buildings and roads is often accompanied by an all-too-obvious haze testifying to particulate matter being churned up. In the growth areas of larger cities, continued demolition and rebuilding of multistory buildings creates an almost permanent haze. It's impossible to lick this source completely, but much dust could be avoided by wetting down debris and maintaining cleaner conditions on construction sites. One consolation in our control failure: results are not smog-forming.

Crop dusting or spraying is akin to construction dust, from a pollution standpoint, since aerosols and dusts are deliberately made airborne. Selective application and careful attention to weather conditions will help.

These are the main air-pollutant byproducts of John Doe's community life. But to compound the problem, we have industry—one big reason for John Doe's city living.



Basic industrial processes, such as evaporation, attrition...

Man's industrial complex is the most-obvious contributor to air pollution, although not necessarily the most serious. Industrial pollutants take three forms: visible particulate matter—smoke and dust; nontoxic odors, which are a nuisance factor; toxic and irritating vapors—CO, SO_2, nitrogen oxides. Of the three, visible smoke and offensive odors will draw public complaints since in the minds of many these alone constitute pollution. In contrast, the hard-to-detect invisible vapor may often go unnoticed although possibly a more-serious pollutant.

A practical way to classify industrial pollution is by source: noncombustive and combustive. The former, as discussed here, produces evaporated gases, attrition dust, particulate carryover, cooking vapors, reduction-process fumes. In various combinations we see these basic noncombustive mechanisms at work in about every industrial plant. Naturally, many factors govern the quantity of pollution from each source.

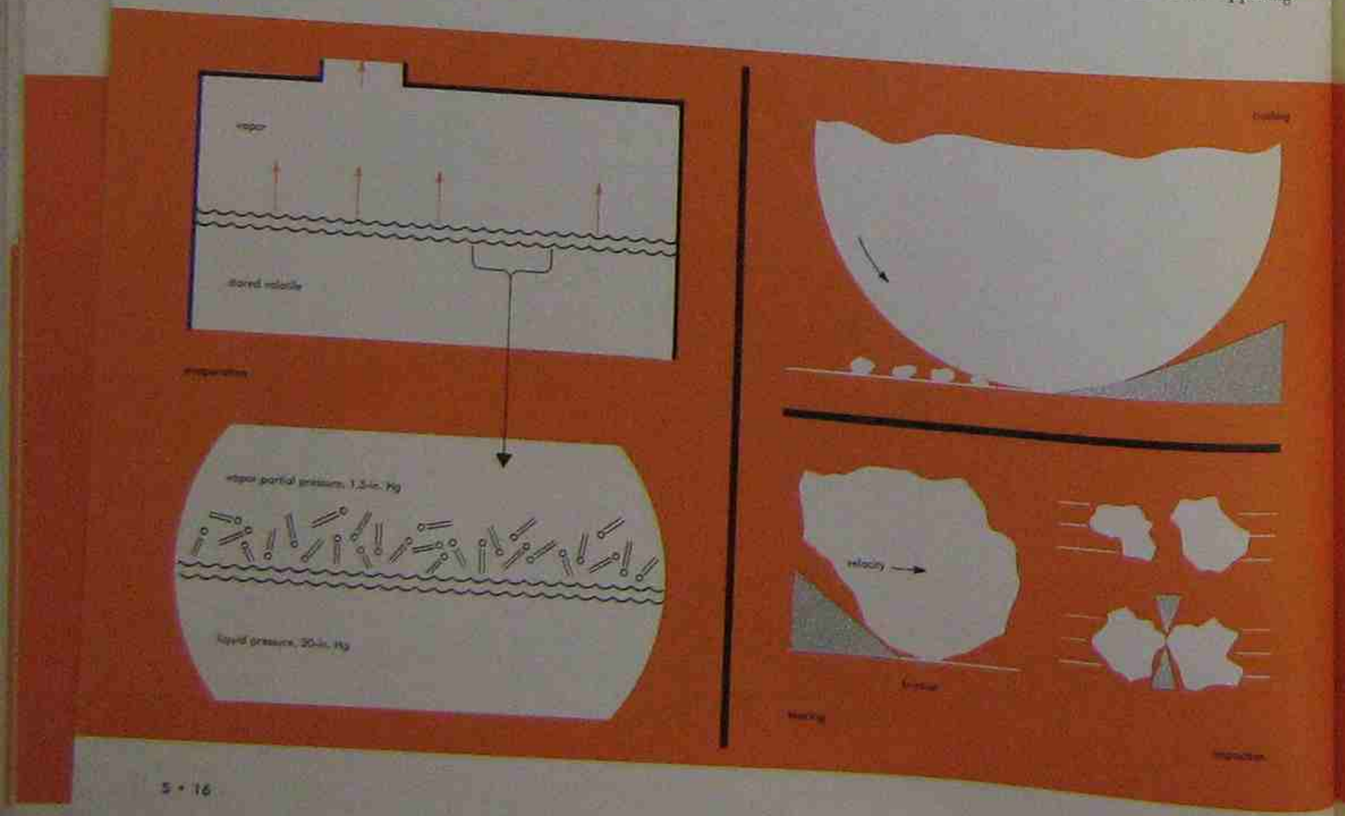
Material evaporation is a continual pollution challenge for several industries. Take petroleum as an example. Problem appears first at wellhead where gases and light ends cook off storage tanks and other oil-field equipment.

Refining crude petroleum into marketable products needs high-temperature and high-pressure processes. The necessary storage tanks, furnaces, boilers, reactors, pumps, lines and valves permit evaporation wherever leaks occur and in any areas where vapor-producing spaces are permitted. In Los Angeles County alone, it is estimated that 50 tons of hydrocarbons per day are released skyward from crude-oil production, even with present restrictions.

To understand the driving force behind evaporation one must know something about the physical characteristics of the liquid involved. Look upon any liquid as a molecular mixture, drawing, left. With these molecules in constant motion, some are bound to reach a temperature and energy level permitting them to break through the surface film. In effect, these escapees have reached a boiling point. As with most processes, this molecular transfer takes place on a 2-way street with some molecules continually re-entering the liquid. But during evaporation most traffic is outward. When does evaporation stop? Not until the partial pressure of vapor equals the saturation pressure for the vapor space temperature. In brief, the requirements for pollution by evaporation: (1) liquid has a high-enough energy level to permit change of state (2) space is available for the released material.

Attrition dust stems directly from grinding, polishing, pulverizing, screening, classification. Look upon the pollution offerings of these many manufacturing processes as industrial counterparts of nature's dust-producing ways.

Attrition normally takes one of three forms: crushing, impaction, frictional tearing, below. Crushing requires enough force behind the crusher to crumble any solid material in its path. Impaction, on the other hand, requires high velocity to supply the kinetic energy needed to break particles. Friction may be defined as the force opposing



...melting and chemical reactions create a variety of pollutants

relative movement of two surfaces in contact. The result of friction is wear and comes about from the tearing apart and gouging of minute "hills" which exist on even the most polished surfaces. In all three cases, sufficient force must be applied to the solid to break bonds holding it together. Sources are myriad, existing wherever solid particles are in motion and come in contact.

Provision is generally made throughout industry to trap products of deliberate attrition. But an equally important source of dust, unintentional attrition, is often overlooked. Handling dry solids is a case in point. Dust from coal or rock conveyors is particulate matter ranging in size from 1000 microns down to 1 micron. In most materials handling, all three types of attrition combine in varying degrees to produce fine pollution particles.

Belt conveyors, pneumatic-conveyor systems, solids-mixing equipment, outdoor coal-pile compacting all give off fine solid particles. But these fine products need not become a source of pollution. So long as dust is not thrown into the air or wind allowed to pick up the particles, no pollution problem can develop.

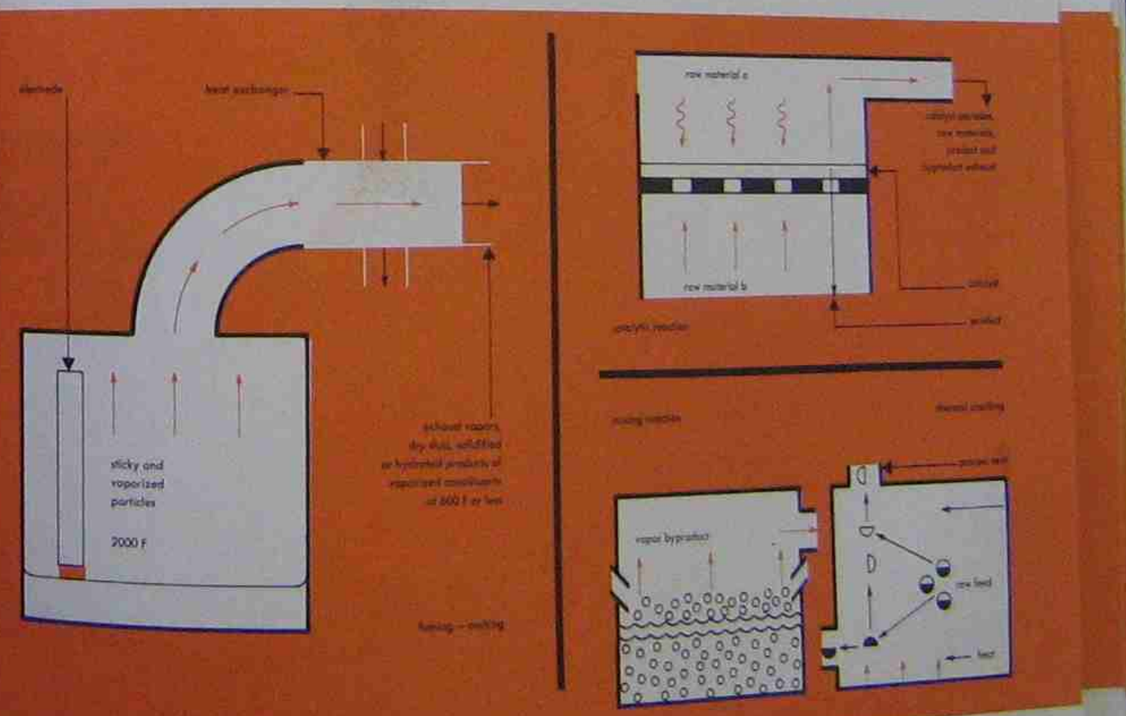
Melting materials introduces several new pollutant groupings. Their newness comes about because of the high temperatures necessary. Most furnace melting calls for mixing solids, then purifying by liquefying and driving off unwanted portions. Some of the unwanted constituents pass through the more-common steps of liquefying first, then gasifying on the way out. Others sublimate; jump directly to the gas state, then exit. Particulate pollution enters when some portion of the melted or gasified material returns to solid form, often as small particles which are carried out with the exit gases.

One big problem facing industry today, at least that segment involved in melting, is determining actual exhaust products and the conditions which create them. Research in the glass industry indicates exhaust products vary not with furnace load but as a function of temperature.

Process reactions pollute the air as an effect of chemical change. Here, raw materials are brought together and permitted to react in such a manner that one or more desired products result. This is somewhat of an oversimplification since in an actual process involving chemical reaction there is some reversibility and some formation of intermediate materials. Actually, the majority of pollutants come about as a result of the intermediate reactions or other relatively minor side reactions.

Thus, understanding the business of pollutant creation from process reactions requires knowledge of process equilibrium conditions, effect of the many operating upsets that can and do occur, reaction characteristics tending to create unwanted side reactions. Once you've pinpointed source of pollutants and conditions leading to formation, you've gone a long way toward actual curtailing.

On the pages that follow we outline the basic mechanical and chemical combinations favoring pollution formation in both the furnace and internal-combustion engine.



The complex process of furnace combustion may yield smoke...

Combustion processes create the largest single class of air pollutants, running the gamut from boiler flue gas and catalytic-reactor offerings to automobile exhausts.

How does combustion create pollutants? In the normal combustion process oxidation is the primary reaction. And in most cases the oxides are stable. But as in any chemical reaction, intermediate compounds and radicals form with all reactions reversible to some degree.

Theoretical combustion reactions always assume perfect conditions. These conditions are approached, but they're never reached in a practical combustion process. And perfect mixing does not occur. Then, when you consider that optimum pressure and temperature for burning may not exist long enough to complete primary reactions, it is apparent that exhaust gases will always carry some small percentage of the intermediate products formed.

Symbolization of furnace combustion appears below. Raw products entering the furnace include combustion air and fuel. Incoming air needs no special preparation. But fuel must be in a form permitting maximum reaction rate for the type of burning equipment being used.

Combustion-zone reactions are not the cut-and-dried affairs we often think of. For example, a prime reaction in most furnace combustion is the oxidation of carbon: $C + O_2 \rightleftarrows CO_2$. In any actual process, however, there are two additional reactions: $2C + O_2 \rightleftarrows 2CO$ and $2CO + O_2 \rightleftarrows 2CO_2$.

Rate at which each of these reactions occurs is a function of temperature and the degree of mixing. Assuming for the moment that mixing is adequate, carbon oxidation follows two methods, depending on whether temperature is below 2200 F or above 2700 F. Below 2200 F, carbon particle's outer layer absorbs oxygen until saturated. Then outer molecules break off and combine with more oxygen to form approximately equal amounts of CO and CO_2. At 2200 F this absorption reaction has reached a maximum rate. Solubility of oxygen in carbon decreases rapidly above 2200 F with reaction rate approaching zero at 2400 F. At temperatures between 2400 and 2700 F there is no active oxidation. This 300-F span in effect is a dead zone through which reaction temperature rises at the start of combustion and drops again at the end of major burning.

Above 2700 F carbon and oxygen combine directly without prior absorption. In this temperature range oxidation produces about twice as much CO as CO_2 because of relative equilibrium coefficients for the extra reactions.

Combustion sequence then becomes: (1) Oxidation to equal parts of CO and CO_2 as reaction temperature climbs to 2400 F. (2) Very slow oxidation of the remaining carbon up to 2700 F with conversion of CO to CO_2 dependent upon the H_2 and H_2O content of gases at that time. Although H_2 reacts with oxygen more than twice as fast as CO, presence of raw H_2 or water speeds CO-to-CO_2 reaction. (3) Carbon oxidation continues after temperature drops below 2400 F. Burning of carbon and conversion to CO_2 slows down as reaction temperature drops below 2200 F. Result: unburned carbon and much CO not converted to CO_2 show up as pollutants in exit gas.

Even total combustion can create pollution problems. What is considered normal good combustion usually results in small amounts of unburned carbon and insignificant traces of CO coupled with sulfur compounds and nitrogen oxides. Sulfur present in the input fuel converts to about 98% SO_2 and 2% SO_3 during normal combustion. In gaseous form these are ready to combine with water vapor in the flue gas or outside atmosphere to produce acids. Coal firing differs slightly: under somewhat special but generally possible conditions a large percentage of the sulfur stays in the ash.

Nitrogen oxides form under conditions we usually think of as "perfect" combustion: good mixing, high gas temperature, adequate excess air. Until about five years ago little was known about nitrogen-oxide formation in furnace combustion. It was recognized that equilibrium constants are such that NO_2 cannot exist at the high temperatures met in a large furnace. But recent study of combustion-gas equilibrium at these high temperatures shows NO can exist at the elevated temperatures, actually increasing in concentration as gas temperatures keep climbing. In addition, the NO percentage increases along with excess air. NO is the primary nitrogen oxide since the high temperatures met in the furnace flame promote nitrogen fixation in combustion air: $N_2 + O_2 = 2NO$. At lower temperatures further oxidation forms NO_2.

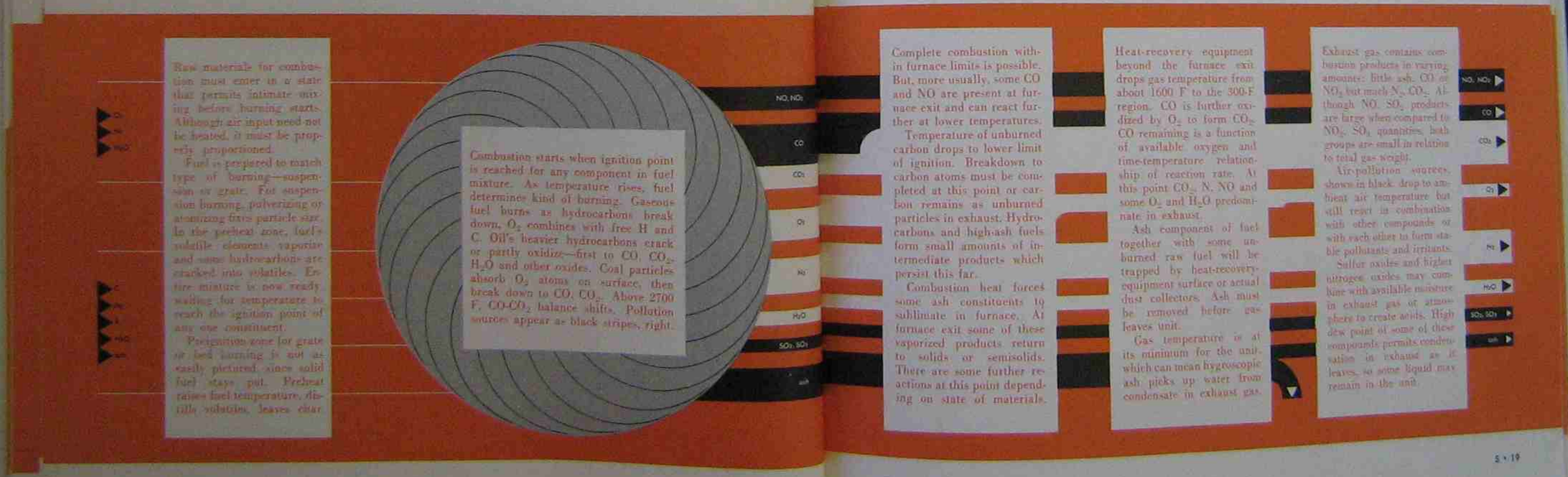
Flue gas is still hot enough at stack temperatures to hold NO_2 to a minimum. Once the gas leaves the stack, atmospheric temperatures and an abundance of oxygen promote NO_2 formation. Furnace exit-gas temperature of 2000 F, followed by rapid relative cooling throughout remainder of unit, produces NO concentrations on the order of 0.1% or 1000 ppm. Converting to NO_2 in the air, this becomes a sizable quantity of pollution-producing gas.

After analyzing the effect of increasing temperature and excess air on NO production, consider the effect when these variables decrease. Naturally NO concentration drops with furnace temperature. But within the practical limits of stable ignition for a given unit, NO reduction is not great enough to do much good. Dropping combustion-air temperature 460 F decreases NO by only 50 ppm.

Reducing excess air, however, lowers NO concentration until the theoretical air level is reached. After that a further reduction, say to 95% theoretical air, cuts NO by the sizable chunk of 30%. Practically all NO formation takes place in a comparatively small high-temperature zone within a few feet of ignition point. So to limit air pollution by NO, remaining combustion air may be introduced just beyond this region. This keeps NO down while still completing combustion in the furnace proper.

This, in brief, is the story of basic combustion. Some pollutants form as a result of poor combustion, other more irritating ones are formed by good combustion. Now let's look at the internal-combustion engine.

...various vapors and gases, dust particles in a wide size range...



...while internal-combustion engines present special problems.

Although internal-combustion engines may not produce the dramatic effluent we see pouring from steel-mill furnaces, majority of the toxic or irritating pollutants in many areas of our country can be traced to the exhaust from automobiles, trucks, trains and aircraft.

These pollutants stem from the complex hydrocarbons used to fuel and lubricate millions of engines. Most of the products formed are not very different chemically from those of furnace combustion. Important distinction hails back to the three *T*'s of any combustion process—the particular *time*, *temperature*, *turbulence* factors inherent in gasoline, diesel and gas-turbine engines.

Even under ideal conditions, the internal-combustion engine cannot attain combustion efficiency of a large furnace, for several reasons. Fuel-air ratios vary widely with load, and acceleration and deceleration modify this ratio. Also, temperatures are lower.

Between unbalanced fuel-air ratio and lower combustion temperature, engine's exhaust gases include sizable amounts of pollutants. Chief constituents of these gases on a volume basis: CO_2, CO and water vapor. But chief culprits in the smog dilemma are the volumetrically much-lower concentrations of unburned or partially burned hydrocarbons and nitrogen oxides. Relative concentration of either pollutant varies with engine operation.

When you're accelerating or cruising in your auto, NO concentrations run about 1000 to 3500 ppm. Conversely, highest hydrocarbon concentrations appear in deceleration exhaust. During deceleration a high vacuum exists in the cylinders so efficient burning is almost impossible, and hydrocarbons run 4000 to 12,000 ppm.

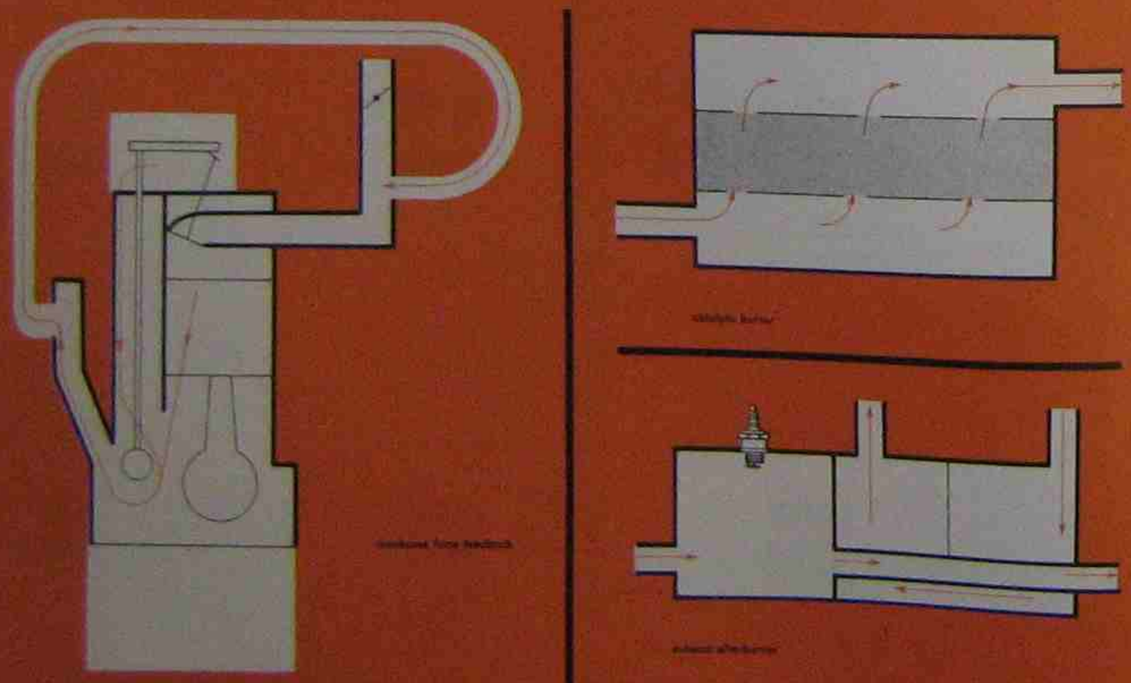
Diesel exhaust presents much the same problem. Having an extremely sharp combustion-efficiency curve, the diesel engine produces exhaust smoke with variations in speed. Gear shifting will not totally eliminate the smoking since most trucks do not have sufficient gear ratios to permit engine operation at constant peak efficiency.

Aircraft engines create most of their pollution during takeoff. Once the plane is airborne pollutants are diluted through a wider area, so they're a very minor source of ground-level contamination. But in the immediate range of a municipal airport, aircraft can be a real problem.

One final source of hydrocarbon exhaust can be traced to the engine lubrication system, below left. Evaporated lube oil and cylinder blowby accumulate in the crankcase and are ejected through the crankcase vent. Just how big a problem this is depends on the condition of piston rings and the amount of stop-and-go driving. In the aggregate, emission of this hydrocarbon contaminant can add up to 30% of all i-c-engine pollution.

Solutions to both these engine exhaust problems are under way. The hunt for answers follows these tacks:

Designers are shifting crankcase exhaust vents from simple open-ending to a feedback. New engines return crankcase vapors through a vacuum valve, back to downstream side of carburetor. Recycling burns hydrocarbons



To make matters worse, some pollutants are changed by sun rays

in the cylinders, dropping overall pollution by 30%.

One tail-pipe-exhaust solution would require complicated throttle controls to shut off fuel input during deceleration. More-popular plan calls for use of catalytic burners or afterburners to rid exhaust of hydrocarbons. But to date the catalytic approach poses a life problem because of poisoning by fuel's lead compounds. And the afterburner needs more work on stability and temperature transients which occur during stop-and-go driving.

I-c-engine exhaust, in combination with many other pollutants described on previous pages, becomes a major problem when these constituents react to form smog. This smog comes about when a combination of natural and man-made pollutants reacts under very specific conditions. The actual pollutant composition will vary from one community to another. In one, particulate matter may be the major factor. In another, internal-combustion-engine exhausts are the big problem. In a third, sulfur compounds and CO will be the chief concern.

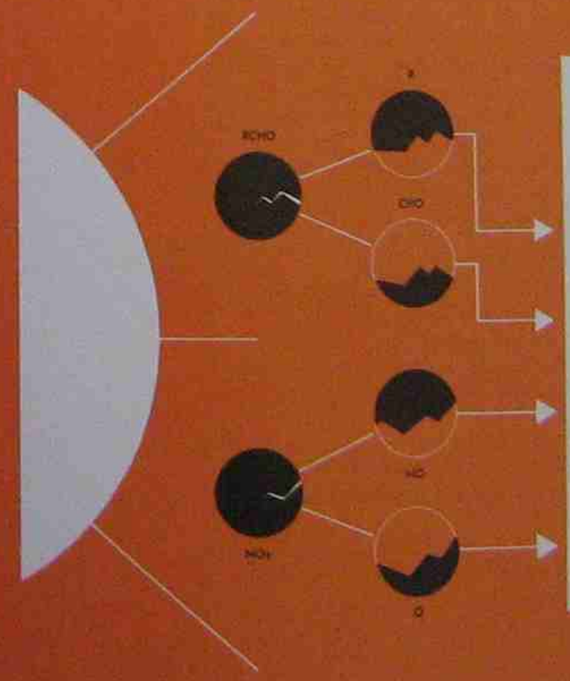
For certain sections of the country, local weather, working with NO and hydrocarbons, tends to boil up a mess of annoying smog. Here raw pollutants thrown into the air are acted upon by the sun; result is further changes. In the photochemical reaction the raw pollutants absorb solar energy, changing their makeup.

Primary photochemical reactions, shown below, involve decomposition of NO_2 and various olefin hydrocarbons by solar radiation. Apparently the olefin-series compounds are the only important hydrocarbons involved. Tests show that paraffin-series compounds do not enter into smog formation to any significant degree. In the photochemical reaction oxygen as O, O_2 and O_3 is needed in addition to NO_2 and olefin decomposition. Reactions outlined below show the important role oxygen plays in the overall photochemistry. For the most part free O combines with O_2 to form ozone. Only ½% of all available atomic oxygen enters into other reactions.

Molecular oxygen, O_2, further oxidizes $2CH_2$ and CHO radicals produced by olefin decomposition. At the same time ozone, O_3, enters into a series of reactions with NO, NO_2 and other oxides of nitrogen. Chain continues to N_2O_5 which combines with water vapor to create HNO_3.

All available evidence indicates that over most of the daylight hours in an urban atmosphere, NO_2 photolysis and NO - O_3 reactions mentioned above occur at much higher rates than any other known reaction involving the same substances. These reactions place severe limitations on the concentrations at which NO and O_3 can exist in air.

Studies carried out to determine the kinetics of ozone-olefin reactions and to identify reaction products show the list of reactions below to be of prime importance in smog formation. In addition to these, intermediate products including peracids, peroxides, hydroperoxides and free radicals appear. Much more work in this area is necessary before we fully understand these reactions. But we do know the prime ingredients: sun, time, exhaust.



Photochemical reactions change raw pollutants into smog. Basic ingredients are solar energy, NO_2 and olefin hydrocarbons such as ethylene or butylene. Latter materials decompose to NO, O, alkyls (R) plus formyl (CHO) radicals.

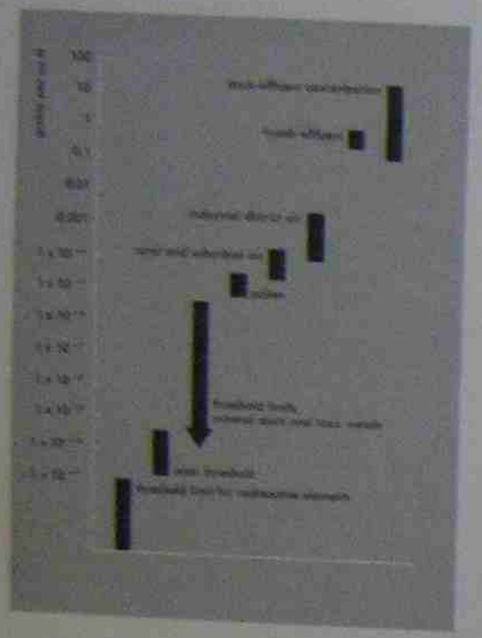
Olefins decompose to produce free alkyls such as CH_3 by absorbing solar radiation of 2500 to 5000 A wavelength. Single link available in alkyl hooks on oxygen to form other radicals—RO, ROO—or combines to form peroxides.

Formyl radicals (CHO) are extremely stable, but slowly decompose over long periods to H + CO. Subsequently H combines with O_2 to form water. In parallel reactions, CHO may combine with O_2 to form H_2O + CO or CHO_3.

Nitric oxide reacts with ozone and oxygen in many secondary ways: $NO + O_3 = NO_2 + O_2$, $NO_2 + O_3 = NO_3 + O_2$, $NO + NO_3 = 2NO_2$, $NO_2 + NO_3 \rightleftarrows N_2O_5$ (reversible reaction) and $N_2O_5 + H_2O = 2HNO_3$.

Oxygen in monatomic form will react with a number of substances known to be in urban air. But over 99.5% of all atoms react with O_2 to form ozone, O_3. Ozone reacts with NO and NO_2 to form compounds above, or with various hydrocarbons to form a family of oxides or more radicals.

Add it all up...and the problem can be severe



All the man-made pollutants discussed on the previous pages show up in varying amounts throughout the world. Our atmosphere will always be called upon to handle man's outpourings: it can take modest amounts without serious effect on mankind.

Trouble occurs when pollutant concentrations step beyond modest levels in the presence of adverse topography and meteorological conditions, as in Los Angeles today.

We started this section of the report by outlining the role John Doe and his fellow men play as pollutant contributors. Keep John in mind as prime contributor but give heed to the many other factors which must be present before his airborne offerings become an actual pollution problem.

First, outputs from a pollution source must accumulate, then geography and weather must act to prevent dissipation of the concentration. In some cases heat and sunlight must do their part by changing products through photochemistry. Of these many factors, the pollution source is the only area we can presently control. And, as pointed out in later pages, before we can intelligently attempt to control a source we must know what pollutants can be expected, their form—gas, suspended solids or liquid particles—particle size and total volume. This information can be determined by test sampling, estimates by experts familiar with the process, or applying average figures.

Pollutant density and particle size for several general industrial categories are shown at left. Remember these figures merely indicate ranges which can be expected under average conditions. They also show relative size and concentration compared to some natural air-pollution sources.

Up to this point we have outlined the nature of our planet's atmosphere, its natural pollutants and the mechanics of their transportation. We have also described how man makes his contributions to the overall problem. Now let's look at effects of air pollution on our social and economic existence.

C



Pollution and the community: In analyzing the ways we're polluted we affects man and his community, we span the range from total inconvenience to severe health hazard and on to a staggering catalogue-load reading billions annually. While we pay millions for research and control of the problem, this sum is but a fraction of what we are losing because efforts fall short of their mark. And unless more thought is given and action taken, these losers will continue to mount in the years ahead.

But what can be done by communities to meet this challenge effectively and economically? The answers are far from simple—but there are answers. First, every community's problem is highly individual. Each community must be carefully analyzed to find out the real pollution causes and most practical solutions. Once the problem has been precisely defined and solutions indicated, then, and only then, can effective legislation be introduced.

Although evidence of pollutants' harm to man's health mounts...

The chart below typifies the range of air-pollution conditions to which man may be exposed during a year, month, week or even day. Pollution may be at the "nuisance" level, evident in a soiled white shirt, smarting eyes, etc. At certain times and places, concentration may reach "episode" levels, like those experienced in Donorra and London. Death may result for the aged and infirm if they're exposed long enough. City dwellers, in particular, are apt to spend some part of the time in the area between, where pollution is above the mere nuisance level. Actual curves vary widely, changing in time and degree for different groups and individuals in the groups.

Medical researchers are probing for answers not so much in any of these particular levels, but rather on the basis of *time-exposure*. In brief, they are attempting to integrate the area beneath the plot for varied groups over extended periods, then to compare the results of many such integrations with specific health problems showing up in the groups being observed. This is far from a simple problem since the pollution-concentration parameter must be well defined, both as to quality and quantity, and the many variables man himself presents evaluated.

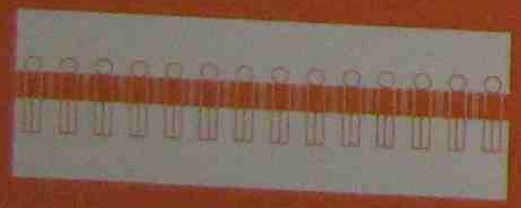
Some of this work has been done, but much more remains before we have definitive answers. Knowledge at hand indicates we can expect any significant damage to man's health to lie principally in the respiratory system. In fact, researchers in Great Britain have established beyond reasonable doubt that community air pollution is directly related to chronic bronchitis, a disease ranked third among causes of death in England and probably first among reasons for absenteeism. And then there is the rise in respiratory-cancer deaths, curves, next page.

What do we know about the link between respiratory cancer and air pollution? It's generally agreed that a number of pollutants found in community air will produce cancer in experimental animals. And we know that ozone and other irritant gases found in the air above us will scar animal lung tissues. Furthermore, such carcinogens—cancer producers—as benzpyrene are found in air.

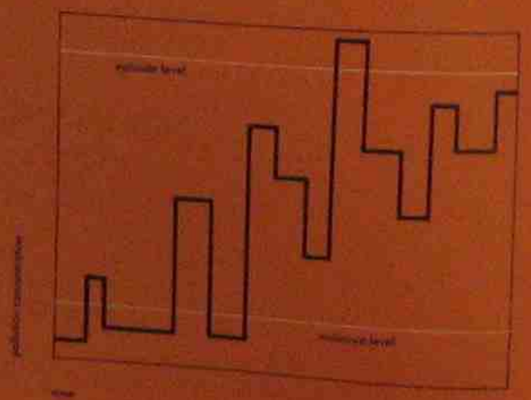
Benzpyrene is a hydrocarbon which finds its way into the atmosphere as a result of the distillation or combustion of fuels. Since it melts at 180 C and boils near 500 C, it generally exists in the atmosphere in the solid state. It is strongly suspected of being carcinogenic to man. Definitive proof is lacking, but there is evidence that human lungs remove this compound from soot, thereby permitting its eventual absorption into the body proper.

Test samples show concentration of benzpyrene is higher in the air above London than in most American cities. Nevertheless, sampling in 131 urban and rural areas throughout our country shows benzpyrene universally present. For most areas this hydrocarbon is at its highest level during winter months. If annual inhalation of benzpyrene is a measure of anything, the exposure is 100 times greater for a city dweller than a rural one.

According to the U.S. Public Health Service, sponsor



Air pollutants enter man's body in many ways—through the food he eats and the water he drinks; by surface contact, generally in form of eye irritants; by inhalation. Latter poses the biggest challenge today.



Man's travel through life brings him in contact with many levels of pollution. In a single day he might well be exposed to all the varying concentrations. Cumulative effect is chief concern of researchers.

. . . more research, especially on long-term effects, is needed . . .

of a continuing program of air-pollution study, there are many opinions among medical researchers as to which factor or combination of factors may play the leading role as a cancer-causing agent. Problems in evaluating harmful effects of air pollution are many. For instance, men performing heavy physical labor inhale deeper and more frequently; sex and individual size cause variations in respiration; smoking cigarettes, driving, even participation in outdoor activities are influential. Numerous studies indicate carcinogens have a cumulative effect.

Whatever the cause, we do know the death rate from respiratory cancer is highest in Great Britain. So using England and Wales as a base, let's examine the comparative health of emigrants who go to countries relatively free of air pollutants—South Africa and New Zealand.

In the case of South Africa, 44% more immigrant deaths were traced to lung cancer in the age group between 45 and 64 than among native-born South African males in the same age range. Remember South Africa has long been the world's largest consumer of cigarettes.

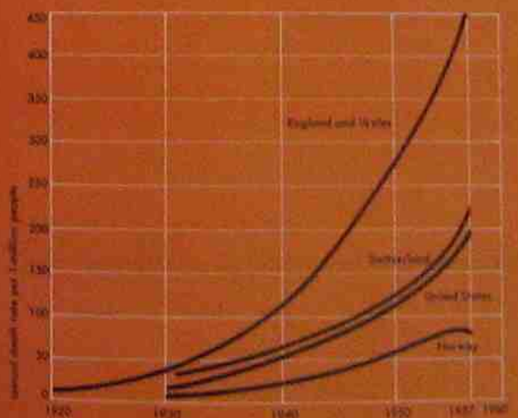
Massive 10-year study of emigrants to New Zealand points another accusing finger at air pollution. Here a quarter-million people who moved from the United Kingdom into the relatively unpolluted atmosphere of New Zealand provided the data. Two virtually identical populations were compared—the same heredity, essentially the same way of life, eating and smoking habits.

In this study, lung cancer was 30% higher among the newcomers generally than among New Zealand's native-born whites. Among Britons who went to New Zealand relatively late in life—first living in the U. K. 30 years or more—lung cancer was 75% over rate for natives.

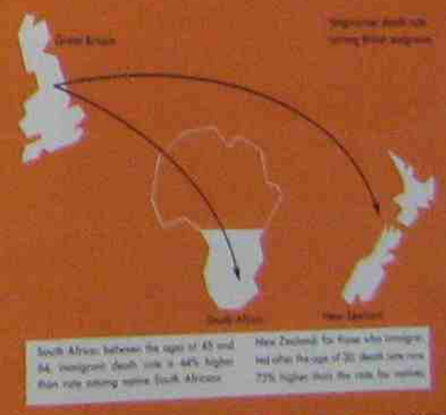
In addition to the other pollutants put into the air by man and nature, let us not overlook radioactive fallout. This is a distinct type of air pollution, consisting of tiny dust particles that persist so long in the upper atmosphere they actually diffuse from pole to pole. This delayed fallout takes place for years after large nuclear or thermonuclear explosions. It does not present the threat of sudden death—its effects, if any, would occur imperceptibly over many decades, perhaps many generations. Radioactive dust may settle on plant surfaces to be consumed with food or fall onto the soil where it's absorbed slowly by plant roots, thence eaten by animals.

What does it all add up to? Two things. First, there are at present gaping holes in our knowledge of pollutant effects on human health. Second—and serious long-range—we are not, as a group, emotionally prepared to act effectively on problems such as this one that seem remote in time. There is thus the risk that in waiting until the dangers are completely proved, we will delay too long.

The wise course would seem to be a parallel approach: (1) accelerated research on the effects of air pollution on human health and (2) increased attention to control programs based on the reasonable assumption that there *is* a relationship between air pollution and human health.



Real cause for steep increase in respiratory-cancer deaths is yet unknown. Many believe, and for sound reason, the answer may lie in our polluted air—including that portion self-induced by tobacco smoke.



Keeping Britain's high death rate from respiratory cancer in mind, above analysis sums up long-term effects when people emigrated from their highly polluted cities to cleaner areas of Africa, New Zealand.

. . . but dollar loss from unclean air is more readily apparent . . .

If we were to ask John Doe for a list of the many ways air pollution affects his pocketbook, he would probably point first to his soiled shirt collar or the laundry hanging on his clothesline that was smudged before it dried, or to his parked auto with its film of soot and dust.

He might well overlook his higher annual medical bills. Whether John suffers from a drippy sinus or a hacking cough, chances are the quality of his air input has some effect. He might also tend to skip over the cost of his annual chest X-ray—now considered a necessary trouble-detection measure, especially in polluted areas.

It's a sure bet he would fail to realize his personal efficiency is affected. But many high-school principals in southern California report a general student lethargy when smog is heavy. And controlled tests in telephone exchanges show operator alertness dropping as pollutants increase. What this loss in efficiency is costing American industry is impossible to measure. But the cost is there.

If John Doe were a farmer he would probably come up with more specific answers to our question. He might well have experienced out-of-pocket losses because of pollution damage to his livestock and crops. Perhaps his damage was only a small reduction in crop yields—or he may have been forced to market his products as second or third grade. But it cost him something.

There are many air contaminants harmful to vegetation: sulfur dioxide, hydrogen fluoride, chlorine, hydrogen chloride, nitrogen oxides, hydrogen sulfide and the sprays of weed killers, to mention a few. Damage will vary with the kind and quantity of pollutant. Symptoms: loss of healthy green color and discoloring of leaf undersides. During 1956, court cases in the United States because of losses on livestock and crops from the accumulation of one pollutant—fluorine—amounted to over $50 million. Some estimates place fluorine atop the list of air-pollution causes of agricultural loss.

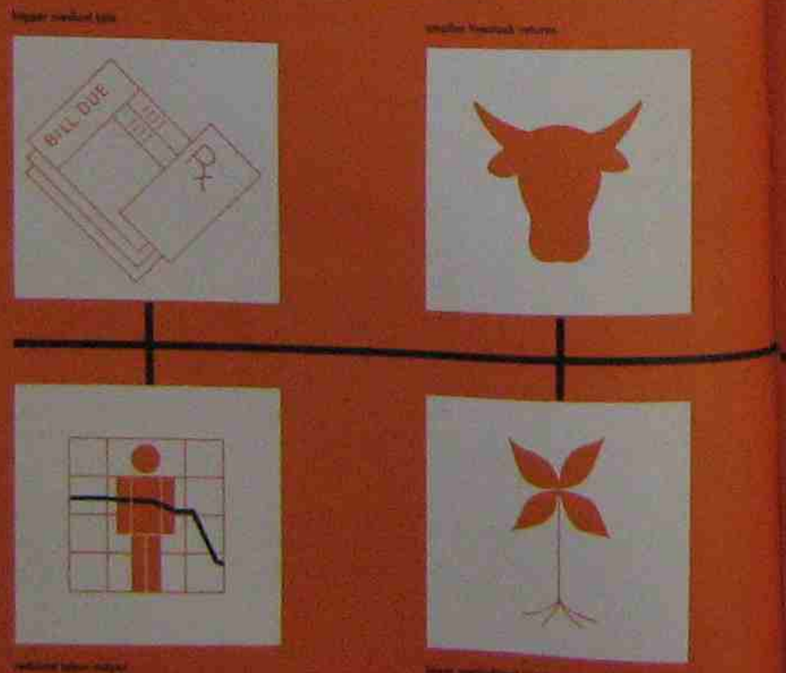
To the home owner, depressed property values are a continuing threat. It is not unusual to find $2000 cut from a home's value in a polluted area. St. Louis estimated, before air-pollution-control measures were enforced in 1941, property values had declined $25 million annually for 10 years. Another estimator puts a figure of $200 million as our present annual loss in real-estate values nationally because of air pollution.

Within the home the real culprits are fine particles that ride in with air currents when a door or window is opened. They settle on drapes, upholstery and carpets. They migrate to walls and ceilings where they cling and slowly accumulate as dark smudges. The fines make their way into clothes closets and into clothes being worn. Result is higher cleaning and painting bills. This soiling not only increases operating costs for the home owner but, in addition, proves a great burden to hospitals, hotels, office buildings, department stores.

Reduced visibility shows its effect in many ways, increased hours of artificial lighting being one. Many

industry keeps laying out a sizable sum each year—at least $900 million—in the never-ending battle to reduce pollutant output from process and combustion sources. During 1960 the bill for air-pollution research ran to over $11 million. Of this total, our Federal government paid $5.2 million, industry $4 million; states and communities paid the remainder.

Even if we add to these figures the annual cost of maintaining pollution-control departments to enforce existing regulations, we are investing in the effort to do something about pollution only a fraction of the billions that pollution costs us annually. On economics alone, expanded research and control seem justified.



. . . running into billions annually, even with present controls

forms of transportation can be affected, notably the airlines. Nature is a frequent contributor to poor visibility, helping create London's smog (smoke-fog), New York's smaze (smoke-haze), El Paso's smust (smoke-dust).

By making a community unattractive to live and work in, air pollution can contribute to higher personnel costs. Employers may have to offer more to enlist top-grade people. Or they may have to settle for less-competent people than they would be able to engage if working and living conditions were fully satisfactory.

Within the industrial plant itself there are many ways polluted air, coming from outside the plant, increases costs. Some industries are more sensitive to airborne pollution than others. For instance, the paper industry is continually concerned about specks of dirt getting into a batch of white paper. The food industry is worried about odor pickup. Grit must be ruled out at all cost in a plant making precision rolling-contact bearings.

Pollutants that find their way into industrial lubricants are a source of headache for the lubrication engineer. To avoid them, costly care must be given to transferring lubes from oil-suppliers' sealed containers into bearings.

Equipment costs will rise somewhat when a machine is destined to operate in a polluted area—assuming you expect a trouble-free life span from it. Seals, paints and other protective finishes, perhaps the use of more-costly base materials, all add to the equipment bill.

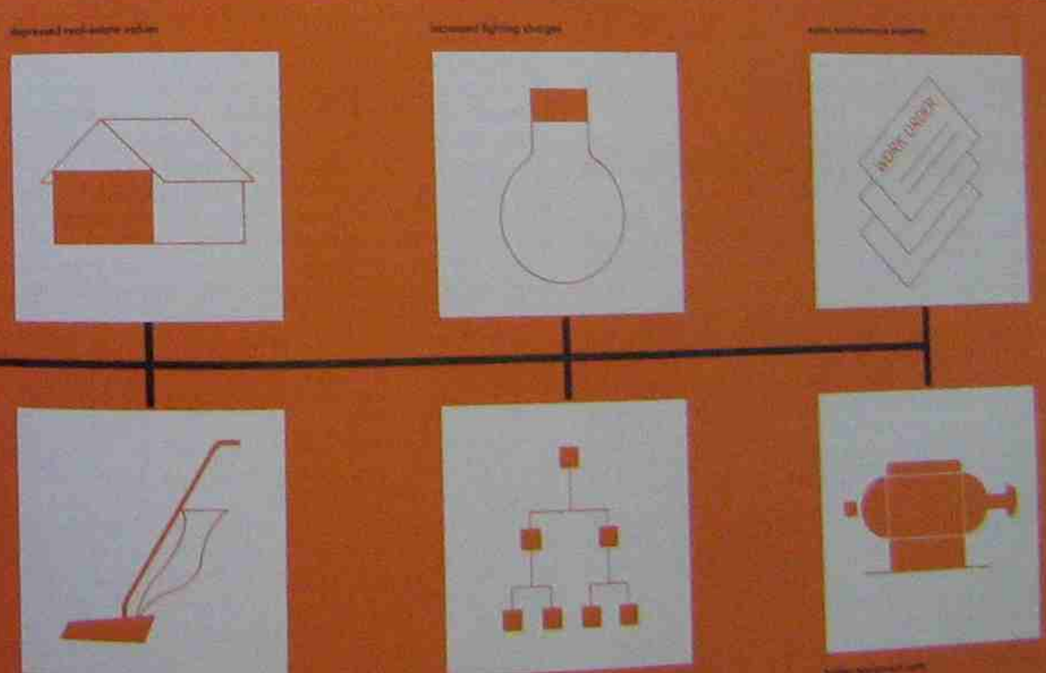
But if we want to put our finger on a single major source of economic damage to man and his community, it will be corrosion. Sulfur dioxide, a prime cause, comes into being as the result of combustion of sulfur-containing fuels. With oxygen present, sulfur dioxide is slowly converted to sulfur trioxide which in turn reacts with moisture in the air to form sulfuric acid.

Sulfuric acid, deposited by the air on metal portions of roofs, eaves, downspouts and a host of metal equipment, results in sizable losses from atmospheric corrosion. In New York City alone the annual bill for such corrosion is put at $6 million. Hydrogen fluoride, hydrogen chloride react with water vapor, forming corrosive droplets.

Salts in the form of ammonium sulfate and ammonium chloride are another pollutant source leading to corrosion. These are salts of a weak base and strong acid, so they hydrolize, yielding sulfuric acid and hydrochloric acid. Sodium chloride and calcium chloride are other salts of importance found more generally in seacoast communities.

Materials other than metals feel the effects of air pollutants. Consider building materials such as stone and masonry. Limestone may have its insoluble carbonates converted to soluble sulfates by acidic rainwater. Stone swells and surfaces peel off in flakes.

Textiles too are vulnerable. Remember the incident in Jacksonville, Fla. where one day women's nylon stockings literally fell into shreds? Leather is also attacked by sulfur dioxide. And the presence of ozone in the air tends to produce cracks in rubber tires and insulation.



In planning a control program, Central City U.S.A. first . . .

The growth of pollution potential

Air pollution promises to be a continuing problem in the years ahead. So long as man engages in social and industrial pursuits, it is impossible to have the relative purity in our atmosphere that would exist in a world without man. And as man increases his numbers, and as his standards of living climb higher, the results of masses and enterprises necessarily mean greater pollution potential.

What is being done about it?

As it stands today, air pollution's known effects range from relatively nil in some areas through "general dirtiness" in others to severe personal discomfort and property damage in still others. Efforts to combat effects appear to be substantially in direct proportion to degree of severity of the area's problem. In the main these efforts have taken the form of specific legislation to control what are believed to be major air-pollution sources. Some of this legislation is effective to a degree. Some is not and never can be for two main reasons: (1) Conceived and promulgated in what may be termed honest ignorance of the facts, legislation is unrealistic and may have punitive overtones. (2) Legislation is passed simply because "this is how Community 'X' handled the problem."

In some cases a community, vaguely aware that air-pollution difficulties may be in the offing, is reluctant to move to abate the problem because suspected pollution sources are vital to the economy of the area. Unsure how to proceed, the community does nothing. Such an attitude at best merely postpones, often aggravates a situation that inevitably must be faced and resolved.

What can be done?

What road should a community travel to reach a goal of effective air-pollution control? More important, what are the first steps that must be taken in setting foot down this road? First must come realization that the area is facing a "unique" situation. There is no such thing as a "typical" air-pollution problem—even though areas a thousand miles apart may contain similar pollution sources such as automobile exhaust or solid-fuels burning. Being unique, any given area's problem can be solved only through tailoring remedial procedures to fit.

Needed next is realization that with community growth comes an increase in air pollution. Our nation's population increase is pegged at about 14% by 1970, meaning a total of some 205 million persons. Our industrial output is expected to double. Because of today's population densities in metropolitan areas more than half of total air pollutants are released over a land area no larger than 1½% of the nation's whole. While it is true that cities will always be subjected to greater air-pollution potential than suburban areas, suburban potential will increase as time goes by. This means that consideration of air-pollution-control measures in many areas must go well beyond today's apparent needs.

Awareness by a community that control efforts should be instigated is meaningless unless the community clearly understands its problems and is determined that control costs be compatible with desired results. Understanding what the problem is may not be as easy as it sounds. Simplified, it means finding out what the pollutants are, where they come from and what harmful or undesirable effects they are producing. Broadly speaking, the path to such understanding is fraught with complexity and uncertainty, particularly concerning pollutant effects.

Get the help of experts

First step is collection and identification of pollutant samples. To a community totally unfamiliar with the enemy's face this can present a staggering obstacle. However, expert help is available. Today's cumulative wealth of experience in dealing with air-pollution problems around the world may be utilized by any who need it.

A hypothetical case: Central City wants an air pollution-control program. Its first need is competent technical advice. It turns, through its local and state Health Officers, to the U.S. Public Health Service with a request that facilities be provided to enable the community to coordinate activities and to develop a logical plan for air-pollution control. In taking this step Central City is availing itself of the provisions of Public Law 159, enacted by the 84th Congress and signed by President Eisenhower in 1955.

Central City's request will result in a thorough survey of its area under the supervision of the PHS. Cooperating in the survey will be citizens of Central City and members of its local government whose sole purpose at this point is to learn all they can about the immediate problem and how to take steps to control it. They are aware that the PHS has no law-enforcement authority and cannot engage in air-pollution-control activities.

PHS will direct and supervise studies of pollutants and their effects and give supplementary support, but the primary responsibility for administration of an air-pollution-control program belongs to agencies set up by local and state authorities. Exception to this rule: radioactive pollution caused by operations directly controlled by the Federal government and, if necessary, instances of interstate and international air pollution. Thus Central City becomes part of a gigantic and complex effort dedicated to erasing a menace.

Public Law 159 is a broad statute. It recognizes that air pollution may place health and welfare in jeopardy, harm agricultural crops and livestock, damage property, provide hazards to air and ground transportation. The law gives the Public Health Service a roomy field in which to roam in its search for causes, effects and the ways and means of possible control. It provides funds to help pay for research, study and testing by agencies at Federal, state and local levels and by private agencies, industry and universities, to arrive at needed answers.

Too, the PHS has, through voluntary action of state and city governments, established the National Air Sampling Network to provide for systematic measurement of air pollution. Every one of our 50 states, as well as Puerto Rico, has at least one urban and one nonurban sampling station, each manned by state and local personnel. PHS provides the equipment, establishes procedures and analyzes collected samples. Good liaison throughout this far-flung complex of sampling, study and research means that if one group discovers something significant, other groups will learn about it quickly. Importantly, added coverage is being provided by a number of states who have established their own sampling networks.

. . . found the many causes for its problem and costs of solution . . .

Assemble all the facts

Central City's survey will let it move toward an effective control program based on intelligent correlation of cause and effect. A significant phase of the survey involves consideration of the area's meteorology and topography. These factors, perhaps more than any others, highlight the individuality of the local problem in that they tend to govern amount of atmospheric concentration or dispersion of wastes thrown into the air. Judicious planning which takes advantage of topography and air movements, such as controlling location of industrial operations with pollution potential, can have more real effect than restrictive legislation aimed in scatter-gun fashion.

Multitudinous samples are taken from the surrounding atmosphere under all conceivable conditions. Pollutants in these samples are subjected to exhaustive analyses to determine identity and quantity. Pollutant fallout patterns are studied and fallout quantities measured. So far as possible, pollution sources are located and their individual contributions plotted in proportion to the whole. In short, the survey produces *facts* without which any air-pollution-control program is apt to be worth little more than the proverbial snowball.

Study the findings

No survey is concluded overnight. Time is essential in which to cover all bases, correlate data, study the findings and consider methods likely to produce optimum benefit. Length of time necessary to conduct a survey depends, of course, on the magnitude of the problem. Cost, too, is important. Surveys can run into money, which means that careful planning is a must if Central City and its state are to get maximum return from the survey dollar.

Important factor in getting this return: emphasis on reducing lost motion in the survey operation. Much help in both planning the survey and interpreting collected data may be had by checking what has been done in other areas. Others have different problems, but Central City can often profit from their experiences.

Most air-pollution causes are relatively easy to define; many lend themselves readily to control, such as poor combustion or odor emission. Some causes, such as photochemical reaction in the atmosphere, fall into a gray area between cause and effect. From a practical standpoint, Central City's goal may be to reduce or eliminate emission of substances which permit such reaction to occur. But in the main, Central City's survey will produce a reasonably clear picture of its air-pollution *causes*. However, the effects of these causes range from the self-evident to far into the unknown, particularly where human and animal health is concerned. Some causes are suspected of having specific harmful effects, but to date there is no established proof. Effects other than those now known most certainly will be determined in time through unceasing research efforts around the world. When they are, air-pollution-control procedures in Central City will be flexible enough to be altered without difficulty because they're being planned that way.

Plan control approach carefully

Central City's immediate task is to apply what knowledge it has acquired to setting up the most effective counterattack. But there is much yet to be learned about the enemy, and much can be lost by a headlong charge. Too little is known about his overall threat to the citizens' well-being, and in planning his defeat, Central City must avoid the possibility of winning a Pyrrhic victory. Central City's plans must be made after full deliberation and with complete understanding and support of its industries and citizens whose livelihood will be affected.

Spell out the economics

Such understanding must be based on a clear picture of the economics involved in an effective air-pollution program. It's a matter of history that much progress has been made in controlling contaminants in milk, food, drugs, water and city wastes. Such progress comes only because enough people "cared" and were willing to pay for improvement. So it is with air pollution. However, this new menace does not tend to make its presence known as forceably upon the public as, say, poor-quality water.

It follows, then, that without public outcry and willingness to foot the bill little progress will be made in air-pollution control in any given area. In brief, people will get air-pollution control only so far as they are willing to pay for it. Further, an apathetic public may, in fact, be paying a price far out of proportion to the relief afforded by politically expedient "control" legislation.

So, as Central City's initial survey draws to its conclusion, accumulated data indicate the scope of its problem and study of procedures employed in other areas has brought an awareness of pitfalls and shortcomings of hasty and ill-advised control programs. Now the time has come for Central City to design its own control organization and methods based on what it has learned.

. . . then picked a qualified Board that acted with public support . . .

During the course of Central City's survey a Public Health Service Engineer from the Taft Engineering Center in Cincinnati supervised the operation. He met with officials of Central City and the state government, representatives of the chamber of commerce, various citizen groups and key industrialists in the area. The city's health officer arranged for other visits and inspection tours.

Helpful information poured in from the local U.S. Weather Bureau office. The PHS engineer then sat down with board of health representatives from city and state. Uppermost was the question: since evidence pointed out that control efforts should be made, what form should they take, what staff, budget, labs and laws would be required?

Based on analysis of all findings to date, he made several recommendations at that meeting. In brief: conduct a more-elaborate air-pollution survey, initiate a local control program, appoint a control board. Under the new board's guidance, the survey would check further into present pollution levels, nature and extent of pollution sources, meteorological pattern in the area. This study would be most valuable in planning control activities and evaluating accomplishments later. It would also serve well in laying out a land-use pattern, present and future. Before leaving, the PHS engineer reminded Central City officials of educational courses available at the Taft Center.

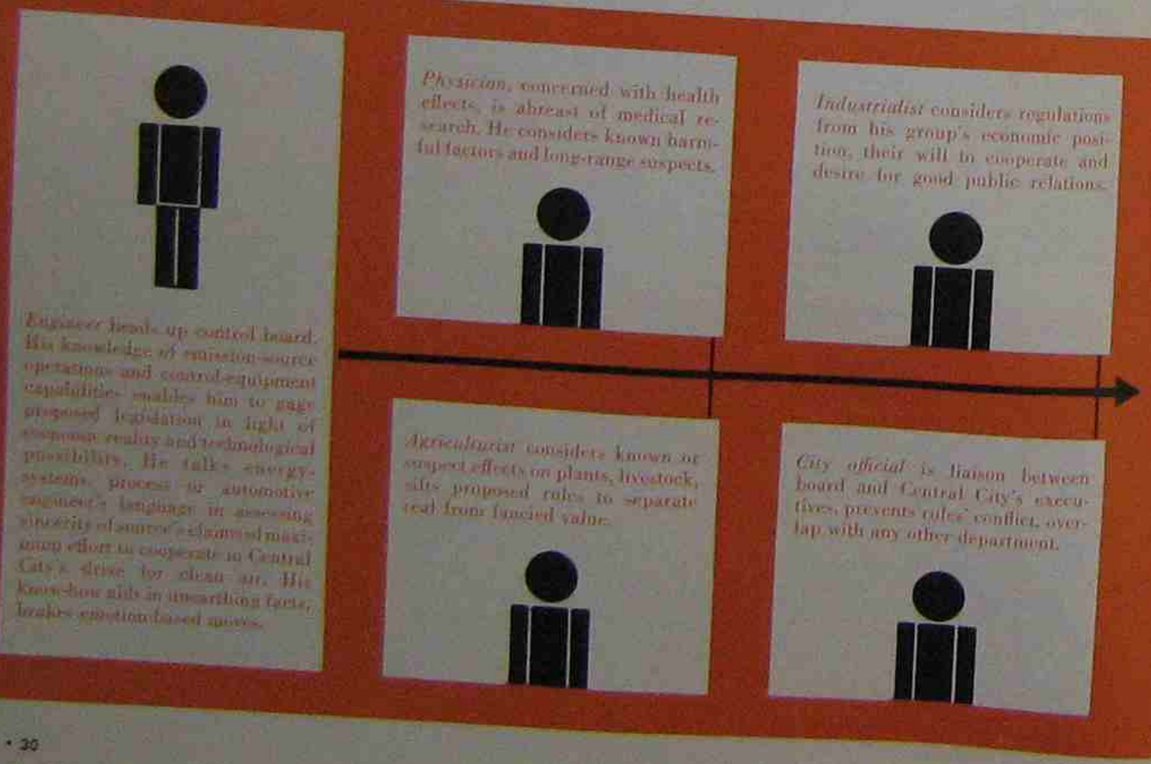
The recommendation to establish prompt local air-pollution control was made only after careful consideration. They felt little was to be gained from waiting for completion of the more-extensive survey, or of any outside research on air pollution then under way.

Central City's mayor, after consulting with state and city health boards, appointed a 5-member local air-pollution-control board. It was autonomous in nature and provided with adequate staff and budget. Headed by an engineer, the board's associate members were: a municipal official, a physician, representatives of agriculture and industry, see below. City council approved a resolution that the board's staff be selected via civil-service procedures. Staff would be headed by an air-pollution-control officer who would direct operation of enforcement procedures. Control officer and his men would be, in effect, Central City's air-pollution-control dept.

The air-pollution control officer, like the board's head, was chosen from the engineering profession. Reason: in pinning down causes, an engineer is a logical choice; he can identify specific pollutants, then classify them, if possible, in terms of sources. Too, his specialized knowledge is called into play judging both corrective and preventive equipment designs.

The a-p-control officer's prime function, aside from directing enforcement of regulations, would be to present the control board with specific factual evidence in connection with alleged violations. He would also present his recommendations on legislation proposed from any source.

The control board, on an equal-footing basis, would pool their background know-how in weighing the facts



. . . and appreciation of the rights of individuals and industry . . .

and determining what proposed regulations should be sent to the city council with recommendation that they be enacted into law. The board would also devise emission-control regulations specifically for the local area. Such regulations would be based on investigation into degree of pollution complaints and on a survey of sources.

Furthermore, the board would strive to obtain compliance through education, inspection and enforcement of regulations. It would be fully aware that its most-important job is to find solutions at the overall or community level. From what it learned through study of other areas' procedures, the board would know that its best chance of achieving effective pollution abatement lies in using the preventive approach, not punitive actions which penalize for pollutant emission.

In approving the program, the city council realized the control board could not, in keeping with American tradition, function as prosecutor, judge and jury. Following this concept of "separation of powers," the city council stipulated that a separate and distinct appeals board be established to which an alleged violator might turn if he believed a regulation had not been interpreted in a fair and objective manner. If further appeal were desired, there would be provision for going to the courts.

Central City's 5-member air-pollution-control board then sat back and took stock. Though vested with considerable power and confronted with pollutant sources needing immediate corrective action, the board was not eager to start passing laws. They realized that attempting to control air pollution by forcing those causing it to cease operation would be tantamount to throwing the baby out with the bath water. Forcing an industry to clean up or shut down conceivably might be necessary in an extreme case. But such measures used with abandon would raise hob with the city's well-being.

Following the fundamental principle recognized by the Oregon legislature's air-pollution-control bill— "reasonable or natural use" of the atmosphere as a natural resource for waste disposal should be permitted—Central City's board knew that one of its first decisions would have to determine how much pollution is too much. They also knew there are no such things as standards of air-pollution control, that there are still too many variables and unknowns. This does not mean that air-pollution limits cannot be established in a specific area, so long as the limits are intelligently related to cause and effect. But arbitrary blanket requirements covering all emission sources, regardless of kind or character, would be highly impractical and economically prohibitive.

The board realized that Central City's people must understand pollution as a 2-way street. All suffer from pollution—but all contribute to it on occasion. The board's big job: impress upon the citizens that air-pollution control will be costly, but cost will tot up to far less than they are paying now, in one way or another, for letting polluted air continue in their community.

Central City's control board thus assembled represented a wealth of combined talent. Collectively they were well equipped to analyze situations involving regulations proposed to them by the control officer or by other sources. However, they were aware of other factors which could easily be overlooked while handling mechanical details of the proposals. And if these factors weren't considered, legislation might be enacted which would not be as effective as possible because it was not truly equitable.

First, they reasoned, industry and the individual have certain basic rights which must be considered. One such right is use of the atmosphere to carry off and harmlessly disperse a certain quantity of emitted wastes. No laws should prevent this natural resource from functioning usefully to its fullest capacity. Such a law could easily prevent industry or the individual from realizing technical, economic benefits. And of course, any tendency to abuse this right could readily be detected and corrected. The board believed that Central City's industry planning should be encouraged to take advantage of this factor when selecting plant sites. By using services offered by meteorologists in addition to those of consulting engineers, industry might provide itself with some natural "built-in" air-pollution controls.

Second, the board believed that regulations would ultimately prove unrealistic if they ignored the significance of equitable zoning laws. Historically, zoning laws protect residential areas against encroachment by industry but make no provision for the reciprocal. Investment in air-pollution-control equipment could be heavy. No industry should have this expenditure nullified by gradually approaching residential areas.

In keeping with this thinking on planned use of the atmosphere and common-sense approach to zoning laws, the board realized that legislation passed to meet Central City's apparent needs of the moment might well be archaic within a decade or two. And laws, once on the books, have marvelous staying power. Too, the board knew that "procedures" have a way of perpetuating themselves, that their successors would tend to follow precedents.

To set the stage for painless demise of outmoded regulations, the board made it mandatory that successive control boards review existing regulations at periodic intervals. Those found not effectively in step with the times must be revised or repealed at the future board's discretion. Thus by choking future control boards with legal responsibility to keep pace with scientific and technological advances in air-pollution-control techniques, Central City's initial control board would perpetuate their philosophy of considerate, rational approach to the job.

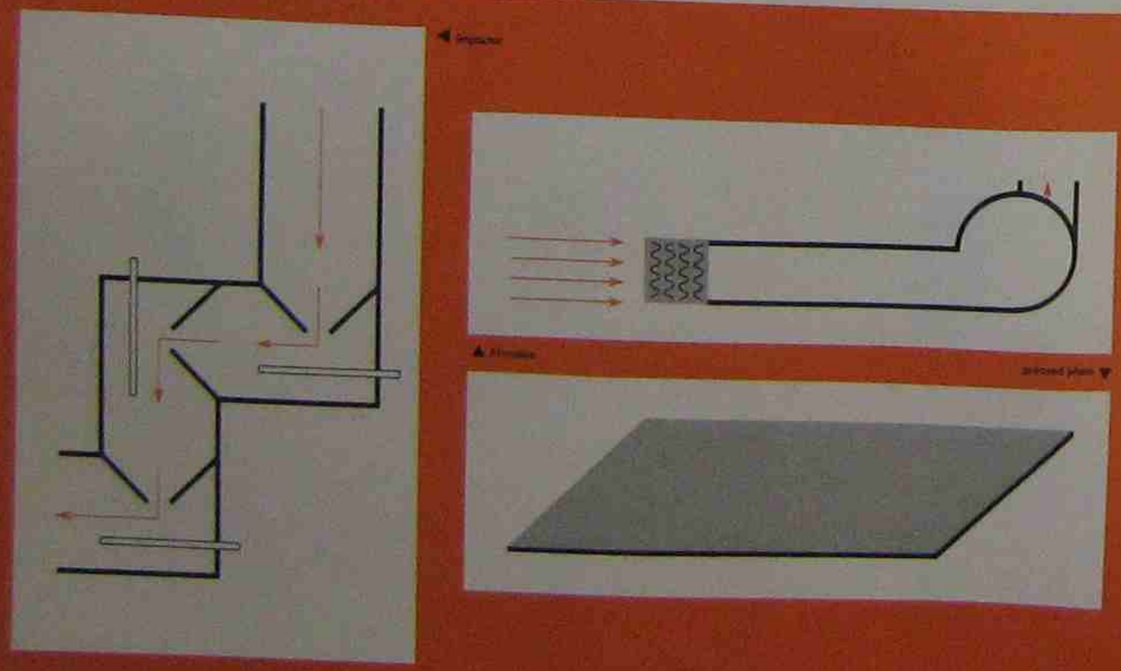
. . . establishing regulations that were definite yet flexible . . .

After more-thorough study and consultation with many outside experts on air-pollution control, Central City's board made its recommendations to City Council. In keeping with the desire for a strong local voice in control activities, and realizing that most problems deal with nuisances requiring equitable balance, City Council held a series of open hearings on the proposed control regulations. Both the board and city council recognized that the people of Central City should be the ones to decide what pollutants are objectionable and to what degree they should be controlled.

The community approved, and council passed a law defining illegal air pollution as: "emission into the outdoor atmosphere of one or more contaminants, such as dust, fumes, gas, mist, odor, smoke or vapor, in quantities, of characteristics and of duration such as to be injurious to human, plant or animal life or to property, or which unreasonably interfere with the comfortable enjoyment of life or property." The law recognized that establishing concentration limits at emission sources as a blanket requirement would have little real value. Instead, contamination would be evaluated "in direct relation to its effect, at ground-level point of contact, on people, animals, vegetation and property." Such effects would be carefully assessed and corrective measures taken as found necessary to comply with the intent of the air-pollution-control law. Corrective measures would be weighed in the light of present understanding of effects of various pollutants. This, of course, ranges from the very self-evident to suspect effects for which there's no established proof.

The law indicated that it could and would be extremely firm with violators who willfully flout or flagrantly disregard the law's intent. It made provision for accidental violations and those of an extremely temporary nature. But, as written, the regulation contained no specific penalties for specific offenses, though it left the door open for future action of this sort at the discretion of the air-pollution-control board.

The board had recommended the basic law, as passed, because it believed that much could be done toward real control without punitive measures. First of all, realistically, they knew that the air-pollution-control officer would be faced with a gigantic task were it incumbent upon his department to ferret out each existing and new pollution source by field inspection alone. It would be practically impossible to staff the control department sufficiently to perform this function economically. Consequently, they had city council include a provision in the regulations to the effect that each existing and projected waste-emission source, above a specified minimum size, be registered by the owner in writing with the air-pollution-control department. Forms would be provided and required data would include (1) outlet's location (2) outlet's size (3) outlet's height above ground level (4) outlet's emission rate (5) composition or description of effluent and (6) description of effluent-cleansing equipment.



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. . . backed up with a continuous sampling plan to measure success

In this regulation, the control board's thinking was that, regardless of what machinery was set up by government to administer air-pollution control, sole and immediate responsibility for holding the release of pollutants within tolerable limits must rest with the source-equipment owners and operators. This regulation, by placing responsibility on the alleged offender, recognized that he is best equipped to handle his particular problem and, with his own technical and engineering staff (plus available help from outside sources) can most economically design and install effective abatement equipment. Further, the regulation made it understood that the control department would not concern itself with process operations ahead of the effluent-cleaning equipment.

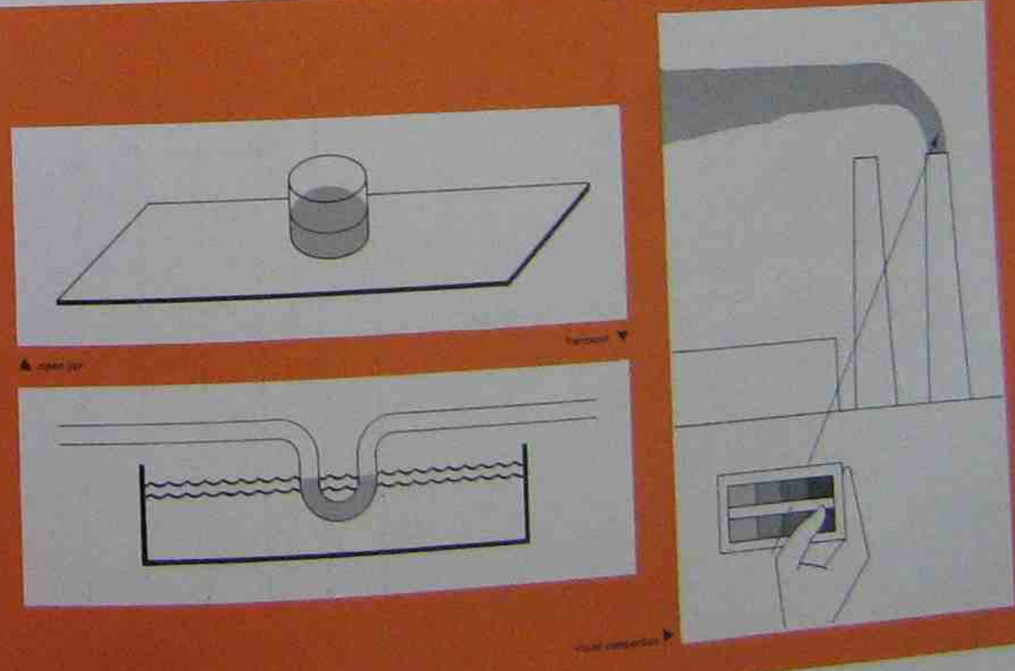
Using its own facilities—backed up by those of the state health department, the U.S. Public Health Service and other research facilities—the control department would employ sampling and inspection techniques, shown typically below. Such continuous monitoring would keep Central City aware of its progress toward air-pollution control. Knowing the complexity of the overall problem, Central City was determined that the air-pollution-control administration keep pace with advancing technology, continue to exercise control on a nonpolitical basis and on an impartial "cause-and-effect" relationship.

In line with the self-enforcement approach, the mayor appointed an air-pollution-code committee composed of representatives of the city's leading industries. He requested that they devise an "emission-limits" code for the area. Committee would be free to select various limits which study showed to be most effective and economically feasible. These limits, recommended to the Control Board, would have been developed by top engineering and scientific talent. It would be unlikely that they would be considered arbitrary or unreasonable by those having to operate under them, and they could cut the air-pollution-control department's operating cost considerably. Industry would be less reluctant to invest in cleaning equipment when it had itself determined the need. It would be encouraged to do an effective cleanup job, knowing the code wouldn't permit discrimination.

Central City took other steps. Present zoning laws prohibited industry's encroachment upon residential areas. These laws would be revamped to prohibit housing developments in designated industrial areas, thus giving industry a defense against future air-pollution problems.

Central City knew that air pollution respects neither political nor geographical boundaries. So the city asked the state legislature to pass enabling legislation permitting Central City's air-pollution-control board to combine activities with other areas for equitable solution of their common problem, if the need arose.

Central City is reasonably certain that its approach to abatement and control, coupled with the policy of keeping all citizens informed, will bring immediate and long-term results in the form of cleaner air.



S • 33

To combat problems created by man and nature, Los Angeles tried . . .

Southern California's Los Angeles Basin is blessed by nature with climate and topography that permit one to loll on a sun-drenched beach and, but a few hours later, ride a feather of snow down a ski run. Once, the L. A. Basin enjoyed an atmosphere as refreshing as the lakes nestled in its mountains or the blue Pacific lapping its shores.

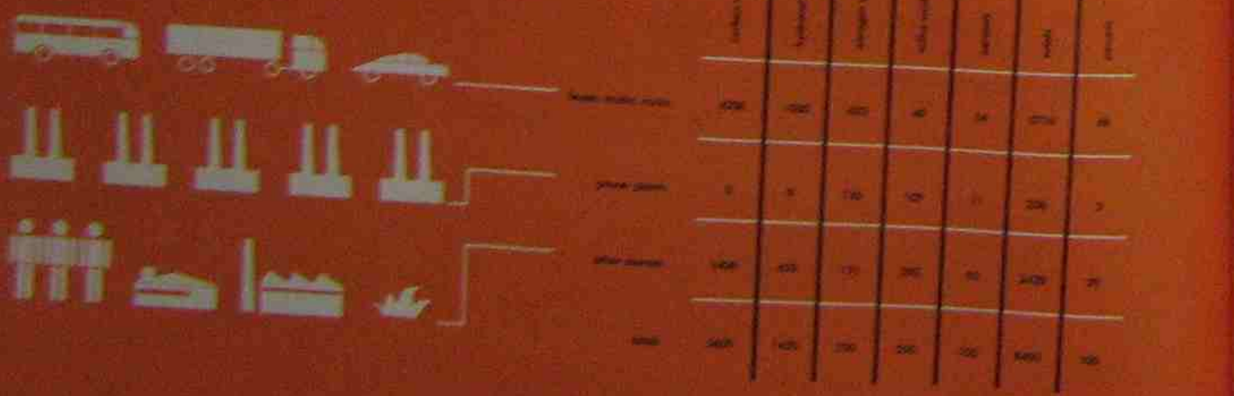
Today, thousands of tons of contaminants entering this atmosphere each day lazily eddy and swirl until the lovely terrain dissolves in a murky haze which climbs oftimes to the very top of the mountains rimming the basin.

This phenomenon, which has probably spawned more study, more research, more literature, more speculation and caused more dollar expenditure than anything else in the air-pollution field here and abroad is directly traceable to two factors: ventilation and people. Nature, in providing the lovely climate and topography, neglected to supply the area with adequate ventilation. Contaminants put into the atmosphere are trapped there. Thermal inversions cause them to concentrate heavily at or near ground level. Exposed to long hours under a brilliant sun the contaminants cook to form a devil's brew that makes eyes smart, tempers short, and causes untold economic losses. And the principal sufferers, people, are also the principal cause—they put these contaminants into the air in the first place and are now struggling to mend their ways. They now know that cooperation among themselves and with nature is the only road to relief.

Entirely unwittingly, human beings in the L. A. Basin for years let contaminants from their activities rise uncontrolled into the air above them. Little significance did they attach to a matter of historical record: On an October afternoon in 1542 the Spanish explorer Juan Rodriguez Cabrillo dropped anchor in what we know as San Pedro Bay. He noted that although mountain peaks were visible in the distance, their bases couldn't be seen. Smoke from Indian fires rose perpendicularly into the calm air for a few hundred feet, then spread out over the valley. Impressed by this phenomenon, he recorded it in his diary and named the place the "Bay of the Smokes." What the Spaniard saw was the combined effect of a thermal inversion and man-made pollution.

It would be 400 years before these factors were recognized as significant. But their significance was not lost on a September day in 1943, when Los Angeles experienced its first "daylight dimout." One newspaper reported, "thousands of eyes smarted. Many wept, sneezed and coughed. Throughout the downtown area and into the foothills the fumes spread their irritation." An outraged demand for action followed. Citizen committees were appointed. City officials were petitioned. Official investigations were launched. A Smoke and Fumes Commission was appointed, studied the problem, made recommendations. As "smog attacks" recurred, citizens' groups, subcommittees and grand juries buzzed with activity.

L. A. petitioned State and Federal governments for help. City and County Health Officers created air-pollution-abatement groups. A model ordinance was considered



. . . many smog-control tacks before grappling with auto exhaust . . .

by some 46 independent city and county governments—without effective results. They couldn't pull together. Meanwhile the smog, no respecter of political boundaries, continued unabated. So did the cry of "do something!"

An air-pollution expert from another area was brought in. He studied the problem and made a red-tape-cutting recommendation: Create a county-wide Air Pollution Control District, give it broad powers to enact and enforce adequate regulations. The District was officially created on October 14, 1947; through "enabling" legislation approved by Sacramento, it received practically carte-blanche power to enact its own pollution-control rules and regulations.

The APCD moved fast. *All* outdoor burning was banned. Having no municipal disposal system, Angelinos traditionally burned refuse in backyard single-chamber incinerators. No more. No longer could commercial salvagers fire heaps of automobile bodies. Suitable covers went on oil-refinery storage tanks holding high-volatile products. Gasoline transfer from tank to truck to service station was muffled to prevent vapor escape to atmosphere. Industrial dust-, smoke-, vapor-, mist- or fume-producing processes invested heavily in emission-control equipment. A large steel mill spent millions, installed electrostatic precipitators on its furnaces.

These and a host of other activities resulted from the Air Pollution Control District's edicts. Insistent public demand brought drastic action to control a situation that had snowballed unheeded, as population explosion and tremendous industrial expansion, principally during and since World War II (now 6-million people, almost $2 billion in new capital investment) created atmospheric conditions about which little was known.

The people of L. A. wanted cleaner air and seemed willing to pay for it. But one didn't have to be an economist to deduce who would finally foot the bill.

Power companies' smokestacks immediately felt the onslaught since stacks, large in size, are easily seen by the man in the street. Visible plume, however slight and no matter what its composition, was cause for complaint by jittery citizenry. Considerable emotion was involved and instrumental in passage of laws such as those limiting sulfur content of fuel oil to a virtually impossible level—despite lack of established proof that sulfur was a culprit. Many engineers across the country look askance at this regulation, and another which permits Ringelmann smoke chart use to judge opacity of stack plumes of other than black smoke. L. A. Basin utilities have spent vast amounts of time, talent and money trying to comply with plume-opacity requirements. Experts doubt that success is possible within the realm of economic reality.

Despite the stringent enforcement measures, crushing smog continued to persecute the public, indicating that the real answer still eluded its pursuers.

In recent years the search has been intensified. Careful scientific research—fostered by the APCD, the Western Oil and Gas Assn and the private, nonprofit, independent Air Pollution Foundation—hinted at an important break-



...pointing up need for careful study beforehand

through. They found that a unique and complex chemical reaction occurs in the atmosphere, catalyzed by the famous Southern California sunshine. Actors in this drama are products of all combustion processes and those associated with hydrocarbons handling. As regulations closed in on refineries and all combustion processes, domestic, industrial and utility, without producing significant results, a previously little-considered source took the spotlight: the motor-vehicle exhaust pipe.

In the L.A. Basin's 4000-sq-mi area public transport is relatively nonexistent. The inhabitants, to a man, use the automobile to move about the area. Some 3-million internal-combustion engines puff along streets, byways and freeways pouring almost 6000 tons of pollutants per day (68% of total) into the air over Los Angeles County, while power-plant stacks in the area contribute a mere 256 tons or 3% of total air contaminants. Remaining 29% is attributed to miscellaneous sources.

Research efforts by the automotive and associated industries and sponsored groups focused on combustion improvement, less fuel loss and special catalytic-combustion or afterburner devices. With the passage of Assembly Bill No. 17 on April 5, 1960, California took legislative action.

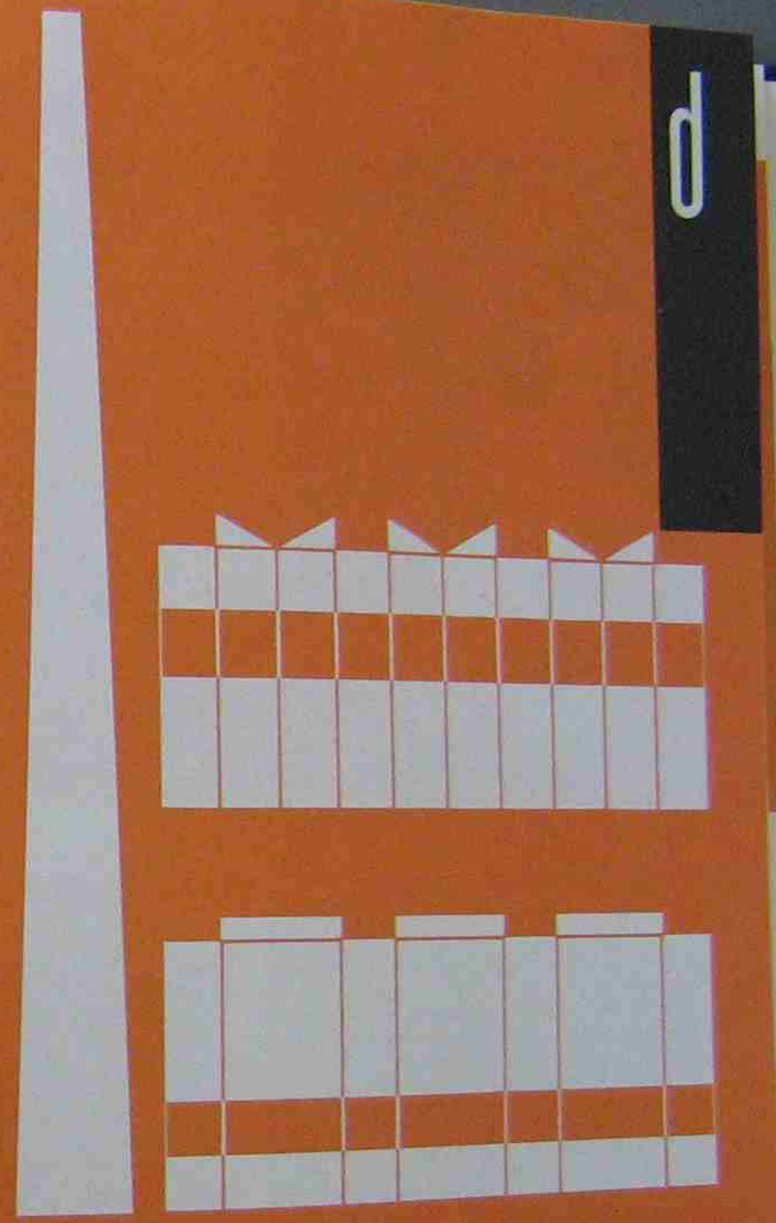
The new law sets up a time-table for installation. Measured from the day a state board certifies that at least two devices are approved, the schedule runs: Within one year, all new vehicles must have control devices. Commercial vehicles must have devices within two years; *all* motor vehicles within three years. According to a report issued by the Los Angeles County Air Pollution Control District, "this new law promises the virtual end of smog in the Los Angeles Basin within five years, *if*: (1) Devices are developed and installed as scheduled and (2) strict control is maintained over pollution from industry and the disposal of rubbish."

Just how soon devices will be approved, how much they will cost the vehicle owner, how they will be maintained, what sort of inspection procedures will be set up, and length of their service life—aside from how effective they will be—is of interest to all concerned with a-p control across the country.

Why, we may ask, did so much time elapse before the automobile came to the fore as an air-pollution source? And we may question other regulations attempting to eliminate smog in Los Angeles. Post mortems are revealing. We all know the wisdom displayed by the Monday-morning quarterback. When the L. A. Air Pollution Control District took over, it was the rookie pitcher fresh from the farm team. It walked onto the mound, found the bases loaded with none out. It knew little about its opponents. So it simply pitched.

In Los Angeles the APCD was up against what is probably the most complex meteorological, topographical and pollutant-source combination in existence. Pressure to "do something" was tremendous from all directions. It went after, obviously, open burning of all types. It moved against smoke emission from stacks and chimneys. Hadn't this solved a major portion of the air-pollution problem for St. Louis and Pittsburgh? It put stringent limits on allowable sulfur content of fuels because sulfur in our lungs *must* be bad for us, and so on. Thus the APCD moved, spurred by public outcry and with little concrete technical help available anywhere in the world, against what seemed the most likely offenders.

Time alone will show what mistakes have been made. The APCD most certainly can take credit for progress to date. But the errors must be charged to the inhabitants of the Los Angeles Basin. They let the situation get out of hand, then demanded a crash program for relief. Chief lesson to be learned from their situation, then, is that air pollution *must* be recognized and plans for controlling it made when it is the potential state, not after it grows into an actual and serious problem. As in hypothetical Central City, citizens who plan to control air pollution before it controls them are already wise and quite likely wealthier and healthier.



Your plant and pollution: Because any community nuisance is but the sum of many individual nuisances, effective control programs begin at individual pollution sources. For us as engineers, this imposes a continuing responsibility to make sure that our plants abide by the spirit as well as the letter of local clean-air ordinances.

There is more involved here, however, than the mere avoidance of penalties or litigation. Being a good neighbor from the pollution-control viewpoint can be a major factor in sound public relations. And it can be good business in another way, as well: Emission of pollutants—smoke is a prime example—is often an indication of inefficient operation. Or in some cases it can mean the loss of materials worth recovering.

The pages that follow outline how intelligent plant design and location can eliminate pollution problems at the start, and then how problems of existing plants can be mitigated.



Pollution-making potentials of a proposed new plant should be known and evaluated before the site is finally decided and detailed design begun. This means looking at each process and operation to gage what pollutants it might normally produce and to estimate, roughly at least, what might be done to eliminate or reduce that pollution. With some idea of pollution potentials and cost of mitigating them, site selection can be approached more intelligently. And the site chosen will, in turn, influence decisions on investment in pollution control.

What might be called "pollution environment" should be added to the usual [illegible]—labor supply, transportation, proximity to [illegible], availability of water and power—that are [illegible]. First, what is the general background level of pollution at the proposed site, and what are the local [illegible] controlling pollution? Are there nearby plants whose [illegible] might damage your product, or neighbor plants that would be sensitive to your emissions? Any risk of damage to [illegible] of nearby farms or parks? Would proximity to residential areas call for special public-relations effort even [illegible] with local ordinances?

When you design a new plant: analyze its potential pollutants...

A surprising number of today's pollution problems could have been solved at the beginning, with little or no expense compared with the cost of curing or mitigating the conditions now. In other words, it's just good business to make pollution control an integral part of the process of selecting a site and designing a new plant.

Consideration of pollution aspects must begin early, because it can affect and be affected by plant location and process design. A good way to start: estimate the pollution potentials of the projected operations. In some light-manufacturing or assembly plants pollution possibilities may be nil, or include only emissions from the stack of a boiler plant for space heating. On the other hand, a steel mill presents many potential pollutants: dusts from handling large masses of friable raw materials, dust, smoke, iron oxides and sulfur gases from open hearths, acid and palm-oil fumes from pickling and tin-plating, fumes and zinc oxides from galvanizing, and a variety of others. And for certain processes, say some in the nuclear field, pollution potentials may be an overriding concern in location and design.

In any case, it will pay to examine each process or operation to determine if it normally produces air pollutants, and to establish the nature and approximate amount of pollution. Along with this should go some thought as to what might be done to reduce or eliminate the pollution and a rough idea of what this might cost.

Drawings, above right and on the next page, symbolize some of the many site factors that may influence the pollution-control problem. They also serve to dramatize the fact that air pollution is always an environmental matter. Even if your plant emitted nothing, it would usually operate, and your people would live, in an atmosphere containing pollution from other sources. In the typical situation, of course, your plant *will* have some emissions and how much of a nuisance they create will depend on where they go and who they affect.

Obvious factors in site selection thus include the general pollution level of the environment, specific sources that might be injurious to your operations, and local features that might put more-critical limits on your own plant's emissions.

If the general pollution level is low, for example, even moderate visible emissions from your own plant might single you out, create public-relations problems. In such a situation the effectiveness of your control might need to be much greater than required by the usual ordinances. On the other hand, a high general level of pollution almost inevitably means increasingly strict regulation; your own program would need to make allowance for this.



...consider the pollution environment in which it may be located...

In addition to studying what could be called the "pollution environment," a site-selection survey needs to examine thoroughly the topography and weather conditions of the area. The broad reasons for this can be seen readily. Under favorable conditions, discharged pollutants can be carried away and dispersed so completely that no nuisance is created. Much more frequently, however, topography and local weather can work together to create a variety of problems that may prove serious, particularly if not anticipated. The well-known temperature inversion that may blanket an area with stagnant air is an example.

Some of the factors involved are: (1) the nature of the emission—rate, temperature, particle size, concentration, chemical characteristics, toxic or nuisance properties (2) discharge factors such as height of discharge, velocity, relation to surrounding structures and terrain (3) meteorological conditions—wind speeds and directions, temperature and humidity, atmospheric stability, topographic effects.

While it is easy to list the elements of the problem, their appraisal in any given actual situation is usually complex. Three basic approaches are used; in general, each is applicable to a different condition. For analyzing the emission problem of an existing plant, a practical method involves the sampling and measurement of contaminants in the air and on the ground under a variety of weather conditions. By applying atmospheric-diffusion theory and meteorological know-how to such information, pattern of pollution dispersion can be determined. Tests of model plants and terrains in wind tunnels can be a help in solving problems of existing plants and in checking performance of plants designed for specific sites.

When it comes to site selection, it is usually necessary to depend on statistical studies of Weather Bureau data and theoretical analyses based on weather data and the known facts about emissions of the proposed plant. The Weather Bureau Tabulation Unit at Asheville, N. C. will prepare statistical summaries of data at cost, and the Climatological and Hydrologic Services Division of the Bureau at Washington, D. C. can also be of help.

This is, however, a highly specialized area and the plant designer would be well advised to seek expert guidance. Qualified private consultants can be contacted through the American Meteorological Society.

How extensive a study the consultant is asked to make will depend, of course, on the seriousness of the anticipated problems. In many cases it may be enough to have the expert scout the site situation, spot conditions that would obviously create difficulties. But for plants



...study the possible effects of topography and local weather...

where nature or amount of emissions are critical, a fully detailed study is amply justified.

When the site is finally chosen, it may prove desirable to accumulate more-detailed information about it. This might include additional weather data such as wind directions at close intervals of time, measurement of surface humidity and temperature as an index to stagnant-air conditions. Effect of terrain cannot be overestimated: detailed information is needed to spot contours that might act as cold-air dams, etc. Finally, it may be a good idea to make a vegetation survey to set a kind of bench mark against which effects of future discharges can be gaged.

As plant design progresses, each piece of equipment and each process should be reviewed in light of previous estimates of pollution production and characteristics of the site. If site conditions are favorable for waste disposal by atmospheric means, less-complex and -expensive equipment may prove suitable. And, of course, under unfavorable conditions some of the original pollution-abatement ideas may need substantial scaling up.

An important part of plant design will be locating and fixing the height of the stack or stacks. This needs to take account of all the meteorological data collected and of the physical environment. For example, if there are buildings nearby, stack needs to be higher. Here is a situation where wind-tunnel testing finds effective uses.

Pollution-conscious plant design must include means for checking pollution-control performance. In many process situations, good operating instrumentation will reveal conditions that raise the level of pollution production. In other cases it will be necessary to add instruments to warn of excessive pollutant production. Example: visible pollutants can be spotted by TV cameras focused on stacks, by photocell devices, etc. Samplers and analyzers handle many nonvisible pollutants such as gases. And ground-station sampling units can be laid out to check actual conditions at selected locations.

During the startup of a new plant, pollution limits may be exceeded either because equipment and processes are not yet properly adjusted or because abatement devices are temporarily bypassed. Every effort should be made to avoid startup pollution—this is the most-sensitive period from a public-relations viewpoint. The impression you make at this time may unfortunately prove almost impossible to eradicate by later good behavior.

When the plant settles down to regular operation, some form of pollution survey needs to be made to see if performance comes up to design anticipations. This may involve only spot checks of dirt fall and air conditions at locations where the meteorological and topographical data

Topography and weather conditions at the proposed plant site need careful analysis, particularly if you cannot avoid some pollution emission. For example, would downdraft on lee side of a bluff bring smoke or dust plume close to ground before it has a chance to disperse? How about effect on dispersion of rough ground downwind from the plant? Are there local circulations caused by differences in solar absorption between, say, farm land and forest? Would the existence of a so-called sea breeze affect day-shift operations of a plant on the coast? All these and many more questions need to be answered to guard against unexpected problems that might arise from the interplay of site topography and local weather conditions.

If your new plant has been designed to reduce pollution emission to a minimum and located so that minimum will not create nuisances, it is only wise to go one step further and provide for monitoring stack exhausts. This might involve photocell devices and TV cameras for visible emissions, sampling equipment to check vents and discharge points for gases and nonvisible contaminants, and where justified, it might also involve ground sampling stations spotted in sensitive locations.



...and, finally, provide means for monitoring plant's emission

indicate possibility of trouble during critical weather conditions. In some cases, more-elaborate sampling may need to be done over a period of time. In all cases checks should be made on the various plant-design factors: actual nature, amount and concentration of pollutants from the various processes; performance of abatement devices.

Preceding discussion of steps involved in making pollution control an integral part of site selection and plant design has, of necessity, been general in nature. This basic procedure applies with equal force to the design of the plant's energy systems, but it will pay to give special attention to the following:

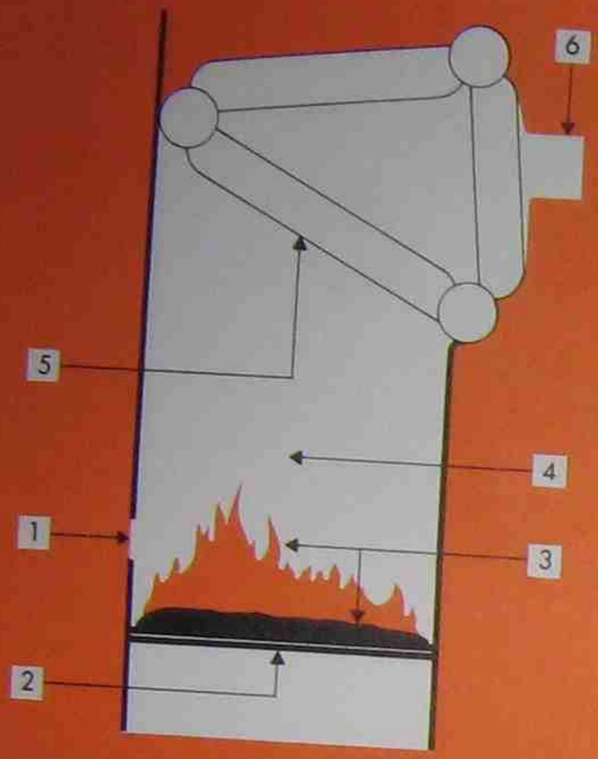
Handling systems for solid fuels often present dust problems. These may be allayed by use of wetting agents and by dust-tight construction of handling-system equipment. In the case of gaseous and liquid fuels, pollution possibilities reside mainly in vents and leaks.

Modern steam-generating equipment should operate smokelessly if properly selected and applied. In specifying equipment and evaluating proposals, provide as much fuel flexibility as economically possible. Be sure loads are adequately stated and allow for the growth that usually occurs: an overloaded unit is apt to be a pollution offender. Perhaps most important of all—in the interests of keeping investment to a desired minimum, don't skimp and cut corners on design elements—adequate furna volume, for example—that will insure efficient, comple smokefree combustion. You'll be money ahead in long run if you shun such false economy.

Formation of nitrous oxide in boiler furnaces has come a pollution problem in areas where photochem action creates smog. Combustion reactions leading to have been described earlier. Current thinking on ways reducing NO production in furnaces involves 2-stage bu ing of fuel. Furnaces are designed to introduce 90% theoretical air needed at burners. Remaining air nee to reach about 115% total air enters combustion cham above the main burning zone. At this lower tempera combustion is still complete, but NO formation drops by about 30%. This design should be considered if is a potential smog-former in your plant's area.

A different form of 2-stage combustion can be app to incinerators. Old problem of distilled vapors unburned refuse can often be solved by following initial furnace with a second combustion zone. E fuel and air is added to complete burning to CO_2, and ash.

Where pollutant emissions can't be eliminated o duced by process and equipment design, you'll nee think in terms of collectors and other abatement de



1 Good combustion begins with delivery of fuel to the furnace. In fuel-bed firing, this means selection of fuel type and size consist to match firing equipment, and maintenance of proper bed thickness. Size segregation must be avoided. In suspension firing, burner must deliver finely divided particles and develop high scrubbing action between fuel and air.

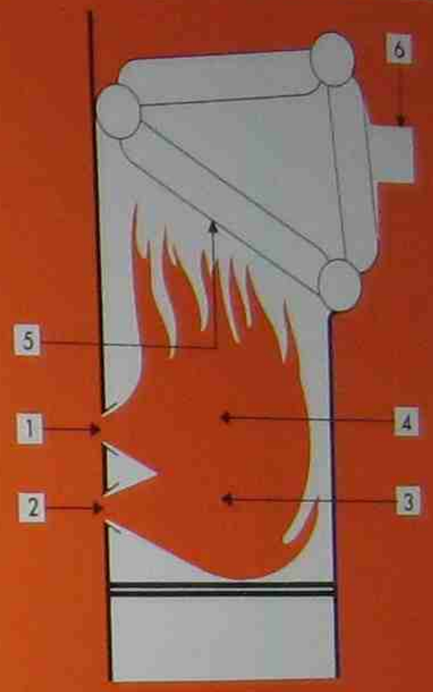
2 Air distribution through fuel bed or at burner is vitally important. Unbalanced air through fuel bed causes uneven combustion conditions . . . is particularly important to avoid air leakage at side and bridge walls. In suspension firing, all air through burners must be carefully matched to combustion needs and distributed to assure intimate mixing.

3 Solid fuels . . . unburned particles. In fuel-bed firing, partly burned fuel particles and ash can be lifted from the bed by high-velocity air . . . suspension form in the combustion space. In suspension firing, all ash appears in the furnace space and the small particles . . . tend to carry a large share of it into the gas stream and the stack.

4 The combustion process begun at the fuel bed or the burner moves to a successful conclusion in the furnace space if air and fuel are continuously and vigorously in contact. Turbulence diminishes the possibility of air-fuel stratification, lengthens the time available for the combustion process and increases relative motion between the air and the fuel.

5 Smoke and other products of incomplete combustion result if chilling effect of boiler tubes and other "cool" surfaces stops the burning process. Basic answer is ample furnace volume, but the limitations of undersized furnaces can be overcome in many cases by increased turbulence provided, for example, by suitably located high-velocity air or steam jets.

6 Stack emission . . . could include gases such as intermediate hydrocarbons, sulfur and nitrogen compounds; suspended particles or "smoke" . . . of unburned solid particles of ash and unburned carbon. Careful fuel selection and attention to fundamental principles of combustion can eliminate some of these entirely and reduce the amount of others, such as flyash.



In existing plants, good operation and maintenance are musts...

...to hold pollution to minimum possible with available equipment

With equipment design and plant environment largely fixed, the pollution-control problem for the management of an existing facility lies in learning how to secure the best results possible within the limitations these impose. And, where "best possible" results aren't good enough to meet local ordinances, how to effect practical modifications that will bring emissions down to satisfactory levels.

Influence of operation and maintenance in this situation can be seen very clearly, for example, in the case of a diesel-engine generator. Here is a unit that should present no pollution problems. But let the engine be overloaded and visible smoke appears in the exhaust. Or let a fouled injection system or worn piston rings develop and again the exhaust shows it.

For energy-system engineers charged with management of existing plants, a major pollution-control concern in many cases is furnace combustion in steam generators, incinerators, etc. As diagramed above, these may emit products of incomplete combustion such as smoke and intermediate hydrocarbons in gaseous form, and products representing the carrythrough of fuel elements such as flyash, unburned fuel particles and sulfur gases.

Chemistry of the furnace combustion process has already been outlined, but while it *is* a chemical reaction, most problems associated with it are mechanical. Fuel must be prepared for burning, it must be brought into active contact with sufficient amounts of oxygen, and the resulting burning has to take place under conditions that insure completion of the process. Each of these steps, as listed in the panel above, depends on mechanical actions and devices and the skill with which they are operated and maintained. Here we have space only for highlights of each firing method and fuel: for greater detail see *Fuels and Firing* (POWER, Dec 1948) and *Clean Air*, a series that began in July 1947 and ended in Jan 1950.

For all practical purposes oil and gas fuels present no entrained-solids problems since there is little or no ash. Sulfur content of some fuel oils will yield objectionable sulfur gases in stack discharge, but this cannot be avoided, only abated, as with scrubbing equipment. To assure complete combustion make sure that burner gets uniformly free-flowing oil, clear of sediment. This means avoiding sediment buildup in storage tanks, keeping strainers in good shape, controlling preheat temperature carefully. Watch for wear of burners and carbon buildup. Many smoke troubles arise from faulty air supply. If installation is manually controlled, make sure air supply is regulated when oil flow is changed. Keep air inlet and fan blades clean; clogging dirt and lint gradually cut air flow.

Smoke is often produced in starting oil-fired furnaces because of cold surfaces. Always start with a moderate flame, shifting to high flame only when furnace has warmed. If steam for preheating isn't available during startup, arrange to use light oil until the furnace is hot and preheating can be done properly. Avoid overloads!

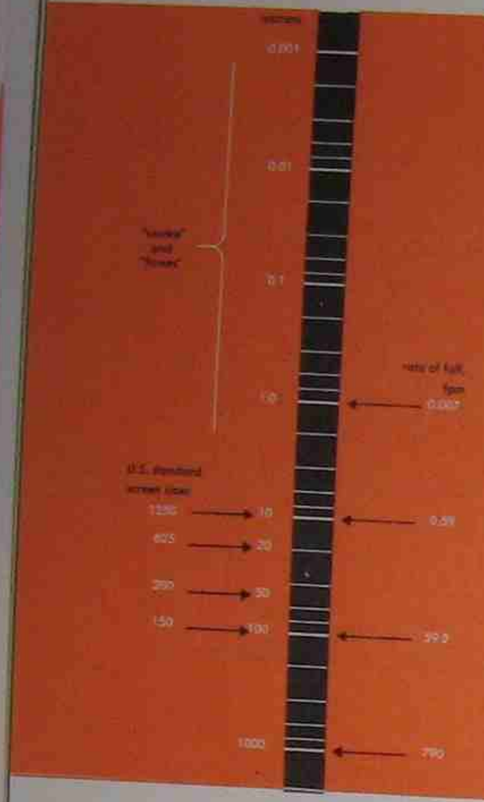
In contrast to gas and oil firing, entrained solids are the usual major problem in pulverized-fuel installations since the coal burns to ash while in suspension. In addition to insuring smokefree operation, complete combustion will reduce the total entrained solids which may include unburned fuel as well as ash particles. In virtually all cases the dust problem of pulverized-fuel units is solved by external collectors, see next section.

Today's widely used stoker, the spreader, burns fines in suspension, larger sizes on a grate. Both flyash and smoke may be problems. Good operation starts with coal having a size consist suitable for the specific unit and avoiding segregation. Control of air flow is of prime importance; it can't be maintained if leaks develop along sides of grate. High burning rates will greatly increase emission.

Chain- and traveling-grate stokers, also of the overfeed type, offer smokefree combustion if proper attention is given to size consist, freedom from segregation, maintaining an even fuel bed, low overfire draft and control of air flow. Only when air velocities through the fuel bed are excessive is there likely to be any solids carryover. The underfeed stoker is inherently free from smoke and entrained-solids problems as long as it is maintained in good mechanical condition and operated at conservative burning rates with suitable caking coals.

Many older boiler installations suffer because of inadequate furnace volume and geometry. But the smoke problem of such units can be materially reduced and even eliminated by the use of high-velocity air or steam jets to promote turbulence and mixing over the fire. The design and application of overfire jets has been intensively studied and extensive data will be found in Technical Report No. VII, "Application of Overfire Jets to Prevent Smoke from Stationary Plants," by R B Engdahl, Battelle Memorial Institute and W S Major, Bituminous Coal Research, Inc.

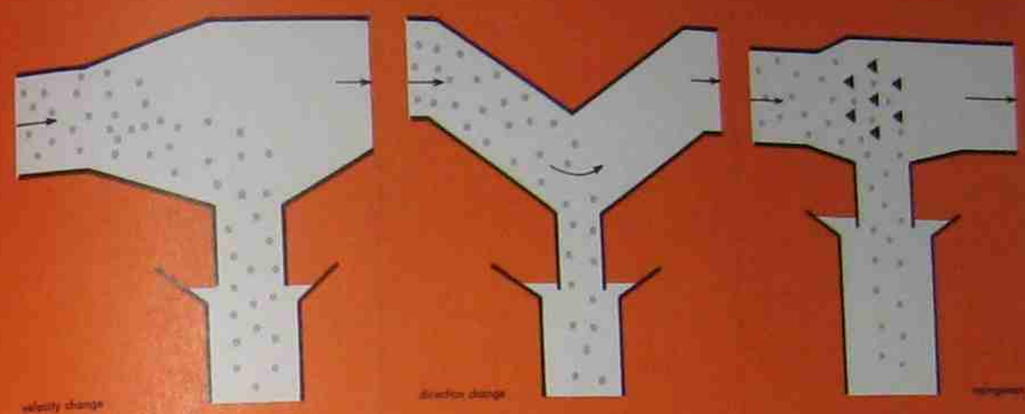
Application of overfire jets is typical of the practical modifications engineers may use to overcome pollution-producing deficiencies in existing-plant design. Other examples: changes in furnace arches and baffles or other features of the combustion space. Modifications to existing plant might also be interpreted to include a shift from one firing method to another or from one fuel to another. Still another modification, or course, is adding one of the collecting devices described on following pages.



Particle size is commonly expressed in *microns*. A 1-micron particle is 1/1000 millimeter, or 1/25,400 inch, in diameter. Some idea of what this means can be gained from the fact that a particle just passing a 325-mesh U.S. standard screen, the smallest practical size, would measure approximately 44 microns. Depending on conditions, individual particles in the 10- to 50-micron range just can be seen with the naked eye.

Definitions of terms like *smoke, fumes, dust* are not precise as to particle size. At the [illegible] diameters of some gas molecules are large enough to [illegible] of the scale, left. Broadly speaking, smoke and fume particles are less than 10 microns.

As a practical matter, most particles are measured by rate of fall in still air, rather than directly. If a group of particles falls at the known rate for [illegible] spherical particles having diameters between [illegible], we say these measured particles range [illegible] in size.



To cope with dust, smoke and gas emission problems, a variety...

As we have seen, many types of pollution can be eliminated at the source by skillful design of equipment and processes. But there are still areas in which even today's best technology cannot prevent the production of some pollutants. And in many existing plants the limitations of older equipment make some pollution formation inevitable.

In these situations, the problem becomes one of reducing to a practical minimum the amount of pollutants allowed to reach the atmosphere, and of handling the discharge in a way that will mitigate its nuisance characteristics. In both cases it is important to know something about the nature and physical characteristics of common industrial pollutants—gases, vapors, smokes, fumes, mists and a variety of dusts.

Pollutants are classified by physical characteristics and by source. Gases, of course, represent one of the three fundamental states of matter. The basic particle in any gas is the individual molecule; for some gases molecule diameters may range between 0.001 and 0.01 micron. Vapors are the gaseous forms of substances that normally exist as liquids or solids.

Small particles tend to go into suspension in air or other gases, forming *aerosols*. Generally speaking, when particle size is below 10 microns such suspensions are essentially permanent and the aerosol behaves much like a gas. Except where turbulence is extreme, aerosols having particles larger than 50 microns are unstable and the particles tend to settle out in time.

Smokes and fumes are, in general, stable suspensions of particles visible only in the aggregate, often of submicron size. Properly speaking, smokes are the products of incomplete combustion, consisting mainly of carbon and other combustible materials. Fumes may be defined as very small particles resulting from chemical reactions other than combustion, or from the condensation of vapors produced in combustion, distillation or sublimation. They are commonly metals or metallic oxides.

Dust is an extremely loose term applied to a range of solid particles, usually produced by the physical degradation of larger masses. Dust aerosols are frequently of an unstable character.

Mists are composed of droplets of vapor that has condensed on suitable nuclei. They are stable when vapor pressure of the particle is low or when the droplets are in a gas that is saturated.

If the range of particle sizes found in aerosols is wide, the range of concentrations is even wider. In normal atmospheric air, concentrations of the order of 1 grain per 1000 cu ft are found. Common loadings for industrial gases run 20 grains per cu ft and values up to several hundred grains per cu ft, and more, may be encountered.

...of methods are available, ranging from basic simple schemes...

In addition to particle size consist and concentration, choice of equipment to remove pollutants also will depend on the volume to be handled as well as the nature of the exhaust stream and its temperature.

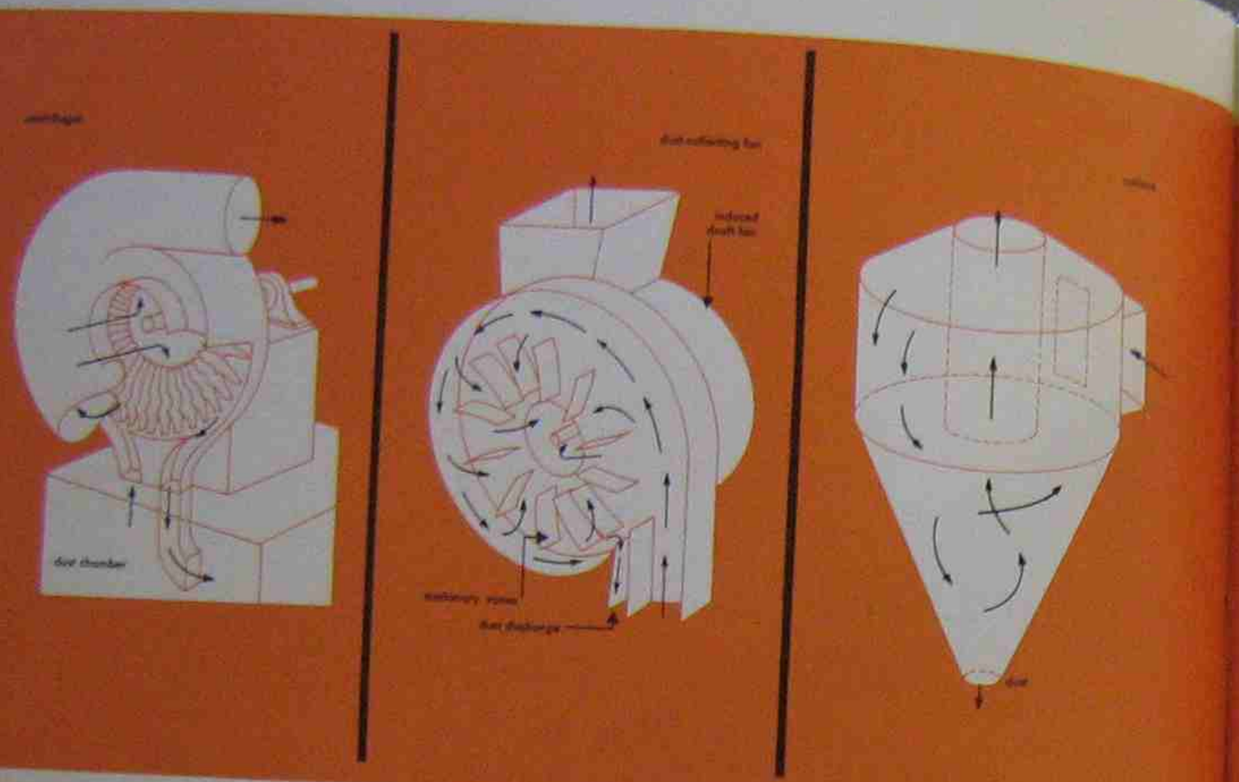
Let's look at the way these various factors are involved in a problem of broad concern—the handling of flue gas from furnace combustion processes. As we have seen earlier, sound equipment design and good operation can virtually eliminate pollutants arising out of combustion conditions—smoke, nitrous oxide, intermediate hydrocarbons. But since most fuels contain some mineral matter that won't burn, and some fuels show perceptible sulfur content, ash particles and sulfur gases may present stack-emission problems.

For all practical purposes, gas fuels contain no ash and oil fuels carry relatively little. But coal rarely contains less than 5% and may carry 20 to 30% or more. Depending on the coal and the firing method, anywhere from 10 to 70% of the ash gets into the furnace gas stream, along with some unburned carbon particles. Some of this flyash or cinder drops out in the boiler passes and breechings, but most of it heads for the stack.

Particle size consist also depends on fuel and firing method. For example, a single-retort underfeed stoker may yield mostly large particles, 75 microns or more, with only a sprinkling of fines. On the other hand, a pulverized-coal furnace may deliver mostly particles under 20 microns, with only a small percentage of larger ones.

In general, the larger the particles, the less stable is their suspension in the gas stream. The sudden change in velocity produced by a wide space in the duct or breeching may be enough to cause heavier particles to settle out. Or, if the gas is forced to flow around a baffle or sharp bend, inertia makes the heavier particles keep going in the old direction and throws them out of the gas stream. Large particles may be "knocked" out of the gas stream by impingement on baffles, illustrated in principle above. In actual cinder traps or cinder catchers, these basic ideas are often combined and elaborated to yield respectable collection efficiencies on large particles.

For finer particles and higher efficiencies, stronger forces need be brought into play. This means collection devices of considerably greater sophistication, involving, in most cases, higher draft losses, more space and greater cost. To an increasing extent such an investment is being necessitated by more-stringent regulations on dust emission. A more or less common limit, for example, is 0.85 lb of dust per 1000 lb of flue gas. An underfeed stoker, burning coal of 8% ash as fired and delivering 15% of



...to centrifugal collectors of several types, various designs of...

that ash to the furnace gas, will show a dust loading close to the 0.85 limit, depending on how much drops out in boiler passes and breechings. Since this example reflects relatively low fuel-ash content and conservative burning rates on a stoker not prone to dust emission, it can be seen that effective dust collection often will be required.

Many types of equipment are available for removing dust from flue gas; diagrams above illustrate operating principles of some of them. In a wide range of collectors depending on mechanical action, centrifugal force is used to separate dust from the gas. This means accelerating the gas stream by a separate induced-draft fan or an integral fan as shown in the dynamic collector, left above.

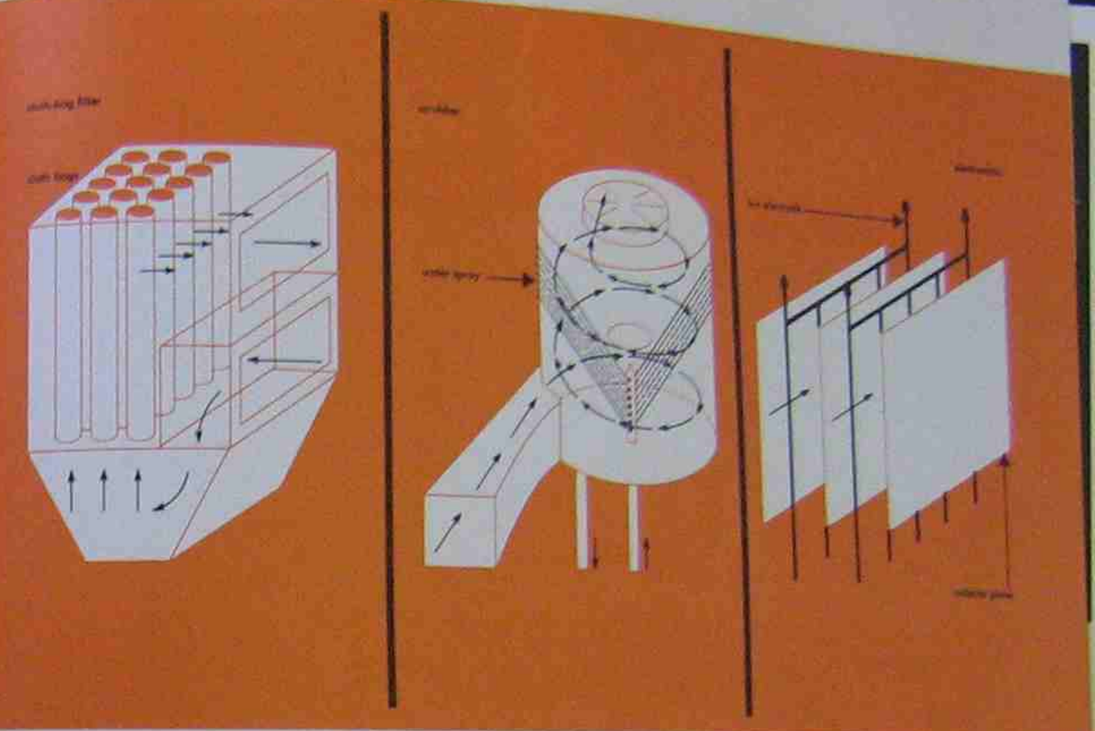
In this design, dust is precipitated by centrifugal and dynamic forces on numerous specially shaped fan blades, is forced along their surfaces to a separate dust circuit within the fan housing and thence to a dust chamber.

Another collector type using centrifugal force consists of a dust concentrator combined with an induced-draft fan. Usual arrangement comprises two such concentrators with a double-inlet fan between them. Outlet sides of the concentrators form the side sheets of the fan. Dust-laden gas enters the primary volute at the outside of the scroll. Decreasing volute radius increases the centrifugal force carrying dust to the outside of the volute. Near the minimum radius a tangential slot removes a small volume of highly concentrated dust-laden gas. A secondary collector may operate on this. Clean gas at center goes through guide vanes to fan inlet.

Most familiar of all collectors using centrifugal force is the cyclone, above. Incoming gas is guided into a cylinder in such a way that a strong whirling action is set up. This generates centrifugal force that tends to throw suspended particles to the outside. Clean gas in the center zone is drawn into a vortex-created updraft and leaves through a center outlet. Concentrated dust-laden gas is withdrawn at the bottom.

In the simple form illustrated, the cyclone is a relatively low-efficiency device with low draft loss. Intensive research on the cyclone principle has led to design improvements that increase the centrifugal force and reduce dust re-entrainment. A number of today's designs employ multiple tubes of relatively small diameter.

Gas may be cleaned of dry dusts by passing it at low velocity through finely woven fabric, usually arranged in tubular "bags" or "stockings". While initial removal depends mainly on screening action of the fabric, build-up of removed material on dirty-gas side contributes substantially, giving a high degree of effectiveness even on submicron particles. Draft loss increases as material



...filters and scrubbers, and devices using electrostatic charges

builds up on dirty-gas side and periodically the filter bag must be rapped, vibrated or reverse-blown to drop the adhering dust into the hopper. Units are usually sectionalized so gas flow can be maintained while one or more sections are being cleaned. New silicone-treated glass-fiber fabrics can handle gas temperatures to 550 F.

Wet collectors or scrubbers of various kinds can remove fumes, mists and soluble gases as well as fine dust particles. They are widely used for cleaning discharges from kilns, roasters, dryers and other process equipment. Use on flue gas from boiler furnaces has, in the main, been confined to cases where removal of sulfur gases was important. Wet collectors include spray types such as the scrubber illustrated above, atomizing and venturi designs, dynamic and centrifugal types, packed towers.

Widely used where high efficiencies on extremely fine particles are required, the high-voltage electrostatic precipitator passes dust-laden gas over electrodes between collector plates. Electrodes impart a negative charge to the dust particles, causing them to move to the collector plates and adhere. Removal of collected material involves rapping or vibrating the elements continuously or at intervals. Pressure drop of these collectors is low, and high collection efficiency is nearly uniform over a wide range of particle sizes from submicron up. But space they require is relatively large; cost is apt to run high.

In any given situation, decision as to which collector to use will depend on evaluation of needed efficiency on the particle sizes involved, draft loss and space requirements, cost. In some cases two types are installed in series; the usual combination is an electrostatic preceded by a mechanical type. Prior removal of coarser particles permits more-effective electrostatic operation.

Discussion here of collectors suitable for the relatively large volumes and high temperatures met in flue-gas work should not obscure the fact that industrial plants will have other emissions. Some of the collectors described here will meet some of these needs; for others the answer may be one of the several types of filters discussed in Powza's special report, *Air Conditioning for Industry* (March 1960, pp 53-68).

Odors emanating from industrial processes present another abatement problem. Measuring and identifying the nature of odoriferous materials is a highly specialized job, as is the task of recommending abatement measures. As with other pollutants, odors may be reduced or eliminated at the source by process changes or may be removed, for example, by adsorption in activated carbon. Odors are also neutralized or masked by mixing a pleasant odor with the unpleasant one. This is work for experts.

Looking back over the many facets of the air-pollution problem as explored in this report, it becomes abundantly clear that *people* are the key. People produce pollution, people complain about it, people support or resist efforts to do something about it. People, or more specifically, people's attitudes, make the difference between the success or failure of pollution-control programs.

In a democracy, the better informed people are, the better will be their decisions. Air pollution is no exception — as a matter of fact, it forms a prime example of the need for an informed public. This is not only true for community approaches to the problem; it applies with equal force to the control programs of individual plants and industries.

For the community, public education needs to begin early, usually before there is any visible pollution problem. This is the time when an ordered, reasoned approach can be made, before pressures of an "emergency" atmosphere force hasty, emotional attacks. This is the time when engineers and other knowledgeable members of the community can display vision and leadership: vision to anticipate the problems the future will bring, leadership to convince the people that action will be needed.

At every stage of examining the community's pollution situation and devising a sound control program, the public must be given the full facts, in a manner that all can understand and appreciate. Only in such an informed climate can the problems be tackled and support won for the procedures evolved to solve them.

Such public information must be an integral part of any plant pollution-control program as well. For a new plant particularly, advance information should be given to let people know that pollution aspects are receiving careful attention. People should be told what specific steps are being taken to eliminate or reduce pollution, and how much the company is investing to make their plant a good neighbor.

It is in this area of public education that we believe this special report has its greatest usefulness. We hope it will be put to work both by communities and by individual plants.



a **Power** handbook

FUEL Handling and Storage

by J C McCabe, Associate Editor

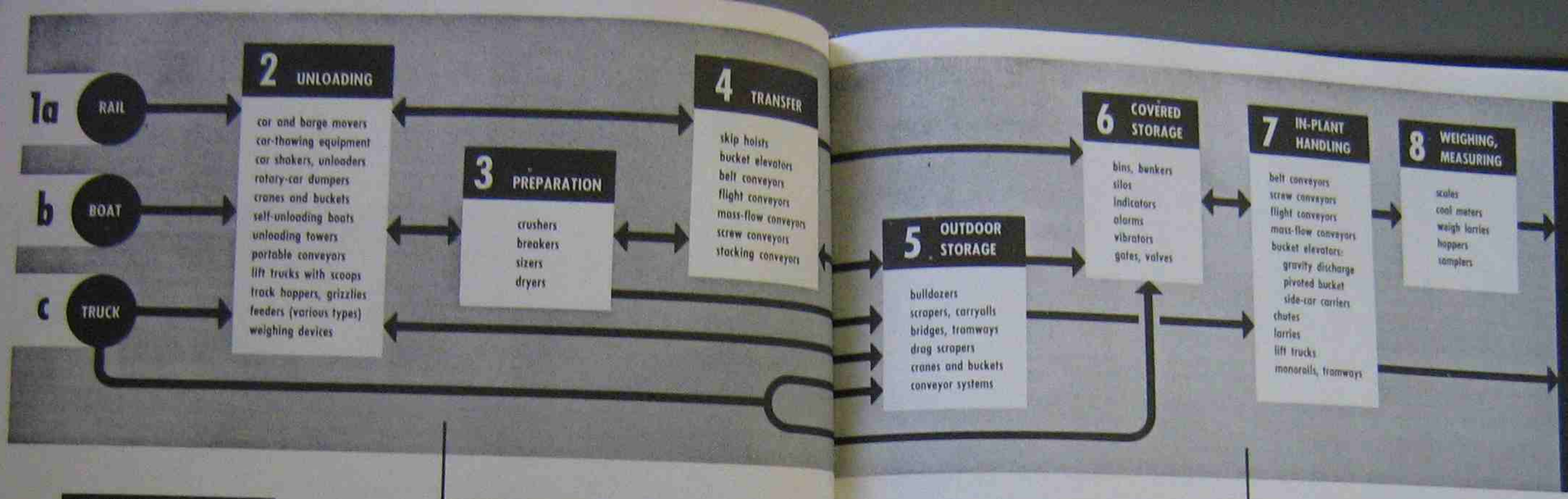
We've come a long way since fuel handling meant a man with a strong back, a big shovel and a rusty wheelbarrow. Faced with steadily rising costs, we have learned the value of mechanizing to eliminate labor, to use men's brains instead of their brawn.

As a result, we now have an imposing array of devices to move fuels faster, cheaper, more automatically. And we have the know-how to make handling and storing not only less expensive but also cleaner and safer. The trick is to apply the equipment and know-how — in your plant and all plants — to get the best over-all results for the given conditions.

To aid you in this dollar-saving job, we present this latest in a long line of POWER handbooks. In its pages you'll find a broad picture of the storage and handling function, a roundup of modern machines for the work, and the basic information you need to fit them into the combination that will solve your plant's particular problem — whether your fuel is coal, oil or gas.

In preparing this handbook, we've drawn freely on the literature of handling-equipment manufacturers and on the writings and suggestions of specialist engineers. We warmly acknowledge the helpful cooperation that everyone has given us.

December 1953



RECEIVING, UNLOADING

Unloading setup depends largely on the way coal arrives. Some forms of shipping — barges, for example — can't self-unload at all, so unloading equipment is an absolute necessity. Other types, like hopper cars, can self-unload, but we often install equipment to speed the job or make it easier under bad conditions (dumpers, thawers, shakers, etc). And frequently we add devices, such as feeders, to set up a controlled flow to the next step in the handling process.

PREPARATION, TRANSFER

If coal is bought unsized, and sizing is desirable for storage or firing, *preparation* may be done near the receiving point, as diagrammed, or in plant near point of use.

By *transfer*, we refer to handling between the unloading point and the final storage point from which coal normally discharges to the firing equipment. It may involve only one piece of equipment, or several, depending on local conditions and whether there is more than one storage.

STORAGE

Since it isn't practical to deliver coal at the rate it's burned, we use storage to permit less frequent shipments and to iron out variations in delivery. Storage may be outdoors or under cover — either in a silo or similar outside structure, or in bins or bunkers in the plant. It's now common practice to have a relatively small storage for normal needs and a larger one (often outdoors) for reserve, with means for transferring from dead to live storage.

IN-PLANT HANDLING

In plant here refers to handling between final storage and the firing equipment. Sometimes this would mean no more than chutes to direct flow to individual firing units and gates or valves to control flow. Or, we might have a conveying system to feed coal from any bunker section to any firing unit and to move coal from one bunker section to another. Weighing or measuring may be done near firing units, at the receiving point, or at both locations.

COAL HANDLING: For its few or many steps . . . . . a growing array of equipment combinations

In essence, the job of a handling system is to move coal from a receiving point to the firing equipment. Whether it's simple or complex depends on how we receive the coal, how the plant is situated, and what we expect from the system in capacity, flexibility, convenience, etc. To meet such a variety of conditions and requirements, we have an extensive array of mechanized handling devices, which may be combined in almost innumerable ways.

Basic Steps. It just isn't possible to set down what we might call a *typical* coal-handling system. What we've tried to do in the chart above is break down the over-all operation into typical steps, explain the general function of each, and give some idea of the many ways they can be combined. And for each step, we've listed typical devices used.

How Chart Works. Before taking a look at some of the combinations diagrammed, let's be sure we know how it works. To make the over-all picture clearer, the chart divides it into steps or functions. Not all of these need be involved in any actual case. Nor will they always stand out clearly as separate operations — a single piece of equipment may, in practice, handle two or more of these functions.

The order in which steps are charted is close to that likely to be followed in many cases. But specific operations, such as preparation or weighing, may be handled at other points than those shown. Finally, while flow arrows indicate a great number of combinations, the chart cannot, in the nature of things, cover all of the many possible arrangements.

Within these limitations, however, the chart helps to show what's involved in this coal-handling job and thus serves as a useful introduction to discussions of functions and equipment that follow.

Simple Setups. Now let's look at some possible setups, see how conditions influence them, and how the chart pictures them. Simplest situation might be a basement plant in a city building, with coal received by truck. Truck dumps directly to a bin, from which a screw conveyor carries coal to a stoker. On the chart this would be 1c-6-7-9.

In another relatively simple setup, railroad cars discharge over a track hopper and a bucket elevator lifts coal to the plant bunker. From here it flows through chutes to stoker hoppers (1a-2-4-6-7-9).

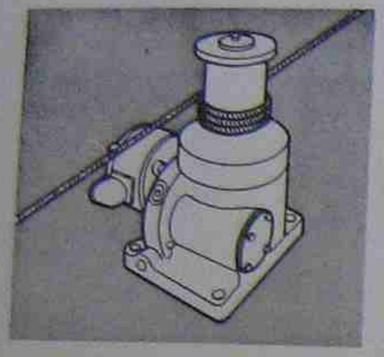
Adding Elements. Now let's suppose the plant gets some more boilers and extends the bunker. To distribute along the length of the bunker we add a horizontal conveyor over it. This means more transfer equipment, although chart sequence is still 1a-2-4-6-7-9. But to improve operation we add coal scales. Then we have another chart step, and sequence is 1a-2-4-6-7-8-9.

To protect against major delays in shipments, we add an outdoor storage and a bulldozer for building the pile. To provide an initial pile for the dozer to work from we use a portable conveyor. The dozer reclaims to the track hopper. Then, when we're using the outdoor pile, the coal-handling sequence becomes 1a-2-5-4-6-7-8-9.

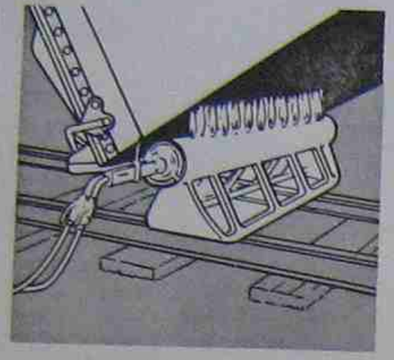
Complex System. Now, to give the chart a real workout, let's look at an actual system receiving coal by both water and rail. A coal tower unloads the barges and a conveyor carries coal to a crusher house (1b-2-4-3). A rotary car dumper unloads rail shipments to a hopper feeding another conveyor leading to the crusher house (1a-2-4-3).

The crusher house serves as a transfer point for routing coal into the plant or to a drag scraper for building an outdoor pile and reclaiming from it. So for direct handling into the plant the over-all lineup is: 1a-2-4-3-4-6-7-8-9 or 1b-2-4-3-4-6-7-8-9. When we're stockpiling and reclaiming, the procedure is 1a-2-4-3-4-5-4-6-7-8-9 and its equivalent for water shipments.

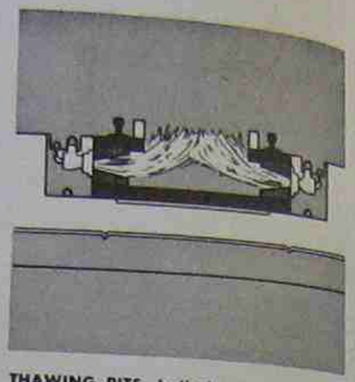
Many Combinations. While these examples are but a few of many possible arrangements, they're enough to show that each system consists of certain basic functions combined to meet specific job requirements and conditions.



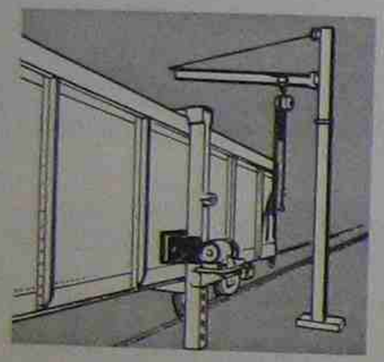
PULLERS and positioners spot cars and barges at desired point for unloading



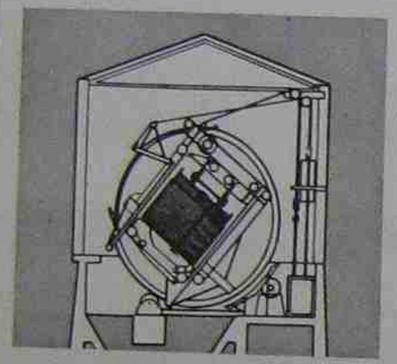
PORTABLE THAWERS prove valuable aids in speeding up unloading of frozen cars



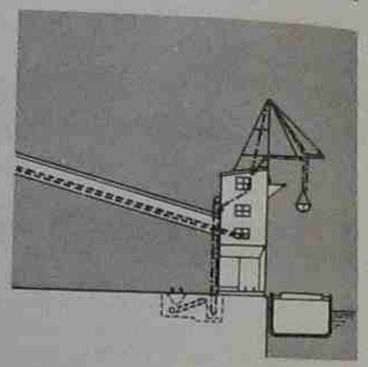
THAWING PITS, built between the rails, serve well for handling large shipments



LIGHTWEIGHT SHAKER, swung from hoist or wheel-mounted, is handled by one man



ROTARY CAR DUMPER gives fast high-capacity unloading, can do weighing also



COAL TOWER with clamshell bucket lifts coal from barges, delivers to conveyor

No matter how your coal arrives, there are . . .

First step in any handling operation, as we've just seen, is unloading incoming coal and doing it rapidly. Slow unloading not only means higher labor costs, it may mean demurrage charges as well. Thus, right at the start, it pays to mechanize as far as possible.

With labor costs looming so big, a host of mechanical aids to unloading have been developed. Which types are used in any given case depends, of course, on the way coal arrives, on the plant location, and the unloading capacity needed. A common rule of thumb suggests enough capacity to unload at least a 2-day supply in one 8-hr shift.

Equipment Used. Just what kind of equipment will do the best job for you depends first of all on how you receive coal. If it's delivered in a dump truck, and your setup is favorable, you may not need any equipment specifically intended for unloading. The truck dumps to a small outdoor storage or into a basement bin and that's it.

But even with self-unloading equipment you may need devices designed to make the job easier and to speed it up. For example, let's look at a plant that receives coal by rail, in hopper cars. In most cases, you'll need some means of bringing the cars to the right spot for quick, clean unloading. Often this will be a capstan (sketch above), also called a car puller or car spotter. With a cable connected to car and wrapped around capstan, motor pulls car to desired spot. In larger operations, motorized car haulers or industrial locomotives (diesel, fireless, steam) may be employed.

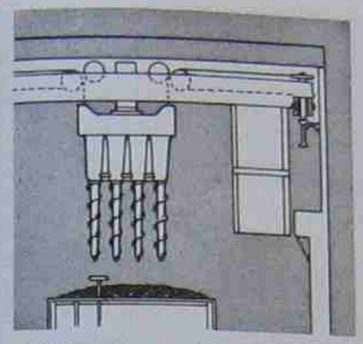
Frozen Cars. Where winters are cold, cars frequently arrive frozen. This can mean a nasty pick and crowbar job. But more and more plants are using thawing equipment—portable units like the one pictured above, or thawing pits built under the tracks and fitted with burners or, more rarely, steam lines. Some coal users pull cars into covered weather-protected sheds and then speed the unloading job with mechanical devices such as the accelerators, displacers or car shakers shown above.

These units really double in brass. Not only do they unload frozen coal—they greatly speed the handling of normal shipments. Coal, particularly when wet, has a tendency to compact in the car and hang up. Mechanical aids can speed unloading to less than 15 min per car.

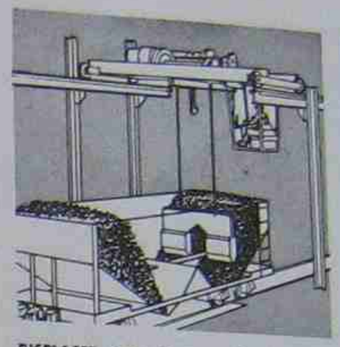
For fast, high-capacity unloading there is the rotary car dumper. This can handle gondolas and other cars that can't self-unload, and can be arranged to weigh coal also.

Track Hoppers. In all these cases, you've got to have some space to unload into. In some plants, coal cars run onto a trestle, with outdoor storage space beneath. A more common scheme is the track hopper, a pit (usually concrete-lined) under the tracks. As we'll see later, this forms the starting point for other handling steps. We'll also see some devices that permit unloading at ground level.

The general run of barges, boats and ships used for coal



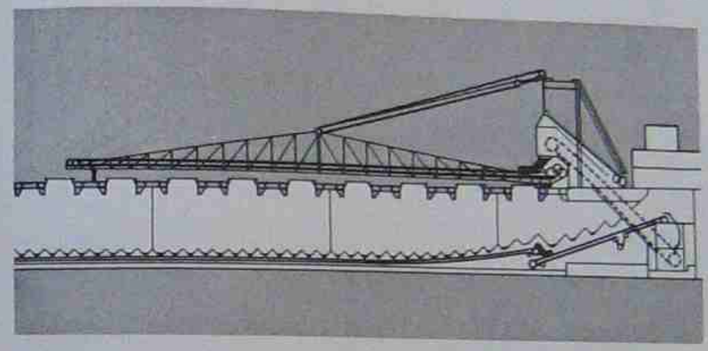
ACCELERATOR gets stubborn coal moving, overcomes wet coal's natural compacting



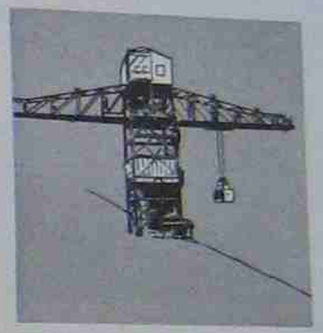
DISPLACER type of car unloader slices down through full width of packed coal



CAR SHAKERS speed unloading, cut time required per car to 15 minutes, or less



SELF-UNLOADING BOATS, found mostly in lake service, have long booms for lifting coal from holds, dumping it on shore. This may avoid need for dockside facilities



UNLOADING BRIDGE takes coal from barge, moves it into position for stockpiling

. . . devices to mechanize and speed unloading . . .

delivery cannot self-unload at all. Various types of fixed and locomotive cranes are used for hoisting from them.

Towers, Bridges. For large operations, specially designed towers and bridges are used. A typical tower is sketched above—a steel structure housing hoisting machinery, and a trolley boom for swinging bucket out over barge. In the inboard position, bucket dumps into hoppers feeding a conveyor. For details of a modern tower, see POWER, June 1951, pp 83-85. In addition to the fixed type discussed here, rail-mounted movable towers are used.

Coal bridges take many specialized forms but the essential feature is ability to deliver coal a short distance inshore, for further handling or stockpiling (see above).

Self-Unloading Boats. This specialized form of carrier, used mainly in lake service, carries its own unloading boom to deliver coal inshore for further handling or storage.

Most unloading methods, as we've seen, deliver fairly large slugs of coal at intervals. Track hoppers and other temporary storage piles absorb these variations in delivery rate but not all forms of conveying equipment can pick up directly from them. So we often add devices that can deliver coal at controlled rates to a point where a conveyor can pick it up conveniently for transport.

Portable Units. Two versatile forms of portable equipment can be used for this job, and for others as well. The familiar portable conveyor (sketch, next page) picks up coal at ground level and delivers it at a controlled rate to a higher point. The unloading conveyor, designed to fit under a railroad car, eliminates need for a hopper.

More often we turn to a family of devices called feeders (see illustrations, next page). These move coal short distances horizontally or at a slight upward angle but their main purpose is to control coal flow and prevent "flooding" of conveyors (or crushers often installed at unloading point). With coal coming at a uniform rate, conveyors operate at maximum efficiency. This reduces power cost and cuts down wear. Let's look at some feeder types.

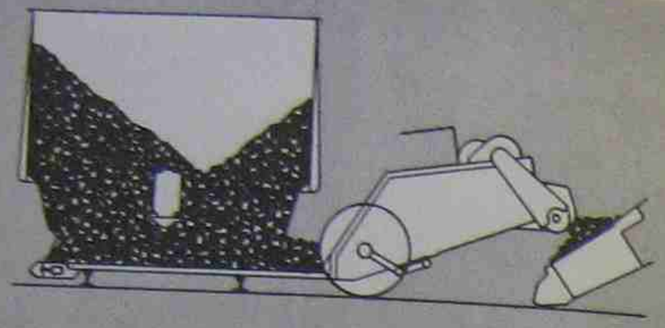
Apron Feeders. Heavy and rugged in construction, these usually have twin chains mounting overlapping pans (18-in. wide and up). They differ from the familiar flight conveyor in that the pans carry the coal rather than drag or scrape it along, but they do have the usual head and foot assembly.

Apron feeders travel at low speeds, usually less than 25-30 fpm. They commonly have fixed side plates or skirt boards to protect the chains and to permit load to be carried at considerable depth before spilling over. As a rule, apron units don't run at angles greater than 25 deg, because at greater angles coal slides backward. If apron is fitted with cleats, it can run at steeper angles.

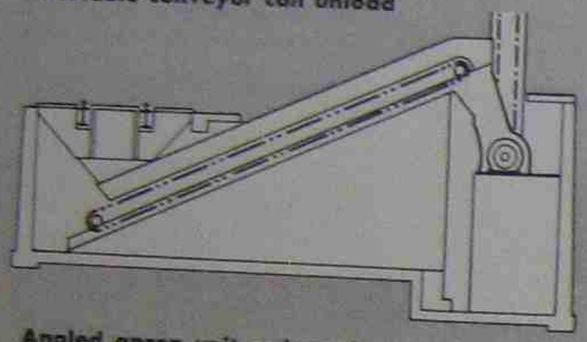
Using an apron feeder with an upward slope to control rate of flow from a track hopper has the advantage of reducing pit depth. In the case illustrated on p 81, an 18-in.



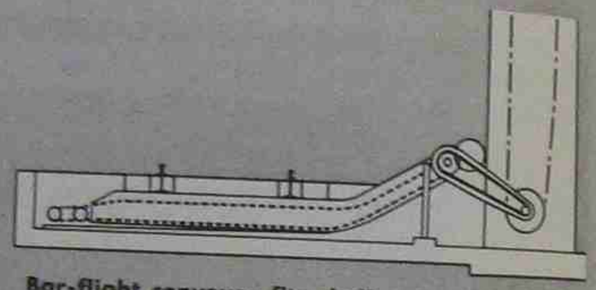
Portable conveyor can unload



Unloading conveyor acts at track level



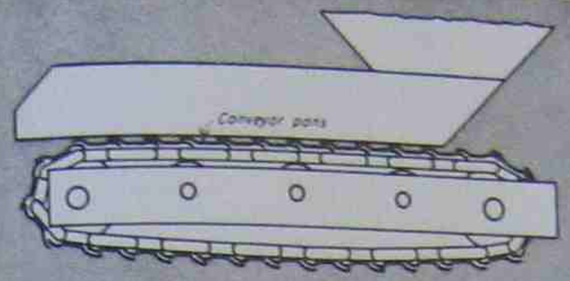
Angled apron unit reduces hopper depth



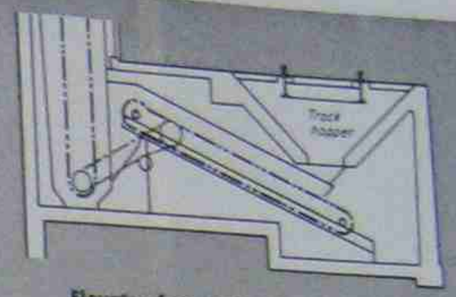
Bar-flight conveyor fits shallow track hopper

RAPID UNLOADING of coal carriers is essential on two main counts: (1) to lower handling costs, and (2) to avoid crippling pileups, with attendant demurrage charges. Equipment pictured here and on preceding spread does the job

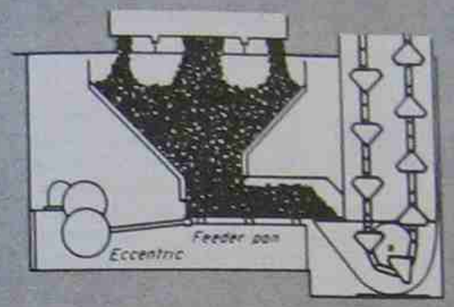
Screw conveyor can be used as a feeder



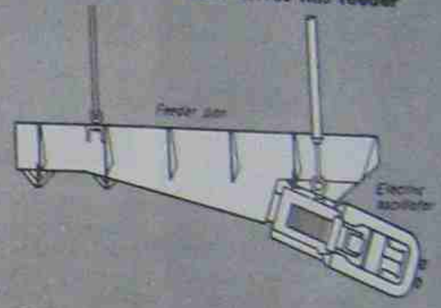
Feeders, like this apron design, control flow



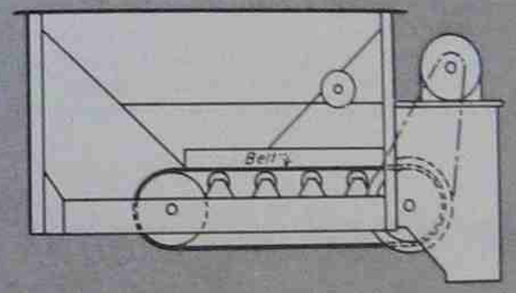
Elevator foot shaft drives this feeder



This feeder uses reciprocating motion



Vibrating feeder is electrically energized



Properly supported, belt conveyor acts as feeder

MECHANICAL FEEDERS like those illustrated here take the coal from its unloading point and deliver it at a controlled rate to the desired pickup point of conveying equipment for moving it into the plant or into reserve storage

. . . and a variety of feeders and conveyors . . .

unit running at 15 fpm can move up to 25 tph of stoker coal from a pit only 10-ft 6-in. deep. This feeder is driven from the foot shaft of the elevator used for moving coal into the plant. The other inclined apron feeder sketched delivers up to 45 tph direct to a crusher or through a bypass to an elevator. Pit depth is only 11 ft.

Bar-Flight Type. Where pit depth must be held to a minimum, the bar-flight feeder serves well. Drawing above shows one in a pit about 2 ft deep, delivering 20 tph at 20 fpm. This type of feeder is a double-strand flight conveyor with shallow flights. Bottom run carries coal and top or return run is shielded to direct flow to lower run.

With the exception of the bar-flight type, which is best suited to smaller capacities and narrow hoppers, apron feeders can have large areas, permitting large openings from track hoppers to conveyors. This, combined with agitating tendency, is considered good insurance against coal sticking.

Reciprocating Feeders. This type agitates incoming coal, working against hangups in the hopper. Of several designs, one illustrated above is common for coal feed from hopper to crusher or conveyor. It consists of a steel plate, 6 to 9 ft long and 15 to 30 in. wide, mounted on tracked wheels between guiding skirt plates. Rods connected to adjustable cranks or eccentrics drive the pan from a motor. As eccentrics revolve they push pan forward with its load of coal. Additional coal falls from hopper to back end of pan, filling space left by that carried forward. On return stroke, coal doesn't move back with pan and some falls off the end.

These feeders do a good job with lump material. Operating speeds range from 10 to 30 fpm, and plate movements, adjusted by crank throw, vary from about 6 to 8 in. Plate width and coal depth set the loading volume rate.

Vibrating Feeders. In this design, a feeding pan attaches to vibrator arms or bars. A laminated armature

. . . for controlled flow to the next handling step

connects to the vibrator bars and an electromagnet is anchored to the main frame. Energized with ac, the electromagnet causes the vibrators to: (1) deflect toward the magnet as current builds up in its coil, and (2) release when current passes through zero. This sets bars, and feeder pan, to vibrating back and forth. Frequency is 7200 vibrations per minute on 60-cycle ac. Although vibrations are so small that feeder pan doesn't appear to be moving, coal flows uphill or down in a smooth stream. Changing slope of feeder or varying vibration intensity changes feed rate.

Vibrating feeders have no parts requiring lubrication and subject to friction wear. Power demands are light. This type has been developed for a wide capacity range.

Screw Conveyors. These units serve quite well in small plants, working on small-lump coals free of tramp iron, wood, etc. They are simple, low in cost, can be built into restricted spaces and can readily be made dust-tight.

A screw conveyor usually consists of a long-pitch steel-plate helix on a spindle carried on bearings within a U-shaped trough. As spindle rotates, coal moves forward under thrust of lower part of helix and discharges through openings in the bottom or end of the trough.

Capacity suffers when helix is inclined. For steep inclines, helix may be given a short pitch and trough made tubular so capacity loss is less. Allowable loading and speed depend as much on nature of material handled as any other factor. For coal, maximum horizontal loading is taken as 38% of helix vertical cross section and speed is from 70 to 120 rpm.

Belt Conveyors. Simplicity, smooth operation and uniform discharge make belt conveyors attractive as feeders. When so used, they're short, with closely spaced idlers for support against impact of hopper-fed coal. Designed for longer runs, belt conveyors find wide use, as we'll see later, for transfer operations and for handling in the plant.



INDUSTRIAL LIFT TRUCK is sometimes used in small plants to transfer coal directly from outdoor storage to firing units



BULLDOZER mounted on a crawler tractor



SCRAPER with rubber-tired prime mover

MOBILE EQUIPMENT

Use of mobile equipment for coal stockpiling has grown enormously in the past 20 years. Reasons are: (1) suitability for building layered, compacted piles (2) adaptability to various site conditions and changes (3) relatively modest first cost (4) possibilities of using equipment for other purposes, such as snow clearing, etc. To the original crawler-tractor bulldozer has been added an array of crawler and rubber-tired equipment.

With either crawler or rubber-tired tractor, the bulldozer fits best for relatively modest production rates on shorter hauls, say up to about 300 ft. Adding wings to the dozer blade raises capacity per push. On large piles, bulldozers are used for dressing, cleanup.

Pulling rubber-tired carry-type scrapers extends the economical work range of tractors. Units of this class can pick up from 10 to 20 tons of coal and haul it well over 1000 feet at relatively low cost (POWER, Aug 1945, p 88). For larger stockpiles (say, over



TWO-ENGINE SCRAPER, rubber-tired and self-loading, fits best in large operations



HOPPER LOADING fills scrapers quicker than they can self-load, is sometimes used in larger stockpiling operations

100,000 tons with piling and reclaiming demands of more than 150 tph) there is now a 2-engine scraper (POWER, Jan 1953, pp 94-96). One engine powers scraper wheels, and the other the tractor-drive wheels.

Selecting mobile equipment thus depends on an economic comparison of the various types in relation to the distances involved and the hourly production rates required. The operation is always much the same. For moving coal out to storage the starting point is a "cushion" pile from which bulldozer or scraper can take its load. (Scrapers are also loaded from overhead hoppers for quicker filling.) The cushion is formed in any one of a variety of ways by the conveying equipment working out of the unloading point.

Coal is spread on the pile in thin layers and the normal traffic of mobile units usually proves adequate for compacting. If not, additional trips can be made just for compacting. In some cases, weighted rollers have been used, but this seems unnecessary. In reclaiming operations, the bulldozer or scraper usually unloads to a hopper or pit feeding conveying equipment.

For the outdoor stockpile: fixed and mobile . . .

Coal storage may be divided into two types according to purpose: *live*, or *active*, storage from which firing equipment feeds directly, and *dead* or *reserve* storage to guard against delays in shipments, etc. Usually, live storage is under cover and reserve storage is outdoors. But in some plants, one storage, covered or outdoor, does both jobs.

So on this pair of pages, and the next, let's look first at outdoor storage, keeping in mind that while it's usually reserve storage it may be live storage as well. That's true in many smaller plants, which may have outdoor storage under a rail-siding trestle or in some corner of the plant yard where trucks dump deliveries. In such cases, and others, industrial lift trucks with scoops (photo above) or specialized motor loaders are used to bring coal from the pile directly into ground-floor boiler rooms.

Stockpiling Equipment. When it comes to outdoor stockpiling, a tremendous variety of means is available. But they break down into two broad classes: fixed and mobile. Perhaps most widely used of the fixed group are drag scrapers. As sketched and discussed at the right, drag scrapers can be adapted to a wide variety of site conditions.

Locomotive cranes, and other types, fitted with clamshell buckets, are used for stockpiling. These can pile and reclaim only a limited distance either side of the track, but track can be looped or paralleled to fit many ground plans. For large operations, gantry or bridge cranes are used, spanning the distance between paralleled sets of tracks and carrying one or more trolleys with clamshell buckets. Such equipment often handles unloading from barges and ships, or railroad cars, as well as stacking for storage.

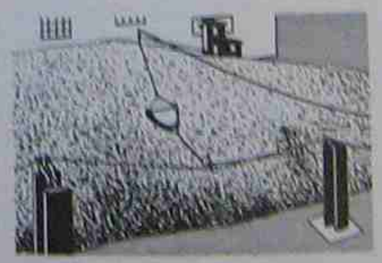
In recent years, use of mobile equipment has grown rapidly. In this group we have what are primarily earth-moving machines — tractors, bulldozers, scrapers, etc — adapted to handling coal. All they need is an initial pile to work from and a point to reclaim to, both of which are normally provided by the equipment for unloading coal and moving it directly into the plant. Thus mobile methods call for no fixed structures and give a high degree of flexibility in utilizing available ground space.

Type of equipment selected for any given installation will depend on a great many factors, an important one being first cost. The fact that coal-handling equipment is frequently used just one shift per day makes it desirable to keep investment down. But experience shows it pays to mechanize to keep down labor costs, so the trick is to secure the best balance between first costs and operating costs.

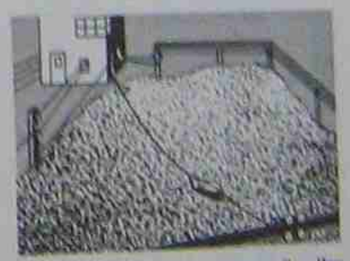
Storage Procedure. Where outdoor storage serves as a reserve, normal practice is to take part of incoming shipments directly into storage within the plant and divert a portion to the outdoor pile. As needed, reclaimed coal is routed into the plant. How much transfer between outdoor and indoor storage there is, and how often stockpile coal is reclaimed depends on the nature of the coal and its storing qualities, size of pile in relation to plant use, etc.

Regardless of equipment used, economical and safe storage calls for know-how. See next spread for the methods.

. . . equipment meets varying site needs, but . . .



DRAG SCRAPER on back post and bridle



MONORAIL and trolley moves tail pulley

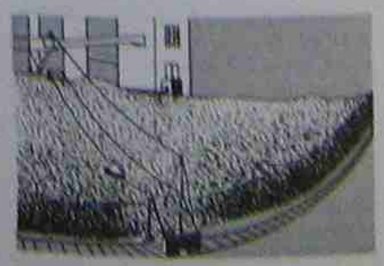
DRAG-SCRAPER LAYOUTS

Simplest drag scraper has fixed back posts. Cable from scraper drive, near head post, passes over one head block, out to scraper bucket, then to tail block and back to second head block and drive. To build pile, bucket works out from initial pile near head post; to reclaim, the bucket is reversed.

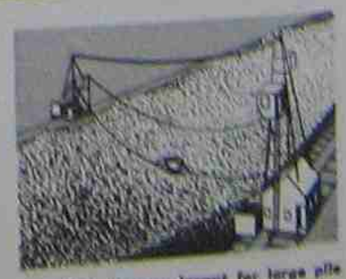
Back post height depends on storage depth and distance hauled. As a general rule, back posts run 8 ft tall for 15- to 20-ft storage depth. In this layout, tail block is shifted by hand.

For larger piles and longer hauls, tail blocks are heavier and easier shifting becomes important. One scheme uses a monorail and trolley, with fixed back posts. But in most larger installations, some form of mobile tower is used, often on a radial track. Towers have outriggers and rail clamps, may be shifted manually or may be motorized.

Fully mobile towers have propulsion motors and brakes controlled from operator's cab; two may be used in parallel layout as sketched. For drag-scraper details, see POWER, May 1946, pp 68-69, and July 1946, pp 74-75.



RADIAL SETUP: back post moves on track



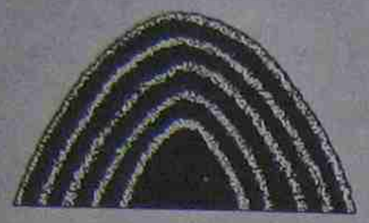
PARALLEL 2-tower layout for large pile

STORAGE LOSS IS SMALL

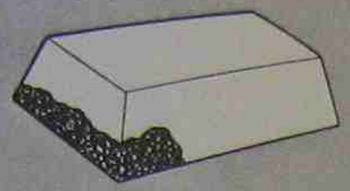
Most coals may be stored for long periods without serious loss of "quality." Tests show loss of heating value doesn't usually exceed 1% the first year, except for low-rank coals, which may lose up to 3% in first year.

Weathering tends to make most coals "slack," that is, causes a reduction in size or crumbling. Slacking is greatest for low-rank coals and near storage-pile surfaces. There is also some possibility of loss of "caking" and ignition qualities. These effects are usually negligible.

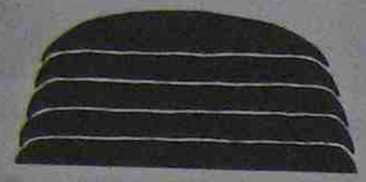
So, when it comes to outdoor storage, even for long periods, your primary concern is to guard against heating and "fires," (see below).



LOOSE DUMPING makes air flow easy



PREFERRED PILE is oblong, layer built



COMPACTED LAYERS reduce air flow

GOOD STORAGE PILING reduces air flow to minimum to avoid spontaneous combustion, excessive weathering loss. Best way to build pile is in layers 2-ft thick, or less, and to compact each layer before adding the next. This avoids stratified pile, which offers easy passage for air

...safe storage depends on proper piling methods

Today, more plants than ever find it smart to stockpile coal outdoors. It's always been necessary for some — plants along waterways subject to freezups, for example. But supply and transportation dislocations during war years and strikes have led many others to follow the practice. Even aside from the emergency reserve angle, there's often sound economic sense in being able to buy coal during "off" seasons.

Safe Storage. Whether your storage is large or small, you want protection against loss by weathering and by spontaneous combustion. And if methods now well-known are used, outdoor storage, even in large amounts and for long periods, can be practical and safe.

All coals tend to combine with the oxygen of the air. Frequently this is an extremely slow process, often called weathering. There's some loss of heating value and change in firing characteristics. But if conditions are right, the action can move faster and we have heating or spontaneous combustion. Knowing what causes this is the key to avoiding storage-pile fires.

Coal-Pile Heating. When coal combines with oxygen, heat is given off. If heat isn't carried away, temperature rises. As it does, the reaction with oxygen, like all chemical reactions, speeds up. So we have a vicious circle — heat, temperature rise, faster reaction, more heat, higher temperature, still faster reaction, etc, until the coal actually burns in the normal sense.

There are two basic ways of combating this action. We can make sure that air moves through the pile fast enough, and uniformly enough, to carry away heat without appreciable temperature rise. Or we can try to cut air flow through the pile to a minimum to reduce possibilities of reaction.

Storing Sized Coal. What might be called the free-air-flow method is the simplest but is limited in application. Only with sized coal, which leaves more or less uniform air passages in the pile, can we depend on this scheme. In smaller plants, particularly the few remaining hand-fired ones, this works well. But larger plants rarely buy double-screened coals, and if fines are present it's necessary to use methods that cut air flow to a minimum. Let's see why this is so.

Avoiding Segregation. If fines are present as well as coarse lumps, we run into the problem of *segregation*. This affects other parts of the handling and firing system but right now we're concerned with its effects on storage. If, in the ordinary way, we dump coal on a pile, the fines tend to stay in the center and the coarse lumps roll to the outside. Such segregation in a coal pile gives areas or lanes where air flows readily and others where it hardly flows at all. Somewhere in such a pile, we're sure to get just the right combination of air flow and heating to produce spontaneous combustion. So the first step is to avoid segregation.

Best defense against segregation is layer piling. To build a layered pile, spread the coal thin over the storage area. Where coal is dumped from buckets, redistribution may be necessary. With equipment like drag scrapers, bulldozers, rubber-tired scrapers, layer piling is merely a matter of proper procedure. Even trucks can be used to build a layered pile (POWER, Nov 1942, p 68). Regardless of equipment, the important thing is to build the pile in successive layers and to keep them thin — less than 2 ft, with 6 to 12 in. being best practice.

Compacting. Such piling tends to mix coal, eliminate segregation. But for troublefree storage, we'd like to pack the coal tightly to cut air flow through the pile to a minimum. Loose coal, for example, has a density of about 50 lb per cu ft. In ordinary storage piles, density builds up to some 58 lb per cu ft at the bottom of a 20-ft-deep pile. By *compacting*, we can raise density to 65 or 70 lb per cu ft.

Compacting goes naturally with layer piling. Each layer can be tamped or rolled to pack it down. Usually, weight of equipment used to spread coal proves adequate. Bulldozers and scrapers, for example, do an excellent job of compacting.

A word about coal sizing is worthwhile here. Don't compact sized coals without fines. Double-screened coals should be stockpiled separately, by the free-air-flow method. Where coal is received run-of-mine, crushing before storage is the usual practice.

Properly piled and compacted, coal stands with hard vertical walls when excavated. The pile itself is firm and hard and water runs off slopes. Yet the slopes are the weakest zone. Segregation is apt to be present in side slopes and wind can force air into sides.

Sealing the Pile. Slopes can be safeguarded in several ways. Where mobile equipment is used for piling, bulldozers should be run up and down side slopes as the pile is formed. This compacts slopes but means a relatively shallow angle, which is a disadvantage if area is limited. You can, of course, surround pile with embankments or store coal in a basin with protected sides. But this raises problems in reclaiming stored coal.

Sealing the exterior surfaces of the pile is probably the best all-round answer. Asphalt and other coating materials are used, but general practice today is to seal with a layer of fine coal, 6 in. or so thick. A carefully placed layer of coarse coal anchors the fines against wind erosion.

If Pile Overheats. A properly built and sealed pile should give no trouble, but you shouldn't just forget it. Probe the pile regularly to check temperature. If it gets up toward 160 F anywhere, you've got a bad spot. Don't try to put out the fire with water. It can stop heating only if it reaches just the right spot and is apt to cause problems of its own. Extra compacting in the heating area may cut air flow enough to throttle the reaction. But best plan in most cases is to remove affected coal without disturbing the remainder. Spreading the heated coal will usually put out the fire. Normally, it's better to use coal you salvage from an overheated area rather than try to repile it.

Some users have been successful in putting out coal-pile fires with CO_2. A pipe fitted with a well-drilling point is driven into the pile and CO_2 allowed to bleed into the affected area. If driller's points aren't available, end of pipe can be crushed and holes drilled in it. Similar methods have been used in fighting bunker fires and some bunkers have been fitted with piping and deflector plates for CO_2.

Coal Selection. Four substances seem to contribute most to the reactions involved in weathering, heating and spontaneous combustion — iron pyrites, water, oxygen and certain of the hydrocarbons. Theory says iron pyrites, water and oxygen combine to form iron sulfate and sulfuric acid in an endothermic reaction. This triggers carbon and hydrocarbon reactions with oxygen. Normally all that happens is weathering but, as we've seen, if air in the right amount feeds this reaction, and heat speeds it, we have trouble.

Today's cleaning and washing equipment at the mines removes a portion of the iron pyrites (what often constitutes the coal's sulfur content) and some seams run low in sulfur anyway. From the storage angle, this points to selecting a coal comparatively low in iron sulfides or iron pyrites. Yet it usually isn't practical to select coal from the storage viewpoint, and more often the problem is to store the coal we have or normally receive. So, in the last analysis, proper storage methods are the answer when you must stockpile coal for long periods outdoors.

WHEN YOU START TO BUILD AN OUTDOOR STORAGE PILE:

DO

Select a well-drained area for coal storage, free of standing water. Best site is raised, not subject to flooding from nearby streams or runoff from adjacent ground

If well-drained area isn't available, install drainage ditches, running length of site along the sides

Make certain ground is solid, not loose and porous and not cinder fill. If possible, grade to uniform level. Sometimes storage areas are top-dressed or hard-surfaced with paving materials

Build up pile in successive layers, not more than 2-ft thick and preferably less. Wherever possible, compact each layer

Dress pile by sloping tops of successive layers and top of completed pile toward sides, to prevent rain or melting snow and ice accumulating and penetrating into the pile

Make periodic temperature checks of the pile, particularly at edges and side slopes. Remember, 160 F is critical temperature

Seal pile as far as possible. A 6-in. layer of fines, anchored against wind erosion by a carefully placed coarse layer, is good

DON'T

Never leave refuse, wood, straw, growing vegetation or any other organic material standing in an area you select for coal storage

Don't pile coal around steel or wooden posts, crane supports, etc. Pile density is bound to be lower around these elements than in the pile proper, providing vents for air and gas movement

Never attempt to ventilate a pile with pipes or wooden ducts for the same reasons you avoid piling coal around uprights (above)

Don't store coal near steam pipes, smoke stacks, boiler blowoff lines, heated elements of any kind

Don't just dump coal on pile. Dropped coal segregates, forming natural flues for air movement through pile

Compact unsized coal only. Sized coal stores well but not by compacting method. If you store sized and unsized, keep separate

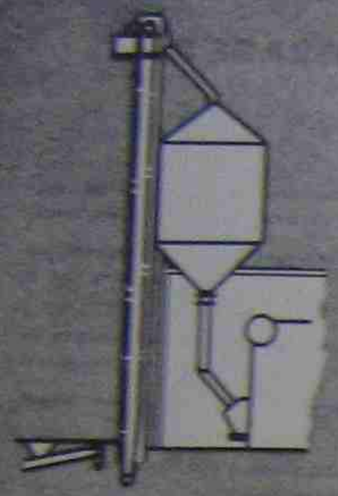
Where you can't compact, and coal isn't sized, avoid conical piles by dumping in small continuously overlapping piles

Don't make pile sides too steep. Keep below 45 deg, with 30 deg a good slope to aim at. Steeply sloping sides risk segregation

If you locate a hot spot, or have a fire:

(1) cut away or isolate heated coal (2) recompact pile, starting at edges and working inward (3) if pile is small and area permits, move coal and respread it (4) try feeding CO_2 into pile, using pipe fitted with well-drilling points or with holes in flattened end

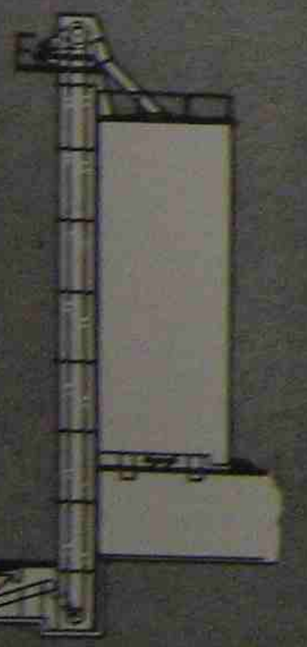
In cutting away heated coal, don't disturb remaining coal. Don't apply water to heated area. The fire may appear to be quenched after soaking, but you set up conditions likely to produce a recurrence of the heating within a very few days



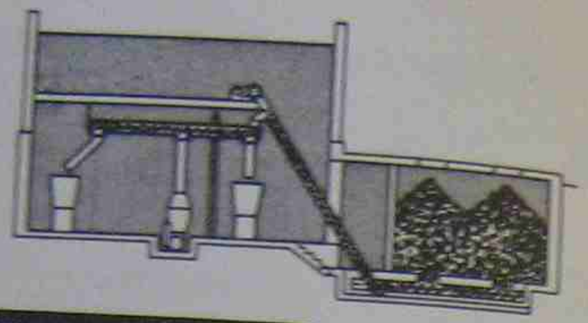
Cylindrical steel tank



Silos: live and dead storage

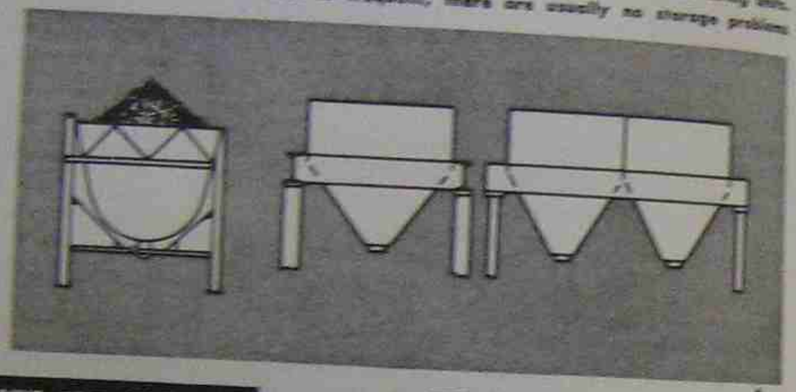


Silos: single storage space



TYPICAL BIN ARRANGEMENT

Small plants, particularly in city locations, often use basement bins into which trucks dump directly. Simple conveying system moves coal from bin to firing units. If coal is sized, or turnover is frequent, there are usually no storage problems



TANKS AND SILOS

Outside-the-plant storage structures include cylindrical steel tanks, silos. Silos may have live and dead storage, center, or single storage space, below

HORIZONTAL BUNKERS

Horizontal overhead bunkers often are of suspended construction, left above. Multiple hopper-bottom design, right, eliminates dead spaces between outlets

For storing coal under cover...

Day-to-day supply for firing units nearly always comes from covered storage—bins, silos, bunkers. Sometimes these units provide the only storage so there is no separate reserve. Or, as in many silos, live and dead storage are included in same structure, but physically separate.

Capacity required often dictates type of storage unit. For small plants, the simple bin may serve. Larger capacity needs point to use of tanks, silos and bunkers designed to save ground space and give more convenient flow to firing units. Outside-the-plant structures include cylindrical tanks and silos. Steel tanks, like the one pictured above, left, serve for storage up to about 100 tons where roof location is attractive. Silos, usually sized to hold a week's supply, are rarely used for less than 100 tons.

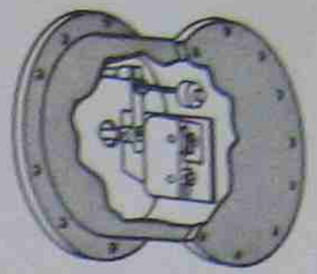
Silos. Often attractive costwise, silos are built of concrete (poured, block or stave construction) and of hollow tile. Usual practice puts a live-storage compartment above, for gravity flow to firing units, and a reserve section below. When live storage is full, coal spills over to reserve, which discharges to pickup point of elevator or conveyor. Thus coal can be fed to live storage directly from unloading point, or from reserve section. With relatively modest live-storage capacity (say, one day's supply) operator can recirculate often from reserve. Live-storage compartment is usually formed by a sloping shelf (about 50 deg). Some silos, however, have a cone-bottom steel hopper for live storage, diameter being about 2 ft less than silo's.

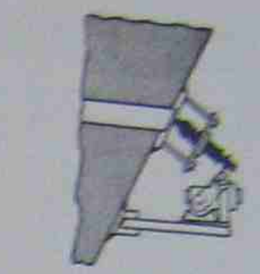
Alternative construction for silos has no separation of live and dead



LEVEL ALARMS AND SWITCHES

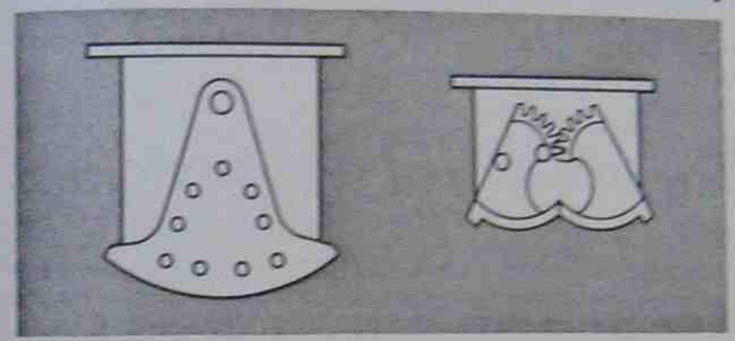
When coal reaches predetermined level in storage, units, above, sound an alarm or start and stop feed. Each contains a switch, actuated in the unit at left by the pendulum-like device and in the unit at right by a diaphragm on far side of casing





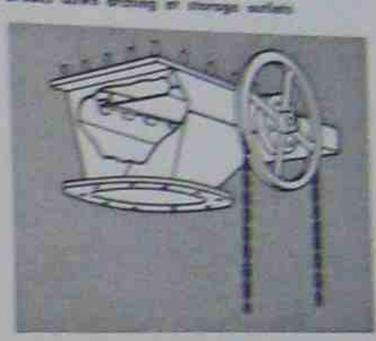
VIBRATORS

Agitation by vibrators, above, or air jets, poking, etc, keeps coal on move, breaks down arching at storage outlets



SWING-TYPE COAL GATES

Discharge outlets of storage units are fitted with gates to control flow of coal. These must open quickly and positively. Gates shown above are of the swing type, the unit on the left being a simplex design and that on the right being a duplex. Such gates are usually made of cast iron to resist abrasive action of moving coal



SLIDING GATE

Sliding design requires little headroom. Protected double rack and pinions drive the gate, which moves on roller bearings in side pockets every time flow of coal

...bins, silos and bunkers prove their versatility

storage, and a flat bottom. Unit illustrated, left, has bottom above level of firing-unit hoppers and feeds them by a monorail system.

Suspended Bunkers. Overhead storage units of generally horizontal layout have been built of concrete, masonry and cast iron, but today's common construction is steel plate, often of the suspended design.

In its familiar form, the suspension bunker consists of plates (¼ to ⅜ in.) hung in a catenary between parallel side girders. Plates are in tension only. To protect against corrosive action of coal, steel bunkers are often lined with concrete or other protective coatings. Another suspended construction has steel straps on about 3-ft centers, acting as bearing members for light-gage preformed steel sheets. These are lined with concrete applied by gunning.

Discharge Efficiency. Horizontal bunkers of suspension and other types have discharge outlets and gates at intervals along the length. Gates, as illustrated above, may be of either swinging or sliding design. Discharge efficiency suffers because of dead spaces between outlets, and trimming these dead spaces can be difficult. One answer is to increase the number of outlets where practical. Another solution uses multiple hopper-bottom construction to eliminate dead spaces.

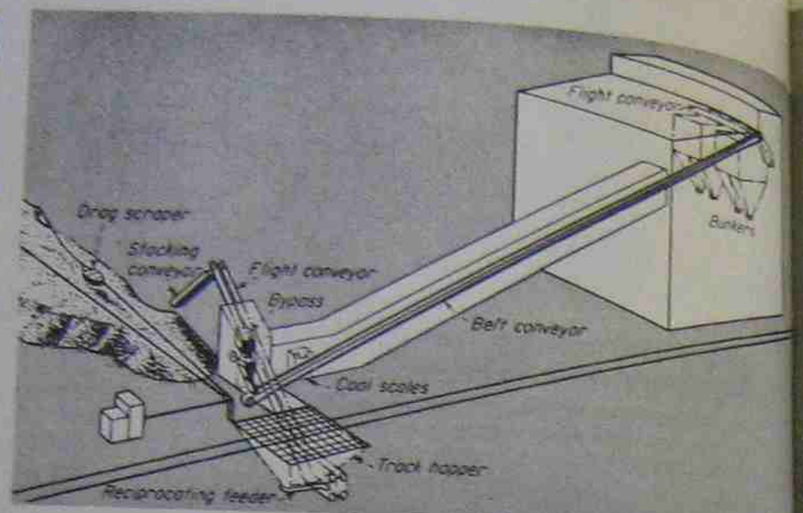
Moisture and compacting can raise coal's angle of repose from about 45 deg to 60 or 70 deg. This may lead to flow problems at storage outlets. Coal immediately above opening drops freely but the remainder arches over and hangs up, stopping flow.

How to Prevent Arching. If a good space above opening can be kept free of coal, say 3 ft or more, arch span becomes too great, and flow usually can be maintained. Poke holes, looped chains reaching down to openings, and the modern vibrator all aim at keeping arches from forming. Another approach is to make slopes to outlets steeper. For existing bunkers, this effect can be achieved in some cases by putting a vertical plate above opening's centerline. In new bunkers this is a matter of design—some recommend bunkers with three vertical sides and one sloped.

Crushers. In these pages we've mentioned the common practice of crushing coal before putting it into storage. Limited space makes it necessary to confine this discussion to handling and storing equipment. For a comprehensive roundup on crushers, see Power, July 1951, pp 73-75; Aug, pp 84-85.

WHAT'S THE JOB?

Diagram of an industrial coal-handling system, right, ties together the functions and equipment we've talked about so far and those still to be covered. Unloading setup is a track hopper with reciprocating feeder. As is common practice, handling system can move coal directly into the plant or can form a cushion pile from which stockpiling equipment works. In the plant there's a horizontal conveyor to distribute coal to the several bunkers. Not shown are chutes and weighing equipment for feeding coal from indoor storage to firing units. Provision is made for a scale.



Next step: Moving coal to and within plant

Thus far, we've taken a look at methods of unloading coal and storing it. Now let's talk about moving coal between the unloading point, storage, and the firing equipment. This may be extremely simple, as in a plant where delivery trucks dump coal in yard storage and a lift truck with a scoop (p 82) takes it directly to stoker hoppers.

Transfer Operation. Handling in most cases is more complicated because we often have both reserve and live storage. Then as a first step (what we called *transfer* in the chart, p 76) we want a conveying system to route coal into either of the storages, or between them. And we have further handling from live storage to firing units (called *in-plant handling* on the chart).

On this spread and the next, we see the conveying machinery that plays a big part in the transfer operation. Then, in following spreads, we consider the chutes, larries, scales, etc, prominent in handling from final storage to boilers. But bear in mind that there's no hard and fast line between — chutes, for example, are used in the transfer stage, and conveyors sometimes deliver coal from bunkers to boilers.

In transfer operations we usually have to lift coal as well as move it. Most conveying equipment will do both, but some designs serve best for vertical or nearly vertical lifts and others for horizontal runs or slight inclines.

Skip Hoists. In its simplest form, the skip hoist consists of a track-guided bucket raised and lowered by a cable from a hoisting machine. Loading takes place at lower end of run, discharge at top. The skip hoist is a tough, durable performer, with few moving parts, suitable for high lifts.

There are three basic forms — uncounterweighted, counterweighted, and balanced. The first, and simplest, sends the bucket up fully loaded and, after dumping, lets it return by gravity. This means braking is needed.

In the counterweighted design, a second cable, wound in reverse direction on the drum, carries a counterweight equal to weight of bucket plus half its load. In either direction, motor load is thus half useful load.

Balanced skip hoists have two buckets operating from one drum and running in opposite directions. This is said to almost double capacity at cost of a similar increase in motor hp but not in hoisting-machine size.

Skip hoists are normally used for essentially vertical lifts but units have been built to run horizontally, distributing coal across bunkers after lifting from ground level.

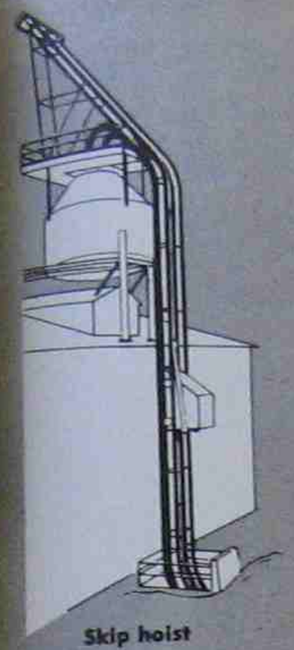
Applying Skip Hoists. Relatively large track hoppers are needed where automatic loaders are used. A 40-cu-ft bucket, for example, would take a hopper 14 x 18 ft and 19 ft deep. This would go to 21 ft for a balanced skip hoist working out of a 14 x 30-ft hopper. Hopper storage capacity is usually at least 20% of skip's rated hourly capacity.

Bucket Elevators. Used extensively for vertical lifts, some types of bucket elevators serve well for horizontal runs also. They consist essentially of relatively small buckets closely spaced on an endless chain, but differ in details of design. Four major types are: centrifugal-, perfect-, and gravity-discharge, and continuous-bucket.

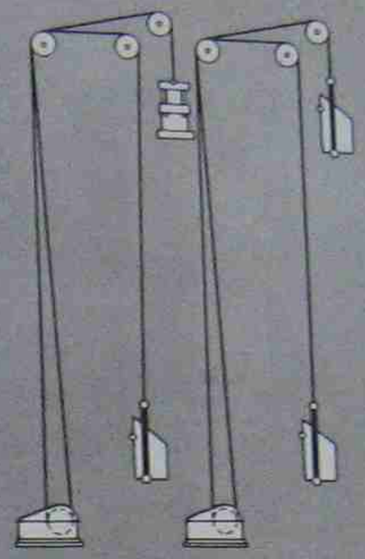
Centrifugal-discharge design has malleable-iron or steel-plate buckets bolted at regularly spaced intervals along a single chain. Incoming coal flows along floor of boot (drawing on facing page) and some of it is scooped up as buckets round the foot wheel, while still more lands directly in the buckets as they enter the loading zone. As buckets pass over the head wheel, centrifugal force unloads them. Design calls for relatively high speed and a close balance between speed, head-wheel diameter, and head-chute position, to keep coal from falling within housing.

Perfect-discharge elevators have the buckets between two strands of chain and use snubbing sprockets under the headwheel to bring buckets into right position above discharge chute. This permits lower speeds yet gives positive unloading. To raise capacity when handling wet coal, buckets are spaced closer or made larger than in centrifugal-discharge designs. Gravity-discharge elevators employ a double strand with spaced V-section buckets. With this design, a vertical lift may be followed by a short horizontal run.

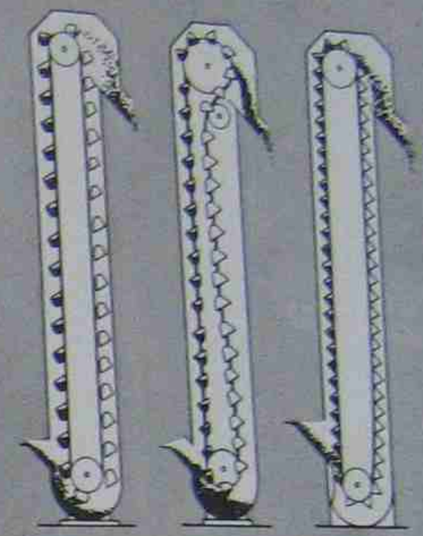
Continuous-bucket elevators deliver good capacity at about 60% of the top speed of the spaced-bucket types (150 rpm) and can handle larger lumps. Buckets are shaped so that as they pass over the head wheel, the discharging bucket can use the flanged back of the preceding one as a chute to deliver coal to the discharge hopper. But this design can do no digging and needs a loading leg, hence



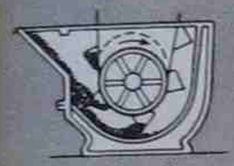
Skip hoist



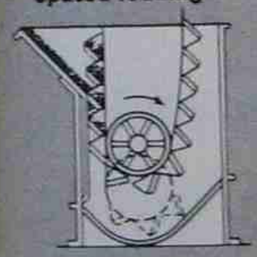
Counterweighting and balancing



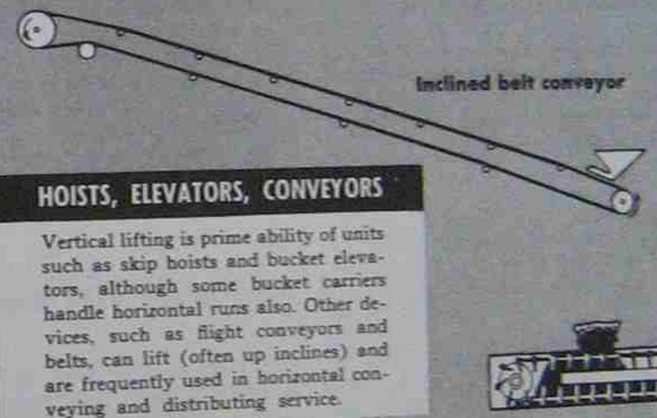
Bucket elevator discharge types: Centrifugal Perfect Continuous



Spaced loading



Continuous loading



Inclined belt conveyor

Redler-type flight conveyor

HOISTS, ELEVATORS, CONVEYORS

Vertical lifting is prime ability of units such as skip hoists and bucket elevators, although some bucket carriers handle horizontal runs also. Other devices, such as flight conveyors and belts, can lift (often up inclines) and are frequently used in horizontal conveying and distributing service.

needs greater headroom and a deeper boot. Boot should have cleanout doors for removing any coal dropped.

For large-capacity handling of run-of-mine coals, the supercapacity continuous bucket feeds at inclines of 35 to 70 deg. It usually works at low speeds, under 150 rpm, to reduce impact and wear under heavy loads.

Horizontal Runs. As illustrated on the next spread, certain types of bucket elevators — gravity-discharge and pivoted-bucket — can serve as horizontal distributing carriers as well as vertical lifters. We've already mentioned the gravity-discharge type and noted it can handle short horizontal runs after the vertical lift. On the horizontal run, buckets act as pushers, propelling coal forward in a steel trough. Gates at bottom of trough permit discharging coal.

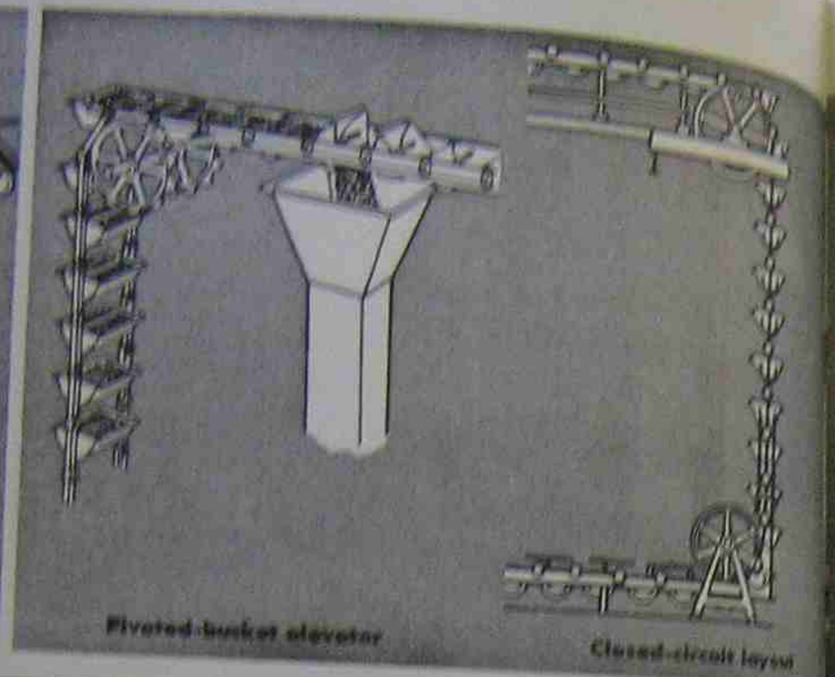
Pivoted-bucket or Peck carrier can be arranged in a complete run-around path. This feature found considerable favor when used to distribute coal to bunkers of boiler hoppers on the top horizontal run and to remove ash on the bottom run. The ash-removal angle must now compete with modern hydraulic and pneumatic methods.

In the Peck carrier, buckets hang from cross rods between two endless strands of roller chain. Chain and buckets are so arranged that buckets overlap automatically on horizontal runs. Buckets always stay upright because center of gravity, empty or filled, is below pivot line. Dumper, or tripper, may be stationary or movable.

Some units lift vertically or on an incline . . .

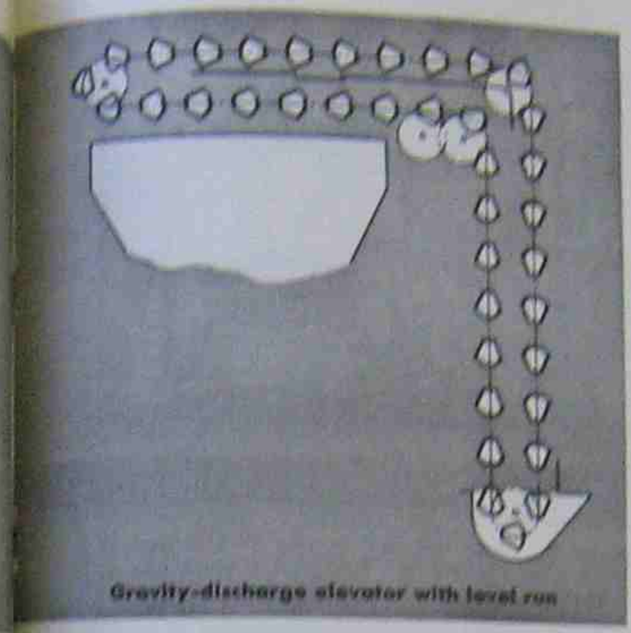


Monorail and hopper

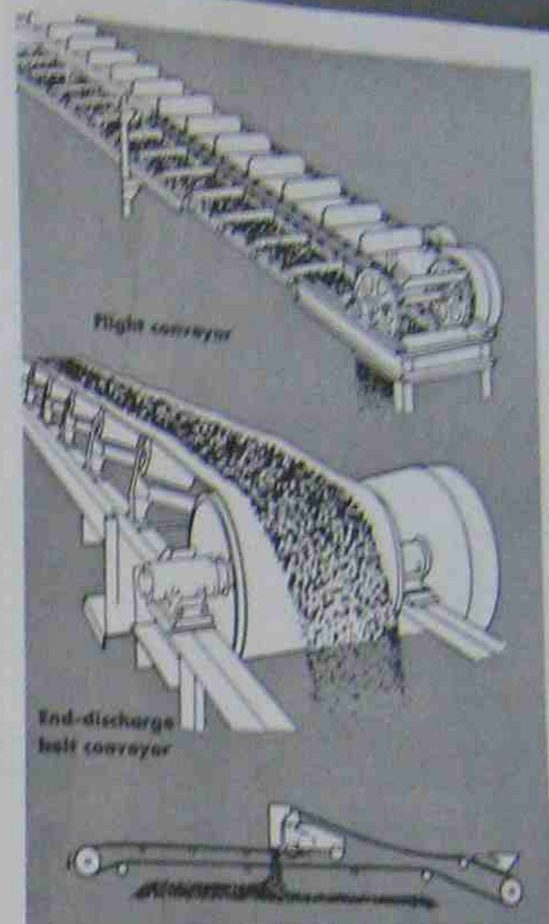


Pivoted-bucket elevator

Closed-circuit layout



Gravity-discharge elevator with level run



Flight conveyor

End-discharge belt conveyor

Movable tripper

Shuttle conveyor

Magnetic pulley for belt conveyor

MONORAILS, BUCKET CARRIERS, BELTS

Some idea of the wide variety of conveying equipment can be gained by looking at designs illustrated here, plus those on the preceding page. Here we have, *left*, the monorail carrier, used in smaller plants for essentially horizontal distribution, from bin to stoker hoppers, for example.

The pivoted-bucket or Peck carrier, *above*, serves equally well for vertical and horizontal runs. It was once extensively used in a closed-circuit arrangement, distributing coal to bunkers or hoppers along the top run and handling ash removal on the bottom run. Gravity-discharge bucket elevators, *right, above*, can handle short horizontal runs after the vertical lift.

Two popular units in today's plants are the flight and belt conveyor, *right*. Drawings illustrate basic flight and belt construction and the trippers and shuttle conveyors used with belts for horizontal distribution.

It is common practice to equip belt conveyors with magnetic pulleys to separate tramp iron from coal before delivery. In addition to the electromagnetic designs, permanent magnets have come into use. Magnetic separators are sometimes used at other points in the handling system.

. . . others serve best on horizontal runs, and . . .

Flight conveyors, like elevators, use endless chains but have spaced scrapers or flights to push or drag coal along a trough. In simplest form, they can be several hundred feet long, travel up inclines of as much as 25 deg without backward cascading of coal. Above about 40 to 45 deg, capacity loss becomes too great. A typical 2-chain conveyor of this type handles 250 tph at 100 fpm. Discharge may be at end or at intermediate points through gates in the trough. On horizontal runs, flight conveyors require little headroom.

Continuous-flow or Redler design employs a duct within which closely spaced skeleton flights act as the conveying element. The conveyor feeds itself at any point with a uniform load that fills the duct and entirely surrounds the conveying element. When the flights move they cause the material to flow upward or forward with them in a solid column. Coal can be discharged at any opening where it can fall away from the flights.

The Redler type requires no deep loading pit, only enough room for gravity feed. Skeleton flights are detachable from the central chain. Connecting joints are flexible, to permit moving around corners. There is normally no metal-to-metal contact in the carrying run since coal completely surrounds the flights. Casings are dust-tight and connections can be made dust-tight also. This design serves equally well for horizontal, vertical or inclined runs.

Belt Conveyors. Relative simplicity, few moving parts, minimum friction and hence low power needs, make belt conveyors a popular choice. In comparing belts with other conveyors, however, supporting bridge, sheathing, walkways etc, must be reckoned in the cost.

With belts, as with bucket elevators, only relative motion between coal and conveyor occurs at loading and discharge. But this holds true for belts only up to an incline of roughly 15 to 20 deg. By varying belt width and speed a wide range of capacity needs can be met. Belt conveyors in horizontal runs need little headroom except for trippers.

Simple construction of the belt conveyor involves carrier or troughing idlers and return idlers. Carrying idlers are almost always of the 3-pulley type. Spacing and diameter of idlers is important: too much space leads to belt sag and shock as it meets each roll. If idlers are too small, belt bend is sharp. Either reduces belt life.

Most belt wear, though, develops at the loading point. So every effort goes into reducing shock there. Oncoming coal is accelerated in direction of belt movement to lower relative motion between coal and belt. Coal should never land directly over a solid pulley; hammer-anvil action wears belt. Hence loading chute should deliver between idlers preferably, but far enough ahead of tail pulley to put in at least one belt-steadying carrier pulley.

Weather, cuts, gouges prove worst enemies of belts. Fabric exposed to weather absorbs moisture if protective cover is gone. In warm weather mildew and rot may set in; in cold weather ice crystals may gnaw from within as belt flexes.

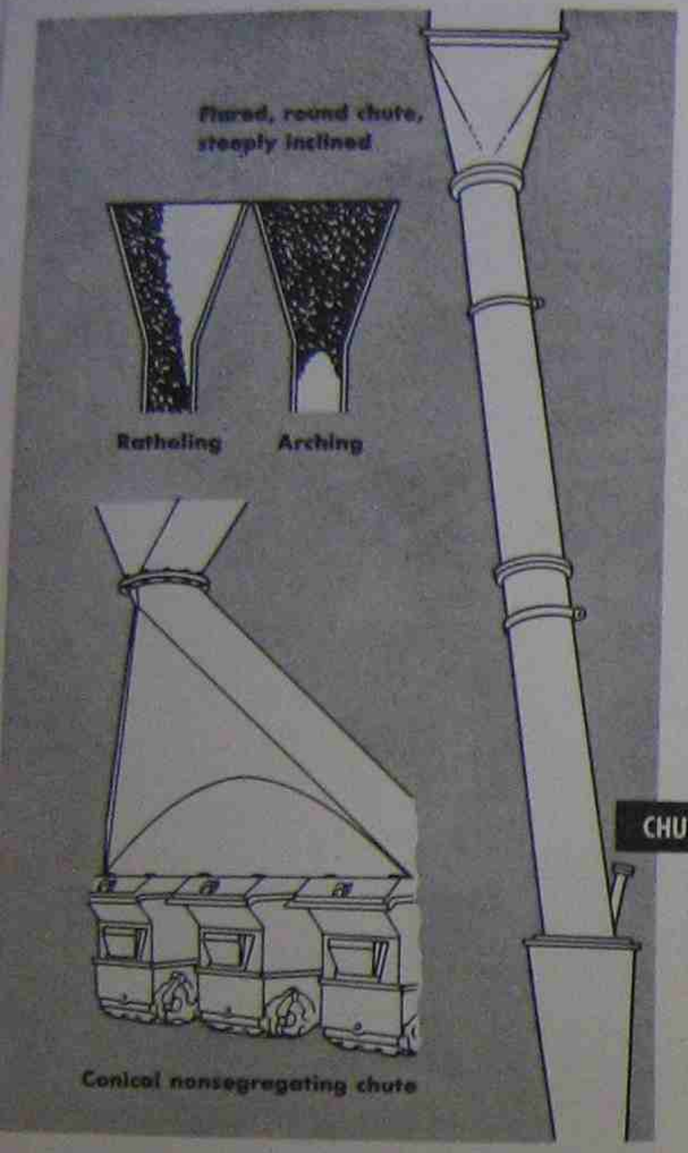
. . . many do both jobs

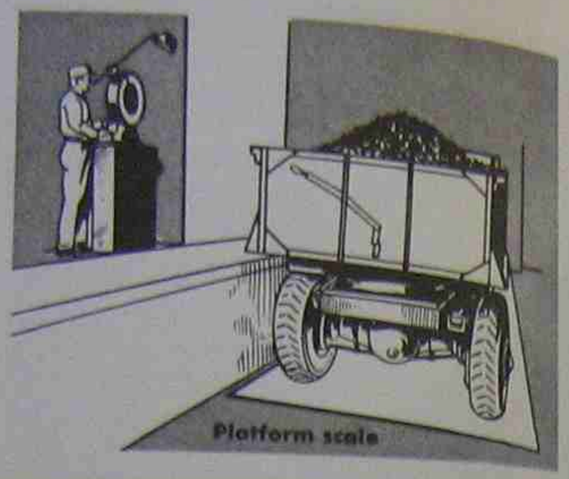
Simplest discharge setup is from the end. When distribution along belt length is needed, as over a long bunker, trippers are used. These may be fixed or movable. In the movable type, snub pulleys that bend back the belt for discharge at the tripper are mounted on a hand- or motor-propelled frame riding on a runway. When it is necessary to pile coal either side of a conveyor, a high tripper discharging to a transverse reversible belt can be used. Such heavy trippers are almost always motor-propelled.

Another distribution scheme uses the shuttle conveyor. It consists of a reversible belt mounted on a frame for longitudinal travel; the frame is hand- or motor-propelled. Coal can be discharged from either end. A shuttle with about 75-ft centers will cover up to 160 ft from a loading conveyor midway in its length. Short shuttles suffer from frequent impacts per unit of belt length.

Screw Conveyors. In smaller plants, screw conveyors, mentioned before as feeders, often serve. Inclined units lift coal to storage bins and frequently directly to stoker hoppers. Horizontal screw conveyors are often used as bin-to-stoker feeders. Simplicity, dust-tightness and compactness make the screw type attractive.

Monorail systems are also used in smaller plants for horizontal movement—often from bunker to individual firing units. Hand-operated systems have tip-over buckets on chain hoists. Carriers may be motor-propelled, with electric hoists and side-dump buckets. Scales may be built in.





COAL IS WEIGHED AS RECEIVED, DURING . . .

With fuel a major cost item, keeping track of quantity and quality is important. Total coal received may be weighed at unloading point or somewhere in the handling system, or coal going to individual boilers may be weighed at final handling step. It often pays to do both.

CHUTE DESIGN FOR GOOD FLOW

Ratholing and arching can be particularly troublesome at the final handling step—but proper design of bunkers, chutes and hoppers can lick them. Chutes, like the one at left, should be steeply inclined, preferably round or oval, and should flare in direction of flow (chute shown is 18-in. diameter at top and 22-in. at bottom). There should be no projections into the flow system, and it is desirable to use corrosion- and abrasion-resistant materials to keep the coefficient of friction a minimum.

To avoid segregation in firing-equipment hoppers, the special conical-design chute, *left*, is often employed.

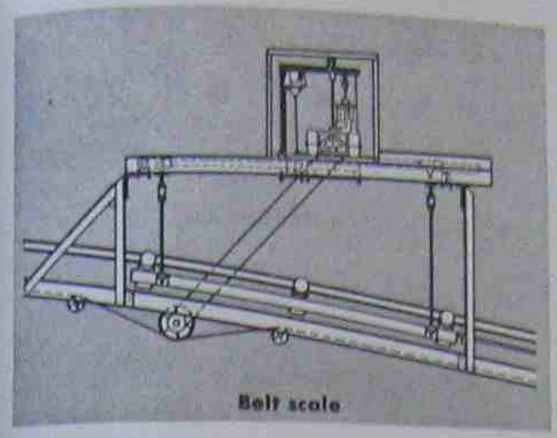
The final handling step, of which weighing is . . .

In the final handling stage—from live storage to firing equipment—conveying equipment just described is sometimes used, to feed any firing unit from any bunker section, or to transfer coal from one bunker section to another. But in most plants, discharge from bunkers is handled by chutes. Apparently simple, chutes can give rise to flow troubles unless properly designed. Recent studies (POWER, June 1953, p 92; Aug 1945, p 70) yield practical tips.

Chute Design. Diagrams and caption above show some features of good practice. Also, chutes should change direction gradually, with, if possible, a *breakaway*, or larger-area section, to give coal a chance to realign itself. Where two streams of coal meet, keep angle of convergence to a minimum. Avoid constrictions, cramped layouts.

Segregation. In talking about storage, we stressed the need for avoiding segregation—the tendency of fine and coarse particles to go their separate ways. This same problem crops up between storage and firing units. How serious it is depends on how much segregation the handling system produces, and on the firing equipment. Segregation can cause size of coal fed to pulverizers to change from minute to minute. Usually more serious is the effect on stokers, where segregation that reaches the fuel bed sets up big differences in resistance to air flow and an extremely spotty fire. First step, of course, is to avoid, if possible, handling-system conditions that cause segregation. Final answer, however, seems to be some form of special nonsegregating chute.

Checking Coal. A frequent part of in-plant handling is keeping tabs on quantity and quality of coal fired. Weighing, of feed to individual boilers or of total receipts, is outlined briefly above, with sketches of typical setups. In addition, there are *measuring* devices working on volumetric principles. One has a vane or helix that projects down into the center of a spout and records movement of coal past it on a meter calibrated to read in pounds. Another employs an endless chain instead of a vane. Similar volumetric principle is used when revolution counters are put on stoker shafts and pulverizer feeders. These serve well for a rough check on unit consumption.



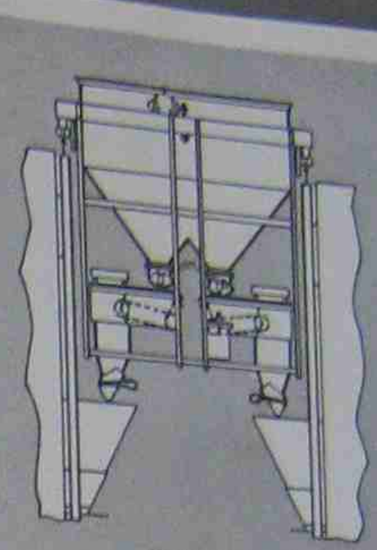
. . . HANDLING, OR AS DISTRIBUTED

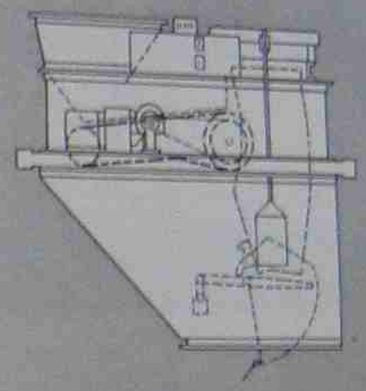
Track scales, often automatic, weigh coal coming in by rail. Truck deliveries may be checked by familiar platform scale, *above, left*. Weighing devices are built into unloading equipment—rotary car dumpers, feeders, etc.—and scales often installed between receiving hopper and conveyor.

Coal is weighed in transit, also. In the belt scale, *above*, the weigh beam connects to a suspended section of the carrying run. An integrator relates running weights and belt travel to record amount of coal being handled.

For weighing coal to each boiler, the time-honored larry still finds use. Suspended from overhead rails or running on floor tracks, it is basically a means of distributing coal. Drive may be by hand or motor. When weighing equipment is added to the basic larry, it may be manual or automatic.

Basic element of many modern systems is an automatic scale of general type illustrated, *right*. Such units are accurate to about 0.5% under average conditions. One shown has multiple-scale lever system with weight carrier and multiple weights, motor-driven belt feeder, hopper and counter to record weighing of preset amounts.



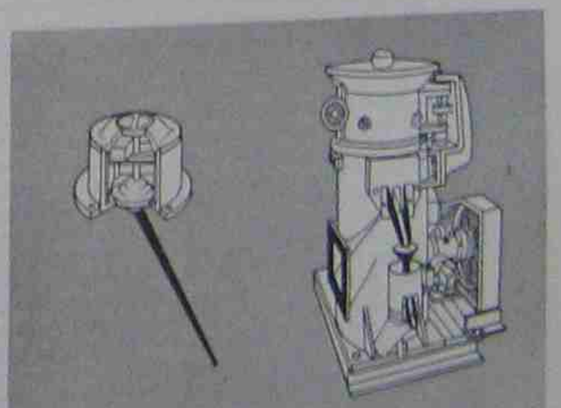


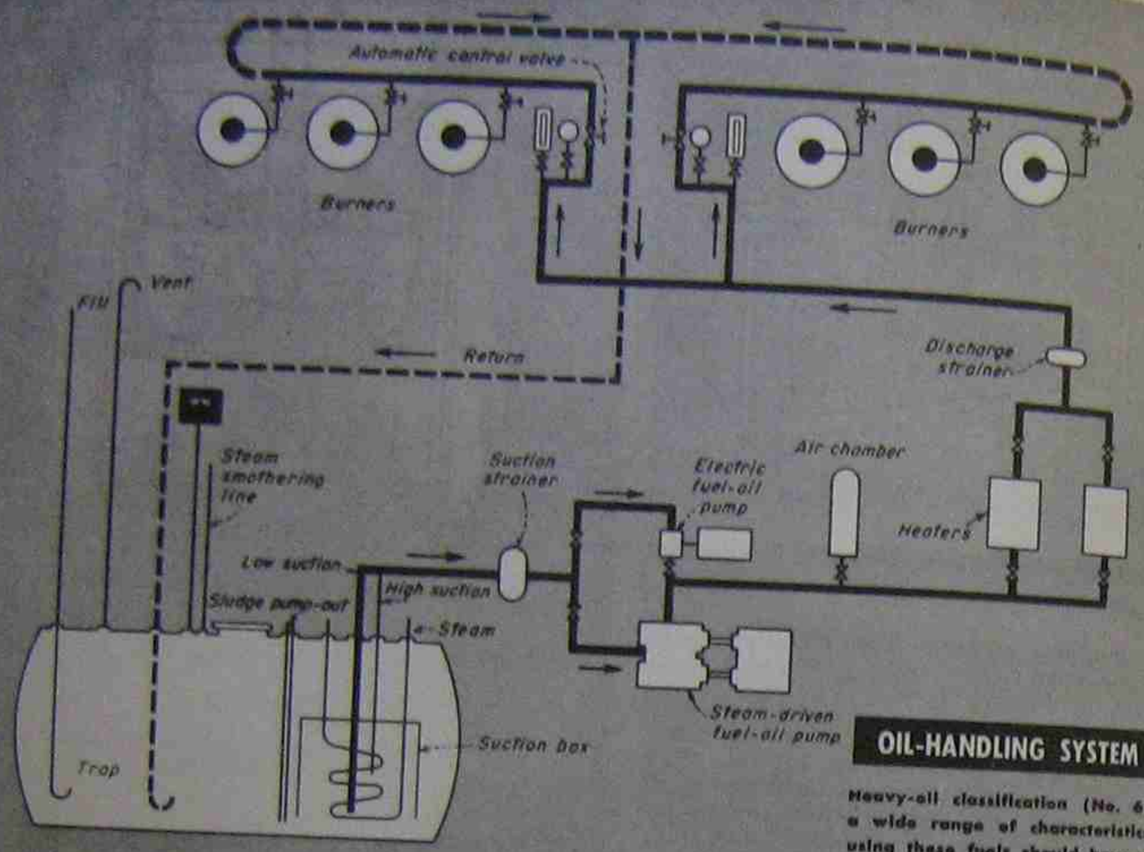
. . . often a part, is important to good operation

KEEPING TABS ON COAL

Just as scales check coal quantity, sampling for analysis keeps tabs on quality. Process of reducing a gross sample by hand quartering and riffling can be eliminated by using an automatic sampler. Unit illustrated (*far right*) has an additional splitter: it can deliver the normal 5, 10 or 15% sample, or a faster-worked 5% sample of anyone of them.

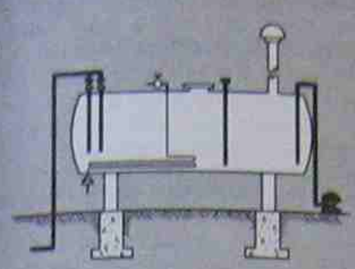
As we've seen, we also want to keep tabs on coal flow and level in bins, silos, bunkers, etc. This applies equally to the final handling stage, where we want to check flow and level in chutes and hoppers. Two units designed for the job appeared on p 87, another is shown, *right*. It has a stainless-steel sensing element, which is said to resist buildup of dust and wet coal. Acting through a spherical pivot and seal, the probe operates a microswitch.



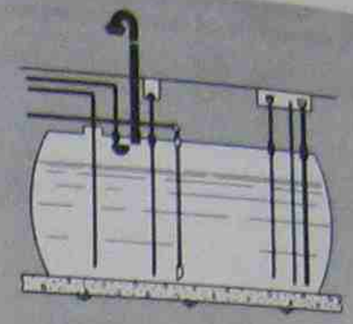


OIL-HANDLING SYSTEM

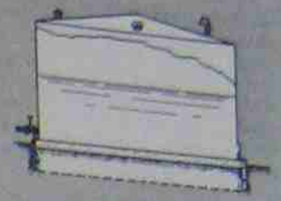
Heavy-oil classification (No. 6) covers a wide range of characteristics. Plants using these fuels should have a system equipped to insure troublefree handling



Outdoor, aboveground storage



Underground storage



Large cone-roofed tank

STORAGE-TANK POINTERS

Smaller fuel-oil tanks may be of horizontal cylindrical construction, usually shipped to plant site completely fabricated. Distance from tank to nearest building cannot be less than 1.5 times greatest dimension, up to 175 ft. A 25,000-gal tank 40 ft long and 10.5 ft in diameter would have to be 60 ft from nearest building or property line. Minimum distance between tanks should be at least ⅓ greatest dimension of smaller tank. So tank above would have to be 20 ft or more from another tank of same size. Tanks holding less than 18,000 gal, however, need only 3 ft spacing.

Underground tanks face different limits. For example, 75,000-gal tanks require 10-ft space between them and nearest building. Tanks of 150,000-gal capacity need 25 ft, 500,000 gal, 40 ft, and all capacities above that, 50 ft. Earth cover on an underground tank needs to be 2 ft or more. With a 4-in. concrete slab, earth cover can be cut to 12 in. In all cases, tank must be below any piping to which it connects, to guard against any gravity discharge.

Large above-ground tanks like the 50,000-gal one above are usually cylindrical, often with cone roof. Such tanks are usually erected on the site, hence space must be available for erection work. Distance from nearest building or tank must be at least ⅓ diameter of tank. Above 126,000-gal capacity, spacing goes up to full diameter of tank.

Semi-buried tanks are also used. They are usually mounded over with side slopes of 1.5 to 1. Recommended 2-ft earth cover is measured at shallowest point. Such tanks find use where water table is high, etc.

If you burn oil, here are pointers on tanks . . .

Before setting up a system for storing and handling fuel oil, be sure you are familiar with the recommendations and requirements of the National Board of Fire Underwriters.* And check any local ordinances that may apply.

Quantity of oil stored depends, of course, on rate of use and regularity of supply. Give thought to economic advantages of larger facilities, which permit purchasing when seasonal swings makes prices favorable. But remember that enlarged storage may bring you up against stiffer NBFU requirements and hence greater cost.

Storage Site. Oil arrives by truck, tank car, barge, or, in some cases, pipeline. Usual storage spot is close to delivery point—near rail siding for tank cars, or dockside for barges, tankers. While ideal, such locations may not always prove economical or easy. For example, a waterfront site may turn out to be swampy and require piling to support a large tank.

Some NBFU requirements may also influence tank location. Tank spacings given, on upper part of facing page, may enter the picture. Or decision might be influenced by need for building dikes around tanks holding more than 50,000 gal, or around smaller ones in congested areas. Since diked area has to be capable of holding entire tank contents, land requirements of tank and dike can be considerable.

Outdoor Tanks. Typical steel tank constructions are illustrated at top of facing page, and some requirements for aboveground, semi-buried and underground tanks are summarized below them. Tanks are also built of concrete and their design, construction and even concrete mixes are spelled out by NBFU in accordance with standards published by National Fire Protection Assn, *National Fire Codes*, Vol 1, 1951.

Inside tanks should be installed in enclosures whose walls are at least 6 in. thick if reinforced concrete or 8 in. if brick. They should rest on concrete or other fire-resistive flooring. Enclosure top should be reinforced concrete at least 5 in. thick, or equivalent fire-resistive construction, except where floor and roof construction above the enclosure is concrete or similar fire-resistive material. In this latter case, enclosure walls may be bonded to the underside of the construction in place of a separate top. Openings should be of approved type and ventilation provided. Gross capacity can reach 15,000 gal in fire-resistive buildings, 50,000 gal where tank room is cut off vertically and horizontally from other floors of main building.

Vents. All fuel-oil tanks must have a vent pipe open to the outside air to let the tank breathe as it is filled or emptied. When oil is pumped from storage, action of atmospheric pressure on the liquid surface helps keep oil flowing to the pump inlet.

NBFU states that vent pipes should be sized to prevent abnormal pressure within the tank during filling and should never be smaller than 1¼ in. for 500- to 3000-gal tanks, 2 in. for 3000- to 10,000-gal, 2½ in. for tanks up to 25,000-gal and 3 in. for those up to 50,000-gal capacity.

Where oil tanks are filled by pumping, a good rule of thumb makes vent at least equal to pump discharge line. If vent is less than 10 ft long, or greater than 2 in. inside diameter, its outlet should carry a vacuum or pressure-relief device, or an approved flame arrester.

Piping the Vent. Vent pipes should (1) drain back to the storage tank (2) connect to tapping at high end of tank (3) never extend more than one inch into tank (4) terminate outside of buildings not less than 2 ft horizontally and vertically from any window or building opening. Put an approved weatherproof cap on top, high enough above grade so snow, ice can't block it.

In addition to normal venting, all above-ground tanks should carry provision for emergency relief to safeguard against excessive internal pressure caused by exposure fires. Venting capacity of normal and emergency reliefs should be enough to prevent rupture of shell or bottom of vertical tanks, shell or heads of horizontal tanks. Bear in mind that responsibility for selecting limiting pressure on a tank rests on the owner or operator.

Fill Lines. Storage tanks for fuel oil should be filled from the outside and in the case of indoor tanks the fill line should terminate at least 2 ft from any building opening at the same or lower level. With tanks that contain heating coils, seal the tank end of the fill line or else extend the fill line to a point below the lower end of the suction line.

Auxiliary tanks should be filled by pumping from main storage tanks and have overflows, at least one size larger than supply pipe, draining to the storage tank. Cross-connections permitting gravity flow are not allowed. Overflow pipes of auxiliary gravity tanks have no valves or obstructions. Those of auxiliary pressure tanks have interconnected valves or other means for automatically venting during filling.

Suction Lines. The storage tank should have suction stubs that are continuous one-piece pipes extending to within 4 to 6 in. of tank bottom. Many use two suction stubs with second terminating 12 to 18 in. above bottom. Second stub provides for pumping clean oil should sludge and water buildup reach lower stub before tank is cleaned. (Cleaning can be done by pumping out or through access manholes built into tank (POWER, Mar 1952, pp 134-135).

Where the storage tank contains a vertical heating coil or suction bell installed through a tank manhole, the heating-medium stubs to the heating coil as well as both suction- and return-oil stubs are welded into the manhole cover plate and the entire assembly is handled as a unit.

Separate Suctions. In installations where two or more burners connect to the same storage tank run a separate suction line to each individual burner. The reason is that no two pumps wear alike and within a short time one pump pulls more vacuum than the other and the burner with

. . . pumps, heaters, and piping to hook them up

* 60 Batterymarch St., Boston 10, Mass.

the weak pump becomes hard to start, unreliable in operation.

All burners and fuel-oil pumping equipment require strainers in the suction line to protect them from foreign matter. Perforated-metal or wire-mesh strainer baskets serve for residual oils. It is also customary to install a discharge strainer after the oil has passed through preheating equipment, especially for mechanical-atomizing burners.

Return Lines. Fuel-oil pumps are usually rated to deliver at least up to 1.5 times the burning rate. On so-called one-pipe installations where there's only a suction line, excess oil is diverted from the discharge line back to the suction side of the pump. The customary and preferred procedure is to run a return line back to the storage tank so all excess flows back to tank.

For residual oil this return circulation is highly important. This excess oil already has been preheated and its return to storage raises the over-all temperature at the storage tank, making pumping easier. The return line provides the further advantage of venting the piping system without the aid of special venting valves required with one-pipe designs.

Return-line pipe sizes are usually made the same as for the suction line. When return line rises above the burner on its way to the storage tank a check valve goes in near the burner hinge but there should be no other valves, shut-offs or obstructions. Where there's more than one tank, and you need to install valves in the return line to divert oil to either tank, insert a relief valve in the bypass line.

Valves. Oil supply lines from storage to burner must carry readily accessible shutoff valves of approved type near each burner and close to gravity and pressure supply tanks. Usually they go in on each side of the oil strainers and on the discharge and suction side of oil pumps. If there is one on the discharge side of an oil pump an approved pressure-relief valve should go in to return surplus oil to the tank or bypass it around the pump.

Further, approved automatically operated valves designed to shut off oil in case of breakage of the oil supply line are smart where burners are not equipped to prevent abnormal discharge of oil at the burner. Anti-siphon valves once required by NBFU for this kind of service are no longer a necessity and should not be put in unless local regulations demand it.

A good tight suction line with a check valve near the burner gives a very good guarantee that the suction line will stay filled and the pump will not lose its prime.

Preheating Oil. All No. 6 fuel oils and most No. 5's have to be preheated for efficient handling and combustion. How closely oil temperature, and hence viscosity at the burner, must be controlled depends on atomizing method. For mechanical-atomizing burners, recommended viscosity is 150 ssu at 100 F. Temperature to produce this viscosity depends on the fuel oil used. The Navy rule puts temperature at 125 F plus the saybolt furol viscosity at 122 F. Rotary cup burners handle oils of viscosities up to 300 ssu, while steam- or air-atomizing burners permit an even wider range.

There is a danger of vapor locking in the suction side of an oil pump if all preheating is done before the pump. Top temperature in the suction line should be of the order of 80 to 110 F and no more. For simplicity's sake, many installations have all their preheating on the discharge side of the pump. But often, especially in cold climates, some preliminary preheating has to be done at the storage-tank stage.

Preheaters, or fuel-oil heaters as they are often called, may use steam, hot water or electricity as a heating medium. Electricity serves best for starting up a cold plant.

Preheaters using steam or hot water are of shell-and-tube arrangement with the oil passing through the tubes and the heating medium passing through the shell over the tubes, or vice versa. High-pressure steam plants use steam almost entirely.

But because this steam has a high temperature and can cause coking of the oil and rapid fouling of the heater, thermostatic regulators should go in the steam line supplying the heater, with the thermostatic bulb put in the oil discharge line. As a further safeguard, a magnetic steam valve in the steam line before the regulator opens when the burner starts and shuts when it stops to prevent a build-up of hot steam within the preheater and an attendant extreme temperature rise in the standing oil within the heater.

Where steam supply pressures run above 50 psi a reducing valve to bring it down to 25 psi is good operating practice. The heater installation runs larger and hence costs more but it returns solid advantages in the way of reduced operating costs, less coking of oil, better regulation of oil discharge temperature, greater service and longer life of the fuel-oil heater.

Insulation. Since temperature plays so important a part in the handling and combustion of fuel oil, thorough and efficient insulation of all piping, heaters, etc., is a sensible move.

Materials like 85% magnesia, mineral wool, or asbestos air-cell do a good job on in-plant piping, with plastic cement taking care of the various pipe fittings. Hairfelt and tar paper are often used for underground piping. Frequently the fuel-oil suction line, return line and steam or hot water supply and return lines to the storage-tank heating coil are wrapped together as one bundle.

CHECK POINTS FOR IDEAL No. 6 OIL HANDLING

- Equipment adequately insulated
- Properly sized oil pumps with adequate drivers
- Twin strainers for each pump
- Suction lines from each pump to storage tank
- Automatically controlled fuel-oil temperature
- Adequate fuel-oil circulation to insure hot oil to each burner or set of burners
- Controlled viscosity by controlled oil temperature
- Adequate pressure control of oil to control valves
- Ability to condition oil after delivery, before use
- Proper instrumentation: thermometers, pressure gages

How to handle gas economically and safely

A major difference between gas and the solid and liquid fuels is that gas storage is almost invariably the responsibility of the supplier and storage on the consumer's premises is rare. And such large-scale storage of the by-far-and-away most important gaseous fuel, natural gas, is relatively new.

Tremendous expansion of natural-gas use into fields like house heating, etc, has led to a demand that varies seasonally as well as hour to hour. But gas fields and transmission systems can't be operated economically at widely varying rates. As a result, gas is made available at the source at reasonably constant rates, as close as possible to capacity ratings of the lines.

Underground Storage. With virtually no gas-storage facilities in consumer plants, the problem of maintaining high and economical transmission rates in spite of widely varying consumer demand has been solved to an increasing extent by underground storage. In 1952, close to 150 large storage projects, with total capacity of about 1,000,000 MMcf were in operation, from New York to California, Michigan to Texas. In the Appalachian region alone there are more than 100, with combined capacity exceeding 600,000 MMcf. More are planned.

Such underground storages have been developed from depleted or partly depleted gas fields, oil fields, abandoned noncommercial gas fields and formerly untested water sands. Some are extremely large — the Oakford storage field of New York State Natural Gas Corp (near Jeannette, Pa.) holds 1,000,000 Mcf.

Gas Properties. The natural-gas pipeline company customarily conditions the gas to give it qualities and properties that make it more transmissible and more desirable to the customer. Methane and ethane constitute the bulk of the combustibles, methane varying in volume from 60 to 95%. Ethane, propane, butane, hexane, etc, follow in decreasing percentages.

Carbon dioxide and nitrogen form the bulk of the inert portion. Carbon dioxide ranges from a trace, to 100% in some Rocky Mountain area wells, while nitrogen averages out at about 7.9% by volume for the various U. S. fields. Helium also occurs in natural gas but is usually less than 1%.

Some gas fields produce gas containing hydrogen sulfide and the various sulfur compounds known as mercaptans. A gas with hydrogen sulfide is known as a "sour" gas, while one without it is a "sweet" gas. When hydrogen sulfide shows up in a gas it may be from a trace to 10 or 15% by volume. For each 1% H_2S by volume you can figure about 0.1 lb of sulfur per 100 cu ft. Usually, gas when produced is saturated with water vapor at prevailing pressure, temperature.

The gas-transmission company conditions the product by (1) removing water and liquid hydrocarbons (2) taking out hydrogen sulfide and inert gases (3) removing dirt and foreign matter. An odorant is added for safety. The gas reaching the customer is thus nearly all pure fuel and his problem is reduced to delivering this fuel safely to firing units. An example from the setup of a large user (POWER, Nov 1951, pp 90-91) gives an idea of what is involved.

Typical Large System. A typical large-scale user of natural gas gets supply from a pipeline at 100 psi, through a 22-in. line connecting to a

RECOMMENDED PRACTICES FOR INDUSTRIAL GAS PIPING

■ **LOCATION.** Be sure piping is located with safety in mind. Avoid putting it under floors, in unventilated crawl spaces or concealed in solid masonry. If you have to, enclose it in a larger pipe, sealed but provided with means for leak inspections at the inner end of the casing.

Never lay gas piping in cinder fill. Protect buried steel pipe against corrosion by suitable coating, or cathodic means.

Remember that many gases, particularly manufactured, contain moisture. Whether above or below ground, piping should not be exposed to freezing temperatures.

■ **MATERIALS.** Standard-weight (ASA Schedule 40) steel pipe is acceptable and generally used since pressures are relatively low, usually below 25 psi.

In smaller pipe sizes, fittings are screwed type, made of malleable iron, cast or forged steel. Larger sizes (4-in. and over) often use cast-iron fittings but welding fittings and welded or gland-type joints have become quite general. For the latter, check your local gas supplier for gland materials resistant to the gas they furnish.

■ **SIZING.** Estimate maximum rate of gas consumption (cu ft per hr) by dividing equipment input rating in Btu's per hr by the Btu per cu ft of the gas supplied. Load diversity may be figured in, but best practice usually designs pipe for maximum rating, so there is room for growth and changes in specific gravity or heating value of the gas supplied.

Allowable pressure loss from meter to point of use under maximum gas demand can be selected by allowing either 0.5-in. water, or 10% of initial pressure, whichever is greater.

Equivalent pipe length to use in determining pressure loss is taken as actual length plus equivalent length allowances for fittings shown in Table XIV, *Piping Handbook*, 4th ed.

■ **INSTALLATION RULES.** Never weaken the building structure by such shortcuts as notching beams to install piping. Never hang, strap or otherwise support gas piping from other piping or electrical conduit.

Securely fasten and support gas piping with hooks, straps, bands or hangers spaced at intervals no greater than: 8 ft for ¾- and 1-in. pipe, 10 ft for 1¼-in. or larger pipes in horizontal runs; at every floor level for 1¼-in. or larger vertical pipes.

Grade piping with a pitch of at least 1 in. in 50 ft and provide a drip at any low point where condensate could collect. Allow for expansion bends or gland-type couplings in long runs of 4-in. or larger piping. Expansion bends should follow usual good practice for radius, uniformity of curvature, uniformity of wall thickness. Locate gland-type couplings where they can be readily inspected and maintained.

(Turn page)

twin reducing station in the plant yard. Each of the two reducing valves can handle enough gas at 35 psi to carry top station load. An 18-in. header in the boiler room feeds individual units through 10-in. plug cocks, followed by two emergency shutoff cocks with an automatic vent between them and a manual or automatic gas-control valve operated from the boiler board. This control valve reduces gas pressure to 1 to 5 psi, depending on burner load.

On first starting up with gas, this user took the precaution of blowing the 22-in. main feed line from the gas company's reducing station to the yard reducing station and atmosphere for 7 minutes. Then he purged the line from there to the individual burners, using nitrogen. Considerable foreign material was picked up from the new gas main — enough in one case to cut out the internals of the yard-reducing-station valve.

Gas-System Piping. It can be seen that the basic problem is to install a correct gas-piping system and to operate it properly. To help industrial gas users in this connection, the American Gas Assn formed the Industrial Gas Practices Committee in April 1952. This committee is to prepare a detailed statement of standard requirements for industrial consumers' gas piping.

It is hoped that the committee's work will serve as the basis for an American Standards Assn recommendation for all gas-piping carrying pressures above 0.5 psig. The committee's present thinking was summarized in a paper by E L Spanagel, Rochester Gas & Electric Corp, at the 1953 Fall Meeting of ASME. Much of the material in this paper (*Installation of Fuel-Gas Piping*) is presented on these pages, headed: "Recommended Practices for Industrial Gas Piping."

Standby Provisions. Many industrial-gas consumers take advantage of the lowest rates offered by the supplier, which often are for service of the interruptible type — that is, service may be cut off without notice and restored as the supplier's situation dictates. Plants using interruptible service usually make standby provisions of one kind or another. Often standby fuel is oil.

In many plants, although gas is not used as a boiler fuel, it is used in manufacturing operations, as in printing machinery, heat treating, etc. For such use any standby fuel should be gaseous and should have nearly the same properties as the fuel usually burned so a minimum of adjustments are needed.

Propane, butane and combinations of them (usually referred to as LPG, for liquefied petroleum gases) are finding increasingly wide use for standby service as well as regular fuel in areas where natural gas isn't available. In the typical standby setup, storage tanks of horizontal cylindrical design are used, with relief valves and extra-heavy pipe and fittings.

An external mixer proportions gas and air to match the physical properties and burning characteristics of the natural-gas supply. Most mixers permit a wide turndown rate, as much as 35 to 1, so load swings should cause no trouble. A vaporizer unit insures that the liquefied gas is properly conditioned for mixing. With such a setup, no changes in settings and burner adjustments are needed. Nor does the gas raise any problems of sludge or gas deposits in the orifices or burners.

RECOMMENDATIONS FOR INDUSTRIAL GAS PIPING, contd

Take branch connections, when needed, off the top or sides of main horizontal pipes rather than off the bottom. This helps to avoid pickup of condensate, scale, rust.

Equip branch connections with suitable manual shutoff valves or plug cocks, placed in the closed position. Close outlets with threaded caps, plugs or flanges until ready to use.

Main shutoff valves on lines to individual buildings should be outside the building to permit cutting off in emergencies. Location should be plainly marked and posted, and provisions made to prevent operation except when authorized.

Gas shutoffs should be gate valves or full-opening plug cocks. Lubricated plug cocks are usually recommended for pipe sizes over 2 in. Where gas pressure runs above 5 psig, tamperproof cocks are a good safety measure.

■ **TESTING PROCEDURE.** Subject the piping system to a test pressure at least 1.5 times maximum working pressure, but never less than 3 psig. System should hold bottled-up pressure for at least 10 min, without drop in pressure after test gas has had time to arrive at ambient temperature. Unusually long piping systems should be tested for longer periods—up to 24 hr.

As test medium, use air or inert gas, such as carbon dioxide, nitrogen or combustion products. Never use oxygen, water or any other liquid.

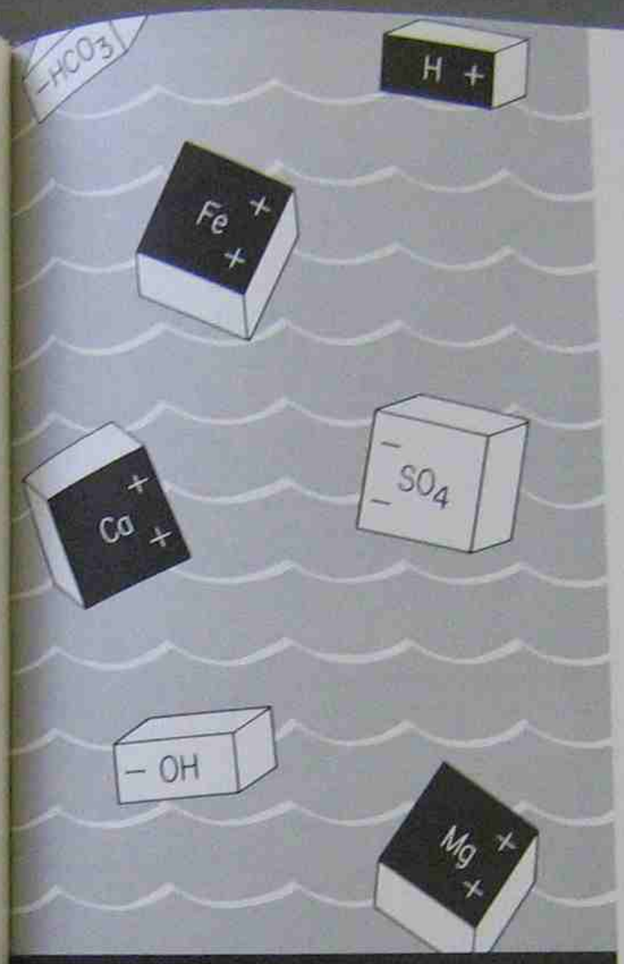
Purge piping after test and after gas meter has been set. Do the purging at the most distant point from the meter, by hose or temporary pipeline leading outside the building. Similarly purge each major branch line.

Make a final check after purging and filling up the gas lines. Test dial on gas meter can be used for over-all leak checks. Observe for 5 min; if there's no movement, consider system tight. If there is, shut gas off at meter and look for open fittings, open ends, open shutoff valves, bad joints.

■ **SAFETY PRECAUTIONS.** Never use gas piping for electrical grounding and never employ piping, control casings, panels or other metal parts in place of wiring. This doesn't apply to the gas combustion system's own low-voltage control and ignition circuits, nor to electronic flame-detection circuits.

Install a backpressure valve wherever air is used for the combustion system at a pressure higher than normal gas pressure. It might possibly back up into the gas lines. Also, put in an automatically operated gas valve with manual reset in the gas-supply line to serve as an interlock between air supply and gas supply. This will prevent flow of gas without accompanying flow of air necessary for combustion.

A second manually reset, automatically operated gas valve should be put in the gas-supply line to close tight at a preset low-pressure limit. Where gas compressors or other devices are installed to raise consumer's gas pressure above that normally supplied, install a similar low-pressure gas cutoff valve with manual reset.



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PART ONE

Water Treatment

By R H MARKS, Assistant Editor

Water is one of our most important raw materials. Industry uses a daily average of about 111 billion gallons. Irrigation takes 110 billion gallons a day. And over 19 billion gallons are distributed daily through municipal and rural water-supply systems. This adds up to an impressive daily total of 240 billion gallons. Demand for water is climbing so fast that experts predict a total use of 450 billion gallons a day by 1975.

Fortunately average daily runoff is about 1164 billion gallons. And not all water withdrawn from well, river or lake is consumed completely. About 90% of the water taken for public supplies and 98% of that used by industry is available for reuse in the same general area. This water is a valuable raw material even though much of it is contaminated with human or process wastes.

Looking at water this way, you arrive at a total daily consumption of only 87 billion gallons. So an overall water shortage doesn't look like a problem for the immediate future, although some areas will have more water than they need and others will have to cope with a short supply.

But it's clear that development of better ways to store, transport, conserve, recondition and reuse water will be economically justified. Since all of this water is a potential troublemaker unless made to behave, water treatment will take on ever-increasing importance.

First section of this 2-part report leads off with a look at water impurities and treatment aims, follows with data on basic water chemistry and concludes by scrutinizing today's water-treating chemicals and equipment.

In order to make this report easy to follow, we've carefully organized it into logical sections. Index, left, shows the structure.

Second part, in an upcoming issue, will show how the basic water-treatment tools are put to work to fashion economical treatment systems for boiler feed, cooling, process and other plant water services.

a **Power** special report
December 1958

What water quality does your plant really need?

First reaction of many engineers to this question is "Pure water, of course!" But translating an answer like that into action often means a lot of needless expense in installing and operating a complex water-treating system. "Pure" or high-quality water is practical only for high-pressure power plants, nuclear power reactors and certain process waters. Generally water that is tailored for each job with a specific end result in mind is less costly, easier to obtain and completely satisfactory.

If water were H_2O and nothing else, or if all waters carried the same impurities, treatment could be boiled down to a nearly uniform prescription for each use. But pure water never occurs in nature and impurities vary considerably. Closest natural approach to "pure" water is rain. But even rain contains enough dissolved oxygen and CO_2 to make it corrosive.

Impurities in natural waters depend largely on the source. Wells and springs are classed as ground waters; rivers, lakes as surface waters.

Ground water picks up impurities as it seeps through the rock strata, dissolving some part of almost everything it contacts. But the natural filtering effect of rock and sand usually keep the water free and clear of suspended matter.

Surface waters often contain (1) organic matter such as leaf mold and (2) insoluble suspended matter such as sand and silt. Pollution from industrial waste and sewage is frequently present. Stream velocity, amount of rainfall and where the rain occurs on the watershed can rapidly change the character of the water.

In general water tends to cause trouble in industry by (1) forming deposits that interfere with heat transfer or impair product quality and (2) damaging metals, wood or other materials of construction used to store, transport or otherwise contain water. So the broad aims of treatment are to prevent deposits and control corrosion. This must be done at a cost economically justified by benefits of trouble-free water.

All natural waters—even rain, snow, sleet and hail—and all treated municipal supplies contain some of these impurities

Turbidity and sediment

Turbidity is suspended insolable matter, including coarse particles (sediment) that settle rapidly on standing. Amounts range from almost zero in most ground waters and some surface supplies to 60,000 ppm in muddy and turbulent river water. Turbidity and sediment are objectionable for practically all uses. Standard for drinking water is 10 ppm max. High-grade pulp and paper calls for water containing not more than 5 ppm turbidity

Color

Surface waters from swampy areas often are highly colored from decaying vegetation. Amount of color is found by comparing its intensity with a standard. Color of 10 units isn't visible in a tumbler, but 20 units (drinking water maximum) are noticeable. Many processes can't stand more than 5 units. In the paper industry, color in process water stains the cellulose fibers, affects brightness or color of white or dyed papers

Microbiological growths

Various growths occur in surface water, seldom in uncontaminated deep wells. Microorganisms include diatoms, molds, bacterial slimes, algae, iron and manganese bacteria, sulfur or sulfate-reducing bacteria, etc. Some are dangerous to health; others cause bad taste and odors or produce clogging deposits. Although many of these organisms are nonpathogenic, water can't be assumed safe simply because it is clear and odorless

Fluoride

Amount rarely tops 4.0 ppm (average is much less than 1.0 ppm). There's evidence that a small amount prevents tooth decay. United States Public Health Service sets 1.5 ppm as the maximum for drinking water

Hardness

Water's content of soluble calcium and magnesium salts equals hardness, expressed as calcium carbonate equivalents in gr per gal or ppm. These salts, in order of their relative average abundance in water, are (1) bicarbonates (2) sulfates (3) chlorides (4) nitrates. Calcium salts are about twice the concentration of magnesium salts. Carbonate (temporary or bicarbonate) hardness is that present as bicarbonate salts. Noncarbonate (permanent) hardness equals the remainder present as sulfates, chlorides and nitrates. Hardness is undesirable because heating or evaporating produces hard stony scale deposits that clog fluid systems, cause damage

Mineral acidity

Surface waters contaminated with mine drainage or trade wastes will contain sulfuric acid, plus ferrous, aluminum and manganous sulfates. They're corrosive and unfit to use

Silica

Most natural waters contain silica ranging from 1 to over 100 ppm. It forms hard scale in h-p boilers, passes over with steam to form glassy deposits on turbine blades

Sodium and potassium salts

Extremely soluble, they don't deposit unless highly concentrated. They'll prove troublesome if distilled-water quality is needed

Hydrogen sulfide

This dissolved gas gives a rotten-egg odor to sulfur waters making them distasteful, corrosive to most metals. Waters with more than 1 ppm are definitely undesirable

Iron

Most common soluble iron in ground waters is ferrous bicarbonate. Water is clear and colorless when drawn but, on exposure to air, clouds up and deposits a yellowish or reddish-brown sediment of ferric hydroxide that stains everything it contacts. Although majority of iron-bearing waters have less than 5 ppm, as little as 0.3 ppm can give trouble

Manganese

Rarer than iron in water, manganese occurs in similar forms and is troublesome in industrial and municipal supplies. Pipeline deposits form rapidly with as little as 0.2 ppm

Carbon dioxide

Free carbon dioxide is found in most natural supplies. Surface waters have the least although some rivers contain to 50 ppm. In ground waters it varies from zero to concentrations so high that carbon dioxide bubbles out when pressure is released. Most well waters contain from 2 to 50 ppm. Carbon dioxide also forms when bicarbonates are destroyed by acids, coagulants, high temperatures. It's corrosive and accelerates oxygen corrosion

Methane

Occasionally enough methane is found in well waters to cause fire and explosion hazard. It's readily identified by its flammability

Oxygen and nitrogen

Both are found in surface and aerated waters; deep wells contain very little, if any. Nitrogen is an inert gas, while oxygen is corrosive to iron, zinc, brass and other metals

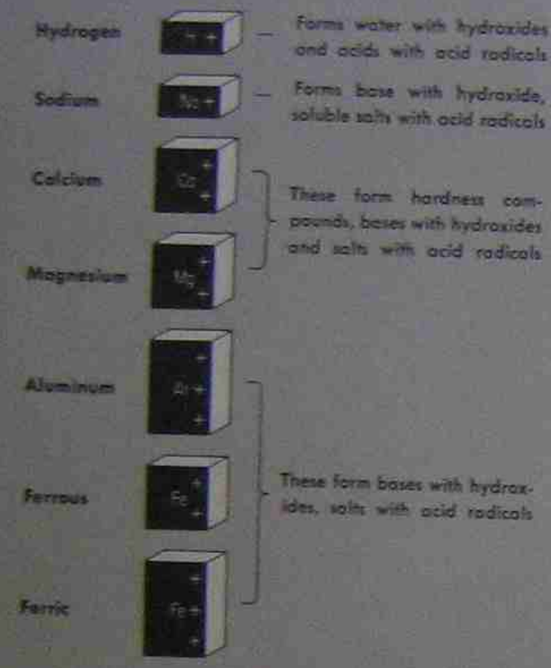
Water impurities will vary with the source of supply

Aside from drinking and sanitary purposes, the five main uses of water in industry are: (1) generating steam to produce power in utilities and industrial plants (2) heating and cooling (3) transporting and processing materials such as pulp and paper (4) as a raw material that becomes part of a finished product such as canned foods and beverages (5) passing along domestic and industrial wastes.

Sometimes water can be used without treatment. But more often it contains impurities that must be removed, reduced or stabilized. First step in selecting treatment is a survey of available water supply and the uses to which water is put. If you have private wells, analyze separate samples from each. When it's from the surface, take a series of analyses over a period of time. Check records carefully to spot any changes in composition. If you use a municipal supply, check their records for maximum and minimum amounts of impurities over a period of years. Water from a deep well usually has a uniform composition. But it is a mistake to assume that water from a nearby well will have the same analysis.

Surface waters except for very large lakes or reservoirs vary greatly in composition during a year. Maximum impurities in rivers can range up to 400 times the minimum amounts. Hardness of Mississippi River water near Memphis, Tenn. varies from 108 to 184 ppm. Turbidity in large lakes and reservoirs also has a wide range. But soluble minerals often show little annual change.

Cations, anions are basic chemical units



ACTUAL COMPOUNDS of water chemistry can be constructed with chemical building blocks, above. Match any cation with any anion block. If their heights aren't the same, pile on duplicate blocks until both piles are equal

First working tool is basic knowledge of water chemistry

Chemical building blocks, left, are used here to represent those cations and anions important in water treatment. Table, facing page, lists properties of the important elements, acid radicals and acids. Atomic weight of each element is merely a way of comparing the weight of its atoms with that of the oxygen atom. For example, the oxygen atom weighs 16 times as much as a hydrogen atom. If the atomic weight of oxygen is 16, then hydrogen's must be 1 to maintain the relationship.

Atoms of elements contained in a chemical compound are bound together in definite patterns as molecules. Formula of a compound is the same as that of the molecule. For example, formula for water is H_2O. This means that each molecule of water contains two atoms of hydrogen and one atom of oxygen.

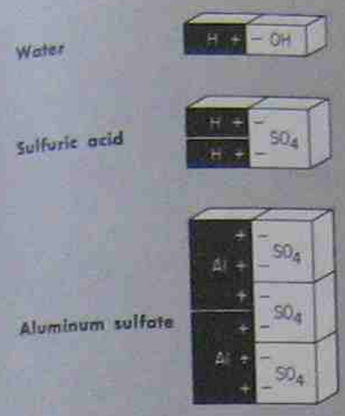
Molecular weights are easy to figure: just add the weight of atoms present in each molecule. Molecular weight of water then becomes $1 + 1 + 16$ or a total of 18. In the same way sulfuric acid has a molecular weight equal to the sum of atomic weights for two hydrogen atoms, one sulfur atom and four oxygen atoms. This amounts to a total of $1 + 1 + 32 + 4(16)$ or 98.

Acids used in inorganic water chemistry consist of hydrogen combined with an acid radical. So the SO_4 group in the molecule of sulfuric acid is called an acid radical. When these acids are brought in contact with other compounds, the resulting reaction brings about many regroupings. But, in most cases, the acid radical moves around as a unit. The four atoms of oxygen and one of sulfur stick together in moving to some new combination. So it's convenient to look on these acid radicals as a chemical-anion unit. In every case the acids listed in table, facing page, are a combination of hydrogen and one of the many acid radicals.

Valence of an acid radical or an element is a measure of its chemical combining power. Hydrogen is taken as the standard with a valence of one. Any atom or radical that combines with hydrogen on a one-to-one basis will also have a valence of one. Hydrochloric acid's formula, HCl, tells us that one atom of hydrogen combines with one atom of chlorine. Thus the valence of Cl is one.

Chloride anions can also combine with sodium cations to produce NaCl or common salt. Since chloride has a valence of one and it unites with one atom of sodium, the valence of sodium is also one. Formula for sulfuric acid is H_2SO_4. Hydrogen has a valence of one. But it takes two atoms of hydrogen to combine with one sulfate radical. This means that the sulfate radical has a valence of two.

Equivalent weight is the number of pounds combining with one pound of hydrogen. In other words it is the



Here's how blocks match up to show actual compounds

The dark cation of hydrogen matches evenly with the light hydroxide anion to give HOH, a graphic way of writing H_2O or water. When hydrogen combines with any of the acid radicals, result is an acid. One hydrogen atom paired with an atom of chlorine forms a matched molecule of HCl or hydrochloric acid. But when hydrogen is paired with sulfate, the sulfate block is twice as tall. Since matching is only complete when each pile is the same height, another atom of hydrogen is needed, as shown by chemical block diagram at left.

Formation of aluminum sulfate, left, calls for a matching combination of two aluminum atoms to three sulfate radicals. In all these groupings, plus signs of cation blocks are opposite minus signs on anion blocks. You can look on these as opposite charges of electricity binding cations to anions.

Number of plus or minus signs on a given block represents valence of that element or radical. Height of each block is proportional to this value. Thus these chemical building blocks graphically show the valence principle. For example, hydrogen has a valence of one, sulfate two and aluminum three.

Important elements, acid radicals and acids in water chemistry

Element	Symbol	Atomic weight	Valence	Equivalent weight
Aluminum	Al	27.0	3	9.0
Barium	Ba	137.4	2	68.70
Calcium	Ca	40.1	2	20.05
Carbon	C	12.0	Variable	—
Chlorine	Cl	35.46	Variable	35.46
Fluorine	F	19.0	1	19.0
Iron (ferrous)	Fe″	55.8	2	27.9
Iron (ferric)	Fe‴	55.8	3	18.6
Hydrogen	H	1.0	1	1.0
Magnesium	Mg	24.3	2	12.15
Nitrogen	N	14.0	Variable	—
Potassium	K	39.1	1	39.1
Oxygen	O	16.0	2	8.00
Phosphorus	P	31.02	Variable	—
Sodium	Na	23.0	1	23.0
Sulfur	S	32.0	Variable	—
Silicon	Si	28.06	4	14.03

Acid	Formula	Molecular weight	Equivalent weight
Carbonic acid	H_2CO_3	62.0	31.0
Hydrochloric acid	HCl	36.46	36.46
Phosphoric acid	H_3PO_4	98.0	32.67
Sulfuric acid	H_2SO_4	98.1	49.05
Sulfurous acid	H_2SO_3	82.1	41.05

Radical	Formula	Molecular weight	Valence	Equivalent weight
Bicarbonate	HCO_3	61.0	1	61.0
Carbonate	CO_3	60.0	2	30.0
Chloride	Cl	35.46	1	35.46
Nitrate	NO_3	62.0	1	62.0
Hydroxide	OH	17.0	1	17.0
Phosphate	PO_4	95.0	3	31.66
Sulfite	SO_3	80.0	2	40.0
Sulfate	SO_4	96.06	2	48.03

weight of substance that will contain a unit weight of hydrogen. For example, 98 grams of sulfuric acid contain two grams of hydrogen. So 49 grams of sulfuric acid are required to carry one gram of hydrogen. On this basis sulfuric acid has an equivalent weight of 49.

Chemical compounds can be formed by matching up cation and anion blocks. Dark cation blocks are metallic elements with exception of hydrogen. Ferric and ferrous blocks represent two different forms of iron. Light anion blocks are acid radicals with exception of hydroxide. Height of each block is proportional to its valence. But, of course, the relative size and shape of blocks don't indicate size or shape of atoms or molecules.

Actual compounds shown above are constructed with this technique. Aluminum sulfate molecule is a good example of the class of chemicals known as salts. These are formed by bringing together a metal and an acid radical.

If we combine a metal cation with the hydroxide anion, we get what is known as a base. These react strongly with acids and are looked upon as their opposite number. Combining the metal sodium with hydroxide gives sodium hydroxide, a base that reacts strongly with acids.

Calcium compounds are found in raw water and added in treatment



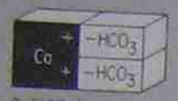
$Ca(OH)_2$

Calcium hydroxide
Used in lime-soda softeners



$CaCl_2$

Calcium chloride
Constituent of hardness



$Ca(HCO_3)_2$

Calcium bicarbonate
Heat drives off CO_2, precipitates calcium carbonate



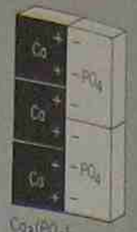
$CaCO_3$

Calcium carbonate
Forms sludge or soft scale



$CaSO_4$

Calcium sulfate
Forms hard scale



$Ca_3(PO_4)_2$

Tricalcium phosphate
Sludge formed by action of phosphates on calcium hardness

Magnesium compounds also have dual role as impurities and treatment chemicals



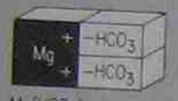
$Mg(OH)_2$

Magnesium hydroxide
Insoluble precipitate of lime-soda process



$MgCl_2$

Magnesium chloride
Soluble, corrosive, constituent of hardness



$Mg(HCO_3)_2$

Magnesium bicarbonate
Heat drives off CO_2 to form magnesium carbonate



$MgCO_3$

Magnesium carbonate
Moderately insoluble



$MgSO_4$

Magnesium sulfate
Soluble



$Mg(NO_3)_2$

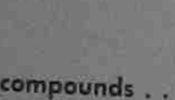
Magnesium nitrate
Soluble

Iron compounds . . .



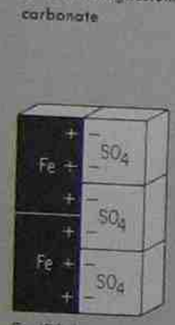
$Fe(HCO_3)_2$

Ferrous bicarbonate
Most common form of iron in water



$FeSO_4$

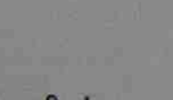
Ferrous sulfate
Common iron coagulant



$Fe_2(SO_4)_3$

Ferric sulfate
Another iron coagulant

. . . find use as coagulants



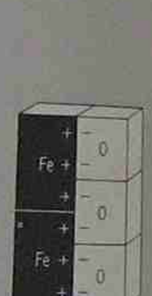
$Fe(OH)_3$

Ferric hydroxide
Floc produced by ferric or ferrous sulfate



FeO

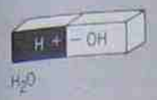
Ferrous oxide
Product of iron corrosion



Fe_2O_3

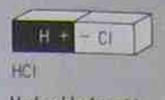
Ferric oxide
Product of iron corrosion

Hydrogen compounds range all the way from water to sulfuric, phosphoric acids



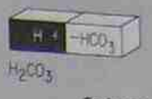
H_2O

Water



HCl

Hydrochloric acid
May be added in treatment



H_2CO_3

Carbonic acid
Breaks down to H_2O and CO_2 when heated

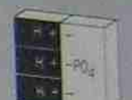


H_2CO_3



H_2SO_4

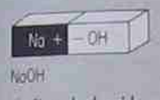
Sulfuric acid
May be used in treatment



H_3PO_4

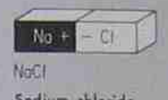
Phosphoric acid
May be used in treatment

Sodium compounds handle a variety of treatment jobs including oxygen removal



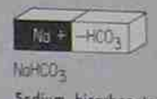
NaOH

Sodium hydroxide
May be used in treatment



NaCl

Sodium chloride
Used to regenerate cation exchangers



$NaHCO_3$

Sodium bicarbonate
Breaks down to sodium carbonate and CO_2 when heated



Na_2CO_3

Sodium carbonate
Under pressure and heat breaks down to caustic soda and CO_2



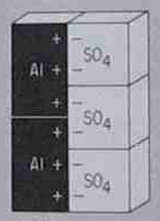
Na_2SO_3

Sodium sulfite
Chemically removes oxygen from water



Na_2SO_4

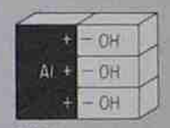
Sodium sulfate
Present in water, sometimes added; also a product of treatment



$Al_2(SO_4)_3$

Aluminum sulfate
Coagulant

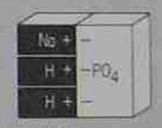
Aluminum compounds are good coagulants



$Al(OH)_3$

Aluminum hydroxide
Dense floc made by coagulation

Sodium phosphates find wide use in water treatment



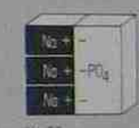
NaH_2PO_4

Monosodium phosphate



Na_2HPO_4

Disodium phosphate



Na_3PO_4

Trisodium phosphate



$NaPO_3$

Metasodium phosphate

Mating cation, anion building blocks help show structure of many common compounds

Compounds shown above include most of those commonly encountered in water treatment. Each group includes combinations of a single cation with various anions.

Except for water, all hydrogen compounds are acids. Carbonic acid is pictured as a bicarbonate and a carbonate of hydrogen. Probably the more correct presentation from a chemical standpoint is carbonate of hydrogen. In carbonic acid the building block of bicarbonate or carbonate is easily broken up. Heating to 212 F destroys the radical, drives off carbon dioxide and leaves plain water. Magnesium and calcium bicarbonate are also unstable when heated, giving up carbon dioxide.

Cold water absorbs carbon dioxide to produce carbonic acid. Ordinary soda water is nothing more than a strong solution of carbonic acid.

Most sodium compounds have the family characteristic of high solubility and are rarely scale forming. In addition to sodium compounds found in raw water, several are often products of treatment. Softening leaves a residual of sodium carbonate. Sodium sulfate appears as an end product when removing oxygen chemically from water with sodium sulfite.

At opposite extreme are the frequently insoluble and scale-forming compounds of calcium and magnesium. Fortunately, bicarbonates and sulfates of both calcium and magnesium are soluble at room temperature. But when calcium bicarbonate is heated carbon dioxide is driven off, calcium carbonate comes down as insoluble sludge or deposits as a crystalline scale.

Four forms of sodium phosphate shown above are widely used in water treatment. Tricalcium phosphate is a fine precipitate produced by the reaction of calcium hardness and the phosphate compounds.

Iron has a valence of two in ferrous compounds and three in ferric compounds. In untreated water it often occurs as ferrous bicarbonate. Both ferric and ferrous sulfate find use as coagulants. With lime or caustic soda, ferric sulfate gives a dense floc of ferric hydroxide that helps remove all types of suspended matter from water. Ferrous and ferric oxide are corrosion products of iron.

Aluminum sulfate produces a dense aluminum hydroxide floc when it is added to the water for coagulation.

When two or more chemical compounds are brought together they often react mutually to produce new compounds. This is called a reaction and is shown by a chemical equation. On its left side are the original compounds. On the right are those remaining after the reaction. However, reactions also tend to work in reverse. Each compound is expressed by its formula.

In every chemical equation the left and right sides must balance atom for atom. Every atom present at the start must be accounted for at the end.

The building-block technique helps show these chemical reactions because the acid radicals usually go through unchanged. Most of the basic chemical reactions in water treatment can be pictured by merely shifting cation and anion building blocks. Chief exception is the case where bicarbonates and carbonates are destroyed by heating or aeration and as a result give off carbon dioxide.

REPORT OF WATER ANALYSIS

		Parts per million	Equivalents per million
Date Collected 10/30/58	Silica as SiO_2	5	
Source well	Iron as Fe_2O_3	1.2	
Date analyzed 11/4/58	Calcium as Ca	62	
Total dissolved mineral solids ppm	Magnesium as Mg	31	
Organic matter none ppm	Sodium and potassium as Na	38	
Suspended solids 5 ppm	Bicarbonate as HCO_3	250	
Chloroform, extractable (oil, etc.) none ppm	Carbonate as CO_3	0	
pH 7.7	Hydroxide as OH	0	
Phenolphthalein alkalinity as $CaCO_3$ 0 ppm	Chloride as Cl	11	
Methyl orange alkalinity as $CaCO_3$ 205 ppm	Sulfate as SO_4	138	
Hydroxide alkalinity as $CaCO_3$ 0 ppm	Nitrate as NO_3	0	
Hardness as $CaCO_3$ 282 ppm	Carbon dioxide as CO_2	10	
Specific conductance micromhos	Turbidity	5	

Physical characteristics of sample Clear when drawn

WATER-ANALYSIS REPORT FORM gives complete information about the water sample including physical characteristics when collected

Now let's examine the water analysis

Analyzing a water sample is the process of finding out how much of the various impurities and other chemical substances are present in water.

Results are usually expressed in parts per million (ppm) and tabulated on a form like the one shown above. Parts per million is a measure of proportion by weight such as one pound in a million pounds. Grains per gallon (gpg) is another way of expressing the amount of a substance present. One gpg equals 17.1 ppm. Individual impurities with possible exception of hardness are rarely reported as gpg. However, quantities in ppm are often converted to gpg for convenience in calculating capacity of water-treating equipment.

Water usually contains a wide variety of dissolved compounds. Each compound breaks into its respective ions when dissolved. In other words, atoms of the combination molecule separate. Although chemists can measure amount of each cation and anion in the solution, it's impossible to chemically analyze amount of each individual compound. We can only assume that various ions recombine in certain ways upon evaporation or precipitation. Ionic weight of ions such as calcium, sodium, sulfate and chloride can be determined. But this doesn't tell us how much individual calcium sulfate, sodium sulfate or sodium chloride originally went into the solution.

Since analysis measures only ions, never compounds, it's logical to use the ionic form. Usually no attempt is made to indicate hypothetical compounds. If the analyses do show them, they are figured by a chemist from their ionic weights by using certain arbitrary assumptions.

The combined form of analysis is best described as a rule-of-thumb attempt to put a water-analysis report in to shape for practical interpretation. It has fallen almost completely out of use because the ionic form is more convenient, easier to interpret and understand.

By adding a column for ppm expressed as calcium carbonate or equivalents per million (epm), it's possible to reduce all ions present to a common denominator. This makes it easy to (1) calculate amounts of reacting chemicals (2) size equipment and (3) check accuracy of analysis.

Expressing an ion such as calcium in terms of its calcium carbonate equivalent is done easily by comparing equivalent weights. Calcium carbonate at 50.1 is 2.5 times greater than calcium at 20.1. So calcium carbonate equivalent of calcium in our analysis is 62x2.5, or 155 ppm. Tables giving conversion factors for all ions are available. This method of expression is accepted as the common standard basis of reporting a water analysis. It's particularly useful for in-plant treatment control.

An equivalent per million is a unit chemical weight equivalent per million units of solution. To get epm, divide concentration in ppm by the equivalent weight of the element or radical. Equivalents are particularly helpful in calculating amounts of reacting chemicals from equations. For example, our sample analysis has 250 ppm of bicarbonate. Dividing by 61 (equivalent weight of bicarbonate) we get 4.10 epm. When we know epm it's easy to find how much 90% calcium hydroxide will match and destroy the bicarbonate. Multiply epm of bicarbonate by equivalent weight of lime. This amounts to 4.10x41.1, or 168.5 ppm of 90% calcium hydroxide. Since 120 ppm equals 1 lb per 1000 gal, our 168.5 ppm becomes 1.4 lb per 1000 gal. The analysis also can be evaluated by totaling positive and negative ions separately. As shown above, the two columns always must be in complete balance.

What is the meaning of pH in water chemistry?

Definition of pH is the logarithm of the reciprocal of hydrogen-ion concentration. It's also a number between 0 and 14 indicating degree of acidity or alkalinity. The pH scale resembles a thermometer or hydrometer scale. Just as a thermometer measures intensity of heat and a hydrometer the density of a solution, the pH scale indicates intensity of acidity or alkalinity.

Midpoint of the pH scale is 7 and a solution with this pH is neutral. Numbers below 7 denote acidity; those above alkalinity. Since pH is a logarithmic function, solutions having a pH of 6.0, 5.0 and 4.0 are 10, 100 and 1000 times more acid than one with pH of 7.0.

Now let's apply this to water chemistry. In addition to molecules of H_2O, pure water contains separated parts of molecules called hydrogen ions ($H+$) and hydroxyl ions ($OH-$). Amount of dissociation is constant at any given temperature. At 25 C the product of the $H+$ and $OH-$ concentrations is $1x10^{-14}$. When hydrogen-ion concentration changes, the hydroxyl-ion concentration changes in proportion and always in the opposite direction. If the $H+$ ions decrease, the $OH-$ ions increase enough so product of the two concentrations at 25 C remains $1x10^{-14}$. The exponent -14 is the basis of the pH scale, a method of expressing hydrogen-ion concentration in terms of a negative logarithm to the base 10.

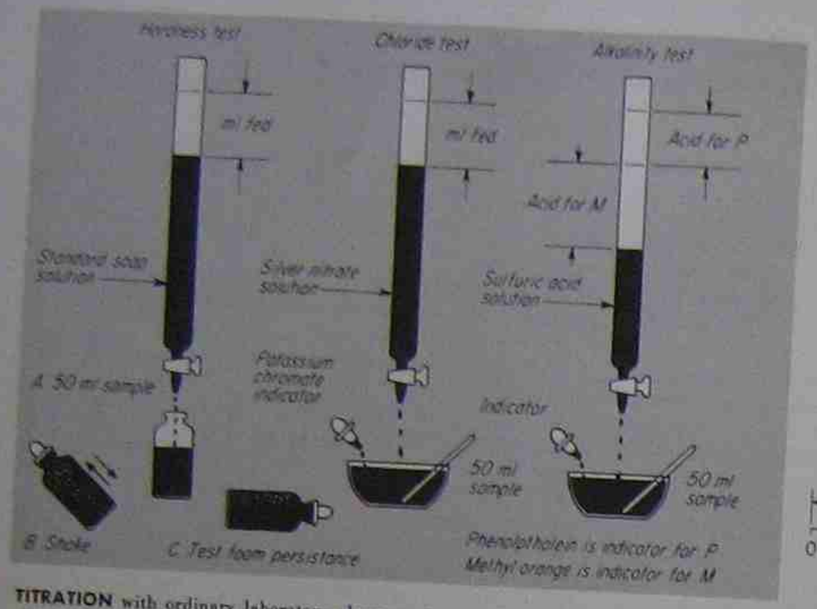
Acid or alkaline nature of a solution depends on whether hydrogen or hydroxyl ions predominate. Ionic theory is that salts, acids and bases are torn apart by water molecules to form positively or negatively charged fragments called ions. When acids are mixed with water, hydrogen ion is one result of the breakup.

In a mixture of bases and water, hydroxyl ions result. Hydrogen ions make a solution acid; hydroxyl ions tend to make it alkaline. When the solution contains one OH ion for every H ion, acid effect of one balances the alkaline effect of the other. Result is a neutral solution with a pH of 7.0.

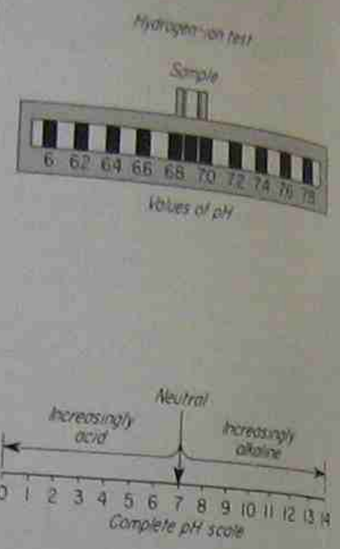
Equivalent weights are a handy tool for calculations

Chart at right tabulates both epm and ppm (expressed as calcium carbonate). Values for the various ions are taken from typical analysis on facing page. Any analysis can be checked quickly by adding equivalent cations and anions. For convenience, if negative anions are higher, balance is usually considered sodium. If totals are way out of balance, the analysis is probably in error. If cations are in excess, the missing anions may be nitrates, provided the remaining part of analysis is both complete and correct. In all cases positive cations must equal negative anions.

Water analysis	Ionic ppm	(+) epm cations	(−) epm anions	ppm as $CaCO_3$ cations	ppm as $CaCO_3$ anions
Magnesium (Mg)	31	2.54	—	127	—
Calcium (Ca)	62	3.10	—	155	—
Sodium (Na)	38	1.64	—	83	—
Bicarbonate (HCO_3)	250	—	4.10	—	205
Sulfate (SO_4)	138	—	2.87	—	145
Chloride (Cl)	11	—	0.31	—	15
Totals		7.28	7.28	365	365



TITRATION with ordinary laboratory glassware is one of many analytical methods available for analyzing water. It's commonly used for hardness, chloride and alkalinity tests



COMPARATOR compares sample color with that of many standards to determine pH

Variety of test methods measure water impurities

Complete water analysis is a job for an experienced chemist. But every engineer should know how to make routine water tests such as are used in the daily operation of a water-treating system. Basic knowledge of testing methods is an extremely valuable tool when it comes to interpreting water analyses, selecting treatment systems and making operating adjustments on equipment.

There are usually many analytical methods available for each impurity or chemical substance in water.

Titration is one of the more commonly used procedures. Standard solution from a burette or calibrated container is added to the water sample. When the endpoint is reached, usually signalled by a color change in the sample, the burette solution level is noted. It's best to use an automatic burette which starts each titration at the zero mark, thus eliminating need for subtraction to get the amount of standard solution used. This reading is proportional to the amount of substance present.

Colorimetric methods also are widely used because of their simplicity. Test is based on developing a color in the sample proportional to amount of substance present. Then concentration of substance in sample is found by comparing its color with color standards of known concentration. Some comparators have color standards sealed in glass ampoules; others use standard colored-glass disks.

Water hardness can be found by several methods including (1) gravimetric analysis for calcium and magnesium (2) colorimetric titration (3) soap test (4) palmitate titration and (5) soda reagent procedure. Last two methods are rarely used. Gravimetric analysis is restricted to the lab for precise work; colorimetric titration and the soap test have proved very popular.

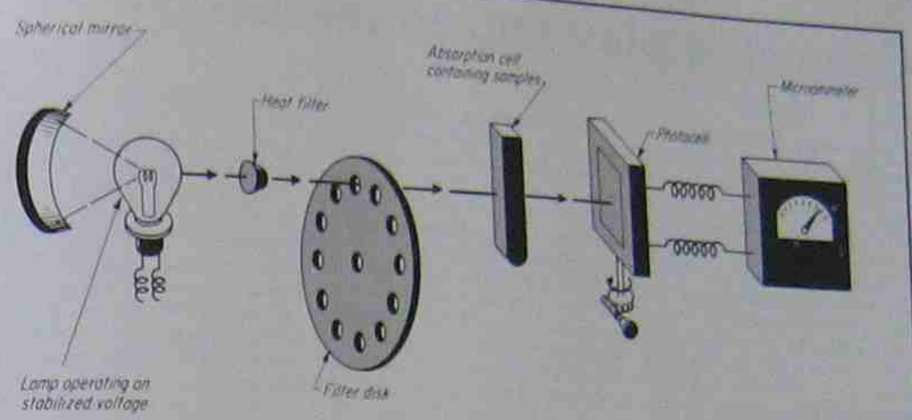
Soap test for hardness is shown above. Fill burette with standard soap solution (APHA), add to 50-ml sample of water in a bottle and shake until permanent lather forms (it lasts at least 5 min). Subtract 0.3-ml lather factor from total soap used. Multiply remainder by 20 to find hardness of sample expressed in ppm as calcium carbonate.

Chloride test calls for a burette filled with standard silver-nitrate solution. Take a 50-ml water sample and neutralize it by adding 4 or 5 drops of phenolpthalein indicator plus enough sulfuric acid to make solution colorless. Then add five drops of potassium-chromate indicator. This turns solution a bright yellow. Slowly add silver nitrate from the burette until one drop produces a permanent reddish color. Subtract 0.2 ml from amount of nitrate used and multiply remainder by 20 to find amount of chloride present in ppm as Cl.

Alkalinity titration is done in two steps. Fill burette with N/50 sulfuric acid (fiftieth normal). Then add 4 or 5 drops of phenolpthalein indicator to 50-ml sample of water. If water turns red, add acid and stir until color disappears. Note reading on burette. Now add four drops of methyl-orange indicator to give a yellow color. Continue adding acid and stir until color changes to reddish orange. Acid used in the first step multiplied by 20 equals P alkalinity in ppm. Acid used in second step plus first step multiplied by 20 equals M alkalinity in ppm. Both figures are expressed in terms of calcium carbonate. Box, on facing page, explains the relationship of P and M alkalinity in greater detail.

Hydrogen-ion concentration, expressed as pH is found in several ways. Simplest method uses color comparators and dye-indicator solutions that cover full range of 0 to 14 pH in a series of steps. For best results select an indicator and color comparator that puts pH of sample somewhere near midpoint of comparator scale. Add ½ ml of color indicator to 5-ml water sample in test tube. As shown on facing page, compare resulting color with tinted liquid in comparator vials and read pH directly on scale when the colors are matched. If close pH control is important, or if color test is impractical, electrical measuring instruments called pH meters will indicate, record and control pH with a high degree of accuracy.

Complete instructions on all phases of water testing are contained in (1) *Manual on industrial water*, published by ASTM and (2) *Standard methods for the examination of water, sewerage and industrial wastes*, published jointly by the American Public Health Association and the American Water Works Association.



Photometers fill need for more accurate analysis

Place water sample in absorption cell, above. Turn on instrument to pass light from lamp and mirror combination through heat filter and filter disk. Select a filter that absorbs all light except wave length that is best for the test. Filtered light goes through solution in absorption cell. When white light enters a solution, some of it is absorbed. Light coming out gives a sensation of color to the human eye. Color depth or strength varies with its intensity. In this instrument photocell takes place of your eye, measures intensity of light rather than color. Electric current produced by photocell is proportional to light intensity on its face. So microammeter reading is proportional to color intensity. This, in turn, is proportional to concentration of the ion measured. Where extreme sensitivity is needed, spectrophotometers can be used to produce filtered light that is more nearly monochromatic. It's invaluable for the lab, but too expensive for routine control except in the larger plants.

Here's what you should know about P and M alkalinity

Phenolpthalein (P) and methyl orange (M) alkalinity titrations don't indicate any one ion directly; they measure the many ions contributing to alkalinity including bicarbonate, carbonate, hydrate, phosphate, silicate, etc. So it's simpler to record results of analyses in terms of P and M alkalinity for plant control. However, alkalinity is usually expressed in bicarbonate, carbonate and hydrate forms. Standard practice assumes that (1) titration to P endpoint determines all hydroxide and one-half of carbonate alkalinity (2) methyl-orange titration measures sum of bicarbonate, carbonate and hydroxide. Table below gives the form of alkalinity in water for each of the five different P and M conditions.

P and M alkalinity	Hydrate (OH)	Carbonate (CO_3)	Bicarbonate (HCO_3)
P = 0	0	0	M
P = M	M	0	0
P = ½ M	0	M	0
P < ½ M	0	2P	M − 2P
P > ½ M	2P − M	2(M − P)	0

Chemicals play important basic role

Growing variety of chemicals are the foundation of water treatment. They may be added directly to fix dissolved oxygen, adjust the pH, neutralize carbon dioxide, form protective film on metal surfaces, etc.

Chemicals are also indispensable in most water-treating equipment. Salt, caustic and acid regenerate ion-exchange units; lime and soda ash precipitate hardness as an insoluble compound in both hot- and cold-process softeners; coagulants and coagulant aids help remove suspended solids in clarifiers. Table lists chemicals most generally used for coagulation, scale and corrosion control, disinfection, softening, etc.

Coagulant aids in organic polymer class are coming more into the picture. They help produce a tougher, faster settling floc than is possible with the coagulant alone. This often increases plant capacity, reduces amount of coagulant and other chemicals used in the treatment.

Hydrazine, neutralizing and filming amines are recent additions to the arsenal of weapons for combating corrosion. Complete reaction of hydrazine with oxygen produces nitrogen and water. No additional solids are added. One part of hydrazine reacts with one part of oxygen. Since it's available as a 35% solution about three parts are actually needed. Hydrazine also reduces ferric oxide Fe_2O_3 to the magnetic oxide Fe_3O_4, to increase heat transfer and boiler efficiency. If used in high enough concentrations, ammonium hydroxide forms as a byproduct of the reaction.

Neutralizing amines are typical of nitrogen-containing compounds used effectively to control corrosion in steam condensate systems. Both ammonia and amines such as morpholine and cyclohexylamine reduce iron pickup by raising pH and neutralizing carbon dioxide. About two ppm neutralizes each ppm of carbon dioxide.

Filming amines protect against both dissolved oxygen and carbon dioxide attack by forming a protective film on metal surfaces. About 2 to 3 ppm fed continuously is enough to form and maintain film.

Chemical and common name	Water-treatment use
Alum, ammonium $Al_2(SO_4)_3 \cdot (NH_4)_2SO_4 \cdot 24H_2O$ *Ammonia or crystal alum*	Coagulation
Alum, potassium $Al_2(SO_4)_3 \cdot K_2SO_4 \cdot 24H_2O$ *Potash alum*	Coagulation
Aluminum sulfate $Al_2(SO_4)_3 \cdot 14H_2O$ *Filter alum*	Coagulation
Amines, filming (Octadecylamine, etc)	Corrosion control
Amines, neutralizing (Morpholine, benzylamine cyclohexylamine, etc)	Corrosion control
Ammonium chloride NH_4Cl *Sal ammoniac*	Disinfection, corrosion control
Ammonium sulfate $(NH_4)_2SO_4$ *Sulfate of ammonia*	Disinfection (combined with chlorine), corrosion control
Anhydrous ammonia NH_3 *Ammonia*	Disinfection, corrosion control, activates silica
Antifoaming agents (Polyamides, polyalkylene-glycol derivatives)	Internal-boiler feedwater
Ammonium hydroxide NH_4OH *Ammonia water*	Disinfection (combined with chlorine), corrosion control

Chemical and common name	Water-treatment use
Calcium hydroxide $Ca(OH)_2$ *Hydrated or slaked lime*	Softening
Calcium hypochlorite $Ca(OCl)_2 \cdot 4H_2O$ *HTH, Perchloron*	Disinfection
Calcium oxide CaO *Chemical or unslaked lime*	Softening
Calcium sulfate $CaSO_4 \cdot 2H_2O$ *Gypsum*	Reduces excessive sodium carbonate and bicarbonate alkalinity
Carbon, activated *Carbo-Dur, Hydrodarco*	Taste and odor control
Chlorinated lime $Ca(OCl)_2—CaCl_2 \cdot H_2O$ *Bleaching powder*	Disinfection
Chlorine Cl_2 *Chlorine gas, liquid chlorine*	Disinfection; slime, algae, taste and odor control; activates silica
Chlorine dioxide ClO_2	Disinfection, taste and odor control
Chlorinated phenols Sodium pentachlorophenate Sodium trichlorophenate	Slime and algae control
Clay Bentonite	Coagulation aid

Chemical and common name	Water-treatment use
Copper sulfate $CuSO_4 \cdot 5H_2O$ *Blue vitriol*	Algae control
Dolomitic lime $CaO + MgO$ 58% CaO, 40% MgO	Softening with silica removal
Dolomitic lime, hydrated $Ca(OH)_2 + MgO$ 62% $Ca(OH)_2$, 32% MgO	Softening with silica removal
Ferric chloride *Ferrichlor* $FeCl_3$ (35-40% solution) Crystal ferric chloride $FeCl_3 \cdot 6H_2O$ Anhydrous ferric chloride $FeCl_3$	Coagulation
Ferric sulfate $Fe_2(SO_4)_3$ *Ferrisul, Ferrifloc*	Coagulation
Ferrous sulfate $FeSO_4 \cdot 7H_2O$ *Copperas*	Coagulation
Hydrazine hydrate $N_2H_4 \cdot H_2O$ *Hydrazine*	Oxygen scavenger
Hydrochloric acid HCl *Muriatic acid*	Alkalinity reduction and demineralizing (regenerant)
Magnesium oxide MgO *Magnesia*	Silica removal
Organic polymers Polyelectrolytes	Coagulation aid
Potassium chromate $K_2CrO_4 \cdot 10H_2O$	Corrosion control
Potassium dichromate $K_2Cr_2O_7$	Corrosion control
Potassium permanganate $KMnO_4$ *Permanganate*	Slime and algae control
Phosphoric acid H_3PO_4	Softening
Sodium aluminate $Na_2O \cdot Al_2O_3$ *Soda alum*	Coagulation
Sodium bisulfite $Na_2S_2O_5$ *Sodium metabisulfite*	Taste and odor control, iron removal from ion exchange units

Chemical and common name	Water-treatment use
Sodium carbonate Na_2CO_3 *Soda ash*	Softening
Sodium chloride $NaCl$ *Salt*	Softening, dealkalizing (regenerant)
Sodium chromate $Na_2CrO_4 \cdot 10H_2O$	Corrosion control
Sodium dichromate $Na_2Cr_2O_7$	Corrosion control
Sodium hydroxide $NaOH$ *Caustic soda*	Demineralizing (regenerant), softening and alkalinity adjustment
Sodium hypochlorite $NaOCl$	Disinfection
Sodium nitrate $NaNO_3$	Caustic embrittlement control, corrosion control
Sodium phosphate, mono $NaH_2PO_4 \cdot H_2O$ *Monobasic ortho phosphate*	Softening
Sodium phosphate, di $Na_2HPO_4 \cdot 12H_2O$ *Dibasic ortho phosphate*	Softening
Sodium phosphate, tri $Na_3PO_4 \cdot H_2O$, $Na_3PO_4 \cdot 12H_2O$ *Tribasic ortho phosphate*	Softening
Sodium phosphate, hexameta $(NaPO_3)_6$ *Polyphosphate*	Softening, scale and corrosion control
Sodium tripolyphosphate **Sodium decaphosphate** *Polyphosphates*	Softening, scale and corrosion control
Sodium silicate $Na_2O \cdot SiO_2$ *Water glass*	Coagulation, corrosion control
Sodium sulfite Na_2SO_3	Oxygen scavenger
Sulfur dioxide SO_2	Scale control and alkalinity reduction
Sulfuric acid H_2SO_4	Alkalinity reduction and demineralizing (regenerant)
Tannins, alginates, starches, glucose and lignin derivatives Organics	Scale and corrosion control, boiler-water coagulation
Quaternary ammonium compounds (Alkyl dimethyl benzyl-ammonium chloride, etc)	Slime and algae control

Clarification is usually first step

Clarifying water is process of removing turbidity and sediment. It's usually first step in treatment since most applications call for water that is essentially clear and colorless. However, as shown later, it can be combined with lime softening in one unit.

Coarse particles settle rapidly and are sometimes removed economically by flowing water through a basin at velocities low enough to let sand and silt settle. This happens naturally in many ponds and lakes if the water is quiet enough. Suspended matter settles leaving a clear if not always colorless water supply.

More common clarification calls for specially designed equipment and use of coagulating chemicals. Two typical systems are shown above. Filters are also employed to remove suspended matter by a mechanical screening action. Settling equipment normally precedes filtration to lighten load on the filters by removing bulk of suspended matter. But if raw water turbidity isn't too high, filters often handle the job alone. There are times when water from basic settling tanks does not require any filtration.

Coagulation is the gathering together of finely divided or colloidal suspended matter into larger particles. In this way coagulating agents speed up settling of suspended matter in water-treating equipment.

Coagulants such as aluminum sulfate (alum), sodium aluminate, ferrous sulfate (copperas), ferric chloride, etc, produces a jelly-like spongy mass called floc. It has an enormous surface area per unit of volume that traps, absorbs particles of turbidity, color and precipitates. Although floc formation is a chemical reaction, the gathering in or adsorption of suspended solids is a mechanical process.

Aluminum compounds, especially alum and sodium aluminate are the most widely used coagulants. They both precipitate a relatively tough, heavy aluminum-hydroxide floc that has remarkable ability to remove suspended solids from water. Iron salts such as ferric sulfate, precipitate ferric-hydroxide floc over a wide range of pH values. But for each specific use pH must be closely controlled. In practice this is done by feeding an acid or alkali such as lime, soda ash or caustic soda. Clay, activated silica, organic polyelectrolytes and other aids are used to foster coagulation. In general coagulant aids help produce larger and heavier floc particles over wider pH ranges with greater ability to remove turbidity.

Alum reacts with soluble alkalis to form aluminum hydroxide. This compound is practically insoluble over the pH range of 5.7 to 7.5. Particles of aluminum hydroxide are positively charged and repel each other. But negative ions in water such as chlorides, carbonates, sulfates, clay and bacteria neutralize these positive charges and allow coagulation into visible floc.

Aluminum hydroxide dissolves and ionizes as a negative acid in the pH range below 5.7; as a positive alkaline compound above a pH of 7.5. The useful insoluble compound forms best in the pH zone between these limits. So from a chemical standpoint coagulation with alum depends on both the water analysis and the pH after adding the alum.

When there is natural alkalinity in the water, aluminum sulfate hydrolizes into aluminum hydroxide, liberating sulfuric acid. This reacts with alkalinity to form calcium sulfate and carbon dioxide. Each ppm alum added consumes about 0.5 ppm of natural alkalinity. If alkalinity isn't high enough, lime or soda ash is added. It takes 0.4 ppm of lime (90% calcium hydroxide) or 0.5 ppm soda ash for each ppm of alum.

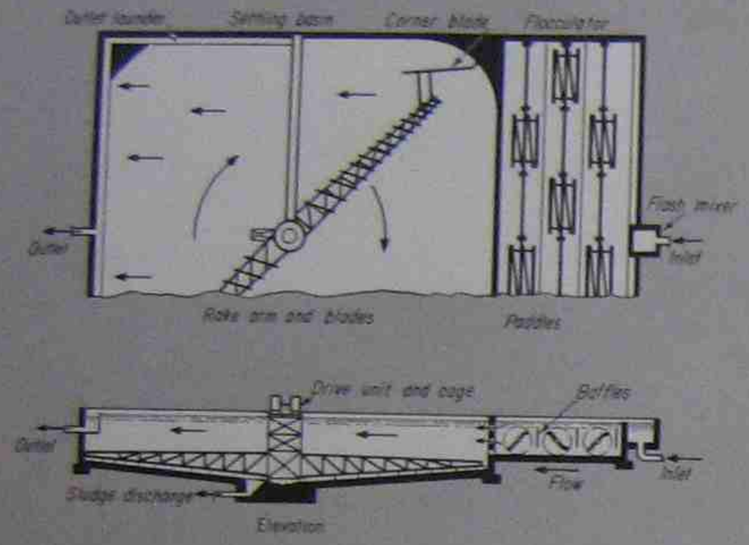
Actual amount of lime or soda ash added is controlled to give the best pH value for the coagulated water.

Amount of alum needed is almost impossible to calculate. Only practical way is to run lab-jar field tests under actual operating conditions and find best dosage by the trial-and-error technique. Actual amount will vary with fineness and quantity of turbidity, water temperature, amount of mixing, etc. Optimum results one day may not be correct on the next.

Since sodium aluminate is slightly alkaline, it's often added with alum for low pH coagulation. But usually it's combined with lime and soda ash in a softener for coagulation at high pH. Sodium aluminate, above, reacts with calcium bicarbonate, throwing calcium carbonate out of the solution to produce aluminum-hydroxide floc. This floc envelopes both particles of precipitated calcium carbonate and suspended matter for easy settling and removal.

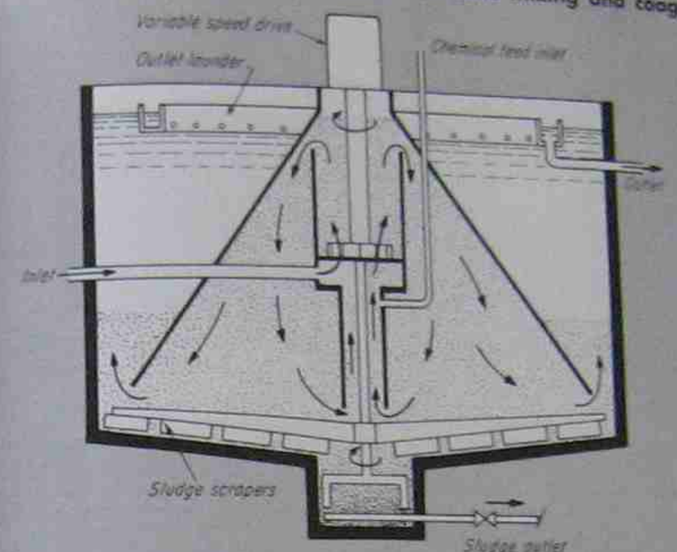
There are no simple rules to guide your choice of a coagulant, coagulant dosage, coagulant aid or pH range. Too much depends on the water analysis, temperature of water, type of clarification equipment, load conditions and end use of the treated water. But a few simple tests conducted under actual operating conditions will point the way to best results at the lowest overall treatment cost.

Flash mixing, flocculation and settling produce clarified water

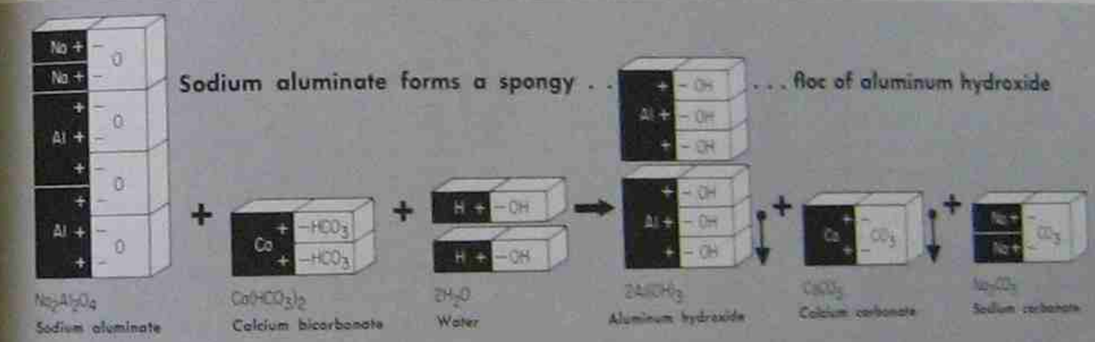


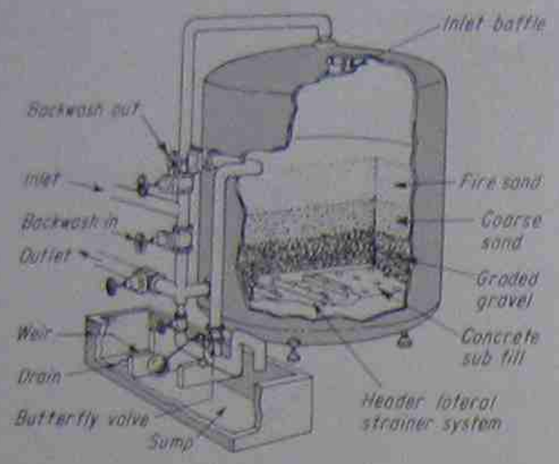
Water enters flash mixer, left, and is mixed rapidly with coagulant by a rotating stirrer. Water, coagulant and finely dispersed precipitates are then given a gentle mixing as they flow through rotating paddles in flocculator. This promotes the growth of small particles of turbidity, color and precipitates into larger sized floc that settles more readily. Settling basin receives this mixture through submerged ports on its right side. Detention time varies anywhere from two to six hours. Basin is equipped with a rotating vertical shaft with radial arms and rake blades that just clear bottom. Solids settled from the water are raked inwardly to a central discharge hopper and removed continuously. Clarified water then flows into collecting flume at far left.

Many clarifier designs combine mixing and coagulation in same unit

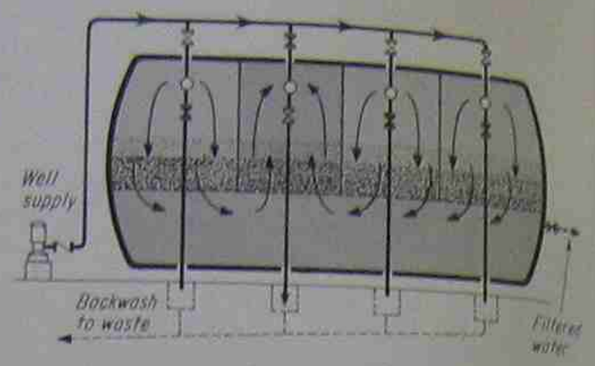


Raw water enters lower part of central uptake, is mixed with treatment chemicals and precipitates from bottom of the unit. Mixture of water and chemicals is lifted through central uptake by a variable-speed agitator and discharged into the main mixing chamber where reactions are brought to completion. Some water and suspended precipitates enter lower end of the uptake for recirculation and contact with incoming chemicals and raw water. New floc formation is encouraged by contact with these previously formed precipitates. Rest of water enters outer settling section. Lighter precipitates are kept suspended and clarified water rises to the outlet flume above. Heavier particles settle and are moved along bottom by a rotating scraper to central sludge pit.

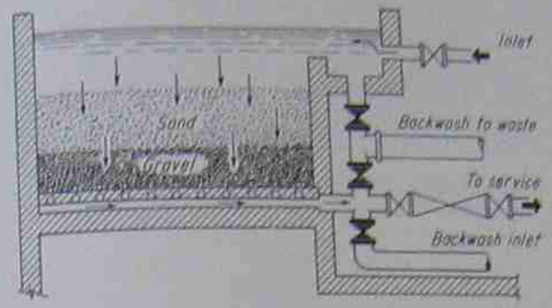




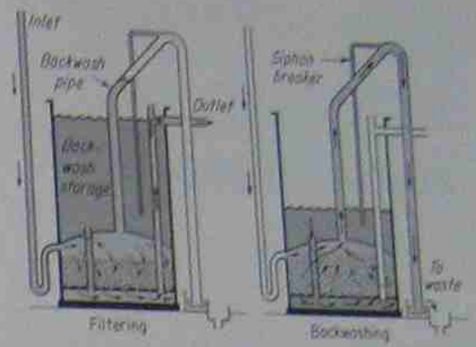
PRESSURE FILTERS operate at rates of 2 to 4 gpm per sq ft. Filter sizes range from 1 to 11 ft in diameter; 4 to 5 ft in height



HORIZONTAL FILTERS may be divided into sections. Here, we take filtered water from any three cells to backwash one cell



GRAVITY DESIGNS handle large flows economically. Rectangular shape and reinforced concrete construction are most widely used



VALVELESS GRAVITY FILTER automatically backwashes at preset head loss, rinses and returns to service without human attention

Many filter designs compete for job of clarifying water

Water is filtered by passing it through fine strainers or other porous media to remove suspended solids mechanically. Degree of filtration depends on fineness of the filtering media and type of filter aid used.

In pressure or gravity designs, above, raw water flows down through graded layers of sand and gravel, anthracite, calcite, etc. Clarified water is collected at the bottom. If filters follow settling tanks, a light floc comes over to form a mat on the filter bed. This keeps any finely divided particles from passing through. When filters are used alone, a separate coagulant feed is needed.

Cleaning filters for effective filtration is important. Frequency of job varies with allowable head loss through the filter (usually 8 to 12 ft). Practical limit is when floc or turbidity appears in outlet.

Backwashing with clarified water is most common cleaning method. Backwash rate varies with water temperature, but is usually in the range of 10 to 20 gpm per sq ft and is chosen to give at least 50% bed expansion. While this keeps grains of filter media close enough to rub each other clean, it doesn't lift them high enough to be lost down the drain. Rinsing puts another mat on the filter before it goes back in service.

Pressure filters are popular because they can be installed in piping systems without repumping. They also permit high-temperature operation without heat loss. Gravity designs, a must for municipal treatment, are generally preferred for handling larger flows. Individual units come in many sizes, shapes, materials, and use numerous filter media.

Horizontal pressure filters can pose the problem of high backwash flows because of large filtering area in each unit. But when filter is compartmented, above, only one section at a time is backwashed. This means lower backwash flows.

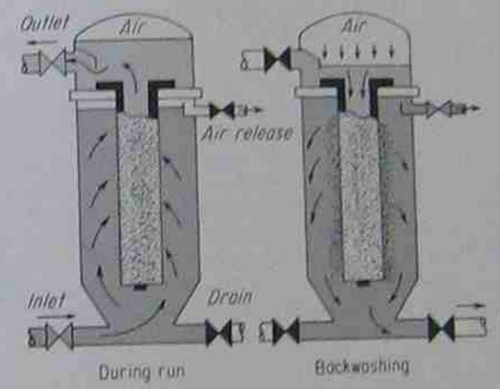
Valveless gravity filter, top right, facing page, is a relative newcomer. During operation, the water level rises slowly in backwash pipe. At preset level or head loss it automatically spills out the pipe to waste. Water then flows up through the sand bed from backwash storage and out the same pipe. Backwashing stops when end of siphon breaker is exposed. Unit rinses and returns to service without any operating attention.

Another unique gravity filter, lower left, facing page, is divided into many compartments. An overhead carriage has pumps for backwashing. Carriage moves automatically and backwashes each filter section in turn.

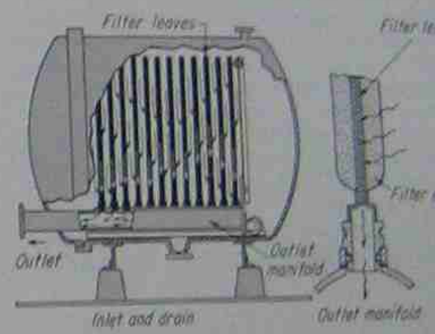
Leaf and tubular filters both employ filter aids to form a cake on their elements. Leaf design handles moderate turbidities, can be used for direct filtration of some water in place of coagulators and sand filters. Operating cost tends to be higher, but equipment cost is usually less and operation is simpler. Entire internal assembly is removed for cleaning and filter cake is stripped off by a shaker or vibrator attachment.

Tubular filter-element units store their own backwash water. Air pressure builds up during run. To backwash, close outlet, then inlet valve. Open air release valve. This forces water through the filter elements in reverse direction at extremely high rates. Filter cake is blasted loose from the elements and drained off.

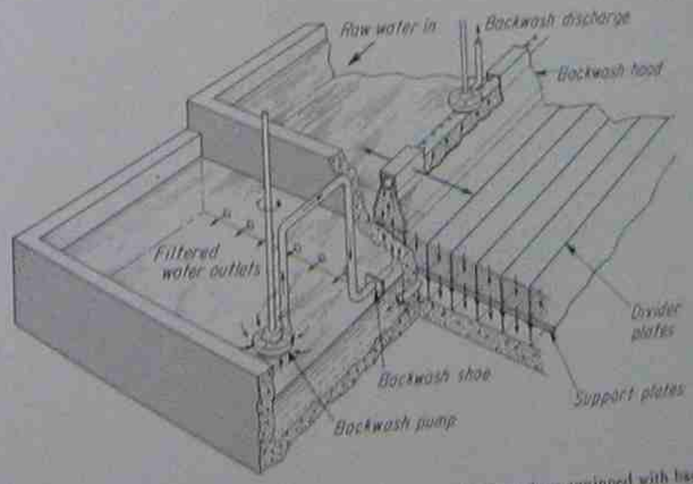
Cartridge filters are widely used for polishing water. Since fine solids in the size range from 1 to 75 microns are readily removed, it's important to know size of the particles in the water. Best foundation is a wet-screen analysis of these solids with an idea of the maximum particle size. When pressure drop reaches 25 to 30 psi, economical life of the cartridge is reached and it must be replaced. These cartridges come in many different materials and some are designed for mechanical self-cleaning.



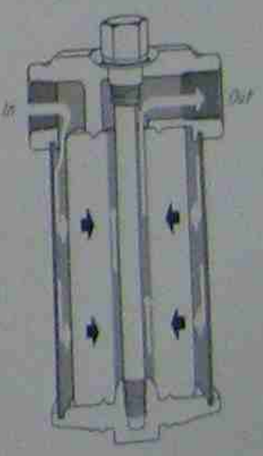
TUBULAR FILTERS often use filter aids like diatomite to form a filter cake on each element. Backwash is powered by air pressure



LEAF DESIGNS also use filter aids. Entire unit of leaves, head and manifold are removed through quick-opening door for cleaning

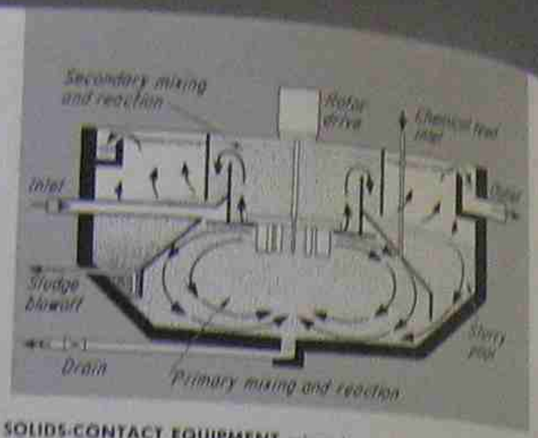


COMPARTMENTED GRAVITY DESIGN has moving overhead carriage equipped with backwash pumps. Each filter-bed section is backwashed automatically in turn with filtered water



CARTRIDGE FILTERS use disposable type elements to remove fine solids from water

Lime softeners tame four raw-water impurities



SOLIDS-CONTACT EQUIPMENT mixes incoming raw water, treatment chemicals with solids formed previously in lower mixing zone

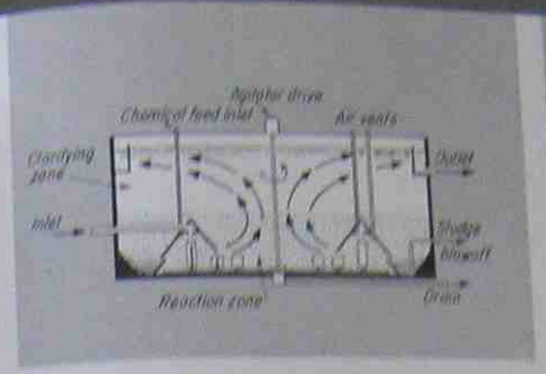
Four of water's most troublesome impurities are removed effectively by chemical reaction with combinations of lime, soda ash and caustic. (1) Calcium hardness precipitates as calcium carbonate and magnesium hardness as magnesium hydroxide. (2) Bicarbonate alkalinity is first converted to carbonate form and then removed as calcium carbonate. (3) Silica comes out as an insoluble silica-magnesium complex when it reacts with magnesium hydroxide. (4) Turbidity from suspended solids and magnesium hydroxide and calcium carbonate sludge is removed by settling and filtration.

Cold process is the term used when these reactions are carried out at room temperature. Solids-contact units, shown above, handle this job with a detention time of 60 to 90 minutes. When water is heated well above room temperature it's called a hot process. This equipment, covered later, actually operates above 212 F. All these units are designed for continuous operation. Batch type treatment is seldom used today.

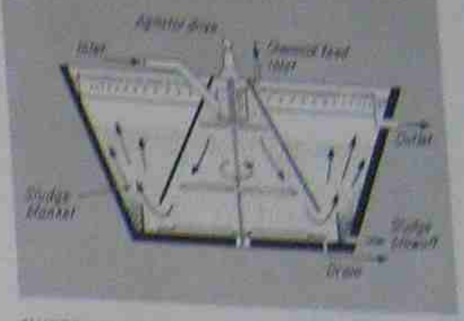
Now let's take a close look at hardness and its removal by precipitation. Calcium and magnesium in water are present as either carbonate or noncarbonate hardness. Bicarbonates of calcium and magnesium are the carbonate hardness. Boiling will destroy it by driving off carbon dioxide and precipitating carbonates. This is easier to visualize when you have a complete understanding of how both carbonates and bicarbonates react.

Free carbon dioxide and water (carbonic acid) react with calcium hydroxide to form calcium carbonate. Calcium carbonate then reacts with more carbonic acid to produce soluble calcium bicarbonate. If enough carbon dioxide is present, all carbonates will be converted to soluble bicarbonates.

Now suppose there is just enough carbon dioxide to change all hydroxide to carbonate form, but only part of the carbonates to bicarbonates. This water then contains both carbonates and bicarbonates, but no free carbon dioxide. All carbon dioxide in the carbonate radical is termed *firmly bound*, along with half that in the bicarbonate. Remaining half of the carbon dioxide in bicarbonate is called *half bound*. If this water is boiled to remove carbonate hardness, it's the half-bound carbon dioxide that comes off when bicarbonates are converted to carbonates.



FLOW RATE of this design ranges from 0.75 to 2.0 gpm per sq ft of top surface. Low range is for coagulation; high range for softening



SLUDGE BLANKET containing the chemical precipitates is kept in suspension by combined mechanical agitation and hydraulic flow

Noncarbonate hardness is present as sulfates, chlorides and nitrates of calcium and magnesium. These neutral salts aren't precipitated by heat, but calcium sulfate forms a hard scale when water is evaporated and concentrated. To show how noncarbonate hardness precipitates as a harmless compound, we'll first explain what happens to materials in solution.

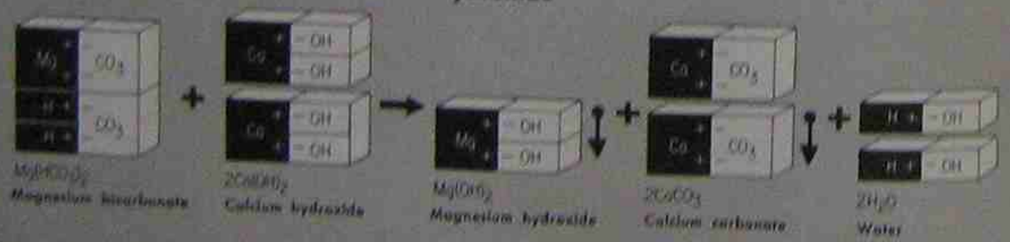
Solubility is the amount of solid that can be dissolved in a solute, in this case, water. For example, add common salt to water and stir. You'll find it dissolves until it reaches a point where no more goes into solution. Take this solution and filter it to remove any undissolved salt. Then evaporate the water and weigh the amount of salt that remains. If there are 3 lb of salt for each gallon of water evaporated, this is the solubility of salt in water at that temperature. If a solution contains less than this, nothing happens during evaporation until the concentration of 3 lb per gal is reached. Then salt starts coming out of the solution.

Precipitation takes place in simple cases of boiling or evaporation because solubility of the compound is exceeded. But when several substances are dissolved in the same solution it's a more complex problem.

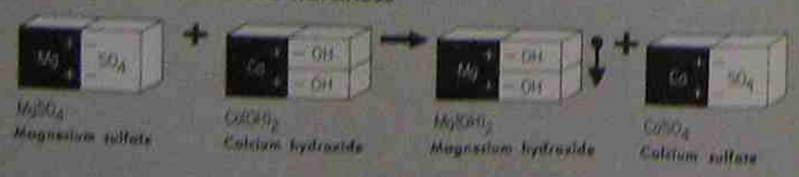
Suppose we have one compound in solution and add another that's also completely soluble by itself. These two compounds may react chemically. One product of the reaction may be less soluble than either of the original compounds. It will then precipitate or come out of solution because of the chemical change.

As inorganic chemicals dissolve in water they dissociate or break into ions. Calcium sulfate forms calcium and sulfate ions; sodium phosphate separates into sodium and phosphate

Carbonate hardness precipitates as an insoluble hydroxide



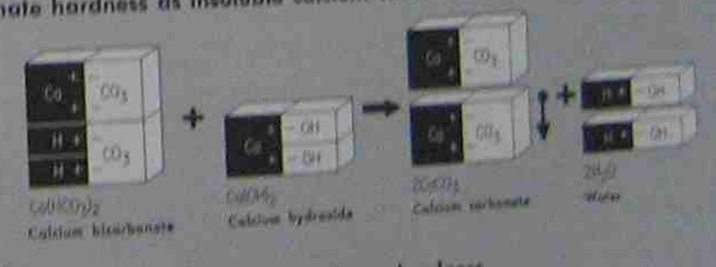
Lime treatment is first step in removing noncarbonate hardness



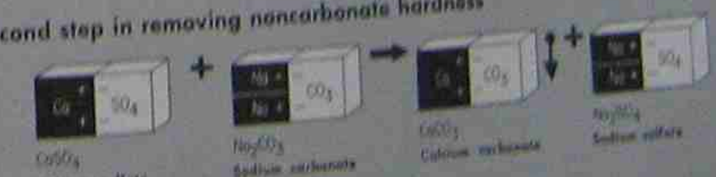
Magnesium hydroxide is precipitated, but reaction forms calcium hardness



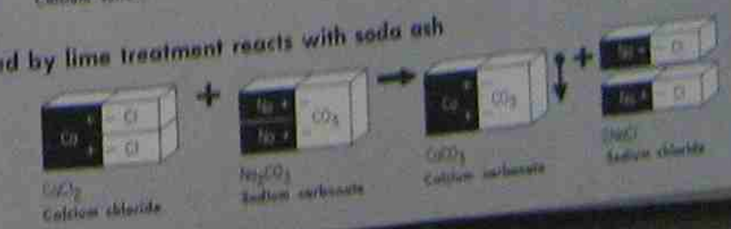
Lime also removes carbonate hardness as insoluble calcium carbonate

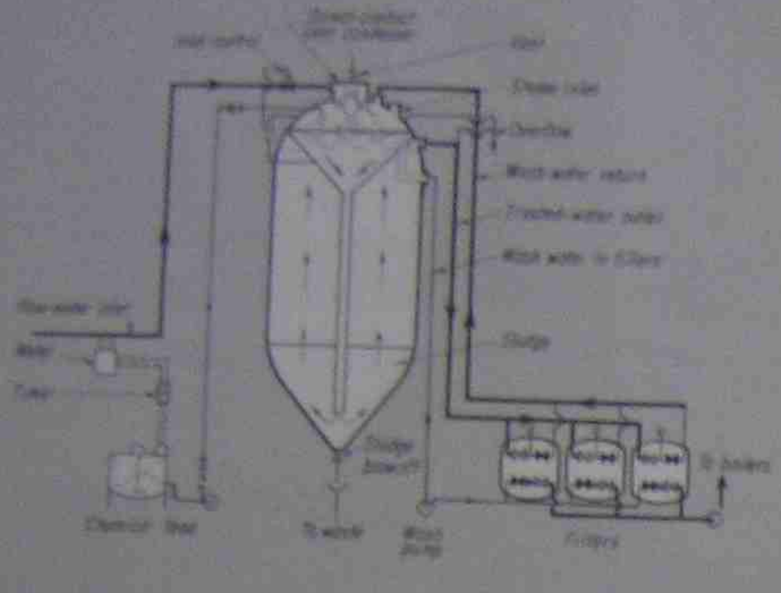


Soda-ash treatment is second step in removing noncarbonate hardness

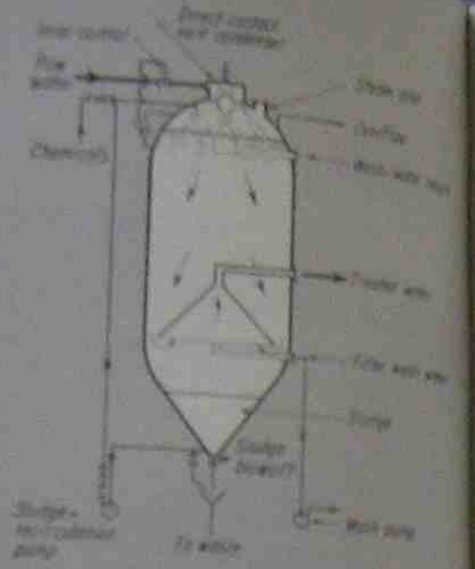


Calcium hardness formed by lime treatment reacts with soda ash





HOT-PROCESS SOFTENER mixes steam, raw water and chemicals in upper zone. Water then flows to bottom, rises through sludge blanket and discharges to anthracite filters



DOWNFLOW DESIGN uses recirculated sludge. Usual detention time is 60 minutes

Hot-process softeners use steam for more efficient removal

ions. When both are present in water we not only must know their own solubility, but that of their reaction products—sodium sulfate and calcium phosphate.

Solubility product of the various ion combinations is used to predict what compounds, if any, will precipitate. In our example, calcium sulfate has a solubility of 1.67 grams per liter. Divide 1.67 by its molecular weight of 136 to get a gram molecular weight of 0.00579 each for calcium and sulfate. The solubility product is then 0.0079 (0.0079) or 0.000062 (6.2×10^{-5}). This is much greater than calcium phosphate's solubility product of 2.2×10^{-33}. So calcium ions precipitate as calcium phosphate instead of calcium sulfate. The sulfate won't precipitate as long as there is excess phosphate present.

Treatment chemicals are generally used to lower solubility product of scale-forming impurities and to precipitate them as a sludge.

Either lime or caustic soda gives hydroxide for precipitation of magnesium hydroxide. Carbonate needed to precipitate calcium is usually added as soda ash. But some carbonate is available when natural bicarbonate is converted to carbonate form by use of lime or caustic soda.

Although raw water may contain enough magnesium to reduce silica content, it's usually added in pure form as magnesium oxide or as a component of dolomitic lime.

Cold-process treated water is never completely softened because (1) it takes too long for reactions to go to completion and (2) both calcium carbonate and magnesium hydroxide are slightly soluble in water. Theoretically residual hardness can be reduced to 25 ppm. Actually it's rarely taken below 50 ppm. Lowest silica residuals produced by cold-process treatment of high-silica waters are in the range of 5 ppm.

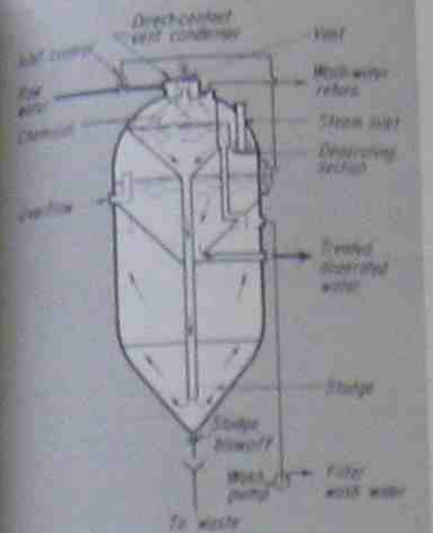
After-precipitation of calcium carbonate sludge from treated water is a problem posed by the high lime excess needed to complete the reactions in cold-process softeners. One solution is to recarbonate by passing carbon-dioxide gas through the softened water. This neutralizes any excess lime and converts residual calcium carbonate to soluble bicarbonate. Organic and phosphate surface-active agents also retard after-precipitation.

Hot-process softeners are used for boiler feedwater treatment. Units, above, operate at 212 F or higher. Heat source is live or exhaust steam.

Cold water enters unit through a float-controlled regulating valve in reservoir for water level changes in the sedimentation tank. Water is heated by spraying it into the upper steam space. Inlet flow actuates a proportioning device to control amount of lime and soda ash fed to the heating and mixing zone. Chemical reactions, already described, take place almost instantly. Sedimentation proceeds at a rapid pace because of the elevated temperature. Sludge collecting cone at bottom receives the precipitates and discharges them to the sewer periodically. Clarified water leaves the settling tank and is fed to the anthracite filters for polishing.

Hot-process equipment is capable of treating large flows in relatively small units. Chemical dosages are much lower than required by cold-process units. Treatment jobs handled by the hot-lime soda softener include (1) softening by removing calcium and magnesium (2) silica removal with magnesium salts (3) oxygen removal and (4) removing turbidity.

Treated water is comparatively stable compared to cold process. However any marked increase in



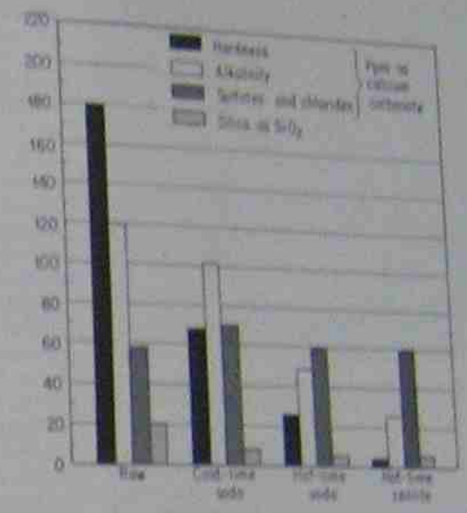
DEAERATING SECTIONS can be added to remove oxygen from the softened water

# of hardness, silica

temperature such as in economizers or closed heaters may cause after-precipitation. Then supplementary chemical treatment is called for to prevent any objectionable deposits.

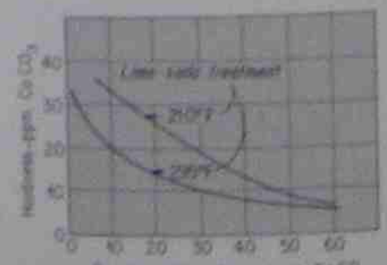
Controlling a hot-process unit is generally more difficult than controlling a zeolite softener since more test and adjustments must be made. Hot-lime zeolite system, below, combines best features of both units.

Here's how cold- and hot-process compare

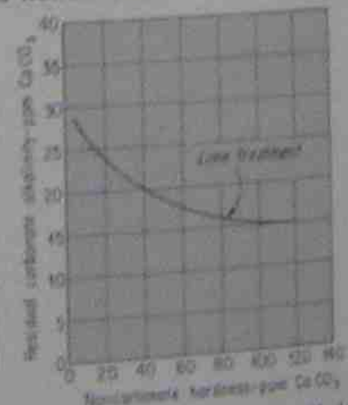


Raw-water analysis selected for this comparison is at left. Cold-lime soda reduces hardness, alkalinity and silica. Note that both hot-process methods do a more complete job of removal. Silica is reduced to 1 ppm compared to 8 ppm for cold process. Residual hardness from the hot-lime soda is 27 ppm. This is actually reduced to zero when hot process is followed by a salt-regenerated cation exchanger. Called the hot-lime zeolite process, it produces the best water in this comparison. Alkalinity is lower since soda ash isn't needed for low residual hardness in the settling tank.

Hot-lime zeolite produces treated water with zero hardness and low alkalinity



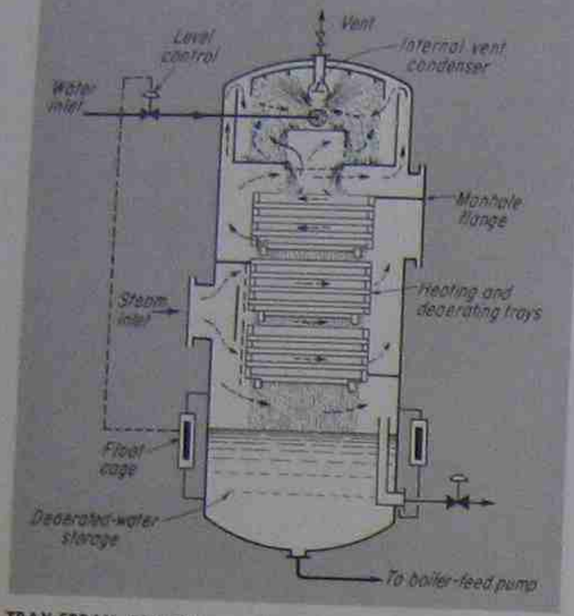
RESIDUAL HARDNESS depends on excess carbonate that remains in treated water



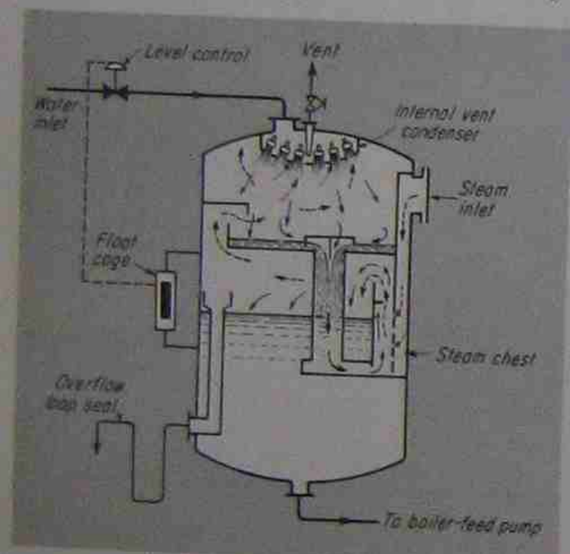
LIME TREATMENT leaves a higher residual hardness, with alkalinity of 15 to 25 ppm

Development of ion-exchange resins for use at high temperatures made the hot-lime zeolite system possible. Effluent hardness is zero compared to 27 ppm from a hot-lime soda unit. Curve, far left, shows that 20 ppm excess soda ash is needed to produce this residual hardness. Resulting alkalinity is in range of 45 to 50 ppm. Alkalinity from hot-lime zeolite runs from 15 to 25 ppm. Curve, left, shows the residual carbonate alkalinity and noncarbonate hardness from lime treatment. This residual hardness is removed by the hot zeolite. It's low costly from the chemical angle to remove this hardness with salt in a cation exchanger than with soda ash in the hot-process settling tank.

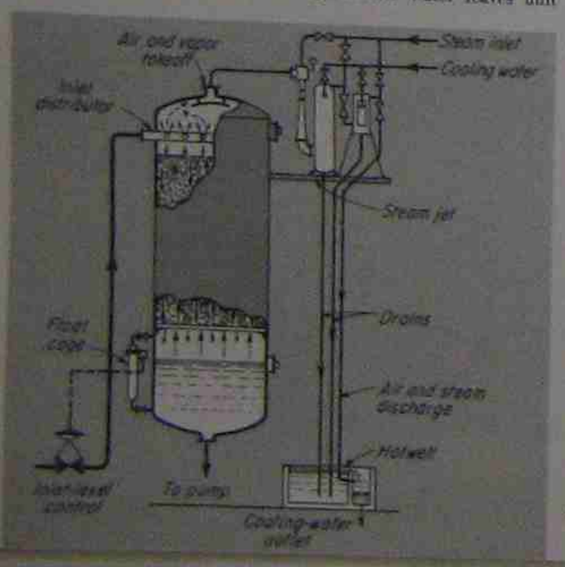
Deaerators and aerators solve many problems



TRAY-SPRAY DESIGN cascades water over trays after initial spraying at top. Crossflow of steam does heating, removes gas



SPRAY DEAERATOR agitates, mixes water with incoming steam to scrub out last part of dissolved gas before water leaves unit



VACUUM DEAERATOR rains cold water down through packing. Steam-jet ejectors pull vacuum; remove oxygen, CO_2, nitrogen

Oxygen is a dissolved gas that doesn't react chemically with water and becomes less and less soluble as water temperature increases. So it's easily removed by bringing water to the boiling point corresponding to its operating pressure. Pressure and vacuum designs are used.

When it's necessary to heat water—for boiler feed—steam deaerators are employed. If water is used for cooling or other purposes where heating isn't needed or wanted, vacuum units are practical.

Steam deaerators break up water into a spray or film and then sweep the steam across and through it to force out dissolved gas like oxygen or carbon dioxide. Oxygen content can be reduced below 0.005 cc per liter, almost the limit of sample testing by chemical means. As carbon dioxide is removed, the increase in pH also gives an indication of deaeration efficiency.

Typical deaerator has a heating and deaerating section plus storage for hot deaerated water. Usually a separate tank is provided alongside or underneath unit to hold ten minutes' storage at rated capacity.

Design of steam deaerators falls into two broad types: (1) spray (2) tray or combination spray-tray. Entering steam, lower left, meets hottest water first to thoroughly scrub out the last remaining fraction of dissolved gas. This gas is carried along with the steam as it flows through the deaerator. Actual direction of steam flow varies with the design and may be crossflow, downflow or countercurrent flow. Steam picks up more noncondensable gas as it goes through the unit and condenses as it heats the water.

Bulk of steam condenses in top of the deaerator when it contacts entering cold water. Remaining mixture of noncondensable gases like oxygen and carbon dioxide are discharged to atmosphere through a vent condenser. For more information refer to *Standards and typical specifications for deaerators and deaerating heaters* published by The Heat Exchange Institute. POWER's special report on *Heat exchangers*, June 1954, also is helpful.

Vacuum deaerators use steam-jet ejectors or mechanical vacuum pumps to pull the required vacuum. Degree of vacuum depends on water temperature and is usually in range of 28 in. Hg. Efficiency of oxygen and carbon dioxide removal doesn't compare with steam units. Oxygen residuals run about 0.2 ppm; carbon dioxide will vary from 2 to 10 ppm depending on amount coming in and temperature of the water. Vacuum deaerator units

are often used in demineralizing systems to reduce chemical operating costs, equipment size and to protect anion-exchange resins from any oxidation damage. Packing consists of staggered wood-slat packing or ceramic Raschig rings.

Aeration is simply a mechanical process for mixing air and water intimately. It can be done with spray nozzles, cascade aerators, pressure aerators or forced-draft units. For low flows, it's also practical to bubble air through the water in a storage tank.

Forced-draft degasifiers, right, are commonly applied for carbon-dioxide removal, although they also do a good job of removing hydrogen sulfide and oxidizing iron and manganese.

Packing in the degasifier consists of horizontal wood-slat trays or Raschig rings that divides the falling water into many small streams. Air is forced up through the unit by a blower and distributed over the lower cross section of the tank. It flows upward countercurrent to the flow of water. Air and gas scrubbed from the water are discharged through the vent at top.

Forced-draft units are extremely efficient for gas removal, and they are less expensive than vacuum deaerators for carbon-dioxide removal. Result: many demineralizing systems have them to reduce carbon dioxide to the level of 2 to 5 ppm. But disadvantages of treated water that's saturated with oxygen often outweigh any cost advantage of the forced-draft design for this use.

Pressure aerators are sometimes employed to oxidize iron and manganese where open aerators and double pumping are undesirable. Unit at right saturates only a portion of the water flow with air, so amount of dissolved air present in the total flow won't be greater than amount that the water can hold in solution at atmospheric pressure. Theoretically each ppm of dissolved oxygen oxidizes about 7 ppm of iron or manganese.

This saturator doesn't reduce the free carbon-dioxide content. And since the effluent usually flows directly to the filters without settling, its use is limited to waters having low iron, manganese and carbon-dioxide content.

Coke-tray aerators are more widely used to aerate iron- and manganese-bearing waters. Unit, right, consists of a series of coke-filled trays. Water enters at the top through a float-controlled inlet valve, percolates through the coke and is aerated during free fall over the trays.

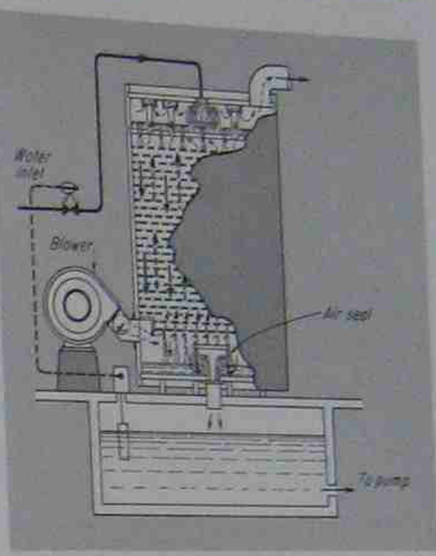
Iron oxide precipitates out on the coke where it contacts incoming iron-bearing water and acts as a catalyst to help bring down more iron.

Wood-slat aerators have a similar design. Trays are staggered to break up the free fall of water and expose the water surface to the air before dropping into the basin below. They are similar to small cooling towers.

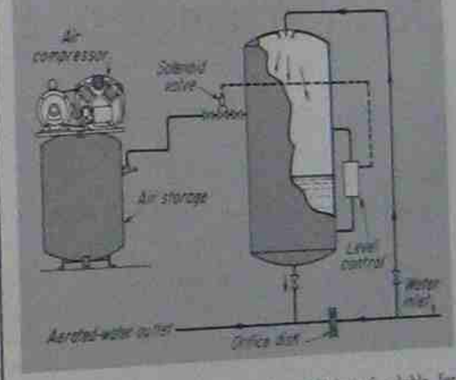
Air-diffusion method consists of bubbling air through a solid mass of water. This is done by forcing air through strainers, perforated pipes, porous plates or tubes at the bottom of a tank containing the water. Large volumes of air needed for efficient gas removal limits use of this method to smaller flows.

Spray aerators sweep out any volatile substances by mechanical spraying action. Spray nozzles are usually mounted above an open basin and discharged into the air. In municipal plants they are used to remove taste and odors from algae decomposition and hydrogen sulfide-

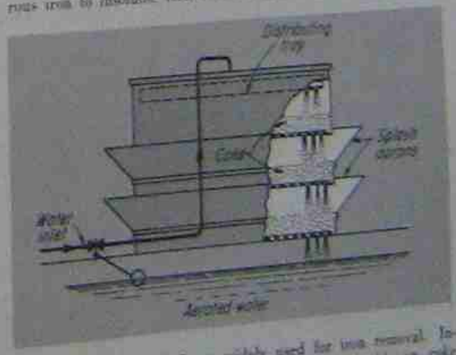
Air removes carbon dioxide and oxides iron



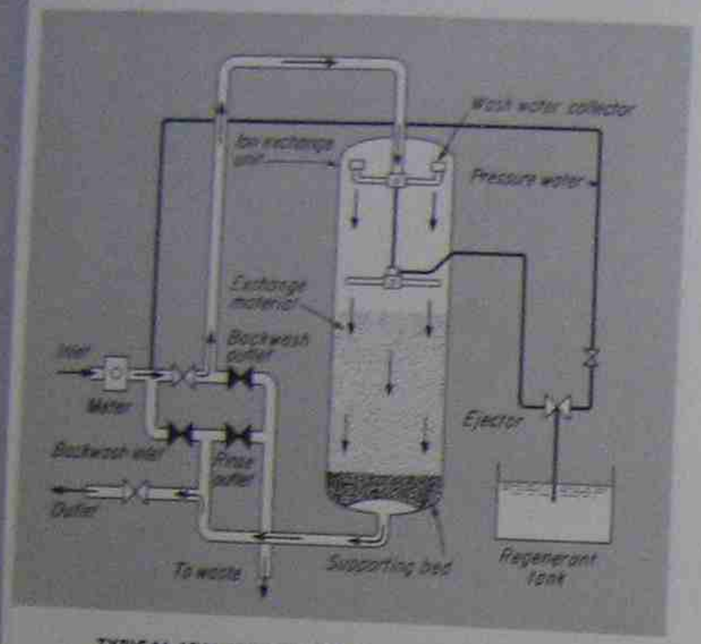
FORCED-DRAFT DEGASIFIER blows air stream through packing countercurrent to downward flow of water to remove CO_2



PRESSURE AERATOR supplies air for oxidation of soluble ferrous iron to insoluble ferric form for later removal by filtration



COKE-TRAY AERATORS are widely used for iron removal. Incoming water contacts freshly precipitated iron oxide on coke



TYPICAL ION EXCHANGER showing service flow with valve nest for regeneration—backwashing, injecting chemicals, rinsing

Variety of exchange materials are used

Ion-exchange materials	Flow rate gpm per sq ft	Regeneration chemical	Regeneration lb per cu ft	Typical capacity kgr per cu ft
Cation exchangers				
Sodium cycle				
Natural greensand	5.0	NaCl	1.25	2.5
Synthetic gel	6.0	NaCl	5.0	10.0
Sulfonated coal	6-8	NaCl	3.15	7.0
Styrene resin	8-10	NaCl	10.0	25.0
Hydrogen cycle				
Sulfonated coal	6-8	H_2SO_4	2.0	8.0
Styrene resin	8-10	H_2SO_4	5.0	11.0
		H_2SO_4	11.0	25.0
		HCl	10.0	30.0
Anion exchangers				
Weakly basic (Aliphatic amine)	6.0	Na_2CO_3	4.2	18.0
Weakly basic (Phenolic)	6.0	Na_2CO_3	4.2	18.0
Weakly basic (Styrene)	6.0	NaOH	3.25	20.0
Strongly basic (Type I)	6.0	NaOH	4.0	11.0
Strongly basic (Type II)	6.0	NaOH	4.5	14.0

Ion exchange is a versatile tool

Here are terms commonly used in ion exchange

Zeolites are processed greensand deposits with ion-exchange properties. Although any ion exchanger is often called a zeolite, it's better to use a specific term like anion or cation exchanger.

FMA stands for free mineral acidity and equals the total amount of strong acid in outlet of a hydrogen exchanger.

TMA or theoretical mineral acidity is the sum of chlorides, sulfates, nitrates in raw water. It equals FMA if hydrogen exchanger is 100% efficient.

Total exchangeable ions are those taken from water by ion exchange. For hydrogen units it usually equals sum of sodium, calcium and magnesium ions.

End point of ion-exchanger run takes place when unexchanged ions in the outlet exceed preset limits.

Exchange capacity is a measure of kilograins of ions removed per cu ft of exchanger before reaching the end point.

Leakage is steady appearance of unwanted ions in an exchanger effluent. In hydrogen units it equals TMA-FMA.

Impurities that dissolve in water dissociate to form positively and negatively charged particles known as ions. These impurities or compounds are called electrolytes. The positive ions are named cations because they migrate to the negative electrode (cathode) in an electrolytic cell. Negative particles are then anions since they're attracted to the anode. These ions exist throughout the solution and act almost independently. For example, magnesium sulfate ($MgSO_4$) dissociates in solution to form positive magnesium ions and negative sulfate ions. Generally, all natural waters contain electrolytes in varying concentrations.

Ion-exchange material has the ability to exchange one ion for another, hold it temporarily in chemical combination, and give it up to a strong regenerating solution. Chart, above, lists capacity of the ion exchangers commonly used in water treatment. Some of these like greensand have been in use a long time. Others such as the strongly basic anion resins are more recent developments. Styrene-cation resins are probably the most widely used today.

Ion exchanger, above, is much like an ordinary pressure filter. Bringing water in contact with the exchange material in this vessel starts the ion-exchange process. The unit is provided with piping and valves for washing and regeneration.

First basic treatment is softening. Let's fill our unit with styrene-base resin and start running water through it. As shown by building blocks, right, the water trades calcium and magnesium cations for sodium cations. This trading continues until the sodium-cation exchanger runs out of sodium. Then softening stops and the bed of styrene resin must be regenerated to restore its capacity.

Backwashing is first part of this process. Flow of water through the exchanger bed is reversed. Rates of 5 to 7 gpm per sq ft for about 10 minutes will remove any dirt accumulated on top of the material and loosen, regrade it to prevent packing and channeling.

Introducing regenerant is the next step. A saturated-brine solution is picked up by the ejector and passed downward through the exchanger bed. This reverses the exchange reaction and sodium from the brine displaces the accumulation of calcium and magnesium on the exchanger.

Rinse water is admitted to flush out calcium, magnesium and the remaining brine. Volume of rinse water is about 25 gal per cu ft. Entire regenerating cycle takes about one hour; it can be made fully automatic by adding time-control devices. Two or more units usually operate in parallel to maintain a continuous flow of treated water. Regenerations are staggered so only one unit at a time is off the line. Since water leaving the sodium-cation exchanger has little hardness, it primarily contains sodium salts. Total solids are not reduced by sodium-exchange softening.

Now let's fill our ion exchanger with hydrogen cation material. As shown, right, calcium magnesium and sodium cations are exchanged for hydrogen ions. In this way the salts are converted into an equivalent amount of the corresponding acid. Bicarbonates, sulfates and chlorides become carbonic, sulfuric and hydrochloric acids. Water leaving the unit is a weak solution of these acids. The carbonic acid breaks up into water and CO_2 which can be expelled by aeration. Thus total dissolved solids are reduced by an amount about equal to water's original alkalinity.

Capacity of the hydrogen exchanger is restored by regeneration with sulfuric acid. Since both the regenerant and the effluent water are acid, the exchange vessel is usually lined with rubber. Piping and valves

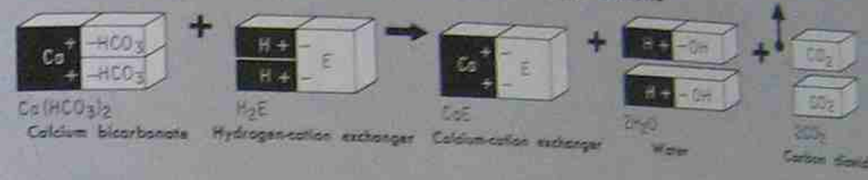
Sodium-cation exchangers swap sodium ions for other metal ions



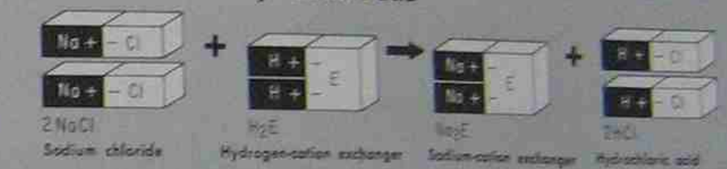
Regeneration restores capacity by replacing calcium ions with sodium



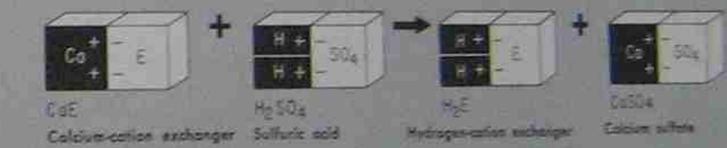
Hydrogen-cation exchangers swap hydrogen ions for metal cations



Cation exchanger turns sodium chloride into hydrochloric acid



Then, regeneration with acid restores hydrogen exchange capacity

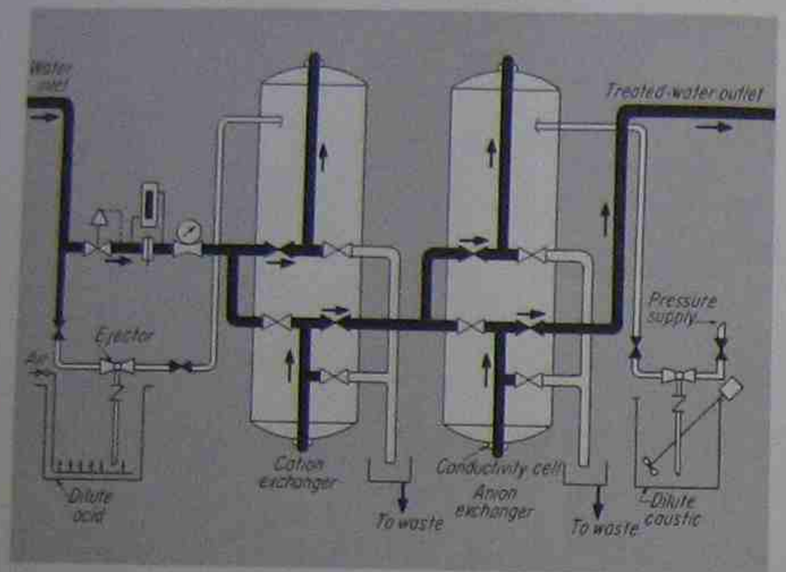


next step. A saturated-brine solution is picked up by the ejector and passed downward through the exchanger bed. This reverses the exchange reaction and sodium from the brine displaces the accumulation of calcium and magnesium on the exchanger.

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These two exchangers demineralize water

Raw water enters hydrogen-cation exchanger through a pressure reducing valve, rate-of-flow indicator and flow totalizer. Water coming out contains dilute hydrochloric and sulfuric acids plus carbon dioxide. Anion unit then exchanges acid radicals for hydroxide ions to form water. Water quality is monitored by a conductivity instrument. With a strongly basic resin, silica and carbon dioxide are also taken out. Often a degasifier or vacuum deaerator is called on to reduce carbon-dioxide load on the anion exchanger. If weakly basic material is used, both carbon dioxide and silica pass through the system. A degasifier is then added to remove the carbon dioxide mechanically to a residual in the range of 2 to 5 ppm.

Cation and anion units team up to remove hardness, alkalinity, dissolved solids, silica from water

in contact with acid water are also rubber lined or otherwise made corrosion resistant. Stainless-steel and plastic parts are substituted wherever use of lining is found impractical.

Hydrogen-cation exchanger effluent needs treatment before it's suitable for use. The pH is extremely low and it contains carbon dioxide. This is remedied by (1) removing carbon dioxide in an aerator and adding an alkali such as caustic soda or soda ash to neutralize the acid and raise pH, or (2) mixing with softened water from a sodium-cation exchanger and running the blended stream through an aerator to remove carbon dioxide. Both methods are practical, but blended-stream technique seems to be more popular. In this method, all water needed is split between hydrogen and sodium exchangers. Exact amount going through each depends upon water analysis and residual alkalinity wanted. Acid in hydrogen stream is neutralized by alkalinity in sodium stream to produce from 5 to 15 ppm alkalinity in the blend. On high-alkalinity waters residual carbon dioxide from the aerator ranges from 2 to 10 ppm.

Anion-exchange resins fall into two general categories—weak base and strong base. Chemical building-block equations, facing page, show how strongly basic exchange material picks up acid radicals and silica from a hydrogen unit, leaving essentially pure water. Weak-base exchangers don't take out carbon dioxide or silica. They remove strong acids by a process that's more like adsorption than it is ion exchange. However the end result is the same, and efficiency of strong-acid removal is far superior to that of a strong-base material doing the same job. So weak-base units are very useful when the water is high in sulfates and chlorides. In these cases they precede a strong-base unit. If silica isn't objectionable, they handle the complete job of demineralizing alone.

Chloride-anion exchange is a relatively new method of reducing alkalinity. When strong-base anion resins are regenerated with salt, they are converted to the chloride form. It's then possible to split salts by exchanging chlorides for the bicarbonate, sulfate and nitrate anions in water passing through the exchanger. By combining a sodium-cation exchanger and a chloride-anion unit, we can produce a soft low-alkalinity water without need for acid feeds or regeneration with acid. Drawbacks include the fact that sulfates and nitrates must also be exchanged. And capacity of anion material may be too low to justify its use in comparison with other methods of reducing alkalinity. Actual anion capacity is usually in range of 5 to 10 kgr per cu ft when regenerated with 3.5 to 4.0 lb per cu ft of salt. Effluent is high in chlorides, but alkalinity may be reduced 85 to 90% depending on the water analysis.

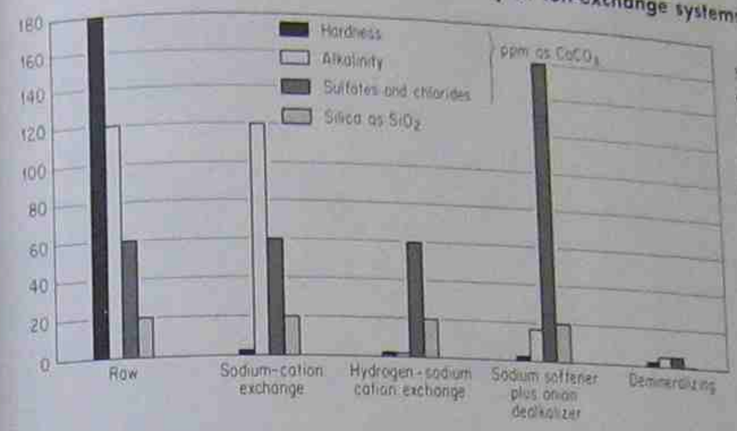
Strong-base anion resins are available as either Type I or Type II. Capacity and efficiency of Type II resins is somewhat higher than Type I. In spite of this Type I is more popular and the majority of strong-base exchangers use it. There are two main reasons for this preference: (1) Type I exchangers are usually more stable and (2) they reduce silica to lower residuals in range of 0.02 ppm.

Porous grades of exchange resins are coming more into the picture to combat organic fouling. They hold organic matter more loosely, making it easier to remove during normal regeneration or special chemical treatment. Generally, these porous resins can be expected to give rated capacity over a longer period of time.

Vacuum deaerators are finding increased use in demineralizing systems. Saturating the water with air in a forced-draft aerator may cause oxidation of anion resins. Vacuum deaerator for degasification has advantage of removing oxygen in addition to the carbon dioxide.

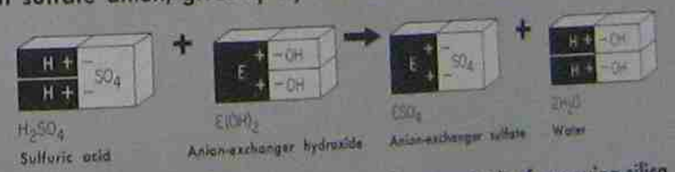
Mixed-bed demineralizer is a single vessel containing an intimate mixture of cation- and anion-exchange material. Cation resin is the styrene-base type, and either Type I or Type II strong-base anion resins are suitable. In effect the mixed bed is equivalent to an almost infinite number of 2-step demineralizers in series. Every anion-resin bead immediately grabs the acid produced by its neighboring cation bead. Removing acid as it forms allows the reaction to go almost to completion. So mixed-bed treated water is one of our closest

Wide variety of ion-exchange systems tailor water to fit each need

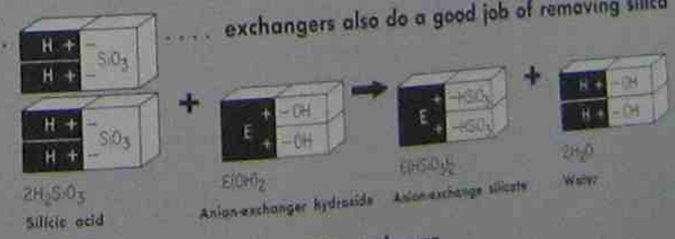


Starting with raw water, left, ion-exchange systems selectively remove all or part of the dissolved solids. Sodium-cation exchangers soften water by substituting sodium for calcium and magnesium ions. If alkalinity is too high, blend of water from hydrogen and sodium-cation exchangers produces a soft low-alkalinity water. Use of a salt-regenerated-anion dealkalizer may fit the need. Here, raw-water alkalinity is on the high side for this treatment. Alkalinity is reduced, but chlorides are increased greatly. Demineralizing removes practically all dissolved solids, but if silica removal isn't needed, use a weakly basic anion-exchange material.

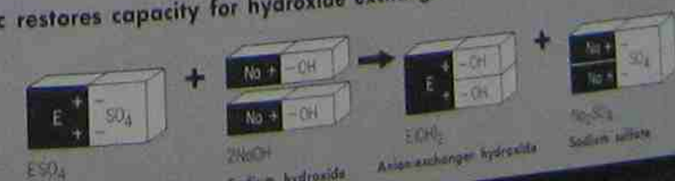
Anion exchanger takes on sulfate anion, gives up hydroxide to form water

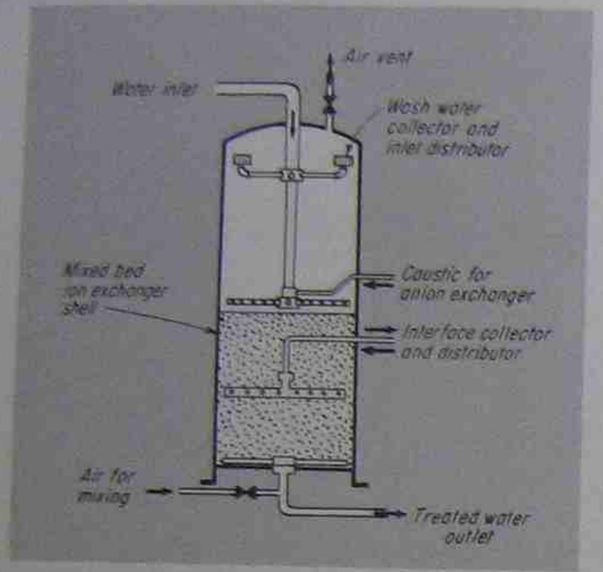


Strong-base anion . . . . . exchangers also do a good job of removing silica

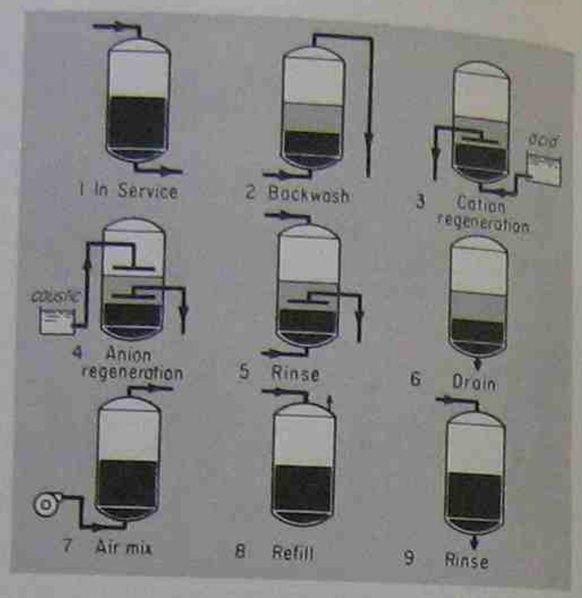


Regeneration with caustic restores capacity for hydroxide exchange





MIXED-BED DEMINERALIZER houses mixture of cation, anion exchange resins. Air for mixing enters through bottom distributor



REGENERATION of mixed bed, from initial backwash to the end of rinse and return to service, takes anywhere from 2 to 4 hours

Mixture of cation, anion resin produces top-quality water

approaches to "pure" water. Specific conductance is often in range of 0.15 micromhos or less.

Typical design, above, shows internal distributors needed to effectively operate and regenerate it. Distributor near top is for inlet flow and wash-water collection. Interface grid is used to handle regenerant flows. Bottom distributor collects treated water, distributes air for mixing and handles acid regenerant.

Regeneration first calls for backwashing to clean the beds and classify the resins. Lighter anion resin rises to the top and heavier cation resin settles to the bottom. A sharp line of demarcation is visible through a sight glass on side of the tank.

Cation resin is then regenerated with acid. Chart, above, shows acid entering bottom of unit, rising upflow through the resin and, finally, out through the interface grid. This is followed by caustic injection through the anion bed. Both beds are rinsed and the unit drained before the air mix. After resins are thoroughly mixed, unit is refilled and given a short rinse to waste before it is returned to service.

There are many variations of this procedure. Sometimes both acid and caustic are introduced simultaneously to cut overall downtime for regeneration. Depending on the sequence this operation can run 2 to 4 hr.

Now let's see how the mixed-bed process compares with a multibed system. In terms of total dissolved solids, mixed bed has an edge. Water produced is the best available. For low flows on relatively low solids and low-alkalinity water, first cost is lower. Regeneration requires less rinse water, and only a short rinse is needed to start a unit after shutdown. The mixed bed produces low-conductivity water right away.

There are disadvantages too. As you can see from the chart, regeneration is more complicated. Chemical operating cost is higher. Unless water is pretreated by a hydrogen-cation exchanger, a degasifier or vacuum deaerator can't be used effectively to remove carbon dioxide. There's also some indication from the experts that mixed bed is more susceptible to organic fouling than separate anion exchangers in multibed systems, shown at right. Some also feel the anion has lower capacity in the mixed bed.

From this comparison it looks like mixed-bed units are well-suited for plants where low first cost is important, operating cost secondary and top-quality water essential. Mixed-bed equipment also has a bright future as polishing units in both multibed systems and on condensate. Chart, right, shows today's systems.

What is conductance?

Specific conductance measures ability of a solution to conduct an electric current. Exactly defined it's the reciprocal of resistance in ohms of a 1-cm cube of liquid at a given temperature. Unit is the reciprocal ohm or mho per cm. Since conductivity of water is very small, micromhos per cm (millionth of a mho per cm) is unit commonly used. Demineralized water with about one-half ppm dissolved salt has a conductance of one micromho at room temperature. Absolutely pure water has a conductance of 0.036 micromhos.

Ten ways to demineralize water with cation, anion exchangers and degasifiers

KEY

Here are symbols for each step in treatment system

Hydrogen cation unit removes Ca, Mg and Na

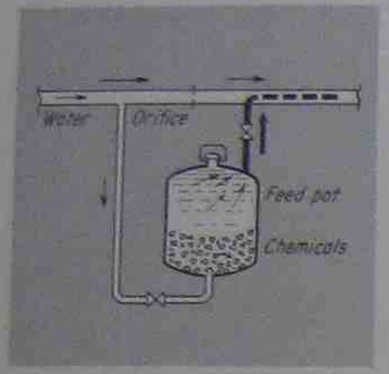
Weak-base anion unit removes Cl and SO_4 radicals

Strong-base anion unit also removes SiO_2 and CO_2

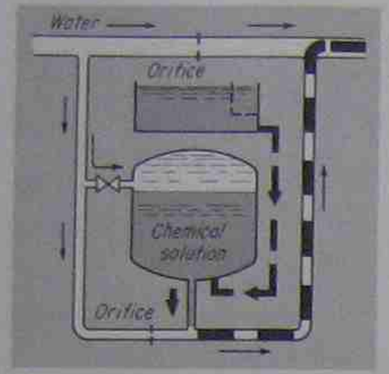
Mixed-bed unit has cation and strong-base resin mixed

Degasifier takes out CO_2; also O_2 if a vacuum type

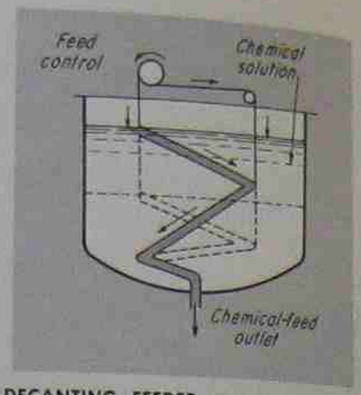
Demineralizing systems	Water quality and application
1	Treated-water conductance ranges from 10 to 20 micromhos. Silica isn't removed. Low-cost anion-exchange material is regenerated with soda ash or caustic
2	Silica in treated water is reduced to level of 0.02 to 0.15 ppm. Conductance ranges from 10 to 20 micromhos. Degasifier reduces CO_2 load on anion exchanger
3	If water is high in sulfates and chlorides, use low-cost weak-base unit to handle bulk of anion load. Water quality is same as above; operating cost is lower
4	Polishing units give conductance of 3 to 6 micromhos. Silica ranges from 0.02 to 0.15 ppm. Series regeneration of both cation, anion units cuts operating cost
5	Use when the alkalinity is major part of anions. Polishing units regenerate infrequently. Effluent conductance is 1 to 5 micromhos with silica same as above
6	Alternating-series hookup is flexible variation of method above. Units run in parallel for peak flows. Each pair gives service flow while other regenerates
7	Treated-water conductance ranges from 0.15 to 1.0 micromhos with silica reduced to level of 0.02 to 0.15 ppm. Operating cost is higher than for multibed systems
8	If alkalinity is high, use cation unit and degasifier to reduce anion load by removing CO_2. This cuts both the size and operating cost of mixed-bed exchanger
9	When raw water is high in sulfates and chlorides, 2-step demineralizer with weak-base anion unit reduces both operating cost and size of mixed-bed exchanger
10	Use a strong-base anion unit and degasifier if water is high in alkalinity and silica. Mixed bed then operates as polishing unit with infrequent regeneration



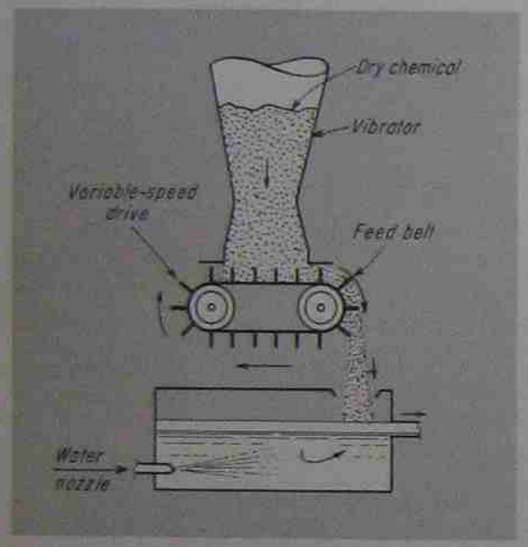
POT TYPE FEEDERS use bypass flow to dissolve chemical crystals, lumps, briquettes



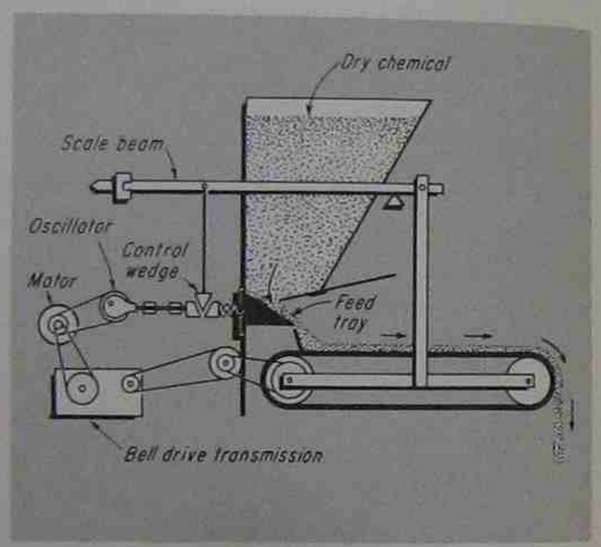
PRESSURE SOLUTION feeds discharge alum, soda ash in proportion to main flow



DECANTING FEEDER uses water meter, timer to control lowering of drawoff pipe



DRY FEED has moving belt with lugs that slice off equal volumes of chemical directly from vibrating hopper above



GRAVIMETRIC FEEDERS have three basic elements: (1) scale or weight sensing element (2) feeding mechanism and (3) controller

Feeders move wet and dry chemicals

Handling and feeding chemicals is an important part of every water-treating system. Treatment reactions must be supplied with the right amount of chemicals at the proper strength. Many feeder designs have evolved to cover each specific treatment.

Feeding equipment falls into three broad categories: wet, dry and gas. While rate of feed may be either constant or proportional, feeding chemicals in intermittent slugs is also common. Dry-chemical feeders are best suited for handling large amounts of chemical. Wet or solution feeders are more convenient and accurate for smaller quantities. Thus, selection of a specific feeder depends primarily on amount and type of chemicals used.

Pot type feeders are usually limited to feeding alum or sal-soda in either crystal or lump form. They're also called on to handle specially prepared chemical briquettes.

In use, the chemical is placed in the feeding pot where it's dissolved by water flowing from the high-pressure to low-pressure side of an orifice. Since this flow is proportional to main-line flow, amount of chemical fed is roughly proportional too. Control isn't exact because there's no way to adjust the solution rate of the chemicals.

Pressure-solution feeders aren't limited to crystalline or lump forms of chemical and feed is proportioned to flow within a reasonable degree of accuracy. An open tank is used to dissolve the chemical. Then solution is charged into bottom of pressure tank and displaced water flows out the top. Sight glass shows level of the chemical. Next, solution is fed from bottom of tank to bypass circuit.

Decanting type feeder has a swing drawoff pipe to remove solution at desired rate. This feed is good for practically any type of solution or slurry. In proportional control the water meter actuates an adjustable timer that starts the feeder motor and lowers the drawoff pipe for a preset time interval. The feeder is usually equipped with a propellor mixer, cover and dust evacuator when handling chemicals such as lime or soda ash.

Dry-chemical feeders are classed as volumetric or gravimetric units. Volumetric type, facing page, uses a moving belt to remove chemical from a vibrating hopper. The adjustable-speed belt has lugs that deliver equal volumes of dry material. Unit is suitable for constant-rate or proportional feeding. Accuracy of any volumetric feeder depends on consistency of the material handled. If density varies so will rate of feed. Normal accuracy of volumetric dry-chemical units is in the range of 5%.

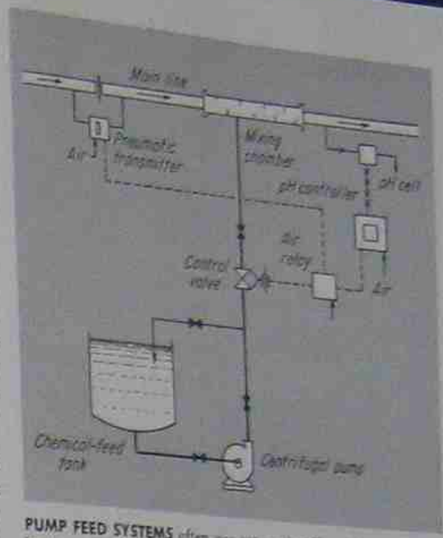
Gravimetric feeders bank on weight to measure the amount of chemical fed. Dry material drops from the hopper onto a traveling belt. Scale beam is set for a constant weight of chemical and rate of feed is varied by adjusting the speed of the belt. Total weight of the belt assembly and the chemical on it controls the amount of chemical dropped onto the belt. If weight is below set point, vibration amplitude of the feed tray increases, upping volume of chemicals fed to the belt. If weight is above set point, vibration amplitude decreases and feed to belt is cut. Accuracy of proportioning is 1 to 2%.

Pump feeding systems come in a variety of designs employing both positive displacement and centrifugal pumps. Pump feed, right, takes care of wide flow swings in the main line. Flow and pH are used as control-signal sources. Control valve on the chemical inlet line receives signals from flow transmitter and pH controller through an air relay. Mixing chamber in main line brings water and chemicals into turbulent contact.

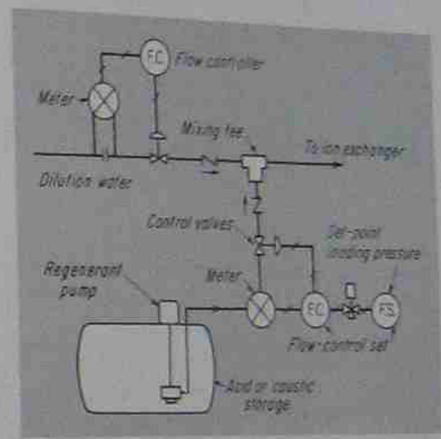
If a positive-displacement pump is called for, the arrangement changes. Here, flow transmitter controls speed of pump motor through a Thymotrol unit. The pH controller adjusts the length of pump stroke. Chemical flow is still sensitive to both of these variables.

Regenerant feeds for demineralizing systems are receiving more attention with the trend to fully automatic operation. Arrangement at right can be used for either acid or causic. In general it must deliver the correct amount of chemical, in proper concentration, in an allotted time. Pneumatic flow-rate controllers are located on both the dilution water and regenerant lines. Thus, the correct proportion of regenerant and water is continously maintained. A timer controls total volume.

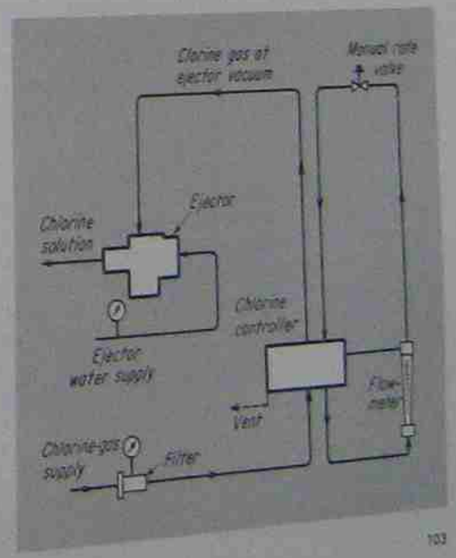
Chlorinator measures, dissolves and feeds chlorine to the water being treated. In design at right, water flows through an ejector continuously. This creates a vacuum that extends back to the chlorine controller. Flow of chlorine gas to the ejector is adjusted by the manual rate-set valve. Chlorine controller acts to keep gas flow constant for any given rate-valve setting. The chlorine flows to the ejector where it's mixed with water just before leaving the unit and discharged to the point of application.



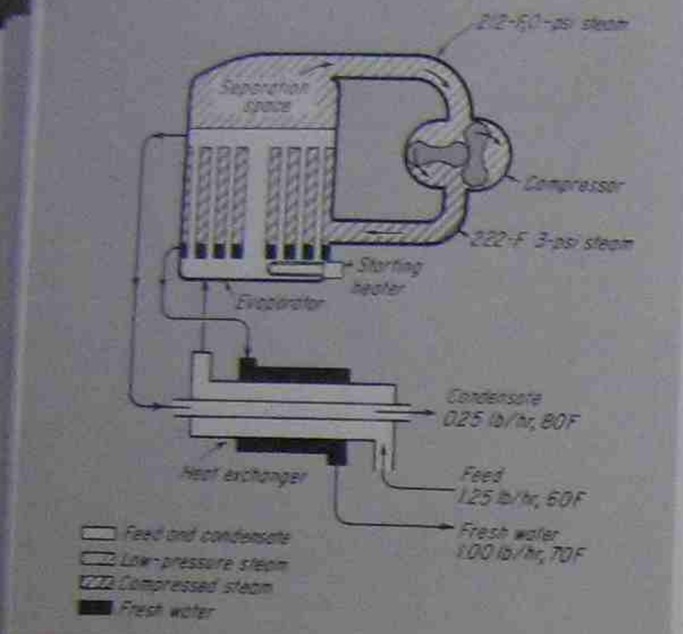
PUMP FEED SYSTEMS often use automatic pH and flow control to handle swings in main-line flow and variations in water analysis



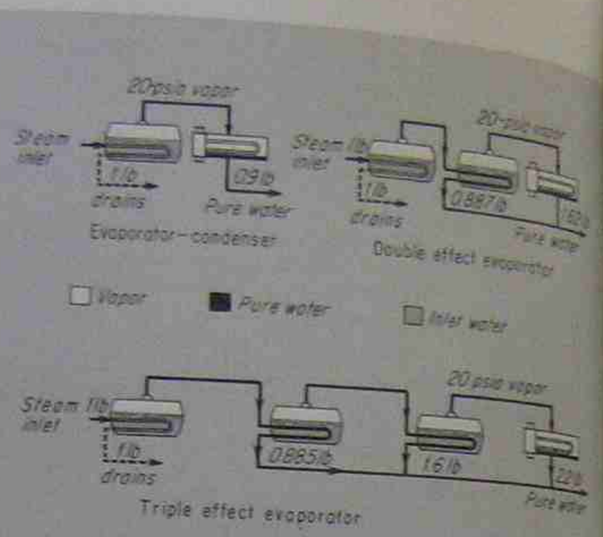
REGENERANT FEED for acid or caustic in ion-exchange systems deliver the right amounts of chemical solution at desired strength



CHLORINATOR uses water-ejector assembly to draw chlorine gas through system, mix it with water and deliver chlorine solution



VAPOR COMPRESSION distillation unit uses mechanical shaft work to heat water vapor by increasing its pressure to 3 psig



EVAPORATORS boil makeup water; resulting steam is condensed to form pure water. Increasing number of effects ups the efficiency

Evaporator plants use heat to remove solids

Dissolved and suspended solids are removed from water effectively by the purely mechanical process of vaporizing water with heat. The evaporator is simply a pressure tank filled with steam coils and a moisture separator on the outlet. Vapor is condensed in a separate heat exchanger to form pure water. Tank shell has coiled or straight-through tubes. Heating steam flows inside the coils and makeup water enters the shell.

When tubes are immersed in the incoming raw water, unit is called a submerged tube evaporator. If water is filmed over tube surfaces and flashed into vapor along the way, it's known as a film type evaporator. Another design, called a flash type evaporator, operates with its chamber under a partial vacuum. Incoming raw water is preheated and temperature is raised high enough to flash water into vapor when it enters the chamber.

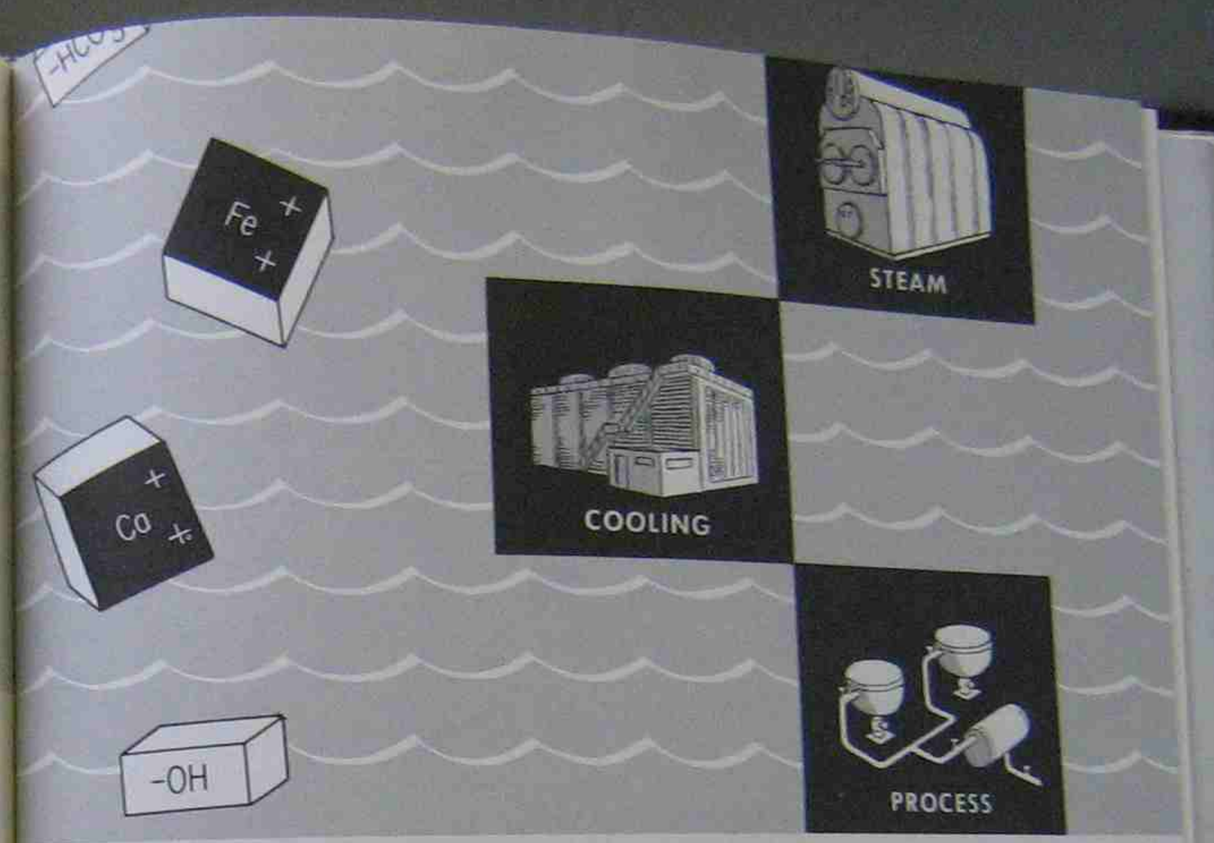
Multiple-effect evaporator is an arrangement of two or more units in series. Steam produced by one evaporator is condensed in heating coils of the next lower pressure stage, and so on. Pure water from each effect flows to a common outlet header.

Single-effect evaporators are preferred for boiler-feed makeup because more water can be produced by a given amount of evaporator-tube surface. Multiple-effect plants are a must where evaporator is called on to produce potable water. Here, increased operating efficiency justifies added plant cost, and larger number of effects reduces the fuel need.

Vapor-compression evaporator consists of a boiling chamber, heat exchanger, vapor compressor and starting heater. Hot water from the heat exchanger enters the evaporator chamber where it's boiled at atmospheric pressure. Resulting steam is fed to the compressor where its pressure is raised to about 3 psig. Compressed steam or vapor flows back to the evaporator or boiling section, condenses and gives up heat to boil more water. Outgoing condensate passes through a heat exchanger to heat the incoming feed. Starting heat comes from an external source. When steam is produced, the motor- or diesel-driven compressor goes into action.

Evaporators are not without scale and corrosion problems. Depending on water analysis and type of plant, evaporator tubes may accumulate scale. This can be loosened by heating the tubes and dousing them with cold water. Some designs let the tubes expand and take on a bowed shape during operation. When shell is filled with cold water, tubes quickly straighten, helping to crack off scale. Pretreatment of evaporator feed is generally favored to minimize cleaning and improve effluent quality. Well-designed evaporators can produce vapor containing less than 0.25 ppm total dissolved solids.

In preparing this report the author had the unstinting help and cooperation of the entire water-treating industry. He particularly thanks J F Wilkes, S B Applebaum, D Miller.



PART TWO

Water Treatment

By R H MARKS, Assistant Editor

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Ways to cut water consumption 88

Broadly viewed, industry uses water to generate steam, to cool and heat, to fill the varied needs of process and general plant services. These are the areas we are concerned with in this report.

Steam generated may power turbines in central stations and industrial plants, or may be fed to space or process heaters. But the water must first be treated. We see huge quantities of water used daily to cool power-plant condensers, compressors, diesel engines. We see steel mills, oil refineries and chemical plants gulping billions of gallons of cooling water . . . treated water.

Transporting and processing of materials, as in the pulp and paper industry, is a job for water. It's also a raw material that becomes part of a finished product such as in canned foods and beverages. General plant-service water is used for drinking and washing.

Water that can be used without some treatment is rare indeed. Impurities must be removed, reduced or stabilized. Part 1 of this report (POWER, December 1958) discussed water impurities, treatment aims and basic water chemistry, while taking a hard look at treatment chemicals and application equipment. Here we show how those chemicals and equipment help solve everyday water problems.

a **Power** special report
March 1959

Rivers, wells, lakes, even the oceans, may be best water source

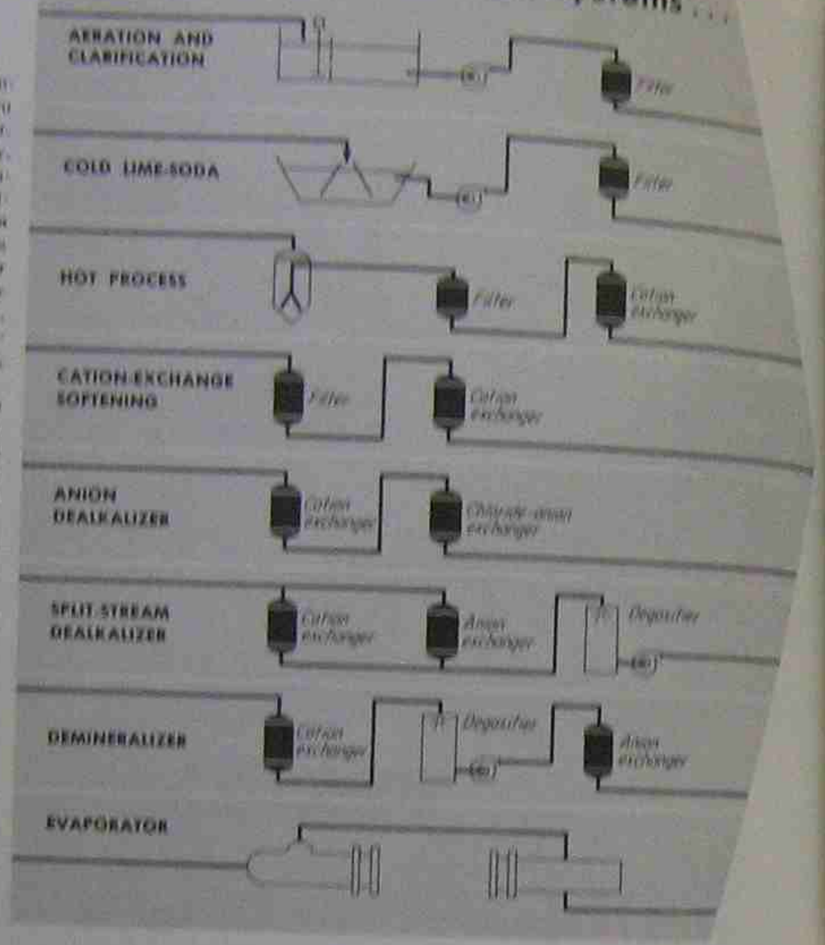
Always think of treatment that incoming water might need when you stack one source against the other. Good rivers offer ample quantity, rapid flow, low hardness and temperature. But dissolved mineral matter, including hardness, may have a yearly maximum that's 2 to 3 times the minimum. Clear river water for once-through cooling will probably need little treatment. But most rivers, carrying high dissolved and suspended solids plus organic matter, need extensive treatment.

Sometimes it's more economical to pump water from a distant lake than to use a nearby river that's badly polluted. Lake water is fairly constant in composition and seasonal changes in turbidity are somewhat predictable. It may be softer than well water, but probably contains organic matter that must be removed.

Well waters usually run fairly constant in composition and are often quite hard. Properly protected deep wells are usually secure from contamination. Water is clearer, has fewer organic colors, tastes and odors than most surface supplies.

Consider sea water where cooling is your basic water need. Supply is practically inexhaustible. Fresh water needs can then be met by city supplies, surface or well sources. Desalting sea water for potable use isn't yet economical in most areas.

Variety of treatment systems . . .



Treatment choice varies with water analysis and use

No matter where you find water it will probably have to be treated before use. Even city water, usually the best available to an industrial plant, needs further treatment for boiler feed, cooling and process.

Undesirable water impurities for industrial use fall into these main groupings: (1) dissolved mineral matter (2) dissolved gases (3) turbidity (4) color (5) taste, odor and (6) microorganisms. Amount tolerated in any given water depends mostly on what the water is used for.

Most large industrial plants use a private water supply since it's usually cheaper to pump water than buy it from a city system. Some well-engineered plants buy city water for drinking and fire protection only. Then the larger amounts needed for process, cooling, etc are drawn from river, well, lake or harbor.

Deciding what water treatment to use is a job for the water consultant. Selection must take into account present and future plant water needs along with an analysis of the water supplies available. Treatment will probably involve one or more of the basic processes shown above. These processes along with the basic chemicals are your tools of treatment for plant water needs, facing page.

Aeration helps remove undesirable gases and volatile impurities. These include hydrogen sulfide, carbon dioxide and volatile organic matter. Iron and manganese are also oxidized and removed by coagulation, settling, filtering.

Clarification equipment removes bulk of turbidity and sediment found in most surface supplies. It's usually first step in treatment since most applications call for a water that's clear and colorless. Coagulants and coagulant aids speed up settling process. Filters follow to remove residual turbidity. If turbidity is moderate to start with, filters may handle the job alone. Coagulants or filter aids are used depending on the design of the filter.

Cold-lime soda unit precipitates scale-forming salts of calcium and magnesium. It reduces hardness, alkalinity and removes turbidity. For zero turbidity and hardness, follow with filters and sodium-cation softeners.

Hot process also reduces hardness, alkalinity and turbidity. But steam must be available for heating and there must be a need for hot treated water. This usually limits its use to the preparation of boiler-feed makeup. It has added advantage of reducing silica and can handle a fair amount of turbidity without need for pretreatment.

Cation-exchange softeners are widely used whenever there is a demand for soft water. Simple to operate, these units produce soft water as long as the ion-exchange resin is properly and regularly regenerated. Filter the incoming water if turbidity is above the range of 5 to 10 ppm.

Anion dealkalizer is preceded by a cation-exchange softener. Treated water has zero hardness and is low in alkalinity. Anion unit is regenerated with salt and a small amount of caustic. This method is used primarily for treatment of makeup to small low-pressure boilers.

Split-stream dealkalizer uses hydrogen- and sodium-cation exchangers to produce a soft supply with low alkalinity. Salt and sulfuric acid are used for regeneration. Elaborate blending controls may be needed, but the whole plant can easily be made automatic. Carbon dioxide released when hydrogen and sodium streams are blended is removed in either a forced-draft or vacuum degasifier.

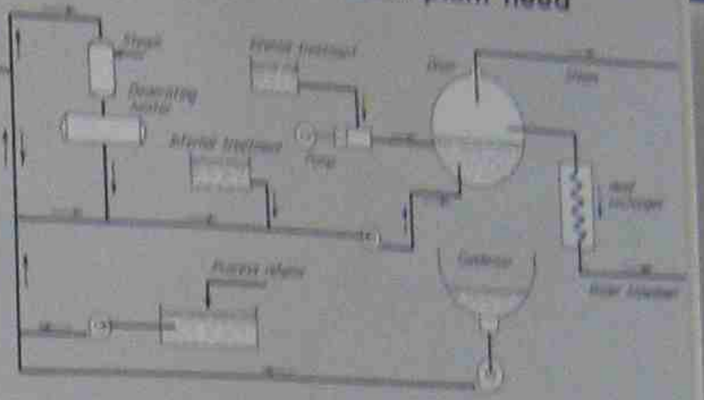
Demineralizing plants remove practically all dissolved solids from water. When a weak-base anion exchanger is used, everything is taken out except silica. This water is completely satisfactory for many process jobs. But, since silica removal is a must for high-pressure boiler makeup, strong-base anion-exchange material is used to reduce silica below 0.02 ppm. Operating and equipment cost for this method is usually higher than the other treatment processes. For this reason, and to improve quality, considerable emphasis is placed on multibed arrangements with special regenerating techniques. Aim is to cut overall investment and chemical operating costs. Even though these systems are complex, automatic controls simplify the operator's job of keeping track of the process.

Evaporators compete with ion exchange for the task of removing all dissolved solids and silica from high-pressure boiler feedwater makeup. Demineralizing has gained ground in many other areas because of lower chemical operating cost. Increasing number of evaporator effects cuts heat consumption but increases first cost of the plant.

. . . and chemicals tailor water supply to fit each plant need

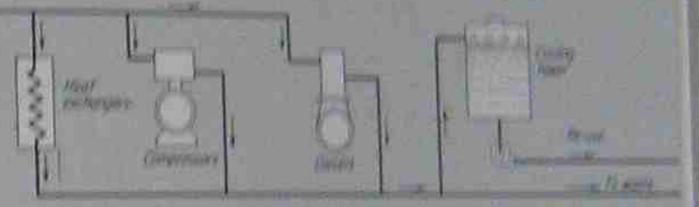
Steam generation

Boiler-feedwater quality specifications depend largely on boiler operating pressure. As pressure increases, quality requirements go up. In general, feedwater should be deaerated. Internal chemical treatment is also called for in all cases. This may handle the complete job alone or supplement external-treatment equipment, left. Amount and analysis of makeup will also affect treatment.



Cooling and heating

Cooling-water quality can vary over a rather wide range. It depends on water analysis, type of cooling system—once-through or recirculating—where cooling water is used and the maximum temperature that it reaches.

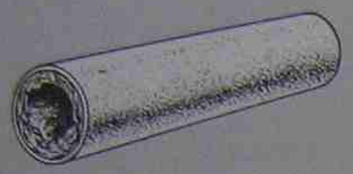


Process and general purpose

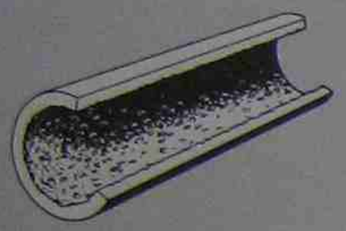
Process-water needs vary with each industry. Most general-purpose water must be clean, colorless, palatable, and free of all pathogenic bacteria.



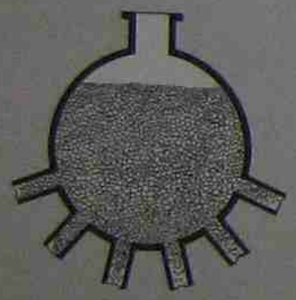
Boiler-feedwater troubles fall into four basic categories



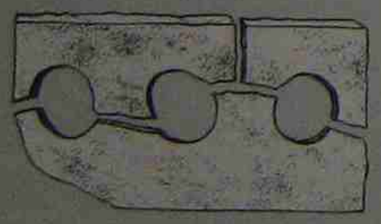
SCALE reduces heat transfer, causes overheating of tube metal. It forms when boiler water containing dissolved calcium, magnesium salts, silica, etc is evaporated



CORROSION of boilers, economizers, feedwater heaters, condensers, piping, etc shows up in a host of ways. Main cause is presence of dissolved oxygen and carbon dioxide



FOAMING and priming cause boiler-water carryover with steam. Results: erratic superheat, engine and turbine mechanical trouble, superheater and turbine-blade deposits



CAUSTIC EMBRITTLEMENT occurs on drum seams, under rivets and at tube ends where water flashes to steam through any small leaks in these highly stressed areas

Treated feedwater cuts downtime, ups performance

Main objective of boiler-feedwater treatment is elimination of the troubles caused by scale, corrosion, carryover and caustic embrittlement. Box, left, helps explain the nature of these problems.

Hard scale on tube surfaces reduces heat transfer to the fluid inside. Contrary to common belief, this reduced heat flow rate may not greatly affect boiler efficiency. Total heat absorbed by conduction and convection through heating surfaces covered with 0.10 to 0.20 in. of scale may be only 1 to 3% less than when the surface is clean. While this loss seems small, it adds up to a respectable amount of fuel for a year's operation. It may also upset balance between boiler and superheater, economizer, preheaters.

Real danger from scale lies in radiant-heat zone where boiler-tube metal sees combustion—waterwall and first-pass tubes. This radiant heat converts into sensible heat in tube metal without regard to waterside conditions. When scale is present to retard removal of this heat by the steam-water mixture inside, metal temperature of the tubes starts to climb. Even a very thin coat of scale in high heat zones can overheat the metal enough to rupture the tube. Accumulated corrosion products inside the tube will have the same effect. Once scale forms, only remedy is to remove it chemically or mechanically and then treat the boiler water or feedwater to keep the same thing from happening again.

Ordinary scale is the result of heating and concentrating the dissolved hardness in water. Feedwater containing dissolved and suspended solids flows into the boiler for continuous generation of steam. Since steam is practically pure, solids are left behind to concentrate. The fact that salts such as calcium sulfate become less soluble as temperature rises accelerates scale-forming tendencies.

Chemically, scale will usually consist of insoluble compounds of calcium and magnesium. Sometimes it's cemented into a hard mass by silica. Under severe conditions it may consist wholly or partly of complex silicates, iron or copper oxides.

Scale formation is prevented by: (1) *External* or *pretreatment* – removing or reducing calcium, magnesium or silica before feedwater reaches the boiler. (2) *Internal treatment* – adding chemicals to the boiler water, causing solids to form a fluid, nonsticky sludge. (3) *Blowdown* – removing concentrated boiler water containing both dissolved solids and sludge.

As boiler pressures get higher, scale problem becomes more critical. Higher boiler-water temperatures produce faster chemical reaction rates and higher tube temperatures. Since tube metal is closer to its sagging point, scale can cause bagging, blistering and rupture more quickly.

Other plant operating conditions affecting scale problems include (1) ratio of makeup to condensate returns (2) boiler operating schedules and (3) condenser leakage and other feedwater contamination. For example, if makeup is a high percentage of total feedwater, elaborate pretreatment may be justified. This is also true when boilers must steam at high rates for long or intermittent periods.

External treatments remove impurities from makeup water before they enter the boiler

Quality of treated water produced by various external treatment methods in common use is an important factor in their selection. Table, right, shows what you can expect in the way of hardness reduction, residual alkalinity, potential carbon dioxide in steam, dissolved solids reduction and silica removal. Quality of makeup water needed depends primarily on boiler design, particularly operating pressure and temperature. Degree of treatment called for also depends on boiler capacity, quantity of condensate returns available and raw-water analysis. Large plants with a high percent makeup usually justify more elaborate external treatment than a small installation. All these factors influence your common-sense answer to the question "How good must makeup water be?"

Method of treatment	Average analysis of treated water				
	Hardness ppm as $CaCO_3$	Alkalinity ppm as $CaCO_3$	CO_2 in steam (potential)	Dissolved solids	Silica
Cold lime-soda	30 to 85	40 to 100	Medium-high	Reduced	Reduced
Hot lime-soda	17 to 25	35 to 50	Medium-low	Reduced	Reduced
Hot lime-soda phosphate	1 to 3	35 to 50	Medium-low	Reduced	Reduced
Hot lime-zeolite	0 to 2	20 to 25	Low	Reduced	Reduced
Sodium-cation exchanger	0 to 2	Unchanged	Low to high	Unchanged	Unchanged
Anion dealkalizer	0 to 2	15 to 35	Low	Unchanged	Unchanged
Split-stream dealkalizer	0 to 2	10 to 30	Low	Reduced	Unchanged
Demineralizer	0 to 2	0 to 2	0 to 5 ppm	0 to 5 ppm	Below 0.15 ppm
Evaporator	0 to 2	0 to 2	0 to 5 ppm	0 to 5 ppm	Below 0.15 ppm

Corrosion of boiler metal will take place when (1) water is acid or (2) dissolved oxygen, carbon dioxide or other corrosive gases are present. Boilers, economizers, feedwater heaters, piping, etc must be protected from corrosive attack. (For detailed info on this subject see POWER's Special Report, *Corrosion*, Dec 1956).

Preventive treatments include (1) neutralizing acidity and raising pH with an alkali (2) removing dissolved gases in a deaerator and following up with a chemical scavenger (reducing agent) to combine with any remaining traces of oxygen (3) neutralizing effect of carbon dioxide with ammonia or neutralizing amines (4) depositing a protective film on metal surfaces (filming amines).

Carryover is entrained moisture and associated solids passing from a boiler with the steam. Erratic superheat and mechanical troubles with engines and turbines are caused by these slugs of moisture. Carryover also deposits solids in superheaters and on turbine blades. It may even spoil materials in process. Main causes of carryover are *priming* or *foaming* or both.

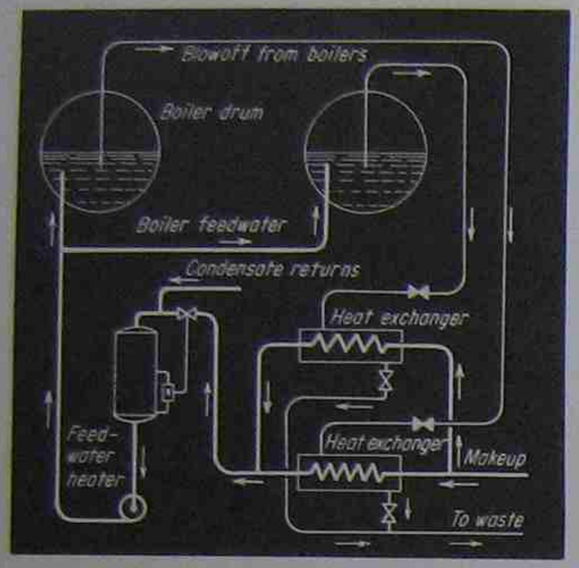
Priming is the spouting or surging of water into the steam outlet. It's caused by too high a water level, uneven fire distribution, load swings, too high a steaming rate or even faulty boiler design. Remedies range all the way from redesigning the boiler or steam drum to installing steam purifiers, lowering water level, improving firing distribution or reducing boiler load. Chemical antifoams also help.

Foaming is the formation of small, stable noncoalescing bubbles throughout the boiler water, box, facing page. Water film around each steam bubble generated at the heating surface is stabilized by an increase in dissolved and suspended solids in the boiler. In other words, the bubble skin becomes tough and doesn't permit coalescence or break readily when the bubble emerges. Resulting expansion of boiler water permits carryover and priming.

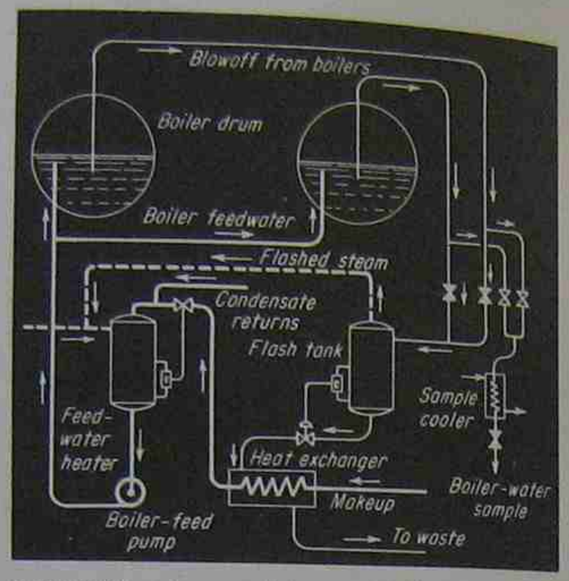
Main causes of carryover are excessive dissolved and suspended solids, high alkalinity, presence of oil and various organics that react with alkalinity. Steam washers and mechanical separators in boiler drums effectively control carryover within reasonable and tolerable limits. Notable exception is silica that passes over with steam as a vapor at operating pressures above 600 psi. Proper water treatment including the right amount of blowdown is the key to maintaining these limits.

Caustic embrittlement or intercrystalline cracking of metal takes place when all of the following conditions are present. (1) Boiler water must have embrittling characteristics and be capable of attacking boiler metal. This calls for presence of free hydroxide alkalinity and some silica. (2) Slow leakage of boiler water through a joint, seam or crevice must occur. As the boiler water escapes, it flashes to steam leaving dangerous concentrations of hydroxide alkalinity in the crevice. Average concentration of hydrate alkalinity by itself isn't enough to cause embrittlement. (3) Boiler metal must be highly stressed at the point of leakage. This may be caused by faulty riveting practice, misalignment, cold working, expansion, etc.

It's generally conceded that maintaining ASME sulfate-carbonate alkalinity ratios will not give consistent protection against embrittlement failure. So this control procedure has been largely discarded in favor of other improved methods, including use of inhibitors like sodium nitrate, lignin derivatives, tannins or regulation of boiler-water alkalinity by coordinated pH-phosphate control.



CONTINUOUS BLOWDOWN RATE from each boiler is individually controlled. Heat is recovered in makeup flow to feedwater heater



FLASH TANK receives controlled amounts of blowdown from one or more boilers and produces flashed steam for feedwater heating

Blowdown removes boiler-water solids

All dissolved and suspended solids entering a boiler with the feedwater remain in the drum and tubes as steam is generated. Continued addition of makeup produces higher and higher solids concentration in the boiler drum. Finally, a point is reached beyond which operation is completely unsatisfactory. The limit may be suspended solids, total solids, silica content, alkalinity, etc. Recommended boiler-water concentrations at various operating pressures are listed on the facing page, lower, right.

Every boiler has a limit for total solids above which priming and carryover occur. Units with ample drums, operating at comparatively low steaming rates, can tolerate 2500 to 5000 ppm total solids. But high-pressure boilers, operating at high steaming rates, call for concentrations of 500 ppm or less to produce steam of acceptable purity. To keep within these limits some of concentrated boiler water must be removed from the drum. So all boilers have blowdown connections — some required by codes, some specifically for chemical control.

Intermittent blowdown is taken from bottom of the mud drum, waterwall headers or lowest point in the circulation system. Blowoff valve is opened manually to remove accumulated sludge. This is done every 4 to 8 hours, or when the boiler is idle or on low steaming rate. Main disadvantage is the waste of hot water. Also, control of boiler-water concentrations is irregular at best. Keeping within safe limits means the operator must maintain a rigid blowdown schedule. Otherwise it's possible to have priming and foaming with resulting carryover.

An external concentrator tank is sometimes piped to the boiler drum. Boiler water thermally circulates to top of this tank and back to the steam drum or a lower point on the boiler. Suspended solids fall to bottom of the concentrator tank. Blowdown then discharges from concentrator to waste. This ejected water contains more suspended solids than an equivalent amount of circulated boiler water.

Continuous blowdown automatically keeps boiler water within desired limits. Continuously removing a small stream of boiler water keeps the concentrations relatively constant. Savings from the heat-recovery features often pay off initial equipment investment in short order. Box, facing page, shows a 4-step approach to calculating blowoff rates and evaluating potential heat savings.

Connection for continuous blowdown is taken from that part of the boiler circulation containing the most concentrated water. In modern units most of the solids are in solution and are best taken from the steaming drum at some point below normal water level. With this kind of system intermittent blowoff valves should be opened occasionally, but on a regular schedule, to discharge sludge from the mud drum or lower header.

Nonflash system, upper left, is generally used for relatively low-capacity low-pressure boilers with low blowdown rates. Usually blowdown from each boiler discharges to waste through separate heat exchangers.

Flash system, upper right, is economical for larger capacity boiler plants where the amount of blowdown is substantial, and the resulting flashed steam can be used conveniently. Boiler water enters the flash tank through a flow-control valve. Since the flash tank operates below boiler pressure, a portion of the blowdown water immediately flashes into steam. This is sent to the deaerating heater or some other steam system. If boiler pressure is high enough to permit flashing at intermediate pressures, one or more flash tanks can be added in series for a multistage system. Individual blowdown lines from each boiler are connected to a blowdown manifold on the first-stage flash tank. Residual blowdown leaves each flash tank through a direct water-level actuated drainer valve. Remaining blowdown is finally cooled to within 10 to 20 F of the inlet temperature by a heat exchanger on the makeup water line to deaerator.

Four steps to evaluating a continuous blowdown system

Let's take a 250-psi boiler with an evaporation rate of 15,000 lb per hr. Makeup-water analysis shows 170 ppm total solids. Temperature is 60 F.

(1) Calculate percent boiler blowdown. Maximum allowable total solids in the boiler water varies with boiler pressure. Table, below, sets this at 3500 ppm for a 250-psi boiler. Solids entering with makeup concentrate as steam is produced. Blowdown removes this concentrated boiler water. To hold solids at a given level, amount entering with makeup must equal that removed by blowdown. Let X equal blowdown, Y the makeup water flow. Then:

$$170 \text{ ppm } (Y) = 3500 \text{ ppm } (X)$$
$$(X) = 170/3500\ (Y)$$
$$(X) = 0.05\ (Y) \text{ or } 5\%\ (Y)$$

In some cases, depending on makeup analysis, percent makeup and type treatment, suspended solids rather than total solids are controlling factor in calculating blowdown. But general approach is still the same, after solids limitation is set.

(2) Then determine feedwater flow. Boiler produces 15,000 lb steam per hr. So maximum feedwater flow must equal this amount plus the water lost through blowoff. In this case, blowoff (Y) at 5% of makeup flow with no condensate return amounts to:

$$Y = 0.05\ (15{,}000 + Y)$$
$$Y = 750/0.95 = 800 \text{ lb per hr}$$

Total feedwater flow is 15,000 plus the 800 or 15,800 lb per hr. If the system calls for 50% makeup with the remainder, condensate returns:

$$Y = 0.05\ (7500 + Y)$$
$$Y = 375/0.95 = 395 \text{ lb per hr}$$

Total feedwater flow is then 7500 plus 7500 plus 395 for a total of 15,395 lb per hr. We are ignoring any solids present in the condensate. This is usually done in practice unless it is badly contaminated or is a considerable portion of the total feedwater flow.

(3) Now calculate flashed steam available. Boiler blowdown can provide low-pressure steam for feedwater heating or process. Just discharge it into a flash tank at lower pressure. Amount of steam produced depends on operating conditions.

$$\text{Steam flashed, } \% = \frac{h_1 - h_2}{H_1}$$

where h_1 = heat of water entering flash tank
h_2 = heat of water at flash pressure
H_1 = latent heat of steam at flash pressure

Now refer to a steam table. Heat of water at 5 psi flash pressure is 196.1 Btu per lb. Its latent heat equals 959.9 Btu per lb. Heat of water at the 250-psi level is 381.6 Btu per lb. Then:

$$\text{Steam flashed, } \% = \frac{(381.6 - 196.1) \times 100}{959.9} = 19.4$$

This amounts to 19.4% of 800 or 155 lb per hr leaving the flash tank. Remaining water (645 lb per hr at 227 F) drains from flash tank to a heat exchanger where it gives up additional heat to the incoming feedwater.

(4) Finally, calculate heat savings. If the final blowoff heat exchanger has a terminal temperature difference of 15 F, blowoff is discharged to the sewer at 60 + 15 F or 75 F. Except for this terminal difference all blowoff heat can be reclaimed in the feedwater. Total heat in this blowoff is 800 (381.6) or 305,280 Btu per hr. Heat going to the sewer as residual blowoff above 60 F equals 645 (15) or 9675 Btu per hr. So heat saved is 305,280 − 9675 or 295,605 Btu per hr. Using this, dollar heat savings per yr are: Btu per hr saved × hours of operation per yr × fuel cost per ton ÷ fuel heat value × Btu per lb × 2000 lb per ton × boiler efficiency.

Boiler-water limits vary with operating pressure

Boiler pressure at outlet, psig	*Total solids ppm	*Alkalinity (Total) ppm	*Suspended solids, ppm	Silica ppm
0-300	3500	700	300	125
301-450	3000	600	250	90
451-600	2500	500	150	50
601-750	2000	400	100	35
751-900	1500	300	60	20
901-1000	1250	250	40	8
1001-1500	1000	200	20	2.5
1501-2000	750	150	10	1.0
2001	500	100	5	0.5

*American Boiler and Affiliated Industries Manufacturers Association's maximum limits for boiler-water concentrations in units with a steam drum

Internal treatment plays a basic role

Treating water in the boiler, while evaporation is taking place, is commonly called *internal treatment*. Aim is to chemically adjust or balance boiler water to prevent scale formation, corrosion, steam contamination, embrittlement. Some form of this treatment is given to practically every boiler. Amount and type of chemicals depends on plant operating conditions and feedwater analysis.

Feedwater analysis in turn varies with raw-water makeup and type of external treatment it's given. This ranges from nothing at all to complete removal of solids. But in all cases internal treatment, using standard equipment with readily available chemicals, is necessary. Long term trouble-free operation also demands regular control tests of feedwater, boiler water, steam and condensate returns. Therefore, carefully scrutinize claims made for "cure-all treatments," "magic formulas" and "spectacular gadgets" before changing your present treatment methods.

Now let's see what happens to scale-forming salts of calcium and magnesium in the boiler. Every internal treatment is designed to precipitate these salts in the most desirable form. This removes hardness but produces an equivalent amount of suspended solids or sludge that is potentially troublesome, but controlled by blowdown. Mechanical attachment of these suspended solids to heating surfaces is one cause of scale inside the boiler.

Amount of suspended solids that can be tolerated depends mostly on operating pressure and load conditions, and may even control boiler blowdown. But when potential sludge in the feedwater is excessive, external treatment enters the picture to soften makeup supply or otherwise reduce dissolved solids. Low-pressure boilers usually permit higher sludge concentrations than are allowed for most high-pressure installations.

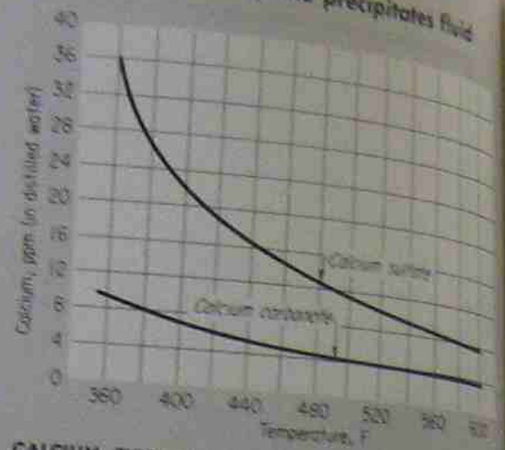
Organic materials such as tannins, lignins, starches and seaweed derivatives should also be used to keep boiler sludge fluid. There are several different ways that organics hinder scale formation. Some coat crystal particles such as calcium carbonate, above, with a protective layer of colloidal material. This prevents precipitated particles from sticking to each other or to the boiler-drum surfaces.

Other organic colloids, such as sodium mannuronate and sodium alginate, react with calcium and magnesium salts to form a floc that entangles precipitates. Organics also distort crystal formation to inhibit scale deposits at point of formation. While these materials solve many problems in low- and medium-pressure boilers, they are not widely used at very high pressures and temperatures.

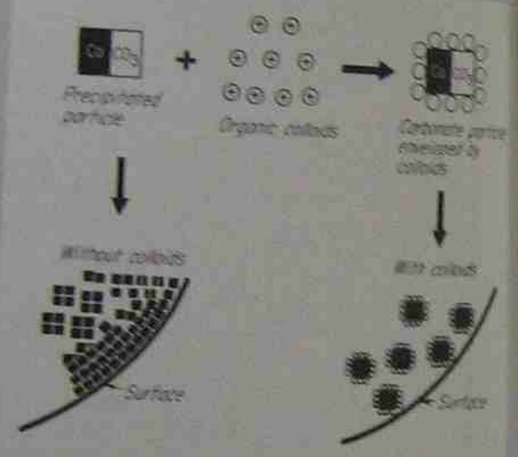
Phosphate treatment to cut calcium in the boiler is almost standard practice for low-hardness feedwater. Forms commonly used include monosodium (acid), disodium (about neutral), trisodium (alkaline) and many complex phosphates. Choice in each case depends upon economics and alkalinity of the boiler water. Once they enter the boiler their reactions are similar. Calcium hardness comes down as a flocculent phosphate precipitate when enough alkalinity is present for the reaction to take place.

Calcium isn't precipitated properly below a pH of 9.5. So it's necessary to select a phosphate that adjusts pH to the optimum value. This may call for blending two of them together or adding an alkali. The phosphate precipitate will be either tricalcium phosphate or hydroxyapatite, $Ca_{10}(OH)_2(PO_4)_6$, if hydrate content of boiler-water reaction zone is high enough. Preferred form is the hydroxyapatite (mixed phosphate and hydroxide) precipitate because it's less sticky than tricalcium phosphate. Caustic

Organics keep the precipitates fluid



CALCIUM SULFATE is usually more soluble than carbonate, making it simple to chemically prevent calcium sulfate scale



CALCIUM CARBONATE precipitated by boiler heat or soda ash forms a sticky sludge unless some colloidal material is used

Wide variety of chemicals adjust boiler-water analysis

Chemical	Purpose	Comment
Sodium hydroxide NaOH (caustic soda)	Increase alkalinity, raise pH, precipitate magnesium	Contains no carbonate, so doesn't promote CO_2 formation in steam
Sodium carbonate Na_2CO_3 (soda ash)	Increase alkalinity, raise pH, precipitate calcium sulfate as the carbonate	Lower cost, more easily handled than caustic soda. But some carbonate breaks down to release CO_2 with steam
Sodium phosphates NaH_2PO_4, Na_2HPO_4, Na_3PO_4, $NaPO_3$	Precipitate calcium as hydroxyapatite ($Ca_{10}(OH)_2(PO_4)_6$)	Alkalinity and resulting pH must be kept high enough for this reaction to take place (pH usually above 10.5)
Sodium aluminate $NaAlO_2$	Precipitate calcium, magnesium	Forms a flocculent sludge
Sodium sulfite Na_2SO_3	Prevent oxygen corrosion	Used to neutralize residual oxygen by forming sodium sulfate. At high temperatures and pressures, excess may form H_2S in steam
Hydrazine hydrate $N_2H_4 \cdot H_2O$ (35% solution)	Prevent oxygen corrosion	Removes residual oxygen to form nitrogen and water. One part of oxygen reacts with three parts of hydrazine (35% solution)
Filming amines Octadecylamine, etc	Control return-line corrosion by forming a protective film on the metal surfaces	Protects against both oxygen and carbon dioxide attack. Small amounts of continuous feed will maintain the film
Neutral amines Morpholine, cyclohexylamine, benzylamine	Control return-line corrosion by neutralizing CO_2 and adjusting pH of condensate	About 2 ppm of amine is needed for each ppm of carbon dioxide in steam. Keep pH in range of 7.0 to 7.4 or higher
Sodium nitrate $NaNO_3$	Inhibit caustic embrittlement	Used where the water may have embrittling characteristics
Tannins, starches, glucose and lignin derivatives	Prevent feed line deposits, coat scale crystals to produce fluid sludge that won't adhere as readily to boiler heating surfaces	These organics, often called protective colloids, are used with soda ash, phosphate. Also distort scale crystal growth, help inhibit caustic embrittlement
Seaweed derivatives (Sodium alginate, sodium mannuronate)	Provide a more fluid sludge and minimize carryover	Organics often classed as reactive colloids since they react with calcium, magnesium and absorb scale crystals
Antifoams (Polyamides, etc)	Reduce foaming tendency of highly concentrated boiler water	Usually added with other chemicals for scale control and sludge dispersion

alkalinity also precipitates magnesium salts as the extremely insoluble magnesium hydroxide.

Carbonate-organic treatment still finds use in many low-pressure boilers. If sufficient alkali is already present in the feedwater to precipitate the hardness the water is called *self-purging*. Then additional alkali isn't required although organics are needed for sludge conditioning. But soda ash usually must be added to avoid calcium sulfate scale by precipitating the more insoluble calcium carbonate. Curves, facing page, show theoretical relationship of solubility with increasing temperature.

Carbonate-organic method is often more economical on relatively high hardness (60-70 ppm) and high-alkalinity water. Resulting sludge is easier to handle than phosphate type. Conversely, phosphate treatment does a better job on low-hardness waters and can handle higher temperatures and pressures. Soda ash must be used with care since it breaks down under boiler heat and pressure to form hydroxide alkalinity and carbon dioxide which goes off with the steam to promote return-line corrosion. The carbon dioxide dissolves in the condensate to form carbonic acid. This lowers pH and greatly accelerates the rate of oxygen corrosion. Table, above, includes chemicals in common use to control corrosion in boiler and return lines.

Boiler pressure is big factor in choice of treatment

In general, as boiler pressures increase, improved feedwater quality is required. Low-pressure boilers are often able to use raw-water makeup with only internal treatment. High-pressure boilers at the other end of the scale may require almost complete removal of all dissolved solids from the makeup. And there are all degrees of feedwater treatment for boiler pressures that fall between these extremes.

But by classifying boilers simply as low, medium and high pressure we can cover the types of treatment most commonly used in each of these areas. Of course, there are always exceptions and special cases that will not fit this general pattern. But even these can be more intelligently handled by using this broad classification of treatment as a starting point.

For purposes of this report let's fix the low-pressure range at 0 to 125 psig. Medium-pressure class will have an upper limit of about 750 psig. This is highly variable since many feel that anything over 600 psig should be called high pressure. Others believe that anything less than 900 psig is still medium pressure. High-pressure class will cover all those boilers operating above this middle range.

Low-pressure plants need external treatment when water analysis and operating conditions indicate that suspended solids in the boiler will be too high. When practical, always include a deaerator in the feedwater cycle to remove dissolved oxygen and CO_2.

When makeup is low, say 20% or less on a 20,000-lb-per-hr boiler, internal treatment is a good bet to handle the job alone. But call in a feedwater treating specialist to recommend type and amount of chemicals and controls needed. Generally, phosphate treatment is used. Enough phosphate is fed to reduce boiler-water hardness to zero and maintain a phosphate residual of 30 to 60 ppm. Adjust hydroxide alkalinity with caustic soda to 100 to 300 ppm level. Feed sodium sulfite to chemically scavenge any dissolved oxygen from the feedwater and keep a residual of 20-40 ppm in the boiler.

When makeup is high, say 80% or more on a 20,000-lb-per-hr boiler, take a careful look at external treatment. Feedwater hardness is an important factor. If it's less than 25 ppm, internal treatment alone is probably enough with blowdown adjusted to regulate both total dissolved solids and suspended solids. Hardness above 25 ppm usually justifies some kind of external treatment. Type depends on the water analysis.

Low-alkalinity makeup is softened by a simple sodium-cation exchanger. Double unit, below, is often used because it gives a steady flow of soft water at any rate up to the maximum design figure. Also, one complete spare is available for an emergency.

Same job can be handled in a single unit by (1) putting all exchange material needed into one tank (2) increasing softener diameter since a higher rate is needed to treat the same volume of water in two or three hours less time and (3) providing enough softened-water storage to handle the service rate while the softener is off the line for its brine regeneration.

Phosphate internal treatment will remove the residual hardness. Add sodium nitrate for embrittlement control. Watch pH of condensate carefully. Either neutralizing or filming amines can be used to guard against return-line corrosion. Since sludge won't be a big problem, adjust blowdown to control alkalinity and total dissolved solids. Hold phosphate, sulfite and hydroxide alkalinity residuals at about the same levels as before.

High alkalinity makeup should be treated to reduce the bicarbonate in addition to being softened. Available systems are shown at right. Selection is based mainly on water analysis and the magnitude of flow. Simplest method is a softener followed by a chloride anion exchanger. Treated water is soft and low in alkalinity. But resulting chlorides may be excessive if raw water is high in sulfates, nitrates and bicarbonates. Other methods shown are capable of doing an even more complete job of alkalinity reduction. But complexity and cost often limits their application to larger plants where trained operators are more readily available.

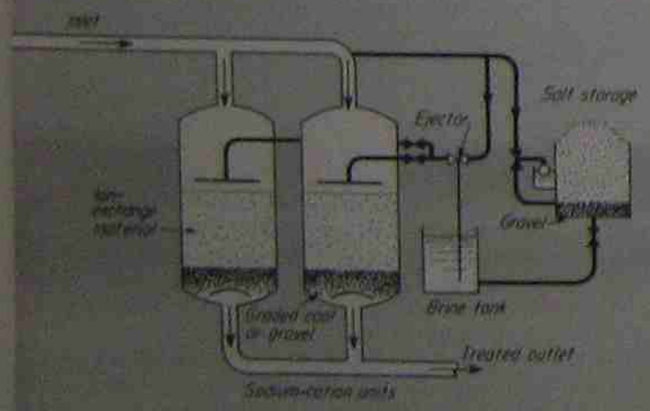
This external system is then followed up with internal phosphate treatment. Sodium nitrate isn't usually required. But a supplemental feed of caustic soda is needed to adjust boiler water hydroxide and pH. Blowdown is based on total dissolved solids.

Medium-pressure boilers — both power and process — need extensive makeup water treatment. Complete deaeration of the feedwater is a must. Degree and type of treatment system will vary with percent makeup, water analysis and overall economics.

Let's take a hypothetical case where boiler capacity is in the range of 100,000 to 500,000 lb per hr at 600 psig. Amount of makeup is 40% and raw water is high in hardness, alkalinity, silica. Turbidity is low.

Hot-lime-zeolite treatment is the first possibility. Bulk of the silica is removed when dolomitic lime or magnesium oxide is fed to the settling tank. Alkalinity is also reduced and hardness practically eliminated in the

Ion-exchange softeners are popular for low-pressure boiler-feed makeup



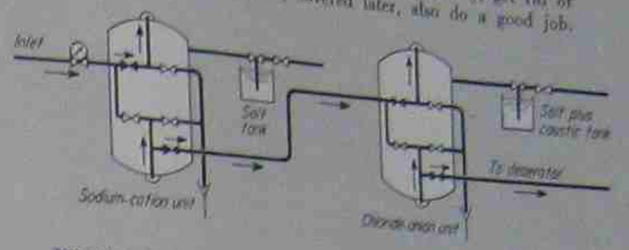
SODIUM-CATION EXCHANGERS are often hooked up in parallel; each unit sized to handle service flow while other is regenerating

Softeners are generally used when percent makeup and raw-water hardness is high. Here's how they are selected:

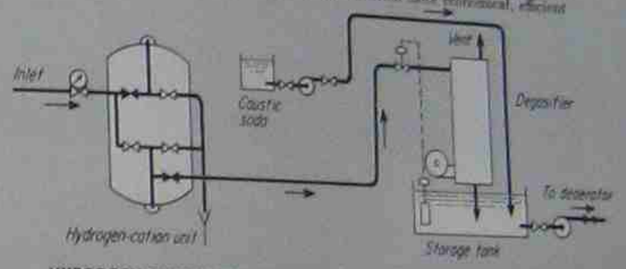
Assume 100 gpm continuous makeup and total hardness of 171 ppm as $CaCO_3$. Since 17.1 ppm equals one grain per gal (gpg), hardness is 10 gpg. Amount of daily makeup is 100 gpm times 1440 min, or 144,000 gal. In double unit system, left, each softener handles half this, or 72,000 gal. If each is sized to regenerate daily, unit capacity must be 72,000 gal times 10 gpg, or 720,000 gr (720 kgr). Amount of styrene-base cation resin for this, rated at 25 kgr per cu ft (regenerated with 10 lb per cu ft of salt), is 720 kgr divided by 25 kgr per cu ft, or 28.5 cu ft. Maximum unit flow rate of 10 gpm per sq ft requires 10-sq-ft area. Closest unit size is 42 in. dia. Exchanger bed depth is then about 3 ft. With supporting gravel and rising space for backwash, straight height will be 7 ft. Regeneration takes 10 lb per cu ft of salt times 28.5 cu ft or 285 lb. Amount per 1000 gal of softened water is 285 divided by 72,000, or 3.96 lb. Salt-storage tank should hold enough for ten or more regenerations of the sodium-cation exchangers.

Potential CO_2 in steam and condensate is cut by reducing raw-water alkalinity

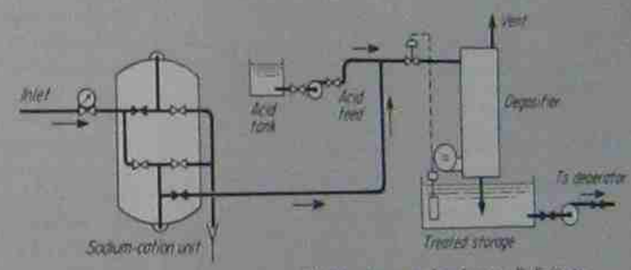
Under boiler pressure and temperature, each ppm bicarbonate alkalinity liberates 0.79 ppm CO_2; each ppm carbonate 0.35 ppm CO_2. Carried over with steam, CO_2 dissolves to form carbonic acid in condensate. With dissolved oxygen it severely corrodes the return lines. Here are four simple ways to reduce alkalinity, get rid of most CO_2. Hot-process units, covered later, also do a good job.



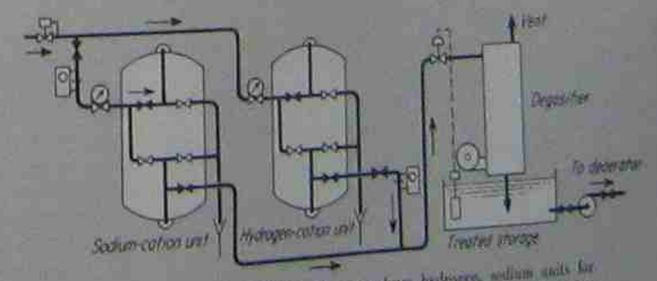
CHLORIDE-ANION EXCHANGER after softener drops alkalinity 80 to 90% using salt and caustic (optional). Since acid isn't required, it's favored for low-pressure boilers even though other methods are often more economical, efficient



HYDROGEN-CATION UNIT destroys all bicarbonate, carbonate alkalinity. Resulting CO_2 is reduced to range of 2 to 15 ppm in degasifier or deaerator. Caustic-soda feed then neutralizes mineral acidity, raises pH to desired level



ACID FEED after softener reacts with bicarbonate and carbonate alkalinity to form CO_2. Degasifier CO_2 residual is in 2 to 15 ppm range. Control of acid feed is critical for good results. Caustic is usually added later to raise pH



SPLIT-STREAM DEALKALIZER blends water from hydrogen, sodium units for 10 to 15 ppm alkalinity. Degasifier reduces CO_2. Proportion through hydrogen unit about equals alkalinity reduction divided by total cations (as $CaCO_3$)

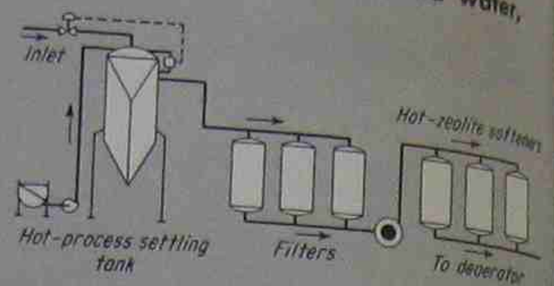
Hot-lime-zeolite plants and demineralizers vie for makeup to medium-pressure boilers

sodium-cation exchangers. Supplementary internal treatment usually includes phosphate, sodium sulfite, organics and possibly an antifoam. Control blowdown rate to keep boiler-water silica below recommended limit of 50 ppm.

Split-stream dealkalizer can be used if raw-water silica isn't too high. Treated water is soft and low in alkalinity. Supplementary internal treatment is about the same except that caustic soda is called for to control alkalinity and pH of both feedwater and boiler water. Calculate the amount of blowdown needed to limit boiler-water silica to 50 ppm. Since this treatment doesn't reduce silica, the required blowdown rate may be too high. In that case another method is needed to reduce silica.

Caustic regenerated-anion exchanger merits attention when the raw-water silica is high and other dissolved solids are low. This unit usually follows a sodium-cation softener.

Hot process handles turbid water,



HOT LIME-ZEOLITE produces treated water with 0 to 2 ppm hardness, 20 to 30 ppm alkalinity and 0.5 to 1.0 ppm silica. Moderate blowdown usually keeps boiler-water silica in 5 to 25 ppm range. Boilers and turbines are protected from carryover, scale and silica deposits. Low carbonate alkalinity means low CO_2 in the steam.

CHARACTERISTICS. Hot-process settling tank handles turbid waters. Resin used in the hot-zeolite softener is stable and replacement costs are reasonable. Chemical operating costs and initial investment are low compared to demineralizing. Lime and salt are easily handled. Settling tank reactions require careful chemical control.

Hot-process units use these chemicals

Raw-water analysis	Chemicals and application
(1) Hardness greater than alkalinity. Both carbonate, noncarbonate hardness present	Lime and soda ash for low-pressure boiler-feed makeup treatment
(2) Same as (1) except that boiler pressure is higher	Lime and soda ash followed by supplementary phosphate to boiler or boiler-feed pump
(3) Same as (1) except that boiler pressure is higher in the medium-pressure range	Lime followed by hot-zeolite softeners. Salt regeneration is more economical than soda ash or phosphate. Produces lower hardness and alkalinity
(4) Contains carbonate and noncarbonate hardness in the proper ratio	Caustic soda to react with carbonate hardness with the resulting carbonates precipitating noncarbonate hardness
(5) Alkalinity much higher than hardness. Sodium bicarbonate is present	Feed lime and gypsum. The gypsum converts sodium bicarbonate to sulfate
(6) Same as (5)	Sulfuric acid to convert sodium bicarbonate to carbonic acid and sodium sulfate, followed by lime
(7) Silica	Feed dolomitic lime, activated magnesium oxide, epsom salts, ionic magnesium
(8) Oil, organic matter and turbidity	Lime and soda ash with coagulants or coagulant aids

Chlorides, sulfates and bicarbonates in the softener outlet are exchanged for hydroxides. Silica is actually absorbed in the process. Type of water best suited for this treatment will probably have silica of more than 20 ppm with total dissolved solids (other than silica) less than 200 ppm.

Since any bicarbonate in the raw water is converted to hydroxide, carbon dioxide in steam is reduced to a minimum. In fact, depending on the analysis, it may be necessary to reduce the hydroxide alkalinity with an acid feed before sending it to the boiler. Operating cost of this system is higher than for hot lime-zeolite, but probably lower than demineralizing. Total investment on an erected basis may be less than demineralizing or hot lime-zeolite. Assuming comparable treated-water quality, economics will determine whether the savings in fixed charges over hot lime-zeolite will counterbalance the higher operating cost.

Demineralizing produces better makeup water than any of the methods discussed so far. Main drawback is higher equipment and chemical operating cost. Advantages include reduced boiler blowdown and a big assist for the production of higher-quality steam. This is why more plants in the medium-pressure range are going to demineralizing systems. But it's hard to justify demineralizing unless the plant is at the high end of the medium-pressure range and the raw water is low in total dissolved solids.

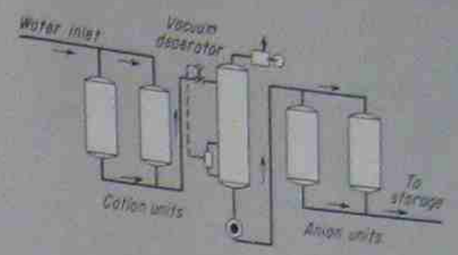
Any comparison between hot process and demineralizing, above, is greatly affected by the raw-water analysis. Hot-process settling-tank size varies primarily with flow. Character of the water changes the type and amounts of chemicals used. These are shown, left, in tabular form. So physical size and, therefore, equipment cost is not greatly

while demineralizers usually require some form of pretreatment

Size of hot-process settling tank, left, is based on flow rate and a standard detention time of 60 to 90 minutes. Raw-water analysis affects only amount and type of chemicals fed to get desired results. Chart, facing page, lists those that are commonly used.

In demineralizing system, right, water analysis has a direct bearing on equipment size. Quantity of ion-exchange materials, as well as chemical operating costs, increase as total dissolved solids in the water go up. Equipment cost for hot process varies almost directly with raw-water flow. But in a demineralizing plant total dissolved solids also affect overall cost. This helps to explain why a demineralizer may compare favorably with hot process in one case and be completely out of the question in another where conditions are essentially the same except for water analysis.

First step in sizing a demineralizer is to compute total exchangeable anions and cations. Start with the anion units using the approach outlined for zeolite softeners on page 74. Then size cation units adding extra capacity for backwash, rinse and chemical dilution used in anion regeneration. This will give you an idea of size and operating cost for comparison with alternate water-treatment methods.



DEMINERALIZING produces top-quality makeup of type demanded by high-pressure boilers. Dividing line for high and medium pressure, as far as water treatment is concerned, falls between 750 and 1250 psi. But many medium-pressure units will continue using demineralized makeup to get purer steam, reduced blowdown, etc.

CHARACTERISTICS. Treated water has about 3 ppm total dissolved solids and 0.1 ppm silica. System can be made automatic. Boiler blowdown is reduced, but chemical and installed equipment cost will probably be higher than other methods. Pretreatment is needed to remove turbidity. Anion resins have short life on some waters.

affected by variations in the raw water. But in the case of a demineralizing system, water analysis has a direct bearing on both equipment size and the chemical operating cost.

Turbidity of water supply is another important factor in treatment selection. The hot-process tank can handle fairly high turbidity from the incoming water. But ion-exchange systems such as demineralizing cannot tolerate more than 5 to 10 ppm turbidity. So they often need pretreatment. It's also a must to help remove organic substances that foul anion exchangers.

Pretreatment may consist simply of a battery of filters to remove moderate amounts of turbidity. More often it involves a complete coagulation, clarification and filtration plant. Then it may pay to use a cold-process softener that reduces hardness and alkalinity while it is removing turbidity. Depending on the water, this can greatly reduce the load on ion-exchange equipment.

Unless the clarification equipment is needed for other purposes such as treatment of cooling or process water the additional investment charges are usually high enough to make most economic comparisons favor the hot-lime-zeolite process in the medium boiler-pressure range.

High-pressure boilers require the most exacting feedwater treatment. Upper limit to this class has been increasing steadily. Not too long ago it went over 2000 psig and now is well up into the supercritical-pressure range.

Main impurity receiving critical attention is silica. At high pressures silica in boiler water volatizes and passes over with steam to the turbine. As steam expands through the turbine this silica deposits on the blades. This cuts

Here's how to figure hot-lime-soda chemical needs

Although the hot-process softener is more conveniently controlled by testing the treated water, chemical needs for lime and soda ash can be readily calculated from the analysis of the raw water. Let:

(1) TH = Total hardness, ppm as $CaCO_3$
(2) Alk = Total alkalinity, ppm as $CaCO_3$
(3) Mg = Magnesium hardness, ppm as $CaCO_3$

These equivalent weights will be used:

(1) Calcium carbonate = 50
(2) Calcium hydroxide, 90% = 41.1 (lime)
(3) Sodium carbonate = 53 (soda ash)

Now assume that the raw water has a total hardness of 150 ppm, total alkalinity of 125 ppm and a magnesium hardness of 50 ppm, all expressed as $CaCO_3$. Amount of lime used is then:

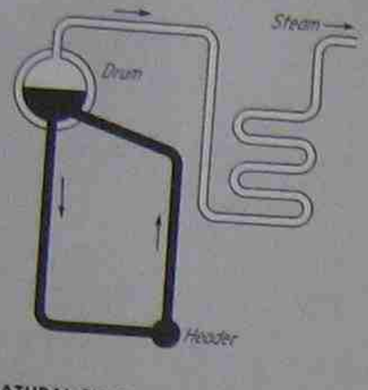
$$\frac{(Alk + Mg)\ 41.1}{50} = \frac{(125 + 50)\ 41.1}{50}$$

or 143.8 ppm equivalent to 1.2 lb per M gal. Amount of soda ash called for is:

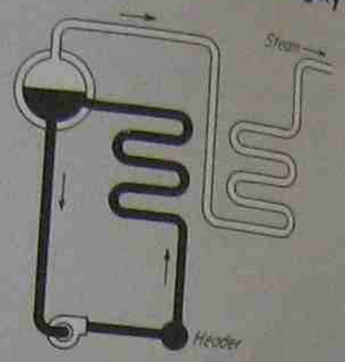
$$\frac{(TH - Alk)\ 53}{50} = \frac{(150 - 125)\ 53}{50}$$

or 26.5 ppm equivalent to 0.22 lb per M gal. Add to this the excess carbonate needed.

Upper limit of high-pressure boiler category

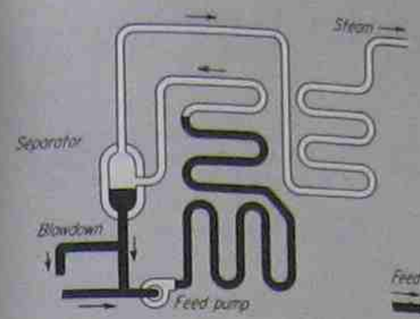


NATURAL-CIRCULATION boilers are used successfully for pressures below 2800 psig

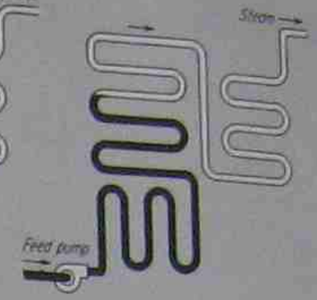


CONTROLLED-CIRCULATION boilers with circulating pumps are used above 2000 psig

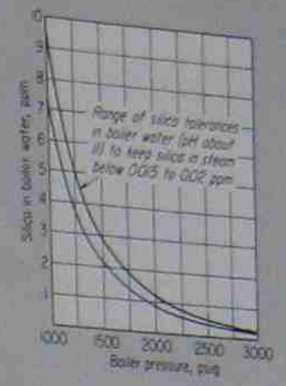
stretches well into the supercritical range



ONCE-THROUGH design for subcritical pressures may include a water separator



SUPERCRITICAL PRESSURE, once-through boilers don't have any drum or separator



ALLOWABLE SILICA in boiler water rapidly drops with rising boiler pressures

High-pressure and once-through boilers call for feedwater

that's extremely low in silica and dissolved solids

efficiency and eventually the turbine must be shut down for thorough cleaning to remove these deposits.

So as boiler pressures increase, silica level in boiler must be carefully watched to minimize amount of volatized silica in steam. Curve, facing page, indicates range of silica in boiler water to keep silica in steam below the 0.02 to 0.03 ppm level.

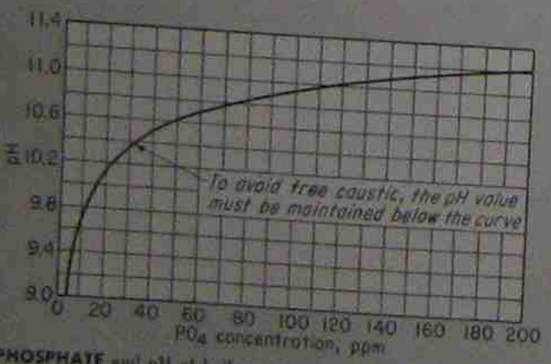
Total dissolved solids allowed in a boiler also drop off sharply at higher operating pressures. However, silica generally controls blowdown at upper end of pressure scale, with resulting solids level somewhat lower than the maximum allowed.

External treatment under these conditions is limited to either evaporation or demineralizing. Both produce top-quality makeup, facing page. There are many factors that influence each decision to use one or the other method in a given plant. Supplementary internal treatment falls into two general categories. Both use blowdown to keep silica and dissolved solids below maximum limits, and both keep 3 to 5 ppm sodium sulfite and a slight excess of hydrazine or both in the boiler. The first is known as the low-caustic method. Hydroxide alkalinity is kept at about 5 ppm with 3 to 5 ppm phosphate expressed at PO_4. Second method, called "Coordinated pH phosphate control," is outlined below. Phosphate alkalinity is carried in the range of 20 to 100 ppm by adjusting pH so there isn't any free caustic present.

Supercritical pressure once-through boilers pose many special treatment problems. Since there isn't any boiler drum, above, all water entering the circuit passes out as supercritical fluid. Any solids present in the feedwater are carried off with the steam. These leave troublesome deposits in the superheater or turbine. Since feedwater is the same as boiler water, these limits in parts per billion apply to both: (1) Total dissolved solids, 50 to 500 ppb; (2) silica, 20 ppb; (3) iron, 10 ppb; (4) copper, 10 ppb; (5) oxygen, 5 to 7 ppb; (8) pH in the range of 9.0 to 9.6.

There are two general sources of impurities that enter the cycle and cause trouble with deposits. The first is mineral impurities in the condensate, usually coming through the condenser from the cooling water. Second is metal oxides from preboiler corrosion. Improvements in condenser design and manufacture are expected to cut leakage from this source to a minimum. But it's still good practice to treat all or part of the condensate stream by sending it through a polishing mixed-bed demineralizer. Total dissolved solids are reduced below 0.04 ppm and silica is taken below 0.01 ppm. Vapor type chemicals rather than solid type are used for supplementary treatment. Both hydrazine and ammonia are typical vapor type chemicals used for oxygen scavenging and corrosion control in the preboiler cycle of today's high-pressure plants.

Coordinated phosphate pH control protects against caustic attack



PHOSPHATE and pH of boiler water are controlled simultaneously so boiler pH is always equal to or less than the value on the curve

This control method aims to produce boiler water that won't concentrate caustic on evaporation and will contain enough alkalinity to give corrosion protection. This is done by keeping only bonded alkali-metal phosphate in the boiler water. Without caustic there can't be caustic attack in the boiler. Any alkaline attack has to come from the relatively weak phosphate alkalinity. Graph, left, is used for control. Plot pH and phosphate concentration of the boiler water on the grid. If this point falls on the curve, all phosphate is in trisodium form. If it falls above the curve, free caustic is present in the boiler. If it falls below the curve, acid phosphate salts are present. When this happens and phosphate content is at desired maximum, add enough sodium hydroxide to increase pH and bring this point back on the curve. All the phosphates are then in trisodium form.

Evaporators and demineralizers produce top-quality water

Demineralizers and evaporators are used to supply makeup water for today's high-pressure boilers. Demineralized-water quality depends on the type of system used. Conductivity may be in the range of 0.5 to 1.0 micromhos with silica less than 0.02 ppm. Recent tests of vapor purity from evaporators, using sodium tracer techniques, consistently report less than 0.01 ppm total dissolved solids.

Before deciding on one method or the other make an economic comparison of both systems. This study should include: (1) installed equipment cost; (2) investment charges; (3) value of evaporator heat-loss or energy degradation; (4) chemical operating cost; (5) labor and maintenance charges. Outcome of this study will vary with each individual case. Amount of total dissolved solids in the water will greatly affect size and chemical operating cost of the demineralizer. Water analysis will also determine kind of evaporator pretreatment needed. Plant heat balance will fix value of heat or energy loss when steam in evaporator coils is degraded to lower pressure.

Intangibles merit attention too. A demineralizing plant has the advantage of being able to produce high-quality water when heat isn't readily available. This is valuable for starting up new power plants and supplying makeup for older power plants now operating at light loads. Evaporator output is closely tied to the plant heat cycle, but the demineralizer can give rated capacity whenever needed. Mixed-bed demineralizers also look promising for polishing service in condensate cycles to remove trace impurities.

Evaporators generally have a consistent record of reliable, trouble-free performance. Their operating problems are usually traceable to poor or no pretreatment of makeup or insufficient capacity. Demineralizers also have their share of operating problems, ranging from resin fouling to trouble with complicated automatic controls.

Cooling waters need careful analysis, chemical control

Industry probably uses more water for cooling than for all other purposes combined. Condensers, heat exchangers, cookers, engines, compressors, etc all need cooling water. Thus cooling-system maintenance can be very costly unless the water is treated to (1) prevent corrosion, deposits, biological growths and (2) protect cooling-tower wood. Water treatment, in turn, is tailored to fit the size and type of the particular cooling system.

Cooling-water systems are broadly divided into two main types — *once through* and *recirculating*. In the once through system cooling water makes one pass through the heat-exchange equipment. No evaporation takes place; water temperature is merely increased about 20 F. Since the water is eventually discharged to waste, its use is limited to areas with an abundant water supply.

Trend is toward the more complex recirculating systems where water is saved by continuous re-use. In the open recirculating type a cooling tower or spray pond cools water by evaporation. Only water losses are from evaporation, windage and blowdown. But treatment problems are more critical because solids are concentrated and water aerated in towers or spray ponds. Closed-recirculating system avoids these troubles by using a fan-cooled radiator or closed heat exchanger cooled by water in a secondary circuit. Water loss is at a minimum and solids are not concentrated. In effect major treatment problems are transferred to a secondary system where the temperature rise can be kept down. These combination hookups are called double-recirculating systems.

Open type is most frequently used for cooling water in chemical plants, oil refineries and power-plant condensers. Closed system is usually limited to uses where the quantity of cooling water is small. Typical applications include compressor and diesel-engine cooling.

Calcium-carbonate scale is the most common type of water-formed deposit in cooling systems. Calcium bicarbonate, naturally present in all raw water, breaks down to form relatively insoluble calcium carbonate. As water temperature rises it becomes even more insoluble.

Langelier Index measures the tendency of calcium carbonate to precipitate from water under given conditions of calcium hardness, alkalinity, pH, temperature and total dissolved solids. Charts, nomographs and special slide rules can be used to quickly calculate this index for any water supply when the complete analysis is known. It equals the pH of the water, minus pH of saturation of calcium carbonate. Positive index means water has a tendency to deposit scale while a negative index shows a tendency to dissolve scale and corrode. Note that the index doesn't measure amount or rapidity of scaling. This depends on amount of calcium carbonate actually present in each water supply.

Reducing the calcium hardness, total alkalinity and pH or a combination of all three will decrease index of the water. Total dissolved solids content has a relatively minor effect. Blowdown, right, is one way of reducing concentration of calcium and alkalinity in recirculating water. But this increases makeup and is seldom used as the only method of control.

External-treatment methods used to adjust analysis of cooling water include: (1) Cold-process softening with lime followed by an acid feed to adjust pH, alkalinity. (2) Ion-exchange softening with hard-water bypass also followed by an acid feed when needed. (3) Sulfuric-acid feed for moderate hardness waters with high alkalinity.

Stability Index, devised by Ryznar, equals twice pH of saturation of calcium carbonate minus pH of the water. It indicates to what degree a given water is scale forming under average operating conditions. Scale is expected when this index is below six. Amount of scaling increases rapidly as the index approaches four. An index above 6.5 indicates a tendency for the water to corrode.

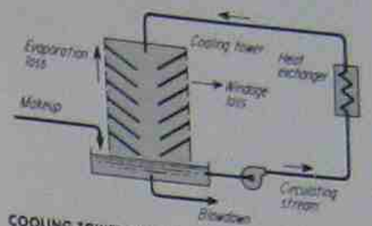
Controlled-scale method adjusts composition of water to insure deposit of a thin impervious layer of calcium-carbonate scale on surfaces of the cooling system. It must be thick enough to prevent any corrosion, but thin enough not to affect overall heat transfer. This approach works well when temperature differential across heat exchangers is low. But when temperature levels vary widely, results are unsatisfactory. If water is adjusted to protect exchangers on high-temperature service, those at lower temperatures will corrode. When control is set for low-temperature applications, high-temperature exchangers will scale. In fact the hot end of an individual exchanger may scale and the cool end corrode with only the center portion receiving adequate chemical protection.

Chemical treatment keeps scale-forming salts of calcium and magnesium in solution by lowering pH of recirculating water with sulfuric acid. Chemical inhibitors are then necessary to prevent corrosion damage.

Surface-active chemicals or chelating agents act to prevent crystal growth and, therefore, scale formation. In effect they increase the solubility limits of the scale-forming salts. This also helps broaden operating range of the controlled-scale treatment. Chemicals in this group include polyphosphates, tannins, lignins, etc. New organic chelating agents show promise.

Corrosion control is provided largely by inhibitors such as chromates, polyphosphates, silicates and alkalies. If doses are high enough either chromates or polyphosphates are effective. But if concentrations are too low, pitting and tuberculation result. Combination treatment with chromate and polyphosphate is most valuable since it gives comparable results with much lower total amounts of chemical. It successfully controls pitting, tuberculation and other metal losses from corrosion. Best results are usually obtained in pH range of 6.0 to 7.5.

Since oxygen and carbon dioxide are primary causes of



COOLING-TOWER EVAPORATION ups solids concentration in recirculating water; blowdown and windage decrease it

How to calculate cooling-tower blowdown

In general the amount of blowdown needed depends on how far the circulating-water dissolved solids are allowed to build up by concentration. Number of concentrations N is one way of comparing dissolved solids in the makeup with that of the circulating cooling-tower water. Since the chlorides remain soluble on concentration, N is conveniently expressed as the ratio of chlorides in circulating water to chlorides in the makeup. System, above, shows the basic items that are part of every cooling-tower system.

C = Water circulating in cooling system, lb per hr
E = Water vapor evaporated from tower, lb per hr
B = Water lost by windage, plus that discharged to waste as cooling-tower blowdown
MU = Makeup water added to system, lb per hr
Cl_c = Chloride content of circulating water, ppm
Cl_{MU} = Chloride content of makeup water, ppm

Makeup water is added to compensate for water losses of evaporation, windage and blowdown:

$$MU = E + B \qquad (1)$$

At equilibrium the amount of chlorides entering and leaving the system must be equal. Amount lost from the system in windage and system blowdown must equal that added in the makeup.

$$MU\ (Cl_{MU}) = B\ (Cl_c) \qquad (2)$$

The number of concentrations N by our definition is $Cl_c \div Cl_{MU}$. Transposing (2) gives:

$$N = \frac{Cl_c}{Cl_{MU}} = \frac{MU}{B} \qquad (3)$$

Substituting from equation (1)

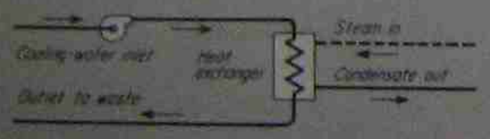
$$N = \frac{E + B}{B} = \frac{E\% + B\%}{B\%}$$

Amount of blowdown needed to limit concentrations in recirculating water is then easily found:

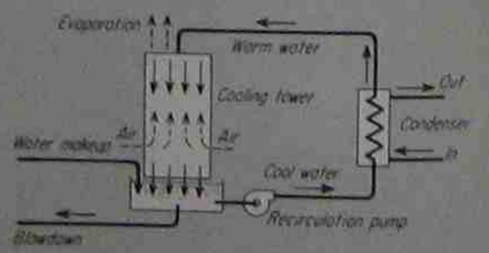
$$B\% = \frac{E\%}{(N-1)} \qquad (4)$$

Evaporation loss varies with temperature drop of circulating water. Evaporating one pound of water in the tower absorbs about 1000 Btu's. This will cool 100 lb of water 10 F. So, for each 10 F cooling, about 1% of the circulating water is evaporated. Windage loss varies with type of tower and local conditions. Reasonable estimates are 0.1 to 0.3% for mechanical-draft towers, 0.3 to 1.0% for atmospheric type and 1.0 to 5.0% for systems using spray ponds.

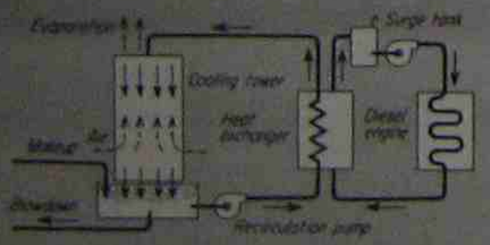
Treatment selected depends largely on the type of cooling-water system employed



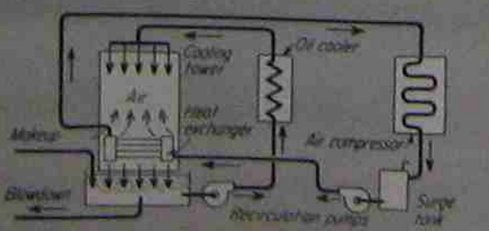
ONCE-THROUGH SYSTEM calls for ample supply of cooling water. The discharge can often be re-used for boiler makeup, process, etc



OPEN-RECIRCULATING HOOKUP makes use of cooling tower or spray pond to cool water by evaporation. Water can then be re-used

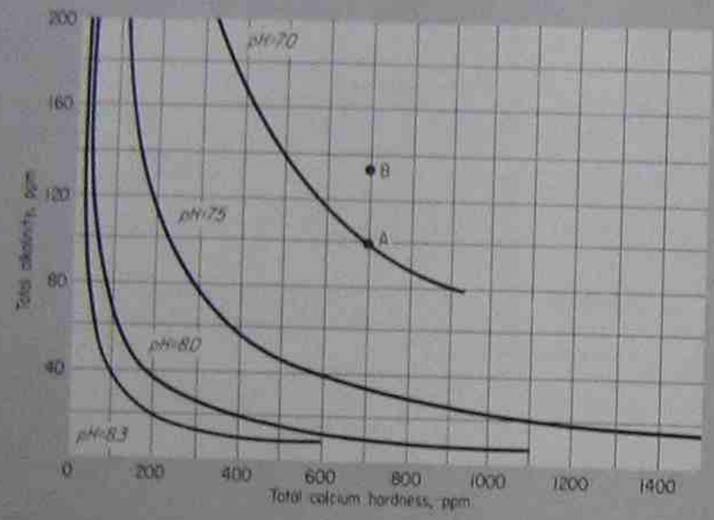


DOUBLE-RECIRCULATING DESIGN combines an open and a closed system. Water passing through closed circuit does primary cooling



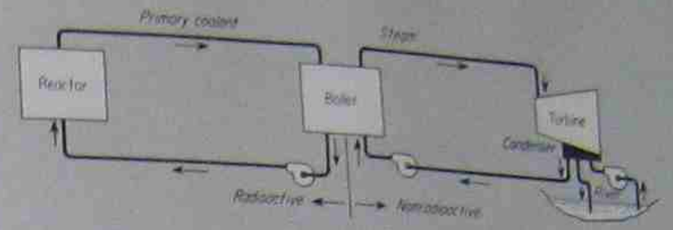
RECIRCULATING WATER passing through the closed circuit is often cooled by a heat exchanger in the bottom of the cooling tower

Calcium hardness, alkalinity, pH are related variables in scale control



CALCIUM-CARBONATE EQUILIBRIUM conditions (neither scale forming nor dissolving) vary with pH at a given temperature. Values above, hold only for a temperature of 77 F

Calcium carbonate is one of the most troublesome deposits found in heat-exchange systems. Factors controlling deposition or solution at a given temperature are shown at left. Water with 100-ppm alkalinity, 700-ppm calcium hardness and 7.0 pH will fall on the curve at point *A*. So this water will not precipitate calcium carbonate. Another water with the same analysis, except for 130-ppm alkalinity, will fall at point *B*. Since this point is above the curve, water isn't in equilibrium and calcium carbonate can be expected to precipitate. Area below the curve indicates a tendency for calcium carbonate to dissolve. Water at point *B* is brought back on the curve by reducing hardness or alkalinity. So two waters with the same calcium hardness may have different scale-forming tendencies. Above 77 F, lower pH, alkalinity are needed to avoid deposits.

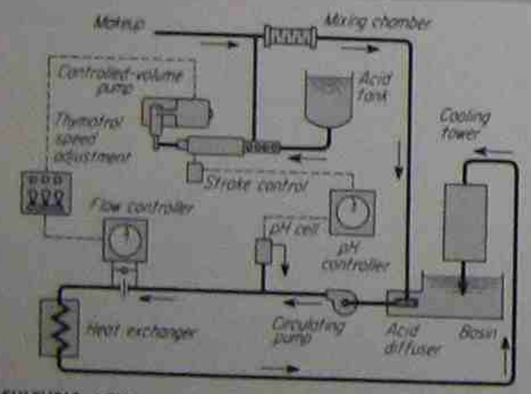


Nuclear-reactor cooling water must be extremely pure

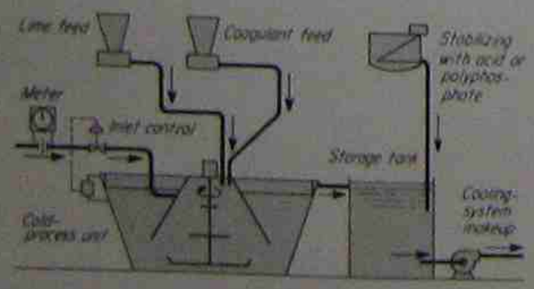
Ample cooling-water supply is a must for nuclear power plants. In a typical pressurized-water reactor, above, water is used for (1) condenser cooling (2) boiler feed and (3) reactor cooling.

Condenser cooling water is treated in normal fashion. But boiler-feed quality must be comparable to that used for very high-pressure boilers.

Cooling water passing through the reactor neutron field becomes radioactive. All water impurities, resulting in residual activity, must be reduced. Cations of manganese, cobalt and sodium are particularly dangerous because they produce energetic gamma rays. Therefore primary cooling-water quality is maintained by treating it with filters and ion exchangers. Both mixed and multibed systems are used to remove and concentrate the radioactive impurities. Although the simplicity of regeneration under remote-control operation favors multibeds, it's often better to discard used resins without regeneration. Then mixed beds are preferred to get the benefit of higher-quality water. If water is badly contaminated, evaporators are best for concentrating impurities for disposal. After cleanup, ion exchangers maintain purity of recirculated water at a lower cost.



SULFURIC ACID converts calcium carbonate to the more soluble calcium sulfate. Flow, pH controls automatically adjust amount fed



COLD-PROCESS SOFTENER reduces carbonate hardness with lime. It's most applicable when alkalinity equals or tops calcium hardness

External treatment combines with chemicals to combat scale, corrosion, biological fouling

corrosion, deaeration effectively helps prevent it. Vacuum deaerator units reduce dissolved oxygen below the level of 0.1 ppm, depending on water temperature and equipment design. But relatively high cost has limited its use.

Microbiological growths on heat exchangers retard cooling, cut plant efficiency and up cost of cooling-system maintenance. When any growths suddenly break loose, lines, pumps and heat exchangers may easily clog.

Iron- and sulfur-reducing bacteria are often a direct cause of corrosion. Iron bacteria produce insoluble salts that can be retained on metal surfaces. Differential aeration under these deposits promotes corrosion. Sulfur-reducing bacteria feed on sulfur compounds in the cooling water. Hydrogen sulfide formed also is corrosive.

Algae growths are composed of millions of tiny plant cells that multiply and produce large masses of plant material in a short time. Slime growths are the gelatinous mass of microorganisms that cling to practically all surfaces in the system. There they trap organic matter, debris and scale-forming compounds.

Mechanical cleaning is the most practical way to get rid of accumulated slime and algae growths. After the system is completely cleaned, start in with a good chemical-treatment program to prevent further growth buildup.

Chemicals that prevent slime and algae troubles are those that are toxic to the microorganisms. Chlorine is fairly general in its toxicity for most bacteria and algae. Residual of 0.5 ppm will destroy most microorganisms. Since chlorine acts on all oxidizable matter, organic material, ferrous iron, etc, overall demand of the water must be satisfied before the needed residual for toxicity can be built up to the desired level.

Chlorine is stable in acid, neutral and alkaline waters. For convenience and economy it is usually fed from a chlorinator in liquid form. Hypochlorite form is best when relatively small quantities are consumed.

Both continuous and intermittent feeds are used. Continuous feeding prevents any buildup of growths, but it's much more expensive than intermittent method. Intermittent or slug feeding runs the risk of allowing growths to build up. Then when they slough off, fouling material in the system increases. Chlorine is usually fed intermittently since overall results are better and cost is lower.

Copper sulfate is toxic to algae, but is less toxic to slimes. Use is limited because it precipitates as carbonate at a pH of 8.5 or over. Phenolic and quaternary ammonium compounds are also used. They resist precipitation at high pH and are not removed by aeration in the cooling tower.

Wood destruction and decay in cooling towers is caused by one or more of the following: (1) chemical attack commonly known as delignification (2) mechanical rupture of wood cells from salt crystallization and (3) biological attack causing wood decay.

Delignification is the removal of tannins, lignins and cellulose products from the lumber, leaving long stringy fibers with greatly reduced strength. It apparently takes place in the presence of high concentrations of sodium carbonate in the circulating water. Oxidizing agents like chlorine tend to speed up the process.

Intermittent splashing on cooling-tower parts produces concentrated salt deposits by evaporation. Salt-saturated water in these areas is absorbed by the wood. Crystals form beneath the surface to disintegrate it mechanically. Result is a mass of soft, loose fibers susceptible to both chemical and biological attack.

Fungus is a form of biological attack caused by microorganisms that feed on wood. These wood-destroying fungi reproduce by spores that alight on the wood surface from the air. Attack is most noticeable in the mist sections and takes place on both wood surface and interior.

Proper control of alkalinity, pH and solids concentration of circulating water will ward off chemical attack. Although it will not prevent biological attack, it will greatly decrease chances of damage from fungus. One good preventive is to use impregnated cooling-tower lumber.

There's a treatment to fit practically every process-water demand

This kind of water-analysis report . . .	. . . points to these process troubles . . .	. . . calling for these treatments
HARDNESS (as $CaCO_3$) ..... 210 ppm (Calcium and magnesium salts)	Forms scale, wastes fuel and soap; spots, streaks and leaves insoluble film on products and containers	(1) Cold process or cation-exchange softening or both. (2) Can demineralize to remove all dissolved solids
TURBIDITY ..... 350 ppm	Objectionable for all uses when over the range of 5 to 10 ppm	(1) Settling tanks (2) solids-contact units (3) filters
COLOR 50	Undesirable for beverages and food processing. Discolors products, etc	Coagulate with alum and activated carbon in (1) settling tanks or (2) solids-contact units. (3) Chlorinate
IRON (Fe) ..... 2.2 ppm Manganese (Mn) ..... 1.6 ppm	Stains everything it comes in contact with. Fosters growth of clogging, taste and odor-producing bacteria	(1) Cation-exchange softening. (2) Aerate or chlorinate and filter. (3) Aerate, settle and filter. (4) Oxidizing filters
CARBON DIOXIDE (CO_2) ..... 40 ppm	Promotes corrosion and pitting of piping and equipment	(1) Deaerate or degasify. (2) Adjust the pH (3) Use corrosion inhibitors
ALKALINITY (as $CaCO_3$) ..... 175 ppm	Cuts tang in soft drinks, interferes with brewing of light beers	(1) Cold-process softening (2) ion-exchange dealkalizing or (3) demineralizing to remove all dissolved solids
TASTE AND ODOR ..... Trace	Affects food processing, beverages, pulp and paper products, etc	(1) Aerate or degasify. (2) Chlorinate. (3) Activated carbon filters

Process-water treatment varies

Practically all process waters should be noncorrosive and free of turbidity, color, iron, manganese and hydrogen sulfide. Microbiological growths, tastes and odors are also objectionable. Limits for each of these items depend on the process, but are generally in agreement with tolerances outlined in Part I of this report (POWER, December 1958). Chart, above, shows type of treatment given.

Hardness must be removed or reduced in a wide variety of process, wash and rinse waters. Water with enough calcium alkalinity will form scale when heated, boiled or concentrated. Result: clogged heat exchangers, pipelines, fixtures, nozzles. Scale in processing tanks may come off in chunks during operation. Processed materials are often spotted, streaked or covered with insoluble films.

Hard water also reacts with soda ash, caustic soda, sodium phosphate, sodium silicate, hydrated lime, ammonia and soap. This wastes the chemical and forms precipitates that lower product quality by adhering to processed material. Hard water is very undesirable in all washing and scouring involving soap since bulky, sticky, insoluble calcium and magnesium soap curds are formed.

Emulsions are difficult to make with hard water since divalent calcium and magnesium ions have a tendency to break emulsions. Clay processing is also affected since these same ions produce a coagulating effect that lowers plasticity of the mix.

Electroplating cleansing and rinsing should be done with softened water to avoid precipitates in alkaline baths and prevent calcium-sulfate deposits in acid baths. Mineral-free water helps avoid product streaking.

Beverage water must be completely sterile to prevent spoilage, crystal clear for appearance and good carbonation, free of tastes and odors, uniformly low in alkalinity. Fermentation processes such as brewing light-colored beers require low calcium, magnesium alkalinity.

Pulp and paper processes need water with little or no color, iron or manganese. Highly colored water affects white and dyed papers as well as pulps. Cellulose fibers readily absorb color and the stain may remain in the finished product. They also absorb iron from dilute solutions to yellow-white pulp or paper and dull-colored paper. Taste and odors may also be picked up by cellulose.

Oil-field flooding operations must keep pores of the ground clear to pass enough water for successful repressurizing. So water must be noncorrosive, stable and free from turbidity, iron, manganese, bacterial action.

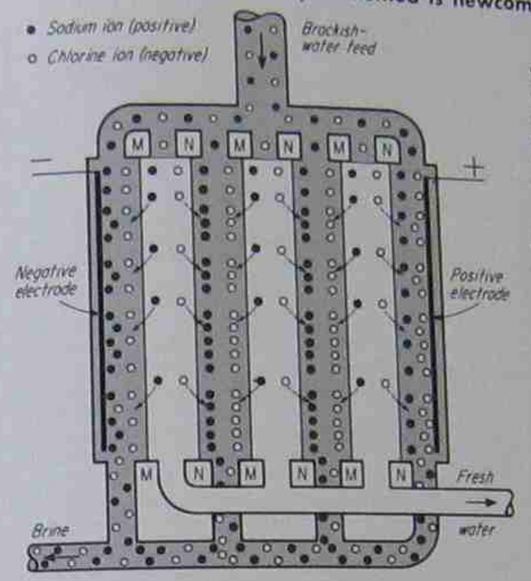
Cation-exchange softening is the most widely used method of removing hardness. Next is cold process using lime only or lime and soda ash. This treatment is particularly good where some degree of partial softening is sufficient. Carbonate hardness can be reduced to the range of 35 to 70 ppm. Often reducing calcium hardness to 35 ppm is all that's needed.

Filters are widely used for turbidity removal. They may handle it alone or follow a clarifier or a cold-process unit. When filled with activated carbon they remove taste and odor. Cartridge and leaf type filters, used for polishing, produce a sparkling-clear water by removing all fine solids.

Iron and manganese present as soluble, colorless divalent bicarbonates are removed by aeration, coagulation, settling, filtration. Cation units on sodium or hydrogen cycle also may do a good removal job. If present in colloidal or organic form coagulation, settling and filtration are needed. Iron can also be stabilized with chelating agents to prevent precipitation.

Mineral-free water is demanded by many processes. Both distilled and demineralized water are used. Demineralized water is uniformly high in quality and usually costs less. So its use is on the increase. Mineral-free water doesn't contaminate materials processed in it, nor does it leave mineral residues upon evaporation. Precipitates are not produced when mixed with water-miscible solvents. Mineral-free water doesn't break emulsions, coagulate colloids or deplasticize clay.

Electrodialysis method is newcomer for brackish-water supplies

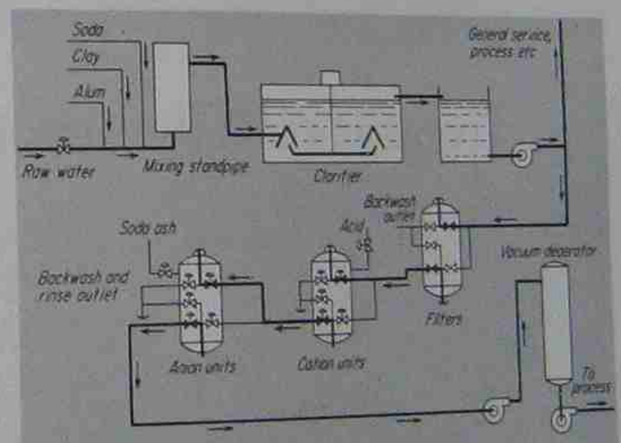


Electric charges of ions dissolved in water help remove solids from solution. Here's how: Sodium chloride dissolves to form sodium ions with a positive electrical charge and chlorine ions with a negative charge. Positive electrode immersed in this solution will attract chlorine ions and a negative electrode attracts the sodium ions.

Combining this action with ion-selective membranes that allow only one type of ion to pass through gives a method of removing dissolved solids from water. Membrane cell, left, shows how this works. Practical units will contain about 300 membranes and work best on brackish waters. This relative newcomer can reduce solids from 4000 to 350 ppm.

Negative electrode makes up one end of cell and positive electrode the other. Brackish water enters compartments between membranes. Positive sodium ions migrate to left toward the negative electrode. Negative chlorine ions go toward positive electrode at right. Sodium ions in center compartment pass through *MM* membrane to the left and are blocked by the next *NN* membrane. Chlorine ions pass through *NN* membrane to right and are blocked by the following *MM* membrane. This alternate passing and blocking removes ions from alternate compartments and concentrates them in neighboring sections. So salt-free water is drawn from one complete set of alternate compartments and concentrated brine from the other.

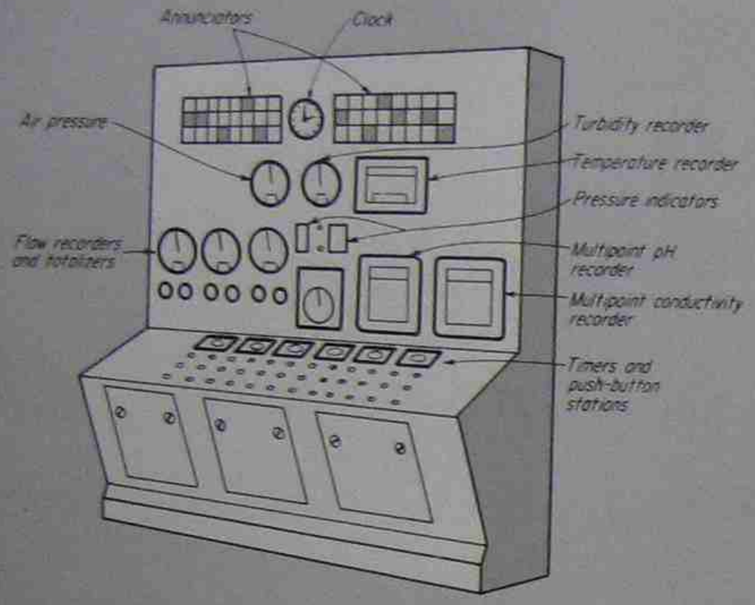
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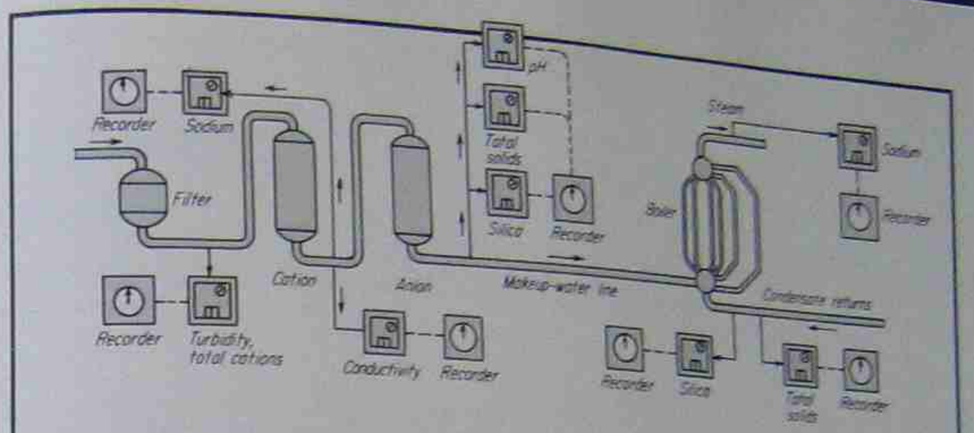
Treatment system meets dual plant needs

River-water supply for this steel mill is coagulated, softened and clarified. This water with less than 10 ppm turbidity is completely satisfactory for preplating treatment of steel and general plant services. But much higher quality is required for the production of tin plate that's free from streaks and other surface irregularities. Therefore part of clarified supply is sent through demineralizing units where conductivity is taken below 10 micrombos. A weakly basic anion exchanger is used since silica removal isn't required for this process.

Instruments and automatic controls are housed in dust-tight steel cubicle



Steel-cubicle method of installing instruments and electrical control has many advantages. First, resulting centralization of control greatly simplifies job of operators and maintenance men. Cubicles are usually completely enclosed and equipped with rear or front doors. This gives easy access for maintenance to electrical control equipment and wiring. Recorders, timers, control-panel switches, level indicators, annunciators and air-loading panels are installed on front of cubicle. Console type is shown although straight-vertical type can also be used. Complete unit is factory assembled, wired and tested. This means better workmanship at lower cost than is normally possible when controls are installed as individual field-erected units.



Automatic chemical analyzers are key to complete automation

Conductivity and pH instruments automatically indicate and record. When an "off-normal" value occurs, they can be used to initiate corrective action. Typical applications include chemical feed and ion-exchanger control. Amount of acid fed into a cooling-tower-system may be controlled by pH of recirculating water. Rinse period during anion-exchanger regeneration is timer controlled, but with a conductivity override. However, it requires accurate monitoring of much more than these two variables before a fully automatic treating plant is possible.

Tomorrow's plant will use automatic chemical analyzers, above, at each stage of treatment and at critical spots in the feedwater or process cycle. Makeup turbidity, cations, sodium, silica and dissolved solids are tested continuously. Condensate is monitored for silica and dissolved solids. Finally, purity of steam is measured by analyzing for sodium. These instruments will sense "off-normal" values and automatically start corrective measures. Several are already available with expected accuracy within the range of 0.01 to 0.05 ppm.

Trend is to fully automatic control

Automatic controls for water-treating systems are many and varied. Some control standardization has taken place for filters, cation-exchange softeners and other simple processes. But the usual water-treating system, particularly in larger plants, consists of a number of separate treatments in stages. This means repumping between stages or, perhaps, blending water from two of them.

Controls for these more complex systems require considerable instrumentation, electrical interlocking between stages, pumping equipment controls and comprehensive alarm systems. Possible variations in equipment hookup are so numerous that the control center, above, must be designed to suit each individual plant.

Operating valves used on automatic water-treating units include hydraulically operated gate valves, motor-operated multiport or single valves, diaphragm-operated globe and Saunders patent valves plus other special designs.

Multiport type valves are designed to replace the five or six valve nest arrangement on pressure filters and cation-exchange softeners. Since one valve does the work of many they are often called single valves. Standard automatic controls are generally available. Typical single valve will have a control box with motor, starter, timer and other control accessories mounted right at the unit.

Pilot valves are used to control cylinder- and diaphragm-operated valves in water-treating equipment. They fall into four main classes: (1) solenoid valves (2) cam-operated pneumatic valves (3) cam-operated hydraulic valves and (4) disk-type hydraulic valves.

Solenoid valves generally control small diaphragm valves. Many plants also use solenoid pilot valves to operate main valves on complex mixed and multibed demineralizing systems. If many solenoids are used, mount them on a rack for easy maintenance.

Pneumatic pilot valves consist of a motor drive, camshaft and a series of 3-way pneumatic pilots. Each of these pilots can deliver air to, or exhaust air from the pilot line controlling a diaphragm-type main operating valve. These pilots are well-suited for control of ion exchangers using diaphragm-type valves. They are also used to control large cylinder-operated hydraulic valves. But this calls for a 4-way diaphragm-operated auxiliary valve for each hydraulic-valve cylinder on the ion-exchange or filter unit.

Cam-operated pilot valve uses water as the control medium. The valve, individually designed for each service, has a motor drive, camshaft and a number of valve units, each of which is essentially a 4-way valve.

Multiport pilot valves also control hydraulic valves. But cam-operated pilot type is usually preferred for the following reasons: (1) Proper cutting of the cam makes it possible to produce complex and special control cycles with relative ease. (2) Pilot valve itself can be installed in

# of water-treating systems

panels, control cubicles or operating tables. (3) Less maintenance is needed than for multiport type.

Auxiliary control devices are still needed to actuate the pilot valves. These may include (1) electrical relays (2) magnetic starters (3) timers (4) sequence switches (5) float switches (6) liquid-level controls (7) flowmeters and (8) conductivity and pH meters.

Instruments most commonly used measure flow, conductivity and pH. Flow instruments handle a variety of jobs ranging from control of chemical feeds to proportioning of flow. For example, flow of raw water to both cold- and hot-process softeners is measured. Volume of water passing through meter then controls rate at which lime, soda ash, coagulants, etc are fed to the softener.

Meters totalize the flow of water treated by individual ion exchangers. Exchange capacity in gallons between regenerations is calculated from incoming-water analysis. This capacity is set on the meter contractor. When preset number of gallons is registered by the meter an alarm sounds or the unit automatically goes into the regeneration cycle. Meter setting usually includes a safety factor.

Controlling flow rate is another important task. Split-stream dealkalizers pass one part of the incoming water through hydrogen-cation exchangers and the remainder through sodium-cation units. Flow split is calculated from raw-water analysis. Primary controllers keep flow in each circuit at preset values to produce the desired alkalinity.

Demineralizing systems employ many different types of controllers for acid, caustic and dilution-water flows. Backwash and rinse rates are also instrument controlled.

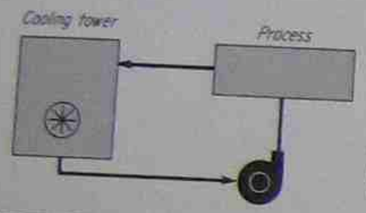
Conductivity instruments indirectly measure the total dissolved-solids content of concentrated solutions like boiler water. They also measure the quality of almost solids-free water from demineralizing systems. Strength of dilute acid and caustic flows during demineralizer regeneration is monitored continuously. Quality of anion rinse water is checked before exchanger is put back into service. The instrument can be a simple, locally mounted indicator or a multipoint recorder-controller mounted on the main control cubicle. Special conductivity systems are also used to signal end-point of ion-exchanger runs.

Chemical feed systems for the treatment of cooling water lean heavily on pH instruments for control. They are also helpful in monitoring plant waste-water discharge, particularly from demineralizers to prevent sending water with excessive alkalinity or acidity to the sewer.

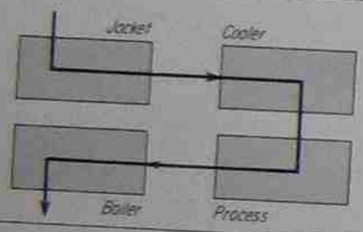
Alarm systems are an important part of every water treatment plant. Panel-mounted annunciators are ideal: they will indicate high and low level in storage and chemical solution tanks. Include alarm points for the end of service run on filters, ion exchangers, etc. Finally, provide alarms for high or low pH and conductivity measurements.

Smart design and operation cut water cost

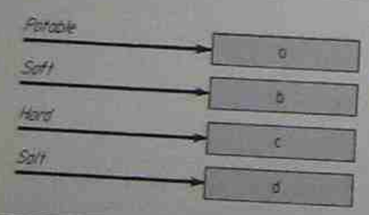
Better water management is called for when plant water demand runs ahead of supply or when plant water costs start to zoom. First step is a complete water survey. Assign the job to an engineer and give him staff help if needed. Another possibility is setting up a water committee that includes one of the plant engineers plus key men from big water-using departments. Consider use of outside water consultants for a fresh view of the problem. Below are five important ways that plant water management can be improved. Investigate these possibilities in your plant. Then prepare a detailed report listing specific steps that should be taken to reduce water consumption, lower overall cost.



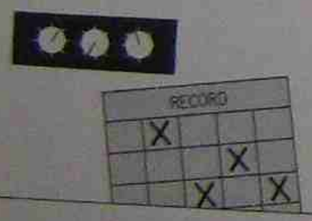
Look into advantages of evaporative cooling. In many plants greatest chance to save is by re-using water now discharged to waste from engine or compressor jackets, condensers, etc. This hot water can be cooled by evaporation if sent through a cooling tower, spray pond or evaporative condenser. With evaporative cooling the water loss is usually less than 5%.



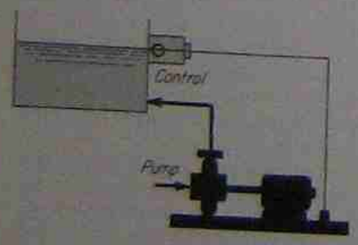
Investigate possibilities of multiple use. Water discharged from one use may be perfectly good for another. For example, cooling water may first go to processes needing a low temperature and then to others able to get along at higher temperature levels. Water heated in this fashion can then be used in some process needing warm water. Possibilities are endless.



Don't overlook savings of multiple supply. Water good for drinking may not be good enough for boilers. Sea water, good for neither, may be good for condensing and cooling. But some plants try to make the entire water supply good enough for deluxe uses. Duplication of pumps, piping, etc may be a small price to pay for a system that hoards the high-quality water.



Use meters and records to encourage saving. Meter the water delivered to each major department and find a way to estimate take of minor users. Follow through with a monthly report or make a direct charge against using department. This gives a real incentive to reduce consumption. Make sure your maintenance program insures regular inspection and repair of water system.



Install automatic controls where possible. They make sure water flows only where and when needed, without human errors. Typical examples are: float and pressure controls for tank makeup, thermostatic valves, etc.

The author gratefully acknowledges the help and cooperation of the entire water-treating industry in preparing both parts of this report. He especially thanks J F Wilkes, S B Applebaum, D Miller, S K Adkins, J M Seamon and D E Noll

a **Power** handbook



HEAT EXCHANGERS

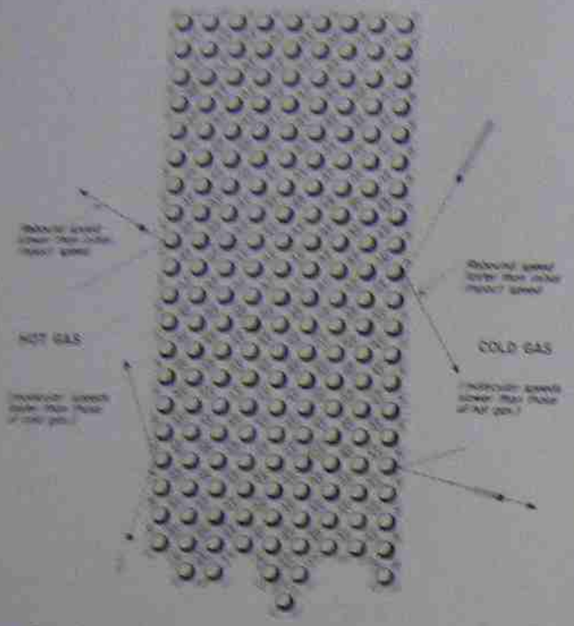
By B G A Skrotzki, Associate Editor and S S Waldron, Assistant Editor

In power plants and throughout industry we're always aware of the rotating machines that *transform* energy—the motors that turn electricity into shaft power, the pumps that turn shaft power into hydraulic energy, and so on. Much less conspicuous, but perhaps of greater importance, is the quiet *transfer* of energy that goes on in the units designed for efficient heat transfer—heat exchangers.

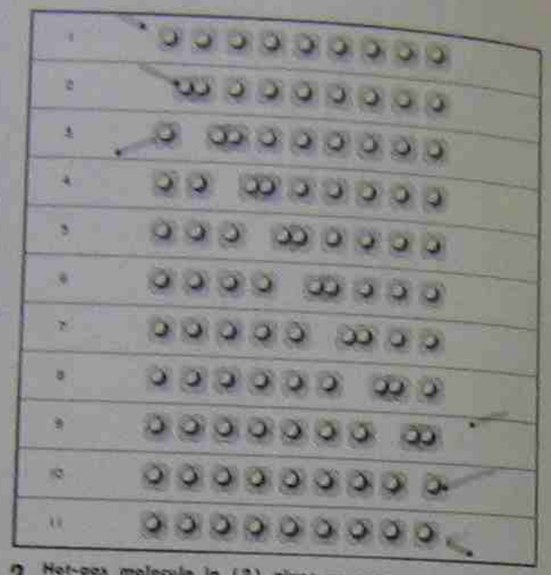
When you stop to think about it, the array of such units is vast—so vast, in fact, that when we planned this handbook we were forced to draw some boundary lines. So, we don't consider here boilers and other fired exchangers. Nor do we include specialized forms of heat exchangers, such as economizers, air heaters, gas-turbine regenerators, space-heating and air-conditioning units, all of which we have discussed in previous handbooks. We've also found it necessary to defer coverage of evaporative-cooling equipment — spray ponds, cooling towers, evaporative condensers, etc — for a later handbook section.

Thus we're able to concentrate here on the wide variety of shell-and-tube and contact exchangers, including such familiar types as feedwater heaters, steam condensers, evaporators, deaerators. With the unstinting help of specialists in the field, we've rounded up a fistful of practical information on fundamentals of heat transfer, and on construction and application of various heat-exchanger types.

Use this new Power handbook to step up efficiency of the all-important heat-transfer jobs in your plant.



1 Energy vibrations of molecules in a solid are raised by impacts from hot-gas molecules. On opposite colder face, contacts with slow-moving molecules reduce rate of vibration



2 Hot-gas molecule in (2) gives up some energy in hitting outer molecule of solid. This energy passes on by impact to neighboring molecules and finally to gas molecule in (10)

Heat transfer . . . *to understand it, take a . . .*

Heat exchangers, as the name implies, transfer heat from one substance to another. We can distinguish three basic ways of moving heat: (1) conduction (2) radiation (3) convection. In actual exchangers, all three usually come into play, in varying degrees.

Conduction. In most exchangers we have a metal wall or walls separating one fluid from another at a different temperature. Heat from the hotter fluid passes through the separating wall to the cooler fluid. This is really a mechanical molecular process, as shown in Fig. 1. Let's take a quick look.

Molecules in a solid (like the separating metal wall of the exchanger) act on each other with two kinds of forces (1) gravitational forces of attraction and (2) unidentified forces of repulsion. When the molecules are a certain distance apart, these two forces are in balance and the molecules hold their places with nothing but space between.

If outside forces try to stretch a solid, gravitational forces come into play, make the molecules resist being torn apart. When we try to compress a solid, repulsion forces (whose exact nature we don't know) make the molecules resist being pushed together.

Molecular Vibration. The molecules of a solid really only stand still at a temperature of absolute zero, about —459 F. As a solid warms up, its molecules shiver and vibrate in place with the heat energy they have absorbed. At low temperatures, vibration is sluggish, but as temperature goes up it gets more rapid. Thus temperature measures the molecules' vibration rate.

Unlike the molecules of a solid, gas molecules are free to move. They shoot about in random paths, moving faster at higher temperatures. In the simplified example of Fig. 1, we have a solid barrier between a hot gas and a cold gas. Swiftly moving molecules of hot gas strike surface molecules of the solid, giving up part of their energy in the slamming impact. This increases vibration of the solid's surface molecules; mutual attraction and repulsion forces pass this stepped-up activity along to the other molecules.

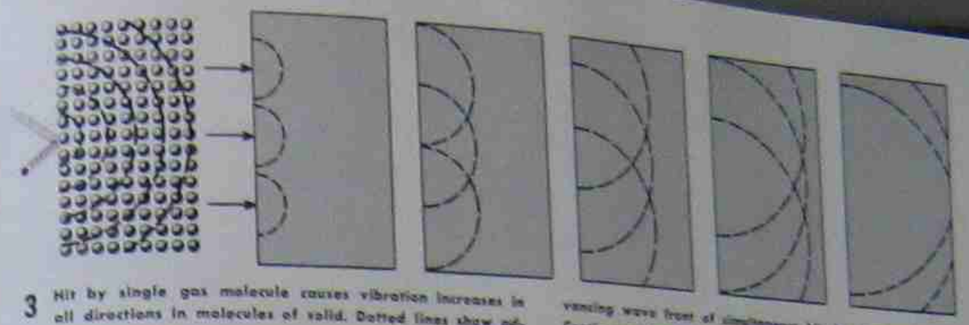
Energy Flow. Fig. 2 shows how energy given up by a hot-gas molecule might be passed along by molecules of a solid barrier to a cold-gas molecule on the other side. Impact from a gas molecule, however, travels in all directions through a solid, as shown by dashed arcs in left panel of Fig. 3. The shaded rectangles show how the "wave fronts" of heat energy might pass through a solid from the simultaneous impact of three molecules.

Actually, there are billions of molecules involved even in the smallest surface. And don't forget that each gas molecule makes billions of collisions each second, with its neighbors and with the solid molecules. So in our heat-transfer problems we are conscious only of the mass effect.

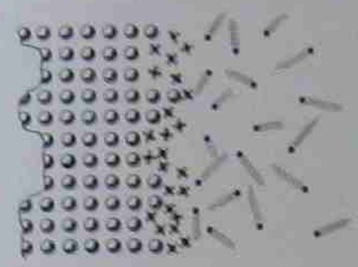
Fig. 4 shows one other effect that can be partly explained from the molecular standpoint. Slower gas (or liquid) molecules get trapped on the surface of a solid by the mutual forces of attraction. These trapped molecules form a thin film on the surface of the solid. Such films cause a temperature drop—we'll talk about its effects later.

The movement of heat *through* a substance is called *conduction*. The amount of energy moved, or the *heat transfer*, depends on (1) the temperature difference between the two faces of the substance (2) the area of the heat path, and (3) the nature of the substance. Before we start putting numbers on these relations, let's look at other modes of heat flow.

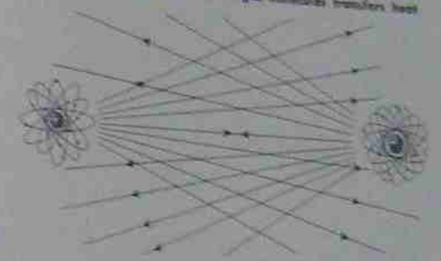
Radiation. We're all familiar with the radiant heat given off by the sun, by a fire or by a hot stove. This form of heat transfer takes place without aid of any substance between, will even work in a vacuum. Radiant heat originates from changes in activity between atoms of a molecule or within the atoms themselves. Any decrease in these activities sends out pulses of energy to other atoms, which step up in activity



3 Hit by single gas molecule causes vibration increases in all directions in molecules of solid. Dotted lines show advancing wave front of simultaneous hits by three molecules. Continuous bombardment by hot-gas molecules transfers heat



4 Gas molecules that get trapped on the surface of a solid form a thin film that reduces the rate of heat transfer



5 Radiant heat originates in the inner activity of molecules, sends energy pulses to other molecules some distance away

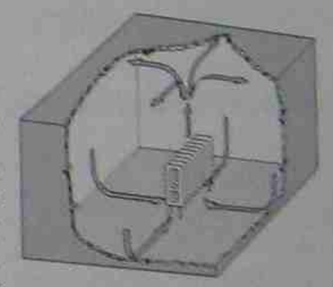
. . . *look at the molecular motion that is heat . . .*

correspondingly. Radiant heat plays a relatively minor part in the heat exchangers we'll discuss in following pages. It is highly important, of course, in fired equipment, such as boiler furnaces.

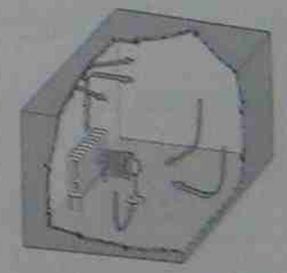
Convection. All around us we see examples of the third mode of heat transfer—convection. For example, Fig. 6 shows a common space-heating radiator standing in the middle of a room. Air between the radiator's elements is heated by conduction, expands and grows lighter than surrounding room air. This makes it float upward as colder air replaces it. Colder air is, in turn, heated and rises. So a continuous flow is set up over the heated surfaces.

The heated air rises to the ceiling and disperses. In its travel over the ceiling surface and walls it loses heat by conduction. The air becomes denser and sinks to the floor, eventually replacing the heated air rising from the radiator. This whole process is known as *natural convection* and occurs in liquids as well as gases. Note that it differs markedly from conduction (heat flow *through* a substance) and from radiation (wave-like energy pulses straight across air space). In convection, heat is carried by a moving gas or liquid.

Forced Convection. If we move the liquid or gas by a pump, fan or other



6 In natural convection, heated gas rises from source to carry heat elsewhere



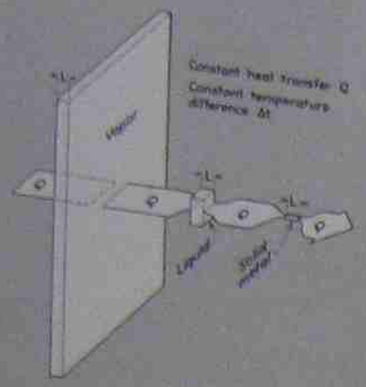
7 In forced convection, gas to be heated is forced to flow over heat source

device, instead of depending on the natural currents resulting from heating and cooling, we have *forced convection*. By forcing fluid to flow over the heat source at higher speed, we can raise the rate of heat transfer, within limits. And the faster forced flow of the fluid makes it possible to carry heat to where it's wanted at a greater rate.

In heat exchangers, convection is an important adjunct to conduction. The convection effect makes a fluid heated at a surface mix with nearby cooler fluid and, in turn, heat it. In addition, movement of the heated fluid from the heating surface allows a steady flow of cooler fluid to take its place and also become heated.

Heat Flow. In all cases the three forms of heat transfer are involved in varying degrees. Take a typical example: heat flow from a hot gas through a tube wall into a liquid. Heat is carried to the tube surface and transferred to the tube by a combination of convection, conduction and radiation. The latter effect is so small we can ignore it. Heat then flows through the wall by conduction to the inner face, and is transferred to the liquid by a combination of conduction and convection.

In heat flow by pure conduction there are three factors that control: (1) nature of the substance (2) difference in temperature of the two surfaces (3) cross-sectional area of the heat



8 Metals need least area to pass given heat, Q; vapors need largest area

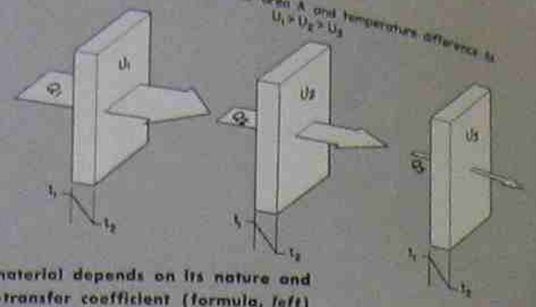
$$Q = U \times A \times \Delta t$$

Q = total heat flow, Btu/hr

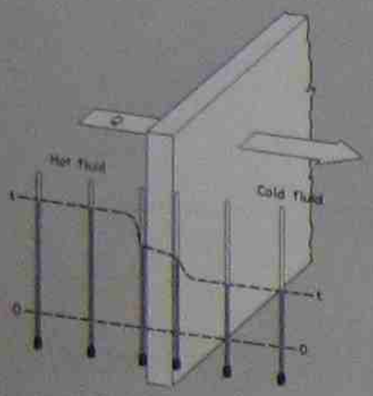
U = heat-transfer coefficient, Btu/hr/sq ft/F

A = area of heat-transfer surface, sq ft

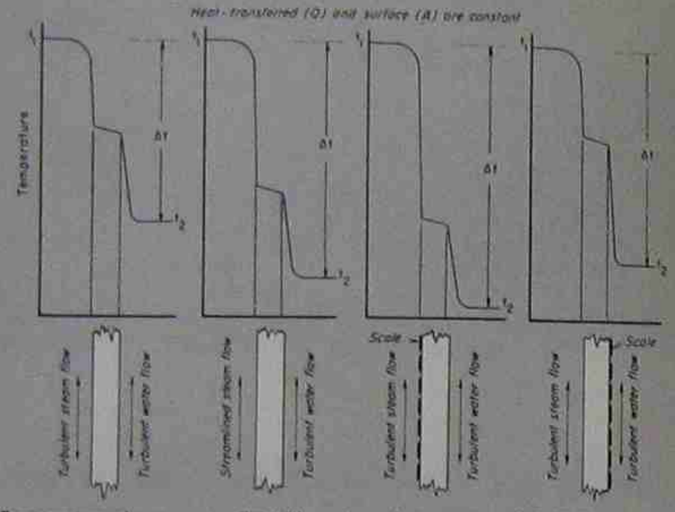
Δt = temperature difference, F



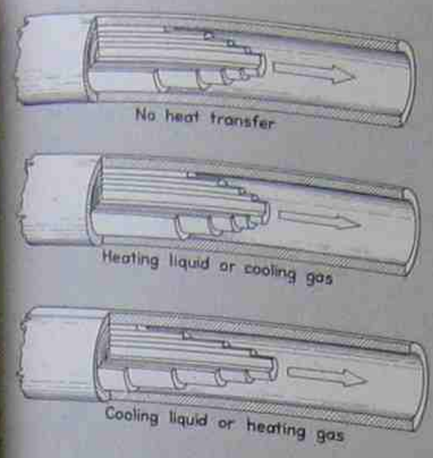
9 Heat transferred by a material depends on its nature and is measured by its heat-transfer coefficient (formula, *left*)



10 Fluid films adhering to surfaces of solid cause sharp temperature drops

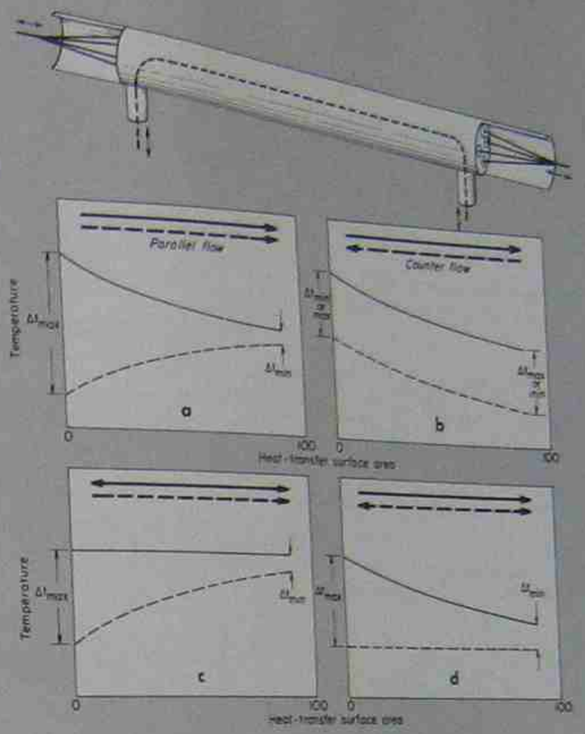


11 Temperature drops across fluid films depend on nature of fluid flow, markedly affect temperature of separating wall. So does presence of scale deposits



With streamline flow, no heat transfer, center core of fluid flows fastest, *top*. Heat transfer changes velocity distribution as shown in next two drawings. Turbulent flow, *below*, shows less speed variation across section

12 Flow may be streamline, *upper diagrams;* or turbulent, *bottom diagram*



13 Splitting up fluid streams into several paths increases heat-transfer surface between them for given volume of exchanger. In upper graphs both hot and cold fluid temperatures change in passing through heater. In lower left hot fluid may be a condensing vapor, in lower right cold fluid may be a boiling saturated liquid

. . . then look at the ways heat flows, how that flow is measured . . .

path. The effect of the nature of the substance is shown in Fig. 8. With the same temperature drop between the two surfaces separated by same distance L, a small area of solid metal transmits as much heat as a vastly greater area of vapor or gas.

Heat-Transfer Formula. For conduction heat flow we can write a relatively simple formula: $Q = U \times A \times \Delta t$, where Q is total heat flow in Btu per hr, A is area in sq ft, and Δt is temperature difference between the two surfaces. Here U is a coefficient measuring the rate at which the substance involved conducts heat. Fig. 9 illustrates this: if three materials have the same cross-sectional area A, and the same temperature difference between their surfaces $\Delta t = t_1 - t_2$, the heat flow Q depends directly on transfer coefficients U_1, U_2 and U_3.

Film Temperature Drop. In Fig. 4 we showed that molecules get trapped as a stagnant fluid film on surfaces like those of the tube wall in the example above. These films cause a temperature drop from gas to tube and from tube to liquid, as shown in Fig. 10. These films thus act like thin layers of insulating material, reducing heat flow.

The temperature drop depends on the thickness of the film. This in turn depends on the nature of the fluid flow, Fig. 11. As shown by the temperature drops the film is relatively thick for slower, streamlined flow, thin for fast turbulent flow. Presence of scale or other fouling films increases the resistance to heat flow.

Over-all Coefficients. Each element in the heat path — fluid film, fouling film, metal wall, fouling film and finally fluid film — has its own heat-transfer coefficient U. These must be combined to get an over-all coefficient to substitute in our heat-conduction formula, which then becomes a general heat-transfer formula. Handbooks and standards give typical values of over-all heat-transfer coefficients; these normally include any effects of transfer by radiation. It is often sufficiently accurate to use such coefficients for design. Be sure your conditions closely approximate those for the given coefficient, especially when boiling or condensing are involved.

Turbulent Flow. When a gas or liquid flows through a tube in streamline flow, Fig. 12, *top*, speed is fastest in center, decreases uniformly to zero at tube wall. When a liquid is heated or a gas cooled, it becomes less viscous and annular sections near the wall flow faster. Reverse happens when a liquid is cooled or a gas heated. With fast, turbulent flow there is less speed variation across tube section. Since turbulent flow usually steps up U, it is the basis of the design point in heat exchangers. But turbulent flow means more pressure drop, hence more pumping power.

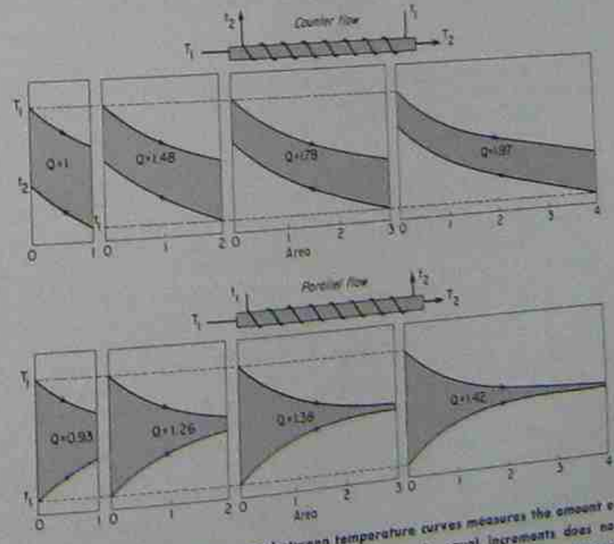
Temperature Variation. In heat exchangers, fluid temperatures change constantly in flow through the unit. Just how they vary depends on relative directions of flow and nature of fluids. In Fig. 13, *a* shows conditions for parallel flow in simple exchanger at top. In *b*, fluids flow in opposite directions, while in c warmer fluid is a

. . . what factors affect it in actual heat-exchanger design practice . . .

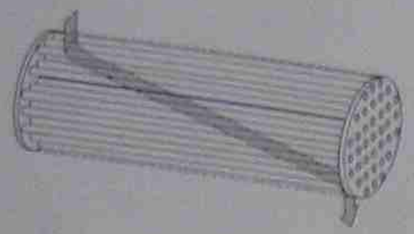
vapor condensing to a liquid at constant pressure. In *d*, colder fluid is a liquid boiling at a constant pressure.

Type of Flow. When two liquids or gases with constant specific heats are exchanging heat, area between their temperature curves is a measure of total heat being transferred. Fig. 14 shows how these vary with amount of transfer area for counterflow and parallel-flow exchangers when fluid inlet temperatures T_1 and t_1 are kept constant. The counterflow arrangement proves superior. If enough surface is provided, leaving cold-fluid temperature can be raised above leaving hot-fluid temperature. This can't be done in parallel flow where the temperatures can only approach each other, regardless of how much surface is used. Counterflow arrangement transfers more heat for given conditions and usually proves most economical to use.

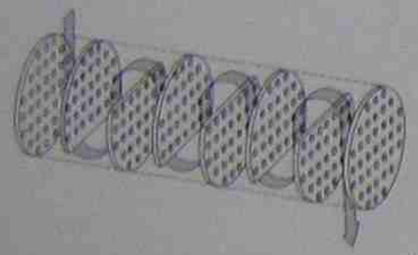
Surface Arrangement. To get maximum amount of surface between two fluids, they must be broken up into thin parallel streams. Familiar shell-and-tube exchanger, Fig. 15, does this



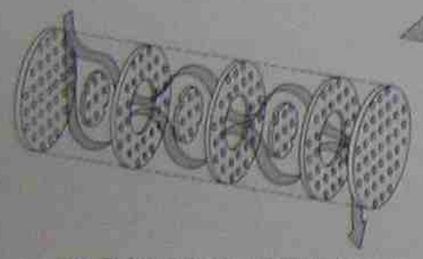
14 For certain conditions area between temperature curves measures the amount of heat transferred. Increasing heat-transfer area in equal increments does not cause equivalent increase in heat transferred. Adding area to counterflow heaters pays off more than in parallel-flow heaters. Counterflow gives hotter cold fluid



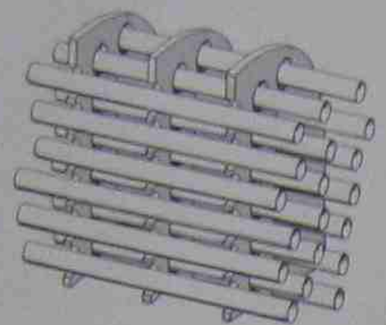
15 Shell fluid tends to take shortest path from inlet to outlet of shell



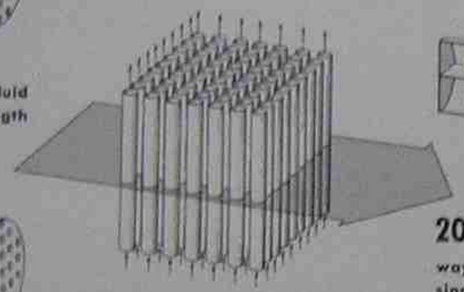
16 Sectional baffling leads shell fluid to contact tube surface along length



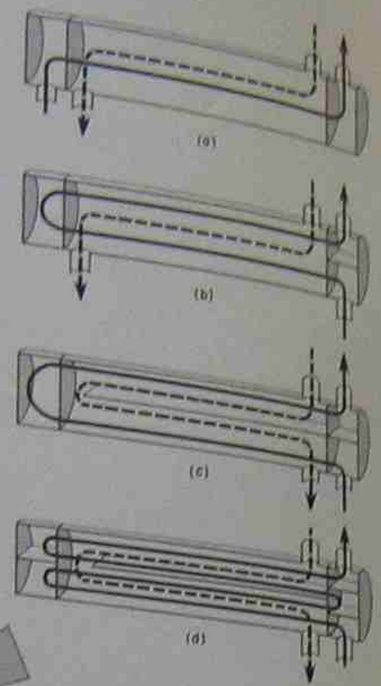
17 Disk-and-doughnut baffling is another method of controlling shell fluid



18 Baffles with annular orifices produce turbulence in the shell fluid



19 Crossflow of the shell fluid alters relation of the temperature changes



20 Paths of fluids through shell-and-tube exchangers can be varied many ways depending on job to be done: (a) single-pass tube and single-pass shell (b) two-pass tube and single-pass shell (c) two-pass tube and two-pass shell (d) four-pass tube and two-pass shell. This last arrangement can be duplicated by putting two heaters like (b) in series for both tube-fluid and shell-fluid flows

. . . and the paths designers take to boost heat-transfer effectiveness

by passing one fluid inside the tubes and the other about the exteriors of the tubes, within a shell. As the ribbon arrow shows, shell fluid will flow by shortest route from inlet, *upper left*, to outlet, *lower right*.

This doesn't make full use of surface, so steps are usually taken to make shell fluid flow over tube exteriors in all parts of the exchanger. This can be done by any of the baffling methods shown in Fig. 16, 17 and 18. The first two involve cross flow of the shell fluid over the tubes, Fig. 19, which affects the variation in temperature and must be accounted for in design.

Shell-and-tube exchangers can be arranged with any number of tube or shell passes, Fig. 20. Arrangement chosen depends on size, cost, nature of fluids and other factors.

Mean Temperature Difference. Although temperatures vary throughout an exchanger, we'd like to have one difference $\triangle t$ to use in our heat-transfer formula. This must be a representative figure. For a simple exchanger, Fig. 13, this would be the logarithmic mean temperature difference (*lmtd*). This can be calculated, Fig. 21, from largest temperature difference, $\triangle T$, and smallest, $\triangle t$.

For more complicated exchanger arrangements, Fig. 20, a correction factor is applied, Fig. 22. The *Standards of the Tubular Exchanger Manufacturers Assn (TEMA)* contain a series of graphs for various heater pass layouts.

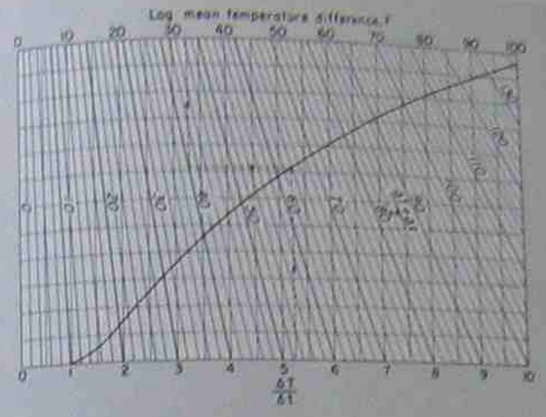
Tube pitch may be triangular or square, Fig. 23; triangular is most used. If exterior tube surfaces require periodic cleaning, spacing must be wide enough to admit a brush or fluid jet.

Boiling and Condensing. As we've seen, changes of state affect heat-transfer rates. In nuclear boiling, Fig. 24, steam bubbles form on minute projections from the heating surface. At atmospheric pressure, water temperature runs 212.7 F and steam 212 F. Increasing buoyancy breaks bubbles away from surface. They absorb heat from liquid and they rise, continuing to grow until they break through the surface. Liquid circulates downward to replace the rising bubbles.

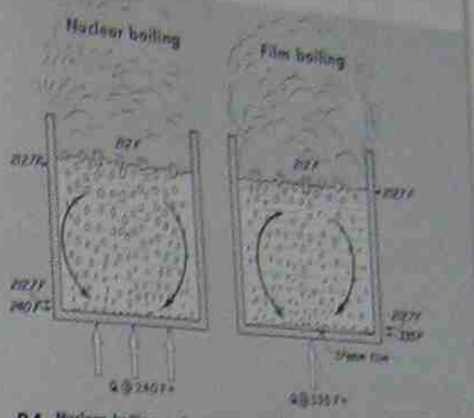
If temperature of heating surface is too high, a film of steam forms between liquid and surface, Fig. 24, *right*. This should be avoided because it reduces heat flow and causes "bumping" in evaporators.

Vapor condensing on a cold surface ordinarily forms a liquid film, Fig. 25, *bottom*. Film reduces heat-transfer rate. In the lab, surface can be treated to produce *dropwise* condensation, which gives better heat transfer. But treatment washes off quickly.

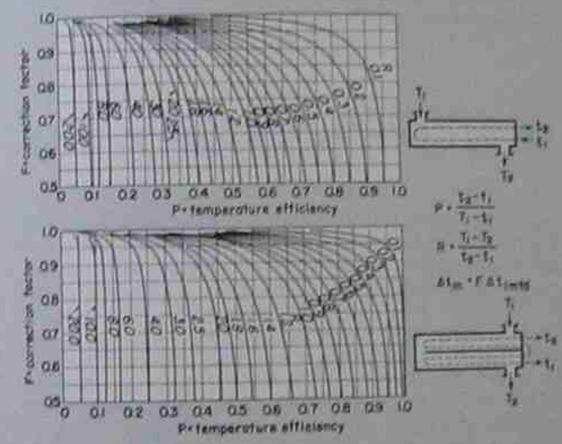
In contact-type heaters and condensers, water is finely divided to mix with steam, Fig. 26. Steam condenses on water droplets, heating them close to boiling temperature. Condensate and heated water leave at shell bottom.



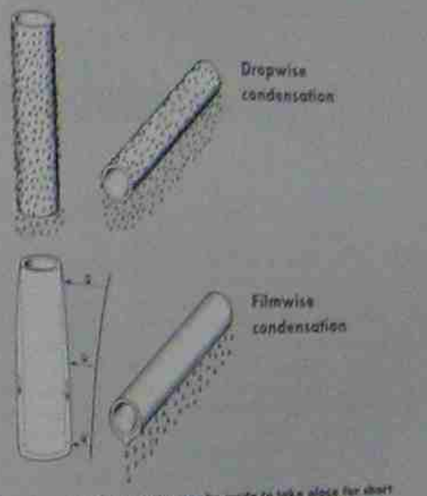
21 Log mean temperature difference can be figured from arithmetic mean and ratio of the temperature differentials



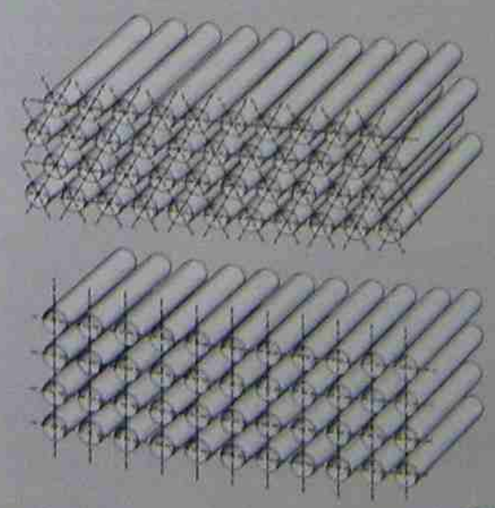
24 Nuclear boiling makes best use of heat transfer surface, too-high metal temperature forms undesired steam film



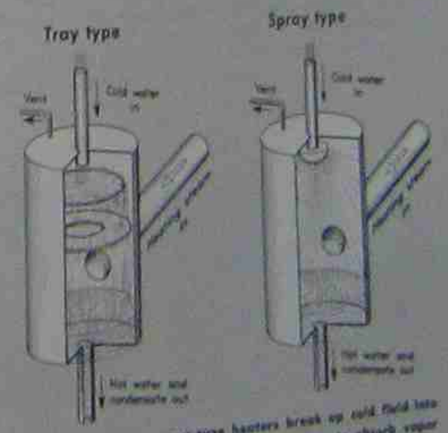
22 When heater flow paths differ from true counterflow a correction factor must be applied to log mean temp diff



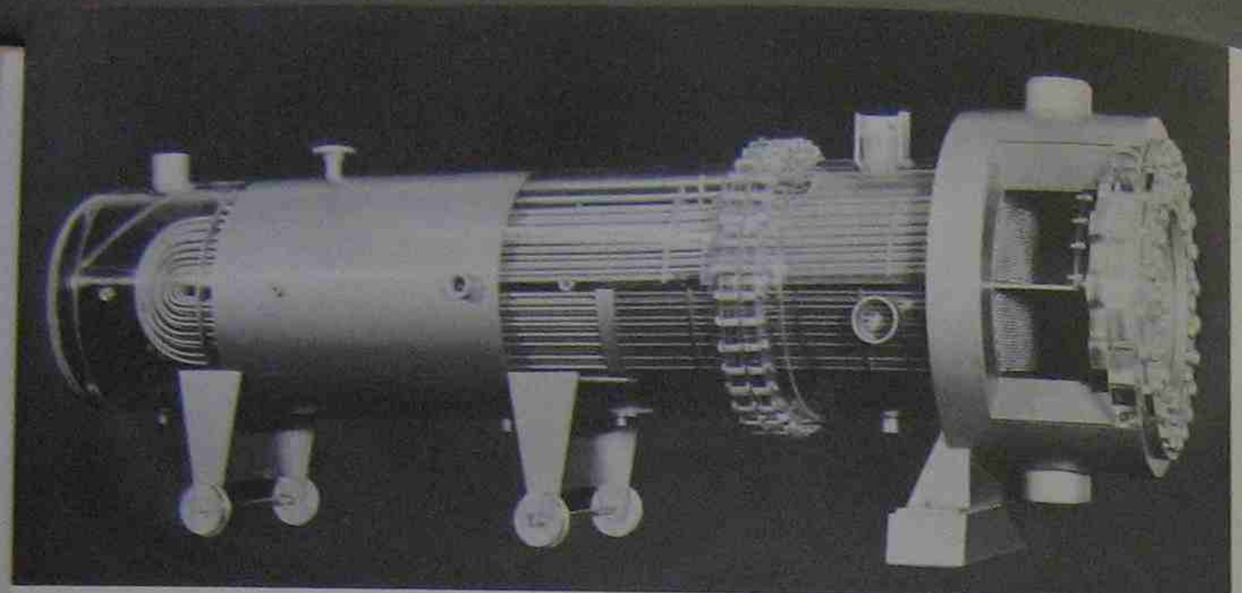
25 Dropwise condensation can be made to take place for short time under lab conditions, filmwise type is most common



23 Tube pitch may be arranged square or triangular, depends on the space needed for cleaning of the tube exteriors



26 Mixing- or contact-type heaters break up cold fluid into small particles to present most surface to absorb vapor



HORIZONTAL FEEDWATER HEATER MODEL shows U-tubes in transparent shell. Water enters through bottom connection of channel, *right*, flows through tubes and leaves at top outlet. Horizontal baffle and sealing plate separates hot, cold water

Shell-and-tube exchangers . . . *they are suitable for many jobs*

Commonest of all heat-exchanger forms is the shell-and-tube construction. Standard models are available for many services; some can be bought "off the shelf." These exchanger "work horses" find a wide variety of power and process applications: (1) feedwater heating (2) lubricating-oil cooling (3) fuel-oil heating (4) service-water heating (5) compressed-air and -gas cooling (6) heat reclaiming from blowdown and other wastes (7) engine cooling (8) transformer-oil cooling (9) refrigeration condensers (10) refrigeration evaporators or chillers, and many others. Chemical and petroleum industries use many forms of exchangers we can't cover here for want of space.

Choosing a Unit. A heat exchanger isn't selected casually. To fit the unit to the job, manufacturer needs the following minimum information: (1) heat losd or duty, Btu per hr (2) total quantity flow of fluids entering exchanger, lb per hr (3) specific heat, thermal conductivity, viscosity and specific gravity of fluids, in appropriate units (4) temperatures into and out of exchanger, F (5) operating pressures of shell-and-tube fluids, psia (6) allowable pressure drop for each fluid (7) cleanliness of fluids, sediment or contaminants carried (8) available installation space (9) data on corrosive conditions that may affect exchanger materials (10) type of unit wanted (11) horizontal or vertical installation.

Standards. *Tubular Exchanger Manufacturers Assn (TEMA)* has set up standards for three classes of shell-and-tube exchangers: (1) class *R* for severe refinery service (2) class *C* for commercial and general process applications (3) class *A* for exchangers using alloys and special materials. In general, standards set up minimums that must be met. These cover all exchanger parts, such as tubes, shells, shell covers, baffles, support plates, tie rods, spacers, floating heads, gaskets, tube sheets, channels, channel covers, nozzle connections, flanges.

Materials. A wide variety of materials is available for exchanger construction; types selected for each part depend on operating conditions, particularly corrosion problems. *TEMA Standards* list the following materials:

SHELLS: Pipe of carbon steel or alloy steel. Plate of carbon, carbon-silicon, molybdenum, nickel, chromium, chromium-nickel steels; nickel; monel; aluminum and aluminum alloys; copper and copper-silicon alloy; cast iron.

FLANGES: Forged steel, forged alloy steel. Ring flanges of any material used for shell plate.

CHANNELS, CHANNEL COVERS, SHELL COVERS, FLOATING HEADS: Cast steel, cast alloy steel, cast brass, any material used for shells.

TUBE SHEETS: Alloys of copper or iron.

BAFFLES, SUPPORT PLATES: Steel, nonferrous materials.

TUBES: Carbon and carbon-moly steels, alloy steels, copper, copper alloys, nickel, monel, aluminum.

TIE RODS: Same as baffle materials.

SPACERS: Same as baffles or tubes.

NOZZLES: Forged carbon steel, forged alloy steel, fabricated steel.

Construction. Main assemblies and parts of exchangers are described on the next two pages. Each must be selected on the basis of the pressure and temperature it has to meet. Design pressures are standardized at 75, 150, 300, 450 and 600 psi. Metal temperatures are limited as follows: Where carbon-steel parts limit strength, −20 to 1000 F; where cast iron limits strength, −20 to 375 F; where naval rolled brass limits strength, 400 F. *TEMA Standards* state that construction shall comply with either *API-ASME* or *ASME Code for Unfired Pressure Vessels*.

Types. Some idea of the diversity of types and services can be gained from the illustrations on these pages. In most exchangers, fluids in both tubes and shell flow continuously during operation. Where both fluids are liquids, or both are gases, there is usually no change of state, simply a temperature change in the fluids. In many of the heating types of exchangers, steam is the energy supply. In giving up its heat, the steam usually condenses and returns to the boiler.

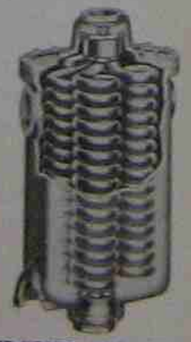
Service-water heaters may be of the continuous-flow type or may provide for storing water in the shell in which it is heated. In the storage type, heating steam may be supplied through a single tube bundle, being admitted in accordance with temperature of water in the tank. Precautions must be taken to prevent boiling stored water. Where intermittent exhaust steam is available, an additional tube bundle may be provided to use this steam in preference to more costly live steam. Whenever exhaust steam can't supply enough heat, live steam is admitted to the live-steam tube bundle.



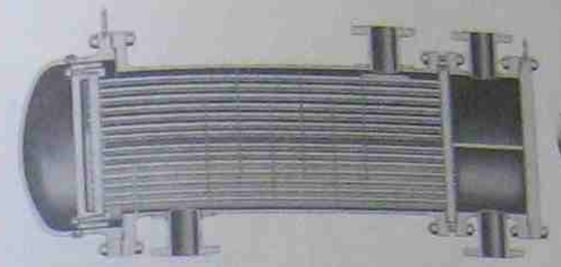
OIL COOLER has fixed tube sheets for economical construction, oil in tubes



STORAGE-TANK WATER HEATER has two tube bundles, one fed by live steam, other by available exhaust steam



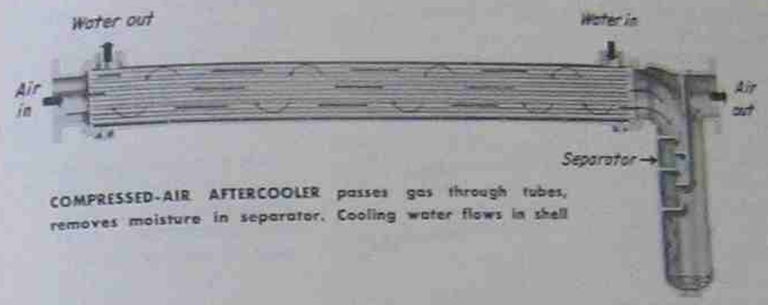
WATER HEATER with coils feeds water-storage tank



HEAT EXCHANGER WITH FLOATING TUBE SHEET uses sectional baffles to direct the flow of shell fluid across the tube surfaces



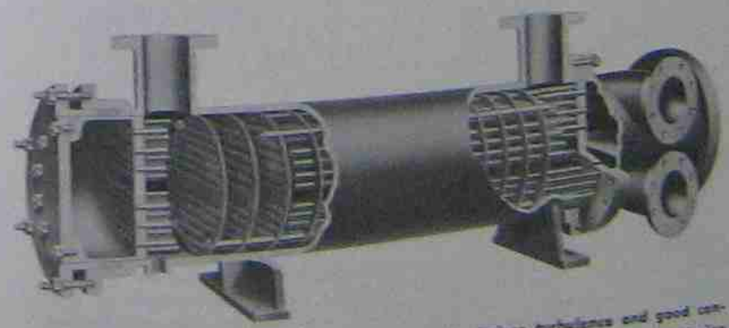
LINE OIL HEATER uses finned U-tubes in two passes. Tubes carry steam to heat oil, which flows through shell in one pass



COMPRESSED-AIR AFTERCOOLER passes gas through tubes, removes moisture in separator. Cooling water flows in shell



TANKLESS WATER HEATER uses copper coils with fins to increase heating area

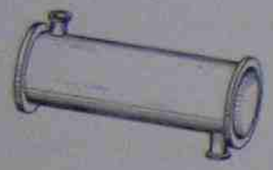


OIL COOLER uses baffles with annular orifices to induce turbulence and good contact of shell fluid and tubes. Packed floating head takes care of tube expansion

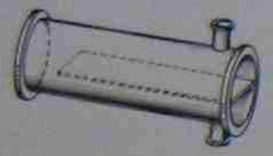


FLOATING TUBE SHEET is designed so tube bundle may be pulled out of shell

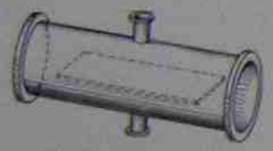
Shells . . . *they house tubes and help to direct flow of one fluid*



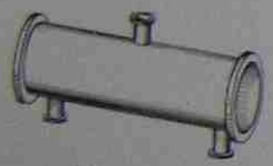
SINGLE-PASS shell has simplest construction, with inlet and outlet at opposite ends. Connections may enter at any angle needed



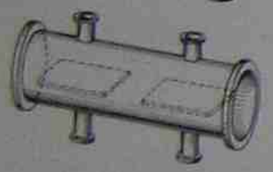
TWO-PASS shell has welded or packed baffle with inlet and outlet on opposite sides of cylinder, may be used for vapor, gas, liquid



DIVIDED SHELL flow has longitudinal baffle for vapor flow distribution along length in both directions, condensate exit on bottom



DIVIDED FLOW without baffle depends on two outlets at ends to distribute flow through full length of the shell. Inlet is at top



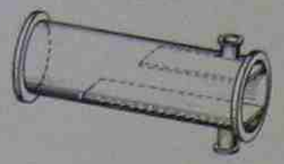
DOUBLE DIVIDED FLOW has two vapor inlets, two condensate outlets, two longitudinal vapor baffles, is used for very long exchangers



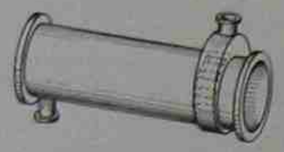
DESUPERHEATING feedwater heater has baffle or shroud at inlet to confine incoming superheated steam around tubes with hottest water



DRAIN-COOLING feedwater heater has baffle or shroud before condensate outlet to confine drains around tubes carrying coolest feedwater



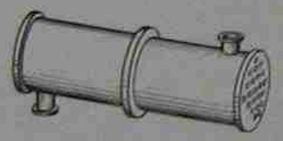
HIGH-PRESSURE heater may have baffles for both desuperheating and drain-cooling sections. Shell may be set vertically if needed



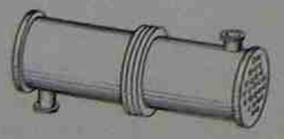
STEAM BELT helps give uniform distribution of vapor to the tube bundle, may reduce impingement erosion of tubes by entering steam



WELDED TUBE SHEETS may be used where shell fluid is clean and will not scale tube exteriors; employed on smaller heat exchangers

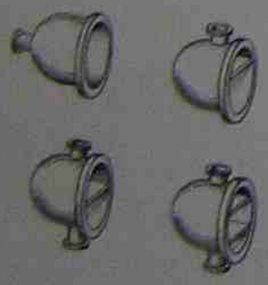


SHELL EXPANSION JOINT must be provided on unit with welded tube sheets when temperatures are expected to vary widely

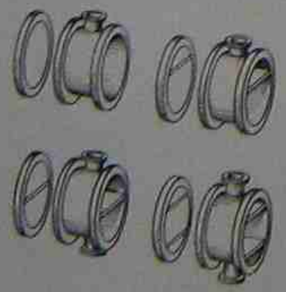


EXPANSION BELLOWS fitted on shell may be used where more flexibility must be provided, but is more subject to corrosive action

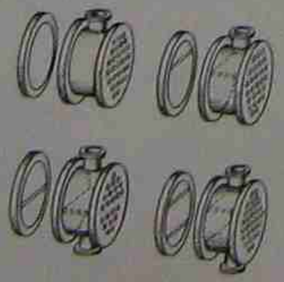
Channel layouts . . . *they follow one of several basic forms*



BONNET-TYPE HEADS direct flow of fluid through tube bundle, *left to right:* single-pass, 2-pass, 2-pass, 4-pass heads. Low cost is offset by need to disconnect piping for inspection of tube sheets



CHANNELS AND COVERS do same duty as bonnets, but allow for easy inspection of tube sheets by simply removing the cover. Two-piece construction is more expensive, requires an extra gasket seal



INTEGRAL TUBE-SHEET channels eliminate gasketed joint between head and tube sheet, are used for high-pressure and high-temperature fluids. Partition plates may be welded-in as needed

Tube bundles . . . *layout must allow for expansion, cleaning*



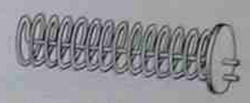
STRAIGHT-TUBE BUNDLE offers the advantage of easy mechanical cleaning of tube interiors, is removed from shell for exterior cleaning



U-TUBE BUNDLE simplifies expansion problem, reduces number of tube-sheet joints. Tubes are difficult to clean mechanically

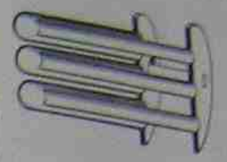


BOWED-TUBE BUNDLE can be solidly bolted to the shell at each end. Bow in tubes takes care of differential expansion in heater

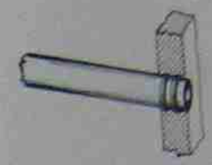


COIL-TYPE HEATERS may be used for very high pressures to eliminate gasketed joints in the h-p circuit. Used in small water heaters

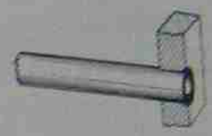
SINGLE-PASS tube bundle may be fitted with an expansion joint internal to the shell to eliminate employing a floating head seal



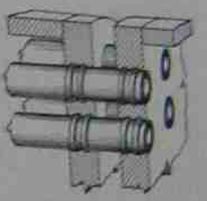
BAYONET-TUBE bundles may be used for some types of tank heaters. Steam enters center tube and returns through annular space to intermediate fluid chamber



ROLLED TUBE JOINT is the most common form of fastening tubes in tube sheets. Cold rolling flows the tube metal into annular grooves cut in the tube-sheet holes

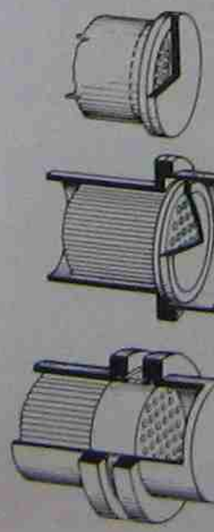


WELDED TUBE JOINT usually remains tighter than a rolled joint where considerable expansion must be handled. Sometimes rolled joints are also welded



DOUBLE TUBE SHEETS give positive protection against accidental leakage of shell fluid into tube fluid or the reverse. If tubes leak in either tube sheet the leakage shows as a drip between two sheets

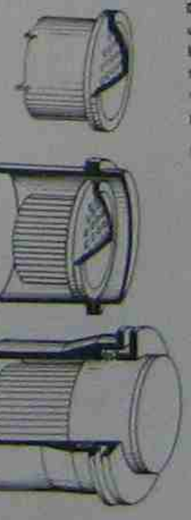
Rear-end enclosures . . . *type depends on service needs*



FLAT-PLATE cover may be used on channel formed by the shell end and welded tube sheet. Cover bolts to the shell flange, must be sealed with suitable gasket

FLOATING HEAD with shell-cover design that reduces clearance between the tube bundle and shell wall. Tube-bundle cover must be removed before bundle can be pulled through the shell

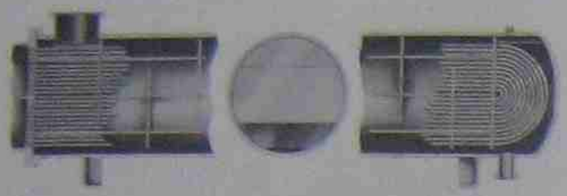
OUTSIDE-PACKED floating head has a dished-plate cover bolting to the shell flange. Two packing rings are separated by a lantern ring, with weep holes. Evidence of leakage from either side shows by drips coming from holes in lantern ring



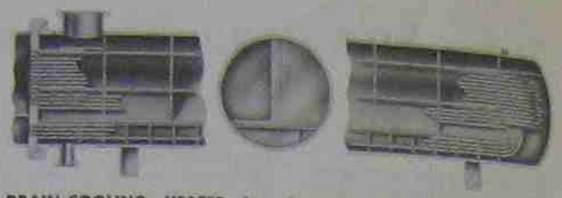
DISHED-PLATE cover may be used on non-removable tube bundle. Cover is bolted on tube-sheet flange, sealed with a gasket or a suitable packing material

FLOATING HEAD for pull-through tube bundle has separate shell cover. Tube sheet and cover move independently of shell. Large annular space exists between tube bundle and shell

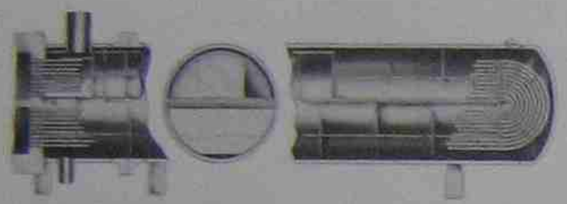
OUTSIDE-PACKED floating head has a flat cover plate on channel with an integral tube sheet. Packed integral gland and gland ring seal the shell and allow the floating head to move independently of the shell with varying fluid temperatures



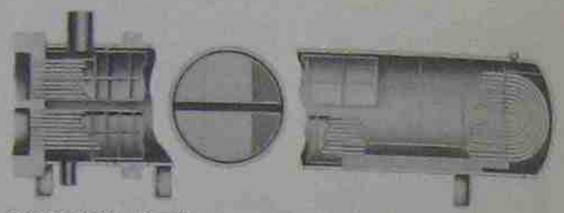
HORIZONTAL HEATER takes in bleed steam at upper left, leads it around baffles for good contact along full tube length. Condensate falls to bottom, drains off at lower right



DRAIN-COOLING HEATER has bottom tubes shielded from main condensing section. Condensate collects at shell bottom, completely covering lower tubes; drains at lower left



DESUPERHEATING HEATER leads superheated steam through enclosed entry section to raise outlet water temperature to maximum possible level. Condensate drains off at lower left



THREE-STEP HEATER desuperheats, condenses, and cools drains of heating steam to achieve maximum possible thermal gain in feedwater-heating cycle where bleed is superheated

Feedwater heaters . . . *these examples of shell-and-tube . . .*

Feedwater heaters normally use steam bled from turbines as the energy supply. Their prime purpose is to raise cycle thermal efficiency by the regenerative-heating principle. Modern cycles may have as many as eight heaters; steam pressure in lowest feedwater heater may be a vacuum and will increase in succeeding heaters to as high as 600 psia, or more. Water pressure in the tubes may run above 3000 psia in high-pressure heaters.

Drain-Cooling Sections. In high-pressure cycles, it often pays to keep energy in the feedwater at as high a temperature level as possible. This is done by using drain-cooling and desuperheating sections in the heaters. In drain cooling, entering feedwater first contacts leaving drains (condensate) before they flash to the lower pressure heater to release their heat at a lower temperature. This lifts feedwater temperature a few degrees it could not realize from the same heat in the lower pressure heater.

Desuperheating Sections. Here, feedwater leaving a heater contacts incoming superheated steam. This again gives a lift to the water temperature that couldn't be obtained from heating at the saturated-steam temperature corresponding to the pressure. Either or both of these special sections may be provided in a heater. Whether they are used or not depends on how cost of more complicated construction compares with the fuel savings realized.

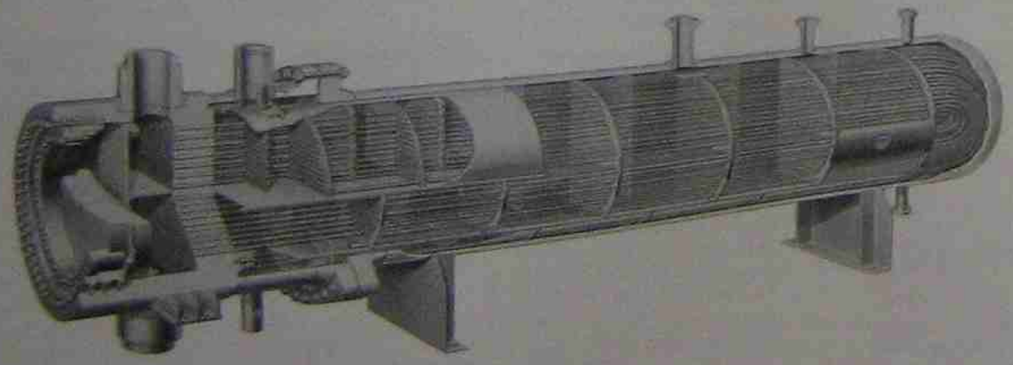
Feed heaters may be installed in either horizontal or vertical positions. In vertical heaters, the channel may be in the upper or lower position. For each of the possible positions, special consideration must be given to layout of the heater controls.

Specifications. Except for drain-cooling and desuperheating sections, feedwater heaters do not differ greatly in principles from the usual shell-and-tube exchangers. The *Bleeder Heater Manufacturers Assn, Inc,* publishes *Standards* for mechanical and thermal design and construction of these water heaters. The *Standards* specify maximum metal temperatures for tube materials as follows:

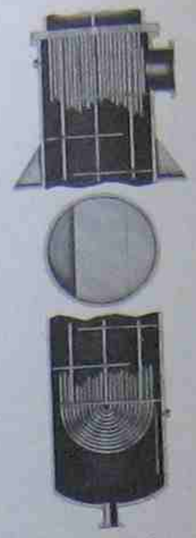
Arsenical copper	400 F
Admiralty metal (all types)	450 F
90-10 copper-nickel	600 F
80-20 copper-nickel	700 F
70-30 copper-nickel	700 F
30-70 copper-nickel (monel)	800 F*
30-70 copper-nickel (monel)	900 F**

*stress relieved **annealed

Baffles. Triangular tube pitches are recommended for feedwater heaters. To avoid exterior tube erosion at steam and flashed-condensate inlets, tubes should be covered by impingement baffles opposite the inlets. These turn aside the steam so it enters the tube bundle around its periphery.



HIGH-PRESSURE FEEDWATER HEATER with integral desuperheating and drain-cooling sections, takes in bleed steam at 931 F. Double-tube steam inlet minimizes any distortion and leakage at flanges. Tube water pressure runs about 2000 psig



VERTICAL HEATER has vents to aid in steam distribution, drains leave shell at bottom



DRAINS FLOW up through cooling section, leave through center channel at heater top



SECTION at inlet cools superheated steam, condensate drains through shell bottom



THREE-STEP HEATER desuperheats inlet steam and cools condensate leaving at the top

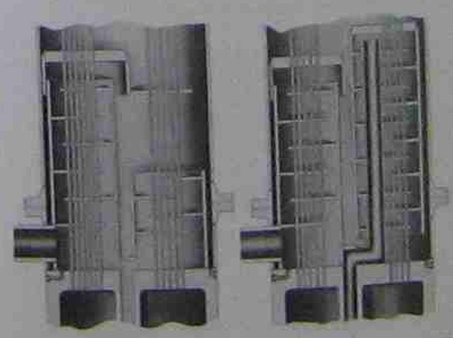
. . . *design use bleed or exhaust steam to boost the cycle efficiency*

For effective heater performance, baffles must fit snugly around tubes and to the shell interior. Any openings allow the shell fluid (steam or condensate) to short-circuit around passes and thus fail to do an effective heat-transfer job. On the other hand, these joints must allow differential movement between tubes and shell, caused by temperature changes. Also, it must be possible to separate tube bundle and shell for inspection and repair.

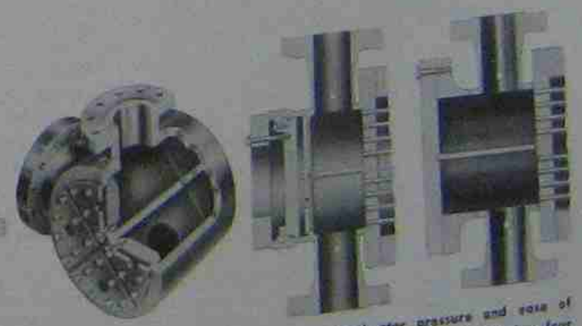
Joints. Note that some of the shells shown on these pages have a flanged joint to the right or below the steam inlet. This allows removing the shell without breaking heavy connections.

Protection. All steam and water lines to a feed heater (as well as other types of exchangers) should be valved and bypassed to allow bringing the unit in and out of service without shutting down the rest of the cycle. On the steam line, a check valve as well as a gate valve is needed to keep water flooding the heater from backing up into the turbine.

Relief Valves. Both tube side and shell side of a heater must be protected by relief valves against accidental overpressures. Valving must take account of high-pressure tubes bursting in a lower pressure shell. The protection scheme of a heater is normally the responsibility of the buyer, but makers stand ready to advise on the layout.

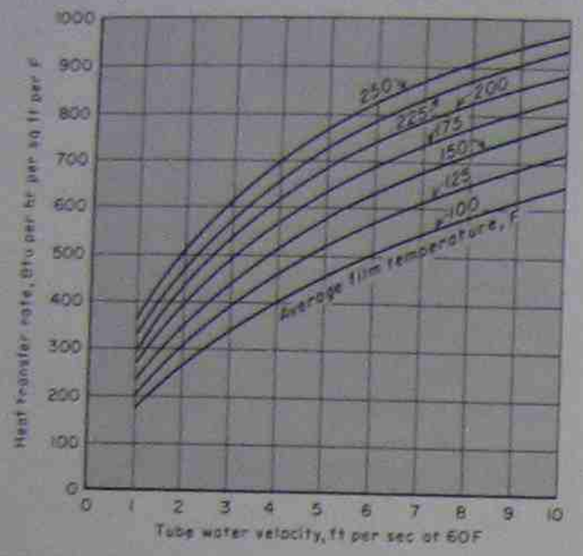


INVERTED CHANNELS on vertical heaters can use desuperheating, drain-cooling sections. Latter may be counterflow, *left;* parallel flow, *right*



HEATER CHANNEL design depends on feedwater pressure and ease of handling during maintenance work. High-pressure head, *left,* has four compartments to reduce wall thickness; medium-pressure, center; I-p, right

Standard factors . . . they're basis for sizing heaters



Basis for designing feedwater heaters is outlined in the *Standards of Bleeder Heater Manufacturers Assn, Inc.* Data abstracted from these standards are given in the left-hand column. The graph gives the heat-transfer rates to be used for given tube water velocities and average film temperatures. The latter is calculated as:

$$F_{ft} = t_s - (0.8 \times t_{lmtd})$$

where F_{ft} = average film temperature, F
t_s = saturation temperature of steam, F
t_{lmtd} = logarithmic mean temperature difference, F

Heat-transfer rates in excess of those for 250-F film temperature should not be used. These rates apply when steam is supplied from: turbine exhaust, turbine bleed point, evaporator vapor outlet, boiler. Water flowing through the tubes should be feedwater as would be found normally in a closed cycle.

The *Standards* specify that condensing zones in heaters and simple condensing heaters should not be designed for a closer approach to saturated steam temperature than 2 F. The heat-transfer rates of the graph are subject to several corrections. If either steam or water differs from the standard specified above, multiply the rates by 0.85. If both differ, multiply by 0.72.

Finally, refer to Table I and find a multiplier corresponding to the tube thickness and tube material, to use on the rate from the graph. The multipliers grow smaller with decreasing tube size and decreasing copper content. Tube material must be chosen to cope with the corrosion conditions that will be encountered.

Subcooling zones in heaters shouldn't be designed for a terminal difference of less than 10 F between the shell drain and the tube inlet.

Pressure drop of feedwater flowing through seamless drawn tubing in the heaters is figured as:

$$\Delta p = F_1 F_2 (L + 5.5D) N / D^{1.24}$$

where Δp = pressure drop, psi
F_1 = correction factor from scale, *left column*
F_2 = correction factor from scale, *left column*
L = total linear feet of tubing divided by number of tube holes in one tube sheet
D = tube ID, in., from Table II
N = number of passes

In figuring F_2 the average water temperature is equal to $t_s - t_{lmtd}$.

Pressure drop through heaters is important in determining condensate- and feed-pump pressures needed.

Heat exchangers for general process and refinery work are covered in the *Standards of Tubular Exchangers Manufacturers Association*. Because of the wide variety of fluids covered, determinations of heat-transfer rates are more detailed than those for feedwater heaters.

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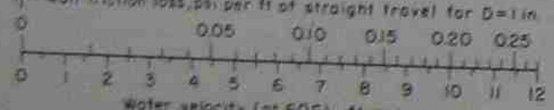
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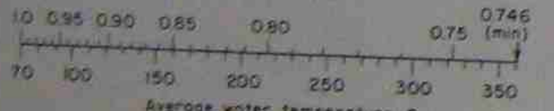
(For tube OD ⅝ to 1 in. incl)

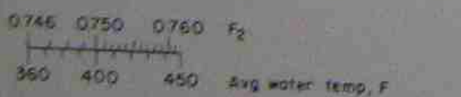
BWG	TUBE MATERIAL: Ars-ku	Adm	90/10 Cu-ni	80/20 Cu-ni	70/30 Cu-ni	Monel
18	1.00	1.00	0.97	0.95	0.92	0.89
17	1.00	1.00	0.94	0.91	0.87	0.85
16	1.00	1.00	0.91	0.88	0.84	0.82
15	1.00	0.99	0.89	0.86	0.82	0.79
14	1.00	0.96	0.85	0.82	0.77	0.73
13	0.98	0.93	0.81	0.78	0.73	0.70
12	0.95	0.90	0.77	0.73	0.68	0.65
11	0.92	0.87	0.74	0.70	0.65	0.62
10	0.89	0.83	0.69	0.66	0.60	0.58
9	0.85	0.80	0.65	0.62	0.56	0.54

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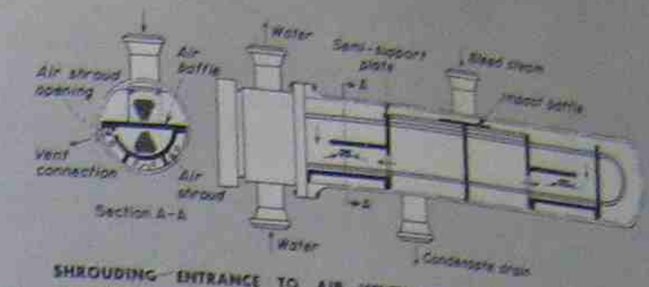
F_2 = correction factor



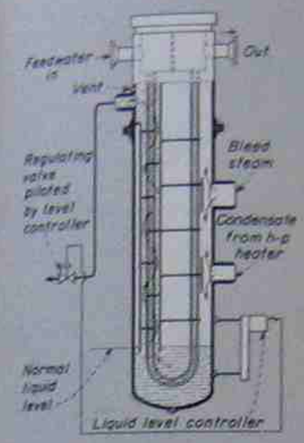


II–Feedwater-Heater Tube Constants

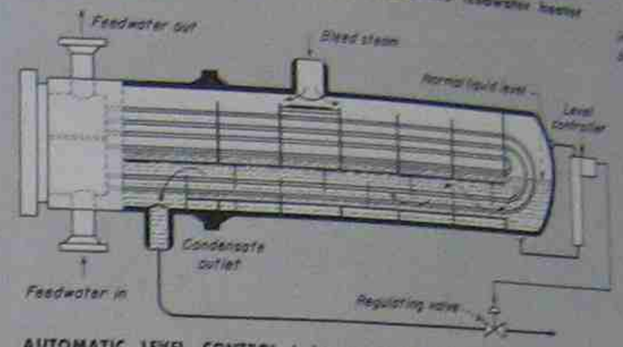
Tube BWG	⅝-in. OD D	⅝-in. OD D' =	¾-in. OD D	¾-in. OD D' =	⅞-in. OD D	⅞-in. OD D' =
18	0.527	0.452	0.652	0.569	0.777	0.731
17	0.509	0.433	0.634	0.567	0.759	0.710
16	0.495	0.418	0.620	0.554	0.745	0.695
15	0.481	0.404	0.606	0.528	0.731	0.678
14	0.458	0.380	0.584	0.514	0.709	0.652
13	—	—	0.560	0.488	0.685	0.625
12	—	—	0.527	0.457	0.652	0.594
11	—	—	—	—	0.635	0.570
10	—	—	—	—	0.607	0.538



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AIR VENTS aid steam distribution in heater's shell

Venting and draining . . . essential to good operation

Successful performance of feedwater heaters depends on proper venting (POWER, April 1952, pp 92-93, 208) and correct draining (Nov, 1952, pp 75-77). These apparently minor considerations make or break operation.

As steam condenses in either a vertical or horizontal heater, the condensate falls to the shell bottom and forms an effective seal against steam blowing through. This seal also prevents noncondensable gases from leaving the heater. Any accumulation of noncondensables can "air blanket" a heater, reducing its effectiveness or putting it out of action. This becomes especially important for low-pressure heaters operating below atmospheric.

Vents are the answer – at proper spots in the shell, they remove any gases that might accumulate. Vents should be placed in each end of the steam space, as shown in the sections, *above*. In addition to removing gases, the vents help to distribute the steam more uniformly throughout the shell and make better use of heat-transfer surface.

Baffles in the shell at entrances to the vent holes make the gas-laden steam flow first over the coldest tube pass, to condense out as much of the steam as possible. High-pressure heaters can be vented to the deaerating-heater vent condenser and the low-pressure heaters to the main-condenser air-cooling section.

Vent piping systems need regulating valves to set the optimum gas-withdrawal rate. This is the smallest rate that has no measurable effect on temperature rise of the feedwater passing through the heater. Excessive venting wastes high-grade uncondensed steam.

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Preferably, each vent opening should be connected by a separate line to the receiver, with as few bends and as short a route as possible. Tying together both vent openings at a heater may reduce venting capacity and makes it difficult to balance flows through them.

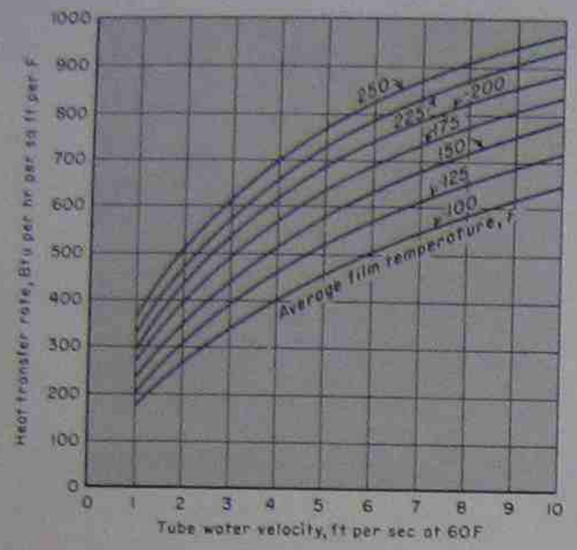
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Two types of liquid-level controllers are used for drainage control: (1) direct-acting ball float, and (2) float-operated pilot valve. The direct-acting controller links mechanically to the drain-line regulating valve. The second type has the pilot valve controlling a regulating medium (pressurized oil or air) to close and open the regulating valve. The first does a fine job where condensate level can vary to some extent, as in an external hotwell. The second type should be used where a critical water level must be maintained.

Make sure that the level controller connects to the shell where water-level indications are correct. Never place one of the taps in or near the drain line itself. Water velocity in the drain line reduces the pressure at the tap.

Gage glasses on both float chamber and heater permit making frequent checks for proper operation. Such glasses must have isolating stopcocks in case of breakage.

Standard factors . . . *they're basis for sizing heaters*



Basis for designing feedwater heaters is outlined in the *Standards of Bleeder Heater Manufacturers Assn, Inc.* Data abstracted from these standards are given in the left-hand column. The graph gives the heat-transfer rates to be used for given tube water velocities and average film temperatures. The latter is calculated as:

$$F_{ft} = t_s - (0.8 \times t_{lmtd})$$

where F_{ft} = average film temperature, F
t_s = saturation temperature of steam, F
t_{lmtd} = logarithmic mean temperature difference, F

Heat-transfer rates in excess of those for 250-F film temperature should not be used. These rates apply when steam is supplied from: turbine exhaust, turbine bleed point, evaporator vapor outlet, boiler. Water flowing through the tubes should be feedwater as would be found normally in a closed cycle.

The *Standards* specify that condensing zones in heaters and simple condensing heaters should not be designed for a closer approach to saturated steam temperature than 2 F. The heat-transfer rates of the graph are subject to several corrections. If either steam or water differs from the standard specified above, multiply the rates by 0.85. If both differ, multiply by 0.72.

Finally, refer to Table I and find a multiplier corresponding to the tube thickness and tube material, to use on the rate from the graph. The multipliers grow smaller with decreasing tube size and decreasing copper content. Tube material must be chosen to cope with the corrosion conditions that will be encountered.

Subcooling zones in heaters shouldn't be designed for a terminal difference of less than 10 F between the shell drain and the tube inlet.

Pressure drop of feedwater flowing through seamless drawn tubing in the heaters is figured as:

$$\Delta p = F_1 F_2 (L + 5.5D) N / D^{1.24}$$

where Δp = pressure drop, psi
F_1 = correction factor from scale, *left column*
F_2 = correction factor from scale, *left column*
L = total linear feet of tubing divided by number of tube holes in one tube sheet
D = tube ID, in., from Table II
N = number of passes

In figuring F_2 the average water temperature is equal to $t_s - t_{lmtd}$.

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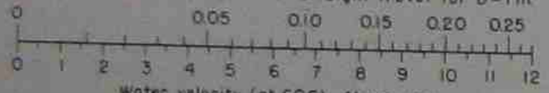
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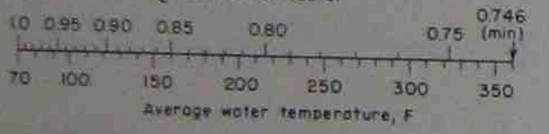
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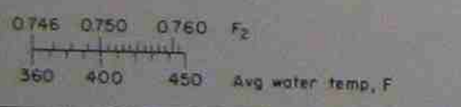
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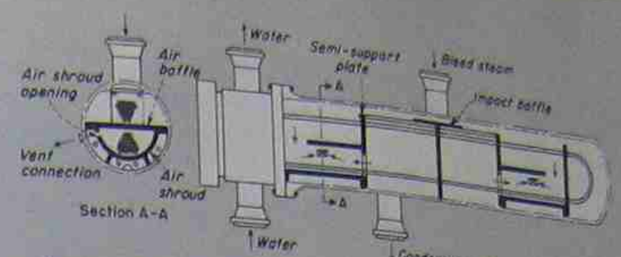
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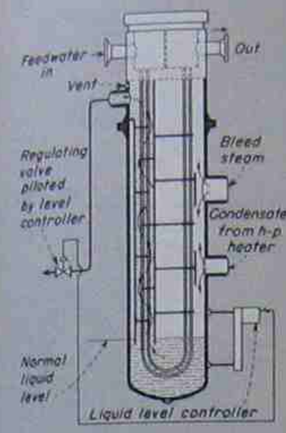


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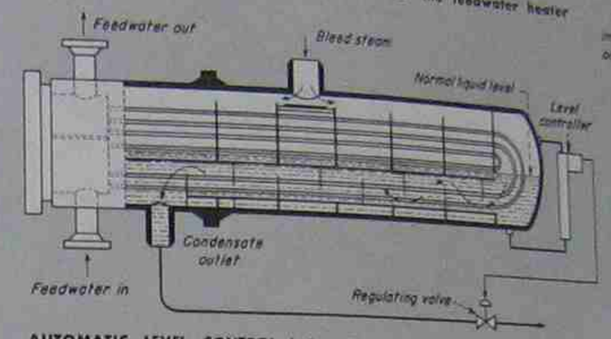
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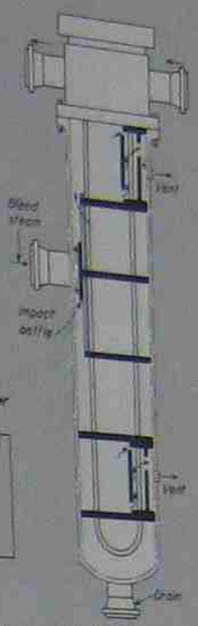
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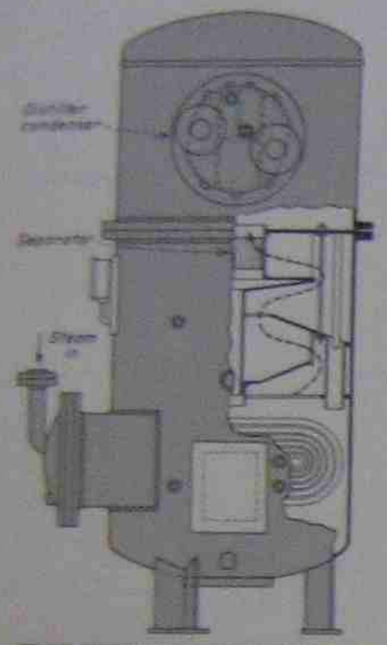
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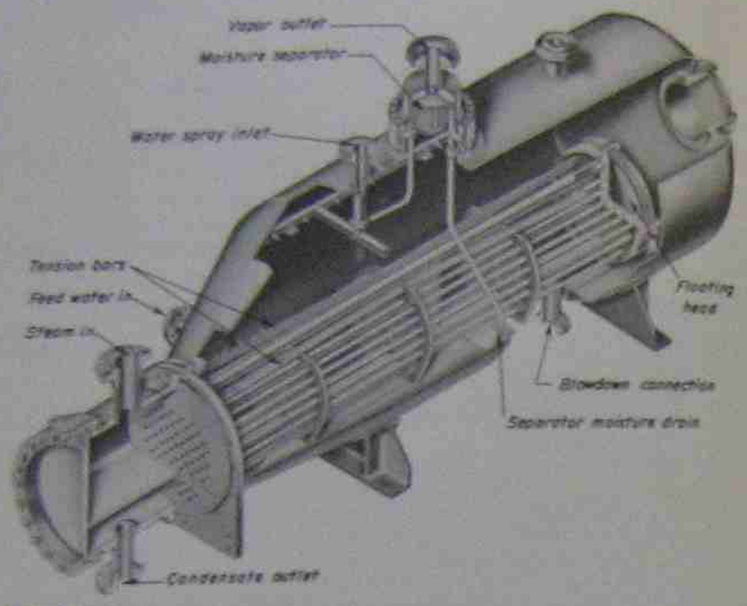
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STEAM BUNDLE evaporates water to vapor, which condenses in exchanger above



WATER LEVEL maintained just above steam tube bundle gives large steam release surface. Tension bars make the tubes bow when hot by restraining their expansion

Evaporators...they deliver purified water

In power plants, evaporators produce makeup for boiler feedwater from raw water high in solids. In some cases, they have been used as steam *transformers*, in which high-pressure exhaust or extraction steam from turbines turns raw water to steam for processing. This scheme isolates the closed boiler-turbine cycle from the process water-steam cycle. On shipboard, and in areas where fresh water is scarce, evaporators distill potable water from sea water (*above, left*).

Evaporators consist of two circuits: (1) "heating" steam condensing to water for return to the boiler, and (2) raw water vaporizing and leaving behind unwanted salts and solids. Input to an evaporator comprises steam to the tube bundle and raw water to the shell. Output includes the condensate of the heating steam from the tube bundle, vapor from the shell, and concentrated raw water (blowdown), also from the shell. Vapor produced is condensed to distilled water, often in a separate heat exchanger.

Tube bundle, completely submerged in raw water, supplies heat for boiling. Shell pressure may vary from a fairly high vacuum to a pressure of 200 psig, or more. Steam feed to the tube bundle must be at a higher pressure to supply temperature differential needed for effective heat transfer. Normally, shell water level is held at the horizontal center line to realize maximum water surface for steam release. This helps to keep down moisture carryover in the vapor.

Moisture particles in the vapor carry solids with them, so steps must be taken for removal. Mechanical separators or eliminators, just before the vapor outlet in most designs, force vapor to turn several sharp corners. Centrifugal force throws the moisture to the separator walls. Collected moisture drains back to the raw water in the evaporator shell.

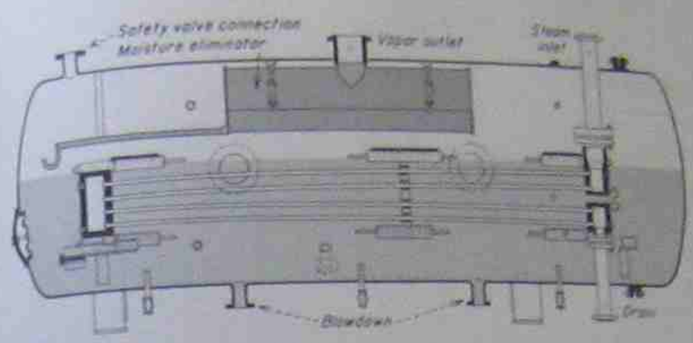
Another method of carryover elimination is the bubble tray (*see facing page*). Vapor from the shell enters the under side of the bubble caps. To pass on, vapor must bubble through clean condensate before escaping to the dome above. The clean condensate must be supplied from the plant cycle. Contaminated condensate overflows through a sealing U tube to join the raw water in the shell.

Blowdown. Continuous evaporation of raw water leaves behind an increasing concentration of salts in the shell water. These must be blown down at intervals, or continuously.

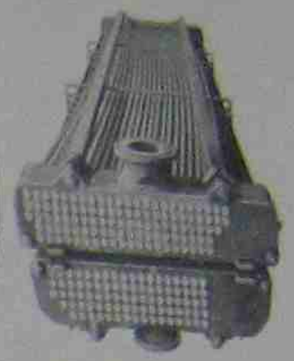
Scale Cracking. In high-temperature evaporators, some solids form a hard scale on tube exteriors. Since scale impedes heat transfer, it must be removed periodically. This is done by draining the shell and spraying the tube bundle with cold water, while tubes are still hot. Thermal shock usually cracks scale and spray washes it off for removal through shell bottom.

Some designs aid scale cracking by bowing the tubes (*upper right above, and facing page*). By using a restraining tension bar, tubes are forced to take a bowed shape when they expand in operation. When shell is refilled with cold water, tubes straighten quickly, helping to crack off the scale.

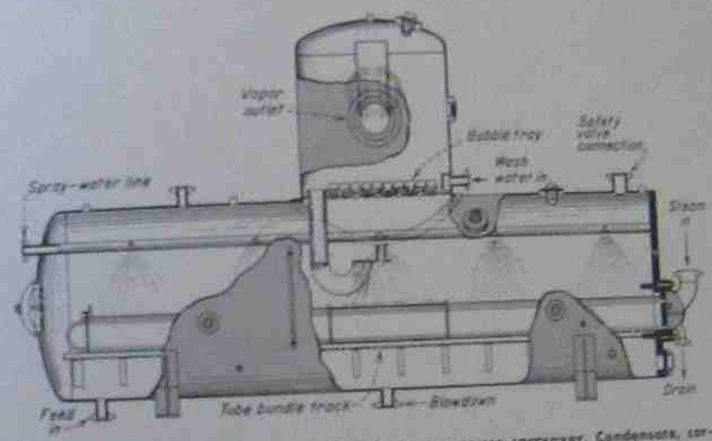
Compression-distillation systems (*on facing page*) take in sea water, pass it through a preheater to be warmed by distilled water and concentrated brine from the evaporator. In the latter, sea water is boiled by condensing superheated and compressed vapor. Vapor from the sea water flows through the separator and into the compressor, then back to the evaporator to vaporize incoming sea water. Preheater is usually a double-tube heat exchanger.



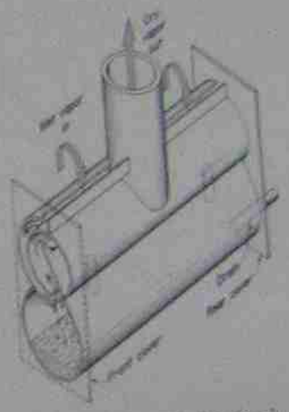
TUBE-BUNDLE INLET AND OUTLET are completely enclosed in evaporator shell. Separator at vapor outlet removes moisture and drains it back to shell above water



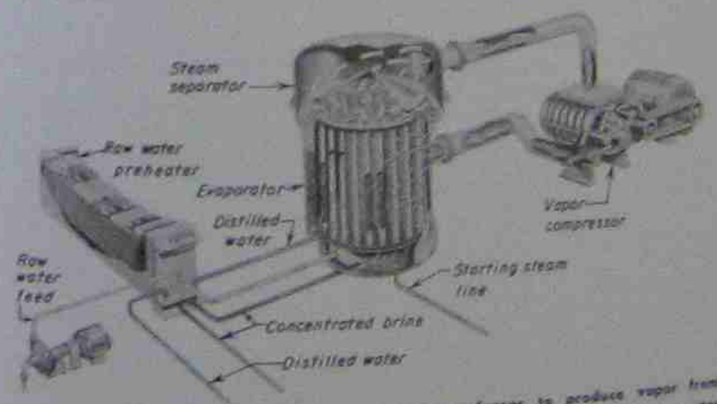
TUBES BOWED in cold position, bow more when heated; this cracks off scale



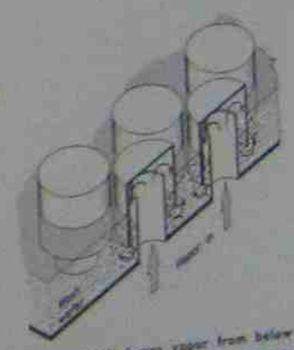
VAPOR WASHED by condensate on bubble tray removes carryover. Condensate, carrying contamination, continuously drains to evaporator shell through U-tube seal



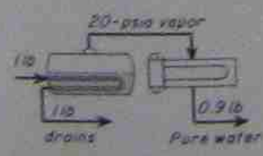
SEPARATOR makes vapor flow through several sharp turns, throws out moisture



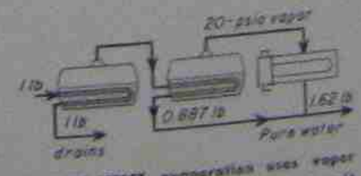
COMPRESSION DISTILLATION uses evaporator-condenser to produce vapor from raw water, compressor to heat vapor which condenses in main unit as pure water



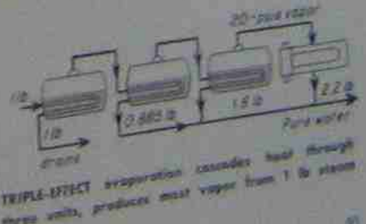
BUBBLE TRAY forces vapor from below to bubble through the clean condensate



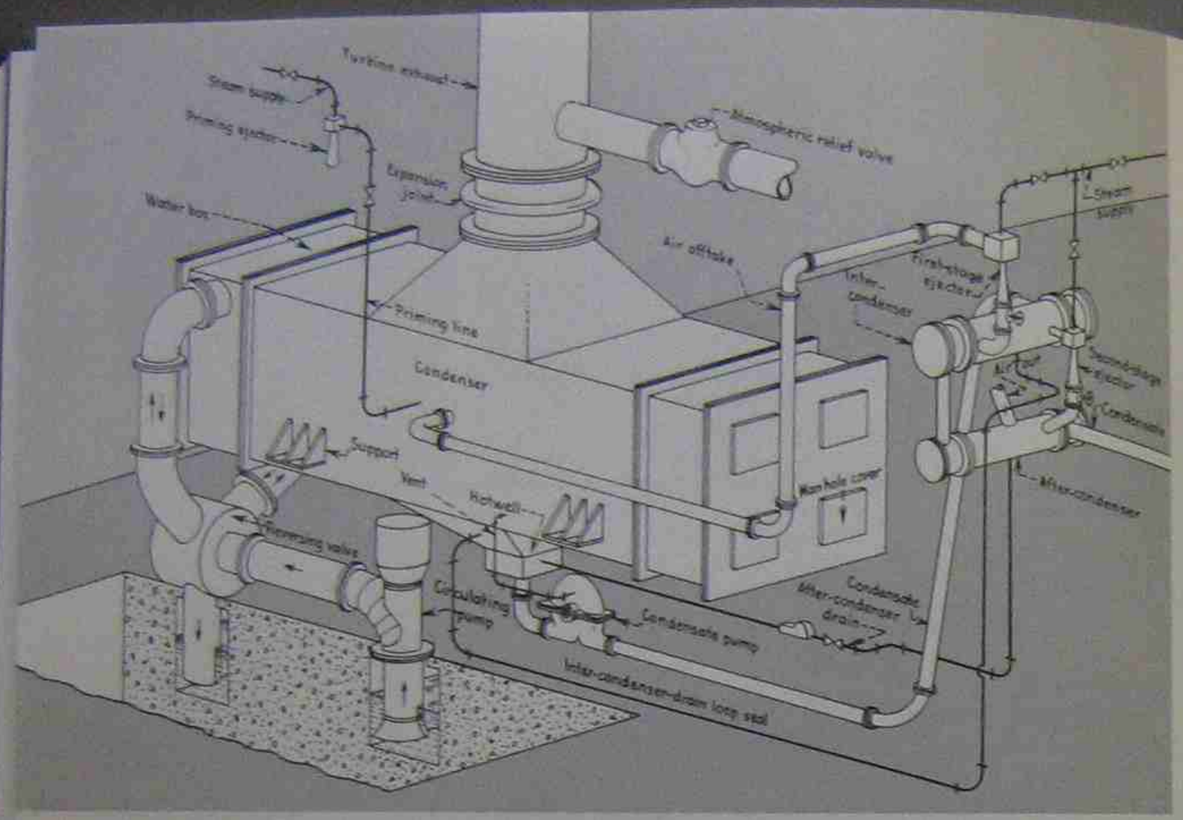
SINGLE-EFFECT evaporation uses but one evaporator



DOUBLE-EFFECT evaporation uses vapor from first unit to heat second unit



TRIPLE-EFFECT evaporation cascades heat through three units, produces most vapor from 1 lb steam



1 Two-pass condenser with principal auxiliaries: Reversing valve provides for backwashing. Pedestals (not shown) give solid support; expansion is taken up in joint in turbine exhaust pipe. Manhole plates on water boxes are usually hinged

Surface condensers... *the major features*

Steam surface condensers do two big jobs: First, and usually most important, they reduce backpressure on turbines so maximum heat energy can be extracted from steam. Power produced in expanding steam from atmospheric pressure to 29 in. Hg vacuum roughly equals that produced in expanding from 200 psig, 600 F to atmospheric.

Second, surface condensers recover low-oxygen-content full-temperature condensate for boiler feed. Where feedwater is expensive, this may be as valuable as backpressure reduction.

Surface condensers are basically vacuum-tight shell-and-tube heat exchangers with cooling water flowing through tubes and prime-mover exhaust steam surrounding the tubes. Cold tube surfaces condense steam; resulting large reduction in volume produces a vacuum. Cooling water carries away latent heat of condensation.

One way or another, exhaust steam is used to heat and deaerate the condensate. This is finally collected in a hotwell and introduced into the feedwater system, thus fulfilling the surface condenser's second major function.

Air Removal. To maintain vacuum, the condenser must get rid of air that always works its way into the shell in small quantities. This air, if allowed to remain, would blanket tube surfaces, reduce heat transfer and eventually destroy the vacuum. One of several forms of air pumps removes it.

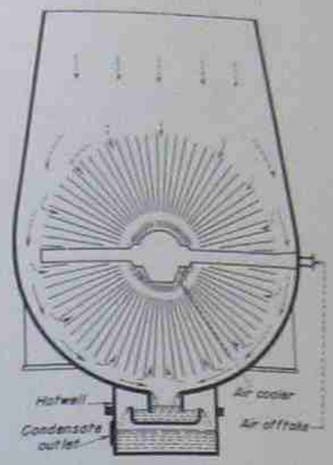
Other major condenser auxiliaries are pumps for circulating cooling water and removing condensate from the hotwell. External parts of a surface condenser and the auxiliaries needed to make it work are shown above. Tube sheets and support plates, along with other features of modern condenser practice, are shown on facing page.

Tube Layout. Today's designers seek to make all tube surface take an active part in carrying away latent heat of condensing steam. Thus, modern condensers use an open arrangement for tubes first hit by high-velocity exhaust steam from the prime mover. As steam penetrates deeper in the tube bank, and condensation reduces its volume, spacing gets closer. Tightest tube arrangement is usually found in the air-cooler section.

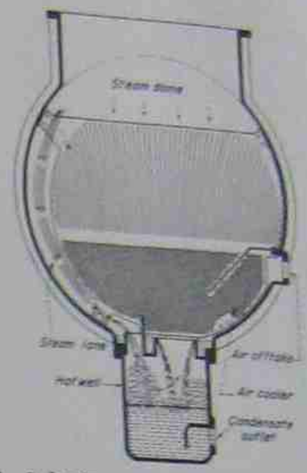
Reducing flow area as steam volume shrinks keeps velocity high enough to sweep air to the cooler, where it is removed by the air pump. Resulting fan-shaped arrangement makes steam scrub all surfaces, puts air in right spot for removal. Last portion of steam comes in contact with coldest tubes. Such schemes for making heat-transfer surfaces work at top capacity reduce surface needs of modern units.

Free steam flow along condenser's length is made possible by leaving openings in tube support plates where there are no tubes (see illustrations). Ample space at top of condenser insures good initial distribution. Area near cooling-water inlet has greatest condensing capacity, hence gets more steam. In addition, designers often put air offtakes and vacuum equipment there, to induce even more steam flow and effectively handle resulting greater load of noncondensables.

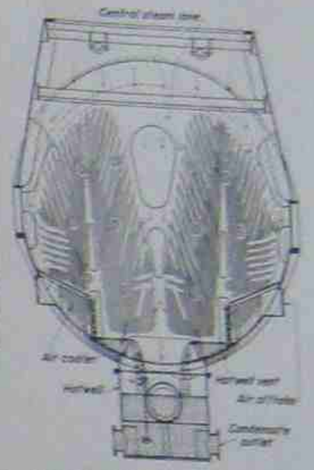
Heating, Deaerating. Steam coming directly from prime-mover exhaust



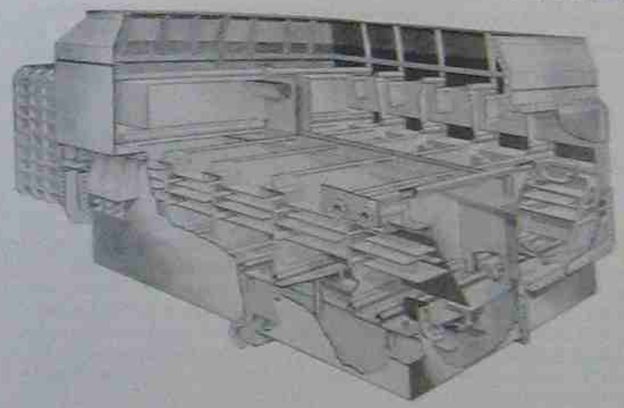
2 Deaeration and heating take place as steam rising from bottom comes in contact with falling condensate. Air is removed at the center of condender



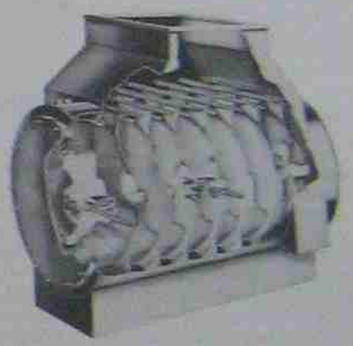
3 Annular space at left in this non-divided-water-box condenser provides passage for part of steam to deaerate and heat condensate flowing to hotwell



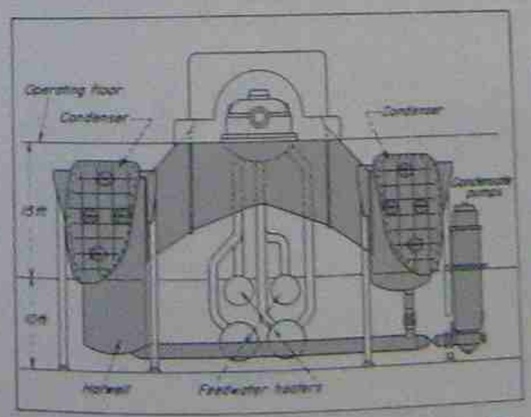
4 A venturi-shaped center lane allows heating and deaerating steam to pass. Note open arrangement of tubes to give steam access to all portions of surface



5 Note air-cooling sections with takeoff pipes, spring mounting, shell expansion joint, strengthening struts across condenser, slight bow in tubes for drainage, center steam lane and heating-deaerating arrangement



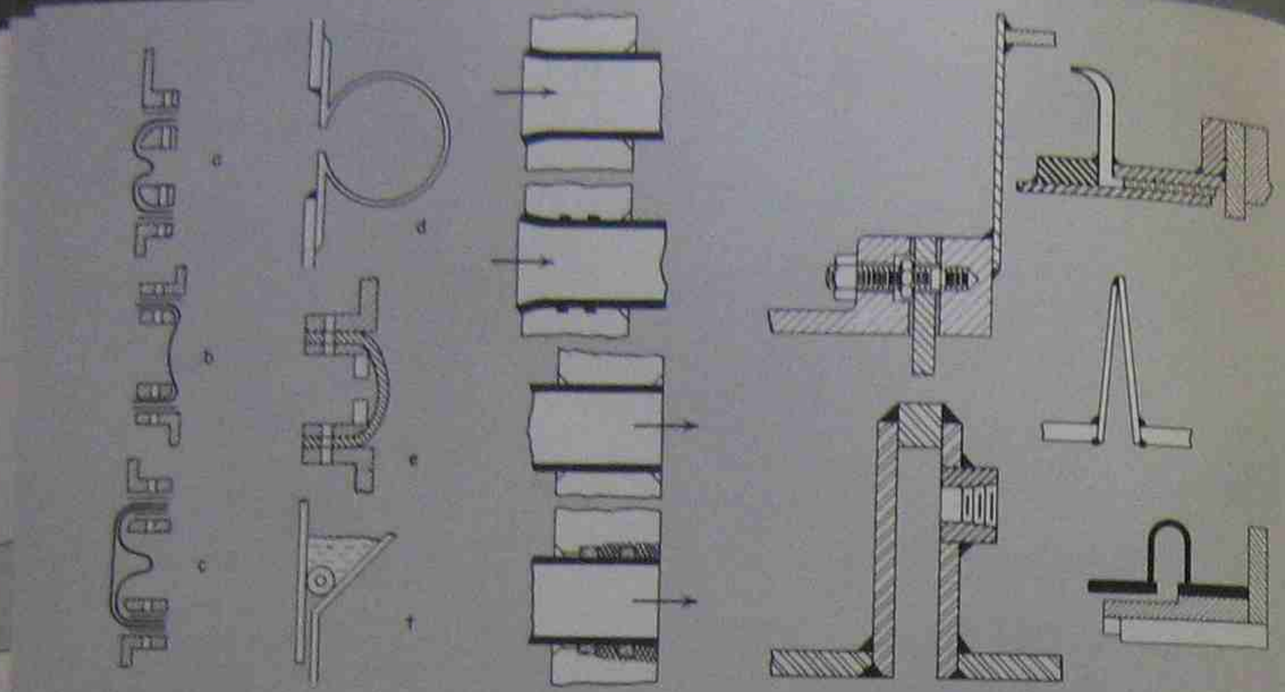
6 Space in tube-support plates, between tubes and shell, allows free distribution of steam throughout condenser. Air takeoff is at shell top



7 Split setup for side-exhaust turbine. Steam enters horizontally, flows up to air cooler; condensate falls to well

8 Foundation-support condenser carries all of turbine weight





9 Typical turbine-exhaust expansion joints: *(a, b)* copper or stainless steel, *(c)* copper with stainless-steel protection, *(d)* stainless steel, *(e)* rubber, *(f)* slide joint with rubber hose and condensate seal. Center drawings show common tube-seating arrangements; fiber-and-metallic ring packing at outlet allows for expansion. Shell expansion joints at right

After a look at condenser basic elements, and their construction . . .

scrubs condensate on its way to the hotwell. This deaerates and heats condensate for introduction into the feedwater system, Fig. 2,3 and 4. Hotwell stores condensate; usual capacity is about equivalent to one minute's operation. Larger hotwells may be used to meet particular plant conditions and sometimes an additional storage tank is installed below the hotwell.

Water boxes distribute cooling water to and from the condenser. Single-pass one-pump condensers have no division in either box. A single partition in inlet box gives a 2-pass setup; four sections in inlet and two in other handle 2-pass operation with two circulating pumps. Deep water boxes and careful location of inlet eliminate undesirable cross flow and turbulence at tube entrances.

Shells. These are usually fabricated of copper-bearing steel, electric welded. Internal T sections, pipe reinforcing struts or I-beams built into the shell stiffen against external pressure and prevent distortion during shipping and erection. Reinforcing pads welded to shell carry supporting feet.

Support. Four basic condenser-support schemes have (1) condenser firmly anchored on foundation, with expansion taken in turbine exhaust pipe, Fig. 1 (2) exhaust pipe rigidly attached to condenser, with expansion taken in spring supports, Fig. 10 (3) condenser attached rigidly to exhaust pipe and suspended therefrom (4) condenser mounted on foundation and supporting turbine, Fig. 8.

Differential expansion between shell and tubes may be taken care of by shell expansion joints, Fig. 9. Tube ends may be fixed and tubes bowed, with fixed or sliding support plates. Or one end of tubes may be fixed and other end packed with fiber and metallic rings to allow tube to slide.

In addition to taking care of expansion, bowed tubes allow drainage when condenser isn't operating. Bowing of tubes has also been used to prevent tube vibration. In another scheme for cutting vibration, support-plate holes are machined to close tolerance and chamfered for a tight tube fit.

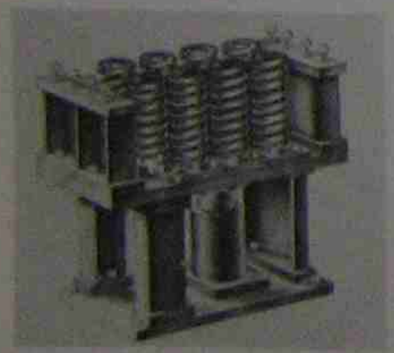
Today's tubes are usually expanded and flared at inlet and expanded or packed at outlet, Fig. 9. Serrations are sometimes used at inlets, as are ferrules, with or without packing. Belling inlets improves flow at tube entrances.

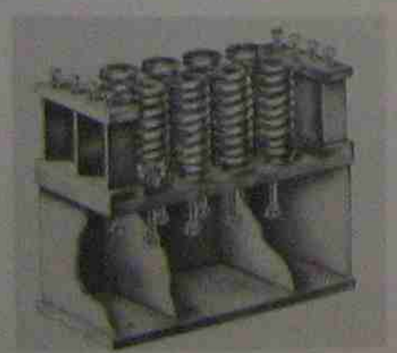
Air-Removal Equipment. Steam-jet air ejectors have largely replaced reciprocating and hydraulic-type vacuum pumps formerly used. A priming jet is sometimes needed for starting. On recent large installations, rotary air pumps have been used (POWER, Aug 1948, p 82). Ejectors offer low first cost, no moving parts, high air-removal capacity. In high-pressure and -temperature plants, rotary air pumps eliminate need for pressure-reducing valves, serve well where ammonia contamination is present, take care of both starting up and normal air-removal needs.

Common system has 2-stage twin-element air ejectors with condensate-cooled inter- and after-condensers. Inter-condenser drains back to condenser by a loop seal, after-condenser drains are trapped back. Drains are usually heated and deaerated in condenser.

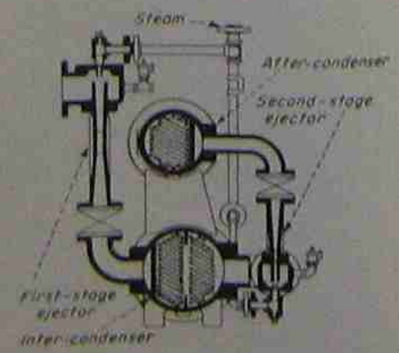
Circulators. Many larger condensers have two half-capacity circulating pumps and a means for reversing water flow in the condenser (see below).

Circulating pumps may be centrifugal, Fig. 14; vertical propeller or mixed-flow types, Fig. 12. Propeller-





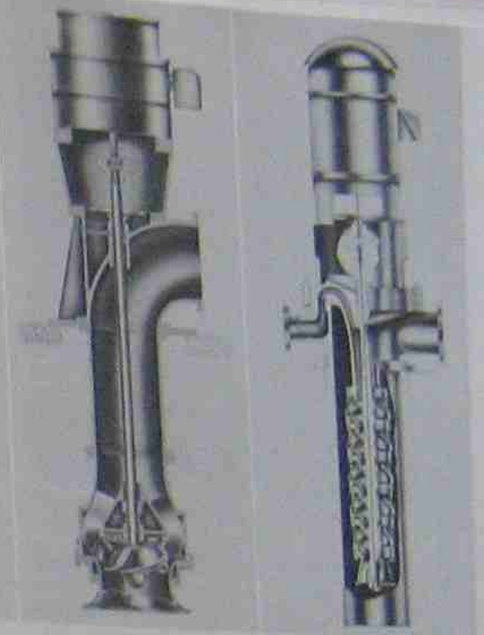
10 Spring supports may have weight they carry adjusted by hydraulic jack, *left*, or jackscrews, *right*. Support screws take condenser weight during hydrostatic test. No exhaust-pipe expansion joint would be used; springs take most of weight



11 Two-stage air ejector with inter- and after-condensers uses condensate for cooling. Drains return to condenser

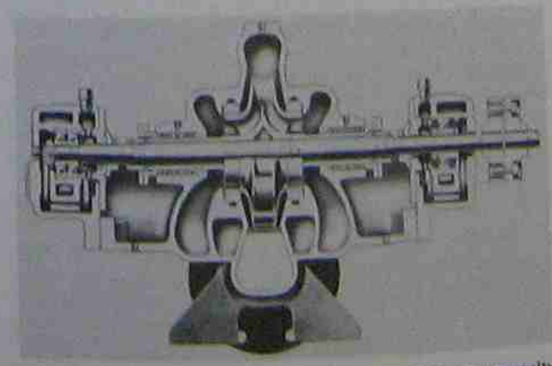


12 Of three vertical circulating pumps above, two at left are propeller type, next is mixed-flow. Mixed-flow pumps operate at slower speed and produce higher head per stage



13 Vertical condensate pumps, *right*, are used where space limitations dictate. Pump submerged in vacuum-tight well extending below floor has right submergence without open pit

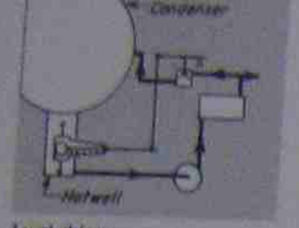
. . . we need to know a bit about auxiliaries: pumps, for example . . .



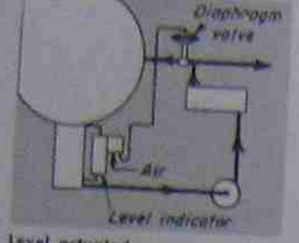
14 Centrifugal circulating pump, often used for low-capacity high-head application, can be used for high suction lift. Mounts horizontally or vertically; normally requires priming



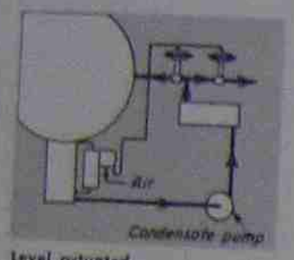
15 Horizontal 3-stage centrifugal condensate pump has double-entry first stage, opposed second- and third-stage impellers. Pressure in stuffing boxes keeps air from leaking in



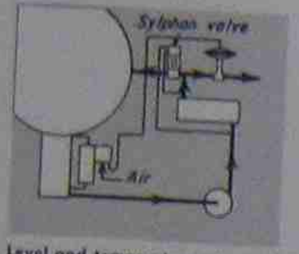
Level driven



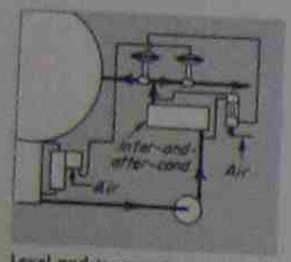
Level actuated



Level actuated



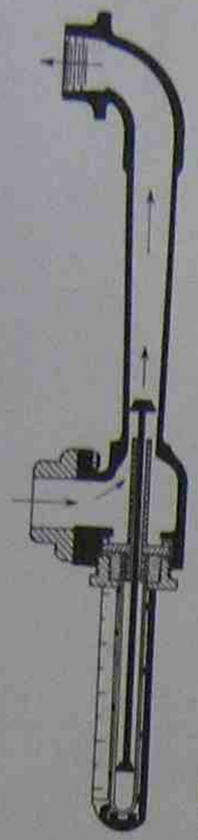
Level and temperature actuated

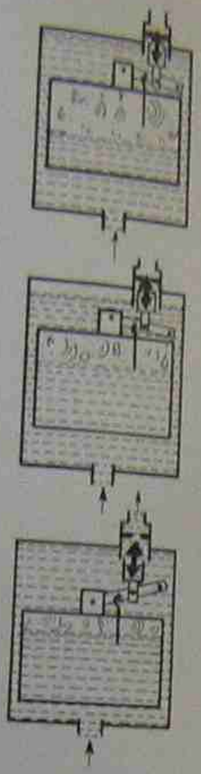


Level and temperature actuated

16 Some condensate recirculation schemes: hotwell level or temperature difference actuates control valves

17 Air-leakage meter's stem and disk float in conical passage to give constant drop in pressure across the disk





18 One type of vacuum trap to drain an after-condenser. Trap discharges when condensate weights down a bucket

. . . and other devices for keeping performance at top effectiveness

type pumps serve for medium or large flows. Driving motor mounts on top of pump, with a solid flanged coupling. This type takes minimum floor space and, in many cases, primes circulating system without external means. Multiple staging takes propeller pumps out of the low-head category.

Where it is necessary to have pump suction substantially below condenser, 75 to 80% of available discharge head can be used in a turbine driving a booster in series with primary pump.

Condensate pumps are usually centrifugals, either vertical or horizontal. Vertical type is usually a multistage pump taking suction from a pit into which condensate flows by gravity, or from a casing, Fig. 13. In both, sealing under pump discharge pressure prevents inward air leakage. Vertical pumps prove useful where there is little headroom; pump suction below floor level, thus well below hotwell level, gives adequate submergence.

Horizontal condensate pumps, Fig. 15, are often used with small and medium-sized condensers. Impeller arrangement (see caption) takes care of hydraulic unbalance. Most units have two full-capacity condensate pumps.

There are three basic methods of controlling hotwell level for safe operation: submergence (POWER, Nov 1948, p 74), condensate recirculation (Feb 1951, p 74), pump throttle control (March 1951, p 120).

Submergence is commonly considered as difference in elevation between hotwell level and pump centerline (horizontal pump). When condenser load decreases, so does amount of condensate, and pump drags down hotwell level, reducing amount of submergence. This lowers suction head on pump and output falls off. Conversely, with greater condenser load, submergence increases, giving a rise in suction head and thus increasing pump output.

Condensate recirculation, Fig. 16, keeps hotwell level essentially steady (constant submergence); amount of condensate recirculated is varied with load. At low loads, recirculation is greater than at high loads.

Pump throttle control regulates discharge so water pumped into condensate system always equals that flowing into hotwell from condenser. Difference between pump head and system head at a given flow is lost in the hotwell-level-actuated throttle valve.

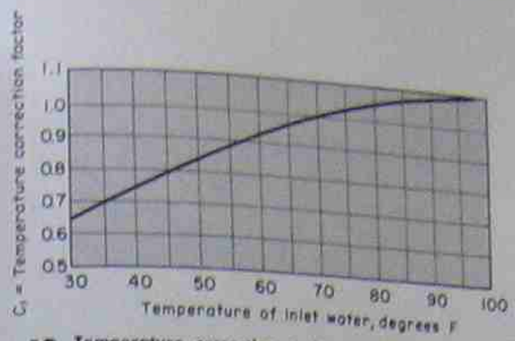
Other Equipment. Atmospheric relief valve in exhaust pipe protects condenser and prime mover in event of vacuum loss. Valve is usually of vertical-lift poppet type, designed to begin opening slightly above atmospheric pressure and to provide full relief at 5 to 10 psig. Valve is equipped with a hand-operated screw lift for non-condensing operation or test work.

Air-leakage meters are frequently installed in after-condenser vent piping. Various designs of piston-type meters follow the principle of Fig. 17; they're damped to give a steady reading. Orifice-type units are also used. Meters are calibrated to read in cfm.

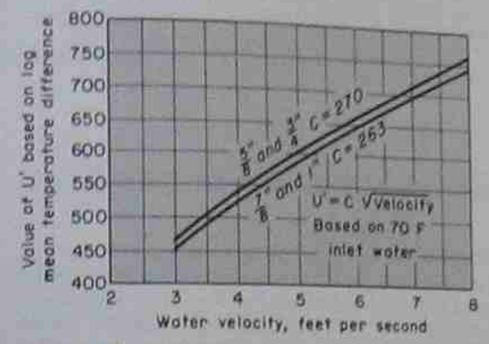
For proper operation, pressure gages and thermometers are installed where they give immediate warning of trouble.

Materials. Today's condenser shells are usually made of copper-bearing steel plate, with cast-iron or fabricated-steel waterboxes and manhole plates. Tube sheets are usually rolled muntz metal; supports copper-bearing steel.

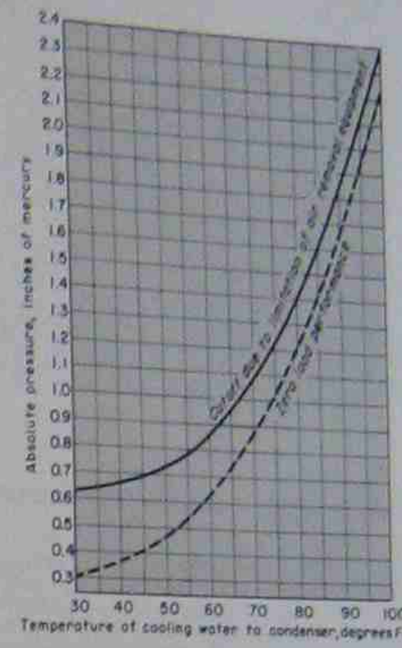
Tubes of inhibited admiralty metal or arsenical copper serve well with fresh circulating water. Admiralty metal (about 70% copper, 1% tin, 29% zinc) is inhibited with a few hundredths of a percent of arsenic, antimony or phosphorus. Arsenical copper has about 0.5% arsenic.



19 Temperature correction to be applied, along with other factors, to heat-transfer coefficient below



20 Transfer coefficient, Btu per sq ft heating surface, per degree log mean temperature difference, per hr



21 At low condenser loads these curves define expected pressures; are higher than those figured from U

Know-how on materials and design aids in choosing the right unit . . .

Aluminum brass (about 76% copper, 2% tin, 22% zinc, small amounts of lead, iron) is also inhibited with arsenic, shows high resistance to erosion by high-velocity aerated sea water.

Copper-nickel (70-30) became standard in American and British navies because of outstanding resistance to erosion and corrosion of sea water. Addition of about 0.5% iron further improves this resistance. Recently it has been found that low-nickel high-iron copper-nickel (say 10% nickel, 1% iron) has properties comparable to 70-30 copper-nickel and is less costly.

Tube Life. Two variables affecting tube life that can be altered are the tube material and the hydraulics of the condenser system. Flow factors causing tube deterioration are: turbulence from non-uniform velocities or other causes; increase in water velocity causing decrease in pressure, or decrease in pressure causing release of air bubbles; vortex in tube with air center; free air entering the system. These items may be minimized by water box design, keeping velocity of entering water as low as possible, arranging angle of entry to water box to eliminate vortices, excluding free air. (POWER, March 1951, p 122).

Selecting a condenser involves considering: (1) steam flow to condenser, (2) cooling-water temperature (3) absolute presure desired (4) water velocity through tubes (5) number of water passes (6) effective length, size, gage, and material of tubes (7) cleanliness factor. Wrapped up in these considerations are quantity and quality of water source, space and accessibility requirements and economic factors.

Once over-all requirements have been established, actual heat-transfer design can go ahead. Basic formula involved is $Q = U \times A \times \Delta t$ (p 78). Q is total heat (Btu per hr) to be extracted in condensing steam and is equal to lb of steam times actual enthalpy removed per lb, at condenser pressure. U is over-all coefficient in Btu per sq ft per F per hr, A is total effective tube surface in sq ft, and Δt is log mean temperature difference. With physical factors established, Q, U and Δt can be calculated and formula solved for effective tube surface.

Values of U' in Fig. 20 are uncorrected. Factors for inlet-water temperature, tube gage and material, and cleanliness must be applied to get proper over-all heat-transfer coefficient. The temperature correction is given in Fig. 19. Corrections for tube gage and material are given in *Heat Exchange Institute Standards for Steam Surface Condensers;* they range from 1.0 for 18 BWG admiralty to 0.76 for 16 BWG 70-30 copper-nickel. Commonly used cleanliness factor is 0.85.

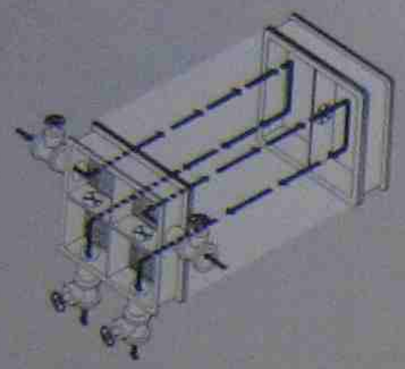
Performance curves show condenser-pressure variation with Btu load. Once design point is fixed, use of heat-transfer and lmtd formulas gives a family of such curves, one curve for each cooling-water temperature and flow.

But at low loads and pressures performance departs from these curves because air-removal equipment doesn't maintain theoretical vacuum. So curves are corrected by use of Fig. 21.

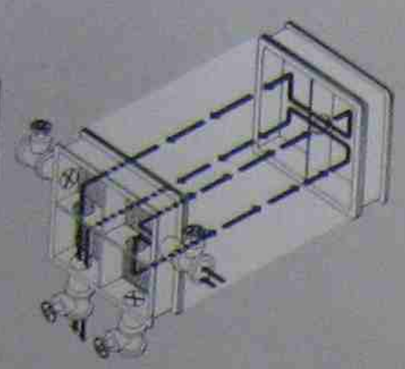
Upper line, Fig. 21, gives lower limit of pressures for which U holds. For any given temperature this fixes a point on the performance curve called the "cutoff." From here down, pressure varies in a straight line, the lower end of which, at zero Btu load, is given by lower curve in Fig. 21.

For each water temperature, cutoff point occurs at a different load. Above cutoff point, U value holds if terminal difference is not less than 5F.

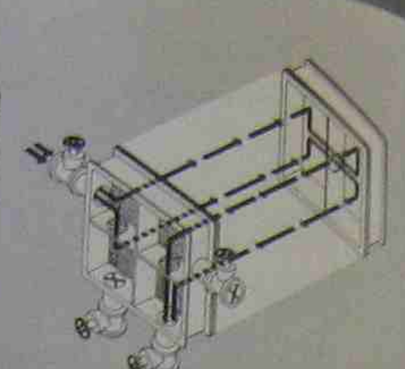
The *HEI Standards* give curves for loss of head in the tubes and the water



22 Normal flow in a divided-water-box condenser, partition valves closed



23 With only one pump running, reverse flow is obtained in two of sections



24 Remaining sections can be backwashed by using other circulating pump

. . . and with a condenser properly fitted to the job conditions, we . . .

boxes, for calculating circulating-pump head requirements.

Low vacuum can be caused by increased air leakage, reduced circulating-water flow, tube scale or slime accumulation, or plugging of air-ejector jets. It's helpful to know your condenser's normal air leakage. Shortly after unit is started up, check the air leakage. If it's higher than normal, take steps to reduce it.

Source of air leakage may be found in several ways: (1) Put shell under air pressure and note effect of soapy water at likely points. (2) With condenser in service, put peppermint oil on suspected joints and check air-ejector discharge for peppermint odor. (3) For large leaks, pass a candle flame over possible openings when condenser is under vacuum. (4) Fill shell and exhaust pipe to turbine shaft with water; check outside of shell for leakage.

To check operation of air ejector, turn on standby ejector instead of suspected unit; see if vacuum improves.

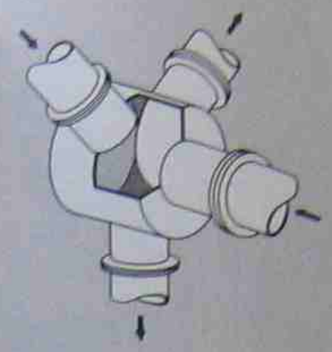
Reduced Water Flow. Temperature rise of circulating water will be greater and vacuum poorer when circulating flow isn't adequate. With pumps and piping in proper condition, low flow may be caused by foreign material in water passages of condenser and inlet screen, or by accumulation of air in water boxes due to improper venting.

Foreign matter blocking flow may be removed by flow reversal, Fig. 22-26. By opening valve in water-box partition of 2-pass condenser, inlet water bypasses to outlet, clearing tube sheets by cross flow. Hydraulic flushing nozzle, Fig. 27, is another means of removing flow restrictions, as is manual cleaning with condenser shut down.

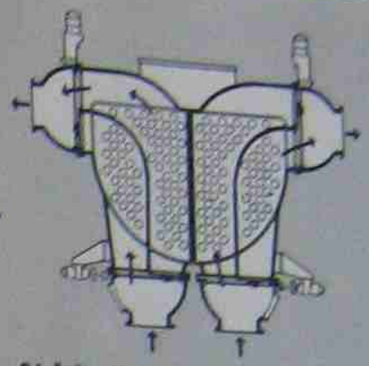
Tube leaks are spotted by candling, hydrostatic tests, and various forms of leak detectors. Recently, good results have been obtained by using a fluorescent solution and ultra-violet light (POWER, July 1950, p 96).

Keeping Tubes Clean. In normal condenser operation, absolute pressure in shell and entering and leaving water temperatures are known. By various means, cooling-water flow can be approximated. Then with tube surface known, over-all coefficient of heat transfer can be calculated, see p 97.

Such coefficients can be set up for various operating conditions when the tubes are new and clean, air leakage is within prescribed limits, and air-evacuating equipment is working properly. These are "clean-tube" coefficients — 1.00 cleanliness factor — for the specific conditions from which obtained.



25 Circulating-water reverse-flow valve for 2-pass condenser, shown in its two operating positions, allows backwashing with a single pump



26 Backwashing scheme built into water box. To reverse: change inlet, outlet valve positions

. . . find that sound operation and top maintenance come a lot easier

After condenser has been operating for a while, again calculate heat-transfer coefficients. Then, if air leakage is within limits and evacuating equipment operating properly, ratio of coefficients to those for clean tubes under corresponding conditions is cleanliness factor. This measures how effective tube-cleaning methods are, shows if cleaning is needed.

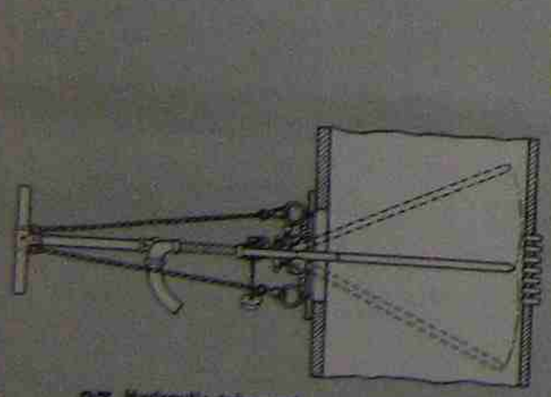
Getting Rid of Slime. Use of chlorine or chlorine compounds in circulating water is usually effective in preventing buildup of slime, which destroys initial tube cleanliness. Slime consists of minute living organisms, colonies of which tend to trap and hold suspended solids from the water. The chlorine poisons these organisms, preventing their growth on the tubes.

Chlorine or chlorine compounds are injected into water ahead of the circulating pump, Fig. 29. Amount of chlorine needed is determined by biological examination of organism's growth, or by experiment. In one plant, for example (POWER, Nov. 1948, p 79), two injections per day, yielding relatively high concentrations of 10 to 15 ppm, give good results. If slime is key problem, proper chlorination keeps condensers in service for long periods.

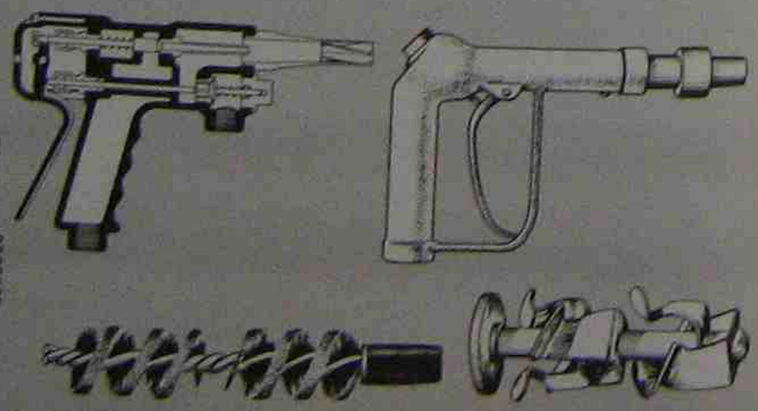
Cleaning Methods. If slime or scale build up, condenser can be cleaned mechanically or chemically, while shut down. In usual mechanical cleaning, air or water under pressure drives brushes or plugs through the tubes, Fig. 28. Brushes scrub, and in some cases scrape, accumulations from tube surfaces. Whether brush has continued scraping action depends on the bristle. Rubber plugs remove loose slime, but may compact remaining slime onto tube surface. Metal plugs usually have flexible scrapers, which give when they hit a solid obstruction. Metal plugs remove hardened slime coatings and any scale that may be deposited.

Special alkaline mixtures held for several hours at 180 F do a good job of removing compacted slime and oily or greasy deposits on tube interiors. Calcium and silica scales can be removed by a weak inhibited-acid solution. For personnel safety and to prevent damage to condenser, acid cleaning should be done with expert advice and supervision.

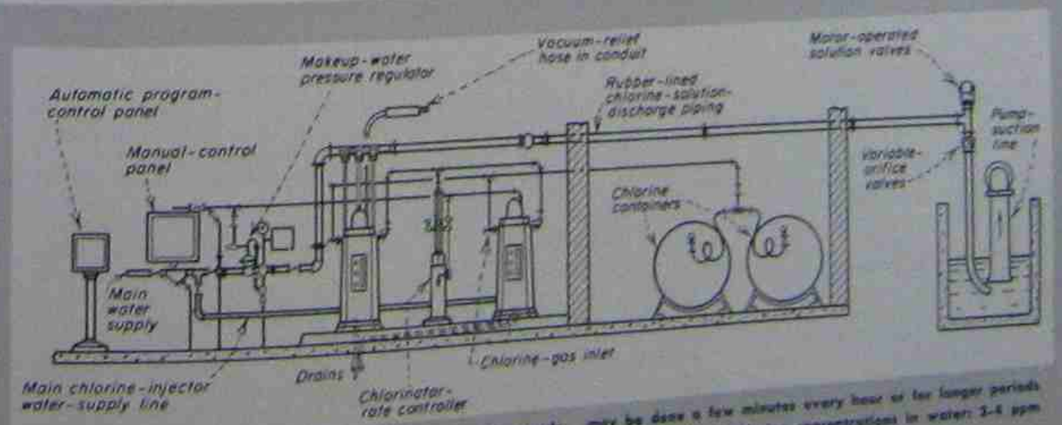
On the steam side, deposits of boiler compound, rust, and sometimes oil, may be removed by boiling out with alkaline solution. Steam-side deposits are usually thinner, less resistant to heat flow than those on water side. Thus cleaning is usually infrequent.



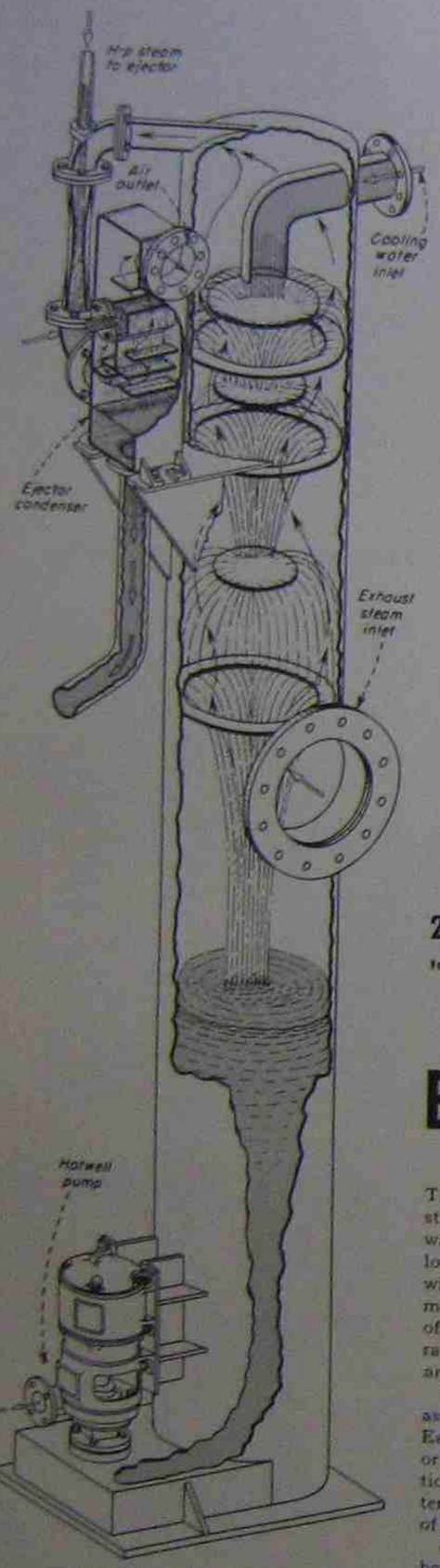
27 Hydraulic tube and water-box flushing nozzle is used to loosen debris while condenser operates



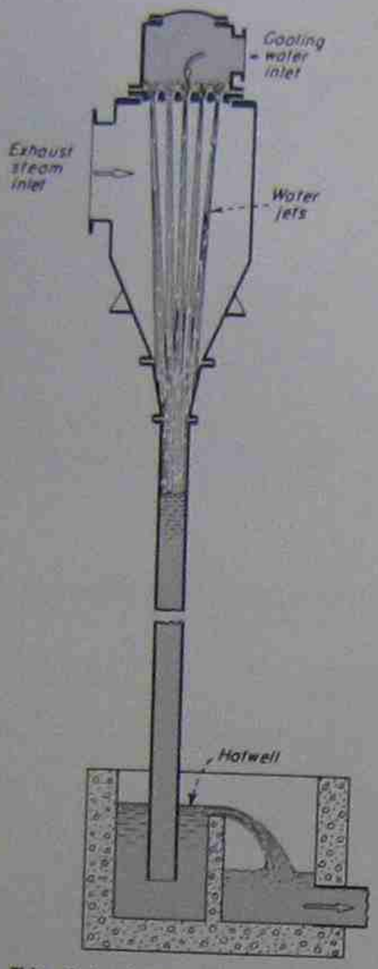
28 Water or air-and-water guns drive plugs or brushes through tubes for cleaning. "Projectile" scrubs or cuts depending on its design



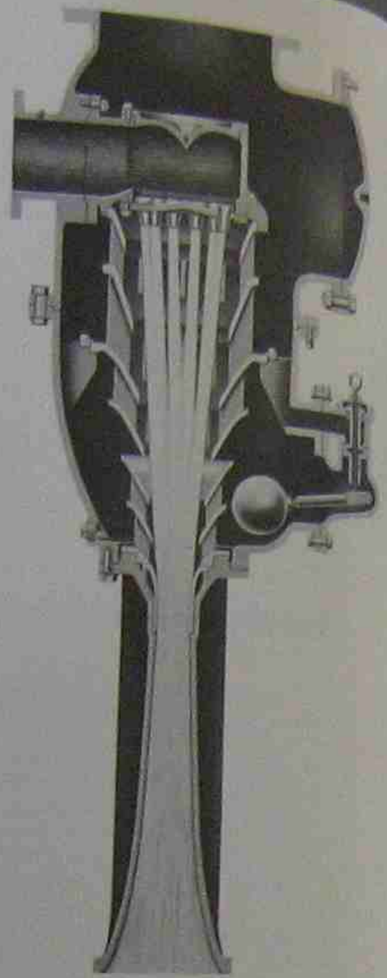
29 Intermittent injection of chlorine or chlorine compounds into circulating water ahead of pump removes slime. This may be done a few minutes every hour or for longer periods once a day. Usual chlorine concentrations in water: 2-4 ppm



1 Floor-mounted countercurrent contact condenser for process work employs single-stage air ejector for evacuation



2 This ejector-jet parallel-flow contact barometric condenser needs no pump to remove entrained non-condensibles



3 Low-level multi-jet condenser has a float-operated vacuum breaker to prevent flooding of the steam exhaust lines

Barometric and jet units...

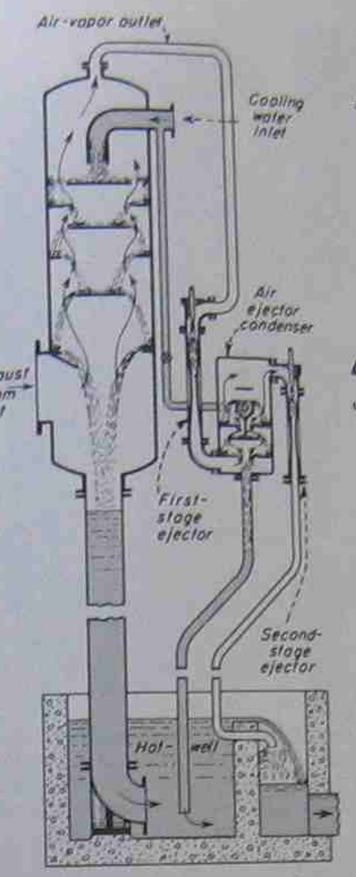
These exchangers condense exhaust steam by direct contact with cooling water. They are simple, compact and low in first cost, but condensate mixes with raw water. Thus jet and barometric units often find use where loss of condensate isn't important, or where raw water is cheap and easily treated and makeup needs aren't stringent.

These condensers may be classified as: (1) barometric, or (2) low-level jet. Each may be either: (*a*) counterflow, or (*b*) parallel flow. First classification refers to method of removing water from unit, second to relative flows of steam and cooling water.

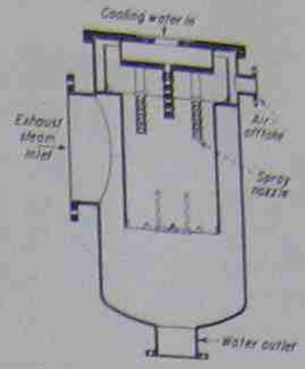
Barometric condensers, Fig. 2 and 6, have shells elevated above discharge water level so water leg in tail pipe has enough head to drain the mixed cooling water and condensate from the evacuated shell. Shells in Fig. 4, 5 and 7 can also be arranged this way (tail pipes aren't shown). Notice that tail pipe seals condenser shell as well as providing head for drainage. Water level in tail pipe depends on both vacuum in shell and barometric pressure.

In counterflow units, steam with its noncondensables flows in a direction opposite to that of cooling water, Fig. 1, 4 and 6. In parallel-flow units, steam and water flow the same way, Fig. 2, 3, 5 and 7. In many designs, cooling water breaks up into a spray to present most surface for steam absorption, Fig. 1, 4, 5, 6 and 7. In these units, noncondensables must be removed by an air pump, as shown in Fig. 1, 5 and 6.

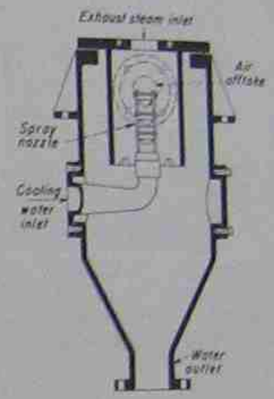
Low-level jet condensers use some type of pump to remove the water mixture from the shell. Unit in Fig. 1



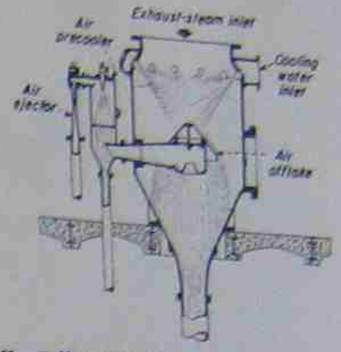
6 Countercurrent barometric condenser uses disks to break up water flow, 2-stage air ejector with intercondenser



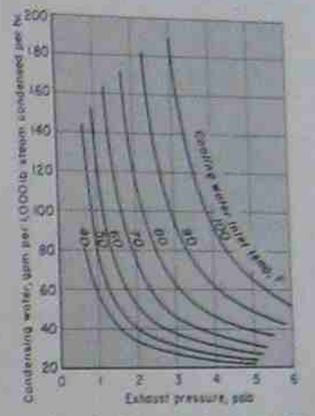
4 Countercurrent barometric condenser has steam and non-condensibles pass up through cooling-water spray, center



7 Small parallel-flow barometric condenser often used as inter- and after-condensers of steam-jet air ejector



5 Air suction chamber, center, draws off non-condensibles for removal by steam-jet air pump through a precooler



8 Flow of cooling-water increases with decreasing exhaust pressure and rising temperature of inlet cooling water

they fit where makeup is good and low-cost

does this by a vertical centrifugal pump at the bottom of the hotwell. In Fig. 3, it's done by the jet action of the cooling water entering the diffuser (at shell bottom) at high speed. Any of the other condensers shown here can use a centrifugal pump connected to the bottom of the shell to remove water.

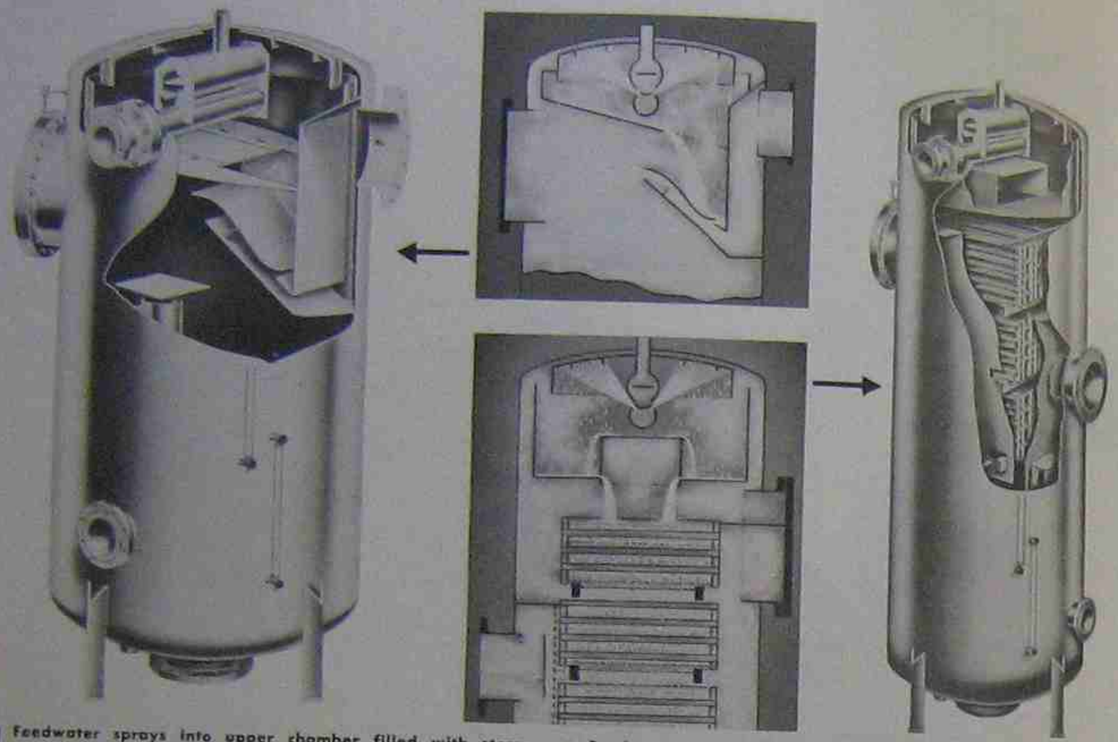
Condensers using water jets, Fig. 2 and 3, do not need a separate air offtake to remove noncondensables. Speed of the jets entrains gases and carries them out with the drainage water. To realize this entraining action, the water cannot be broken up into a spray to get maximum heat-transfer surface, but the steam condenses on the surface of the fast-moving jet streams. In Fig. 3, the annular diffuser arrangement surrounding the jets directs steam entering at the top of the shell into the jets for absorption.

Performance. Amount of cooling-water flow needed by a condenser depends on vacuum to be held and amount of steam being condensed. Fig. 8 shows the relation for counterflow condensers serving steam turbines. These curves are based on 950 Btu per lb in exhaust steam. For parallel-flow units this relation is slightly different.

In well-designed contact condensers there will be little pressure drop between steam inlet and air offtake for small amounts of gases in the steam. When the noncondensable load builds up, pressure drop increases accordingly and backpressure held by the condenser rises. Air in the steam caused by leakage through porous walls and joints in the exhaust system, and leaks past shaft seals, can usually be kept at levels varying from 3 cfm for steam flows of 25,000 lb per hr to 10 cfm for flows of 250,000 lb per hr, when serving turbines. The cooling water carries in a certain amount of dissolved air that releases in the evacuated shell. Designers allow for this at rates varying from about 2 cfm per 1000 gpm at 100-F inlet temperature to 4 cfm per 1000 gpm at 35 F. This air must also be removed with the noncondensables entering with the steam.

Fig. 3 shows a float-operated vacuum breaker to keep discharge water from backing up into the condenser and flooding turbine exhaust system.

For aid in specifying conditions for contact condensers, refer to *Standards of Heat Exchange Institute—Barometric and Low-Level Jet Condensers.*



1 Feedwater sprays into upper chamber filled with steam, heated water falls on an inclined baffle below. Entering steam jets it into upper part of storage chamber, scrubbing out gas. Gas sweeps along with steam, leaves through vent in top center

2 Feedwater spray is heated in steam-filled upper chamber. Water collects on baffles and falls in drops and thin sheets on deaerating trays below. Entering steam flows over trays and carries along released gas to leave through vent at top

Deaerating heaters... *they remove gases*

Deaerating heaters raise feedwater temperature by direct contact (mixing) with steam, and remove all dissolved oxygen in excess of 0.03 ml per liter. When the unit can reduce the dissolved oxygen to 0.005 ml per liter it is called a *deaerator*. Removal of dissolved gases depends on heating the water to boiling, agitating it and presenting as big a surface as possible to liberate the gas and absorb heat by condensing the steam.

Spray Heaters. Two types of heaters do this job: (1) spray and (2) tray. Methods may be combined. In the spray type, Fig. 1, 5 and 7, the feedwater sprays into a steam-filled space, to be heated and scrubbed for gas release. In these three examples, the water undergoes a second agitation by the steam entering the deaerator. This releases the last remaining portion of dissolved gases that can be removed before the hot water leaves the heater.

Tray and Combination Types. In the tray type of heater, Fig. 4, feedwater is led into a series of trays and falls from tray to tray by overflowing or passing through small holes. Steam completely envelopes the trays, heats and deaerates the water during its trip to the bottom of the shell. In combination-type heaters, Fig. 2, 3 and 6, feedwater first sprays into a steam-filled space and then rains down on top of a series of trays through which it passes to be further agitated or scrubbed for gas release.

In entering a deaerating heater, steam usually meets the hottest water first, to work on the last fraction of dissolved gas. It carries this gas with it as it flows through the countercurrent water, picking up additional gas load along the way. The steam also condenses partly as it heats the feedwater along this route. Steam reaches the top of the heater rich in gases. When this mixture meets the cooler incoming feedwater, almost all the remaining steam condenses. The gases saturated with steam then leave the heater through the vent.

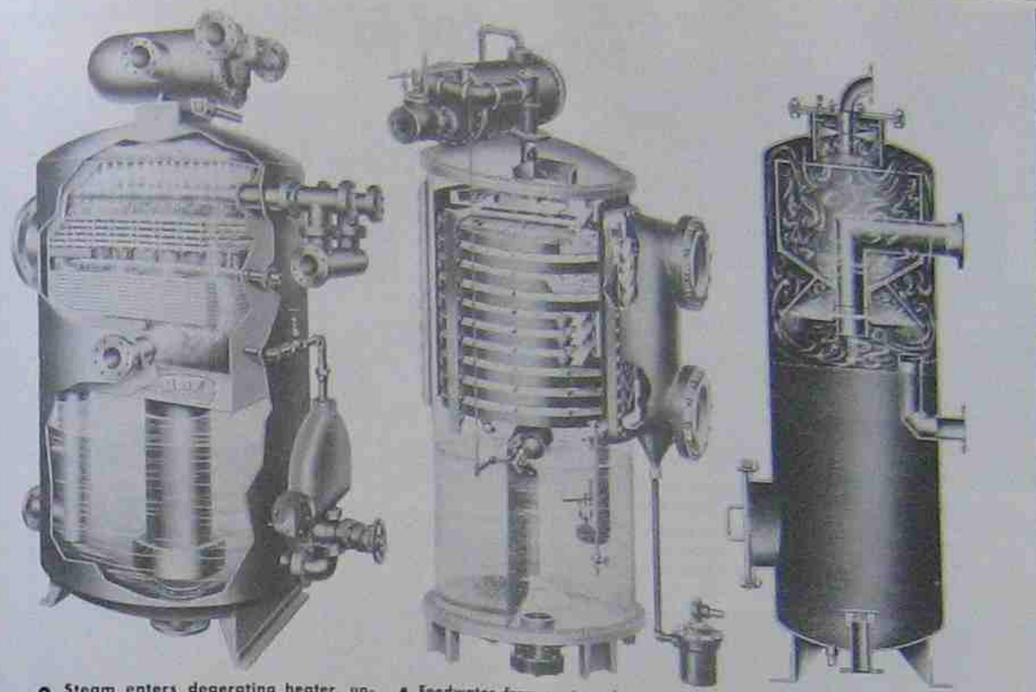
Some heaters, Fig. 3, have incoming steam and water meeting in the same area of the heater and moving down in parallel flow to the heater bottom.

Vent Condensers. These elements cool the vented steam-gas mixture with colder incoming water to condense as much of the steam as possible. Condensate returns to the heater. Condensers may be of the direct-contact type, Fig. 1, 2, 5 and 6, or the shell-and-tube type, Fig. 3, 4 and 7.

Deaerating heaters may operate at pressures as high as 200 psig, or under vacuum. In the latter case they vent their gases to an evacuating pump, or the main condenser.

Since the wet gases can be corrosive, deaerator internals must be made of corrosion-resistant materials such as stainless steel or monel.

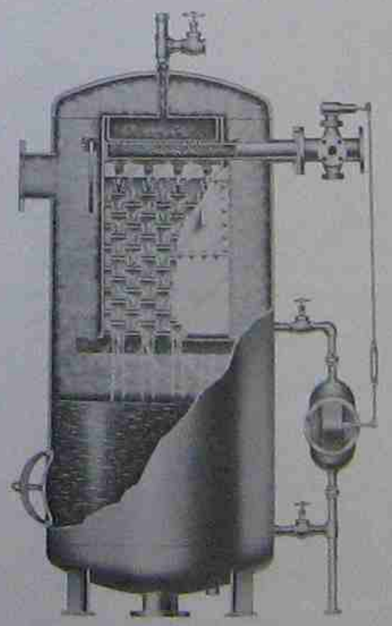
Most heaters have automatic control valves to admit makeup when storage level drops too low, and to pass heated, deaerated water to storage when level rises too high, see Fig. 3, 6 and 7. For details of these heater types see *Standards and Typical Specifications for Deaerators and Deaerating Heaters*, issued by the *Heat Exchange Institute*.



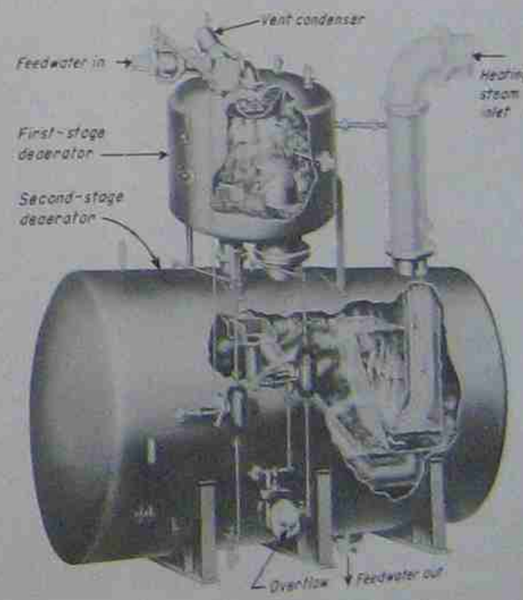
3 Steam enters deaerating heater, upper left, to meet sprayed inlet water at top. Both flow down through trays; wet gases leave through outlet at center

4 Feedwater from vent condenser falls on top tray and works its way down from tray to tray in a zigzag course, being heated and deaerated on the way

5 Water enters through top elbow; part sprays into direct-contact vent condenser, rest forms the main deaerating spray. Steam jets water into final spray



6 Water sprays up into a chamber above trays, falls down from tray to tray. Steam flows countercurrent upward past trays. This degasifies and heats water



7 First-stage deaerator receives water in spray form, where steam heats it and removes most of dissolved gases. Water flows down inclined pipe into second stage where incoming steam bubbles through it and removes remaining gases. Steam, carrying gas along, rises into first stage to heat incoming water close to boiling

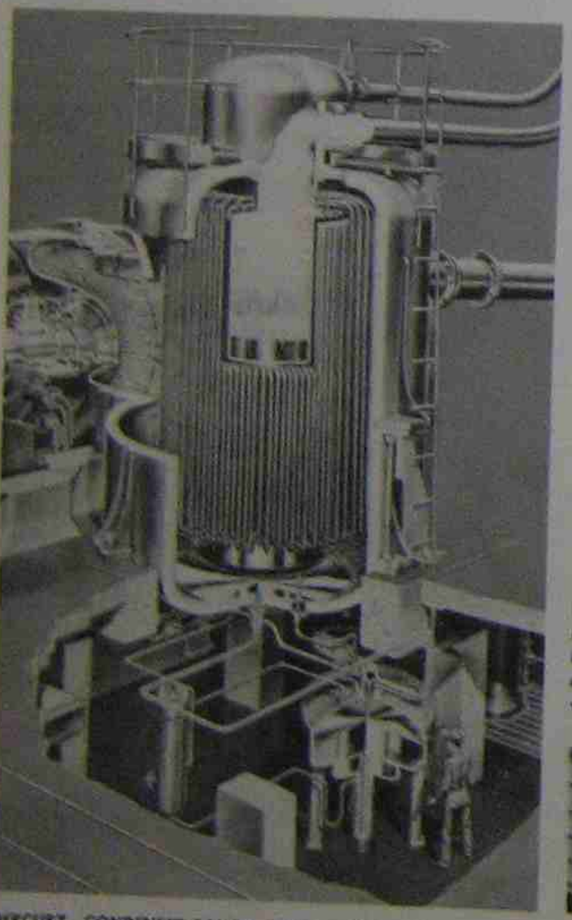
For special jobs...



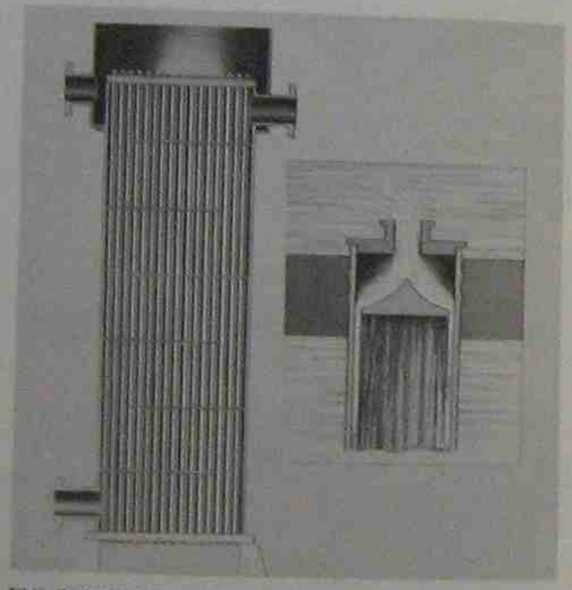
DRY COOLERS may be used for fluid cooling or condensing service. Diesel-engine jacket-water cooling and turbine exhaust-steam condensing are typical applications. Motor-driven fans force air over finned tubes carrying fluid in a closed circuit. There's no contamination and no evaporation loss



LUBRICATING-OIL RADIATOR is a form of small dry cooler used in areas where cooling water is scarce. Motor-driven fan may be thermostat-controlled for automatic operation. Oil circulates between upper and lower headers through vertical finned tubes. Air side needs most heat-transfer surface



MERCURY CONDENSER-BOILER takes exhaust from mercury turbine; evaporates feedwater to saturated steam in tubes and central vertical drum. Condensed mercury falls to hotwell in basement for return to mercury boiler. Steam flows to superheater in boiler before entering the steam turbine



FILM-TYPE COOLER handles silt-laden water as a cooling medium. Water from river or well enters top channel, which is open to atmosphere. From here water flows through ferrules in upper ends of tubes, *inset right*. Ferrules cause water to flow down interior tube wall in thin film to bottom

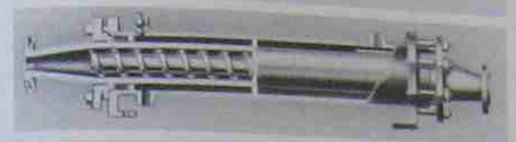


PROCESS HEAT EXCHANGERS handling gases must overcome problem of poor film heat-transfer coefficients by making available maximum possible amount of heat-transfer surface. This is done by extended surfaces of various shapes formed to produce desired turbulence with minimum of pressure loss

heat exchangers can be tailored to the needs



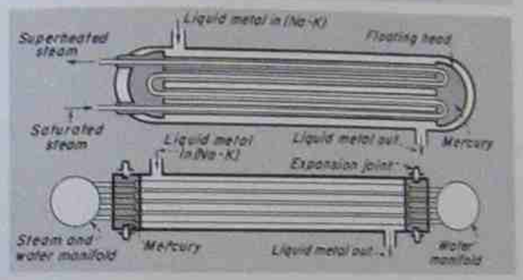
DOUBLE-PIPE EXCHANGER with finned-tube surface often serves as fuel-oil heater, to lower viscosity. Steam serves as heating medium. These units can be hooked up in series to give total amount of heat-transfer surface needed to do job



LUBRICATING-OIL COOLER of small capacity uses annular-pipe arrangement. Core in center tube makes oil take helical path at high velocity. Cooling water flows through annular space between tubes, making one pass. Cock vents space



BLOWDOWN HEAT EXCHANGER of small capacity takes blowdown from boiler through a small tube. Makeup entering feedwater cycle passes through surrounding pipe. Blowdown goes to waste, but heat that would otherwise be lost is salvaged



LIQUID-METAL STEAM SUPERHEATER for atomic plant uses mercury between tubes to prevent a disastrous reaction between steam and sodium-potassium mixture, in case of tube-joint leakage or accidental tube rupture on either side of heater

LIQUID-METAL STEAM BOILER normally stands in tilted position with water manifold at a lower level. Mercury in annular spaces between tubes isolates the liquid metal from water in case of accidental leakage. Note expansion joints

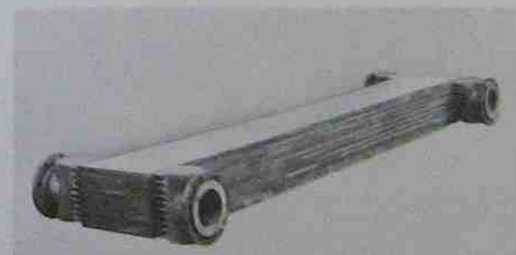
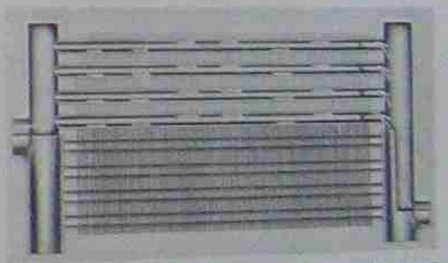
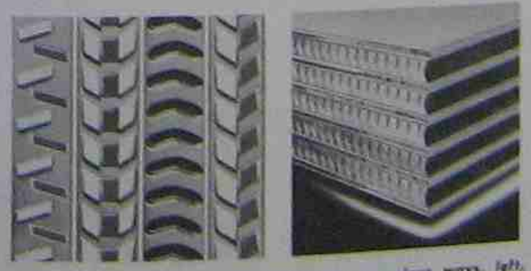


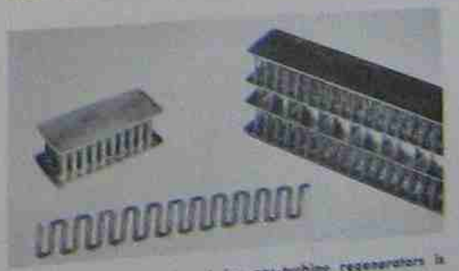
PLATE-TYPE EXCHANGERS may have plain open passes or use extended-surface passages such as those shown below and at lower left. These are used for air and gases. Note that manifolds at right and left ends tie into alternate passages between plates. Clean gases must be used to prevent fouling



STEAM-HEATING EXCHANGER with finned tubes may be placed in duct to heat air flowing over fins. Center tubes distribute steam along length to get more effective duty from all of surface. Similar finned-tube arrangements are used in generator hydrogen coolers with cooling water flowing in tubes



EXTENDED SURFACE may be embossed in various ways, *left*, to induce turbulence in gas flowing between plates, *right*. Note thin cross-section with channel separators makes gas flow at right angles to gas in channels with embossed plates. Extensive heat-transfer data are used in designing surfaces



PIN-FIN SURFACE developed for gas-turbine regenerators is compact, light. Pins may be circular in section or streamlined, *foreground*. They are machine-formed in continuous strands, with lugs for brazing to plates. Pins can be used in each passage, or alternated with strip fins, as at right

SUMMARY OF TYPICAL HEAT-EXCHANGER APPLICATIONS

	Heat-transfer fluids	Equipment	Action	Type	Pressure range	Typical range of U
HEATING	Liquid—liquid	Boiler-water blowdown exchanger	Blowdown cooled, feedwater heated	S	M, H	50–300
		Laundry-water heat reclaimer	Waste water cooled, feed heated	S	L	30–200
		Service-water heater	Waste liquid cooled, water heated	S	L, H	50–300
	Vapor—liquid	Bleeder heater	Steam condensed, feedwater heated	S	L, H	200–800
		Deaerating feed heater	Steam condensed, feedwater heated	M	L, M	DC
		Jet heater	Steam condensed, water heated	M	L	DC
		Process kettle	Steam condensed, liquid heated	S	L, M	100–500
		Oil heater	Steam condensed, oil heated	S	L, M	20–60
		Service-water heater	Steam condensed, water heated	S	L, M	200–800
		Open flow-through heater	Steam condensed, water heated	M	L	DC
		Liquid-sodium steam superheater	Sodium cooled, steam superheated	S	M, H	50–200
	Gas—liquid	Waste-heat water heater	Waste gas cooled, water heated	T	L	2–10
		Boiler economizer	Flue gas cooled, feedwater heated	T	M, H	2–10
		Hot-water radiator	Water cooled, air heated	T	L	1–10
	Gas—gas	Boiler air heater	Flue gas cooled, combustion air heated	T, R	L	2–10
		Gas-turbine regenerator	Flue gas cooled, combustion air heated	T	L	2–10
	Vapor—gas	Boiler superheater	Combustion gas cooled, steam sup'h't'd	T	M, H	2–20
		Steam pipe coils	Steam condensed, air heated	T	L, M	2–10
		Steam radiator	Steam condensed, air heated	T	L	2–10
COOLING	Liquid—liquid	Oil cooler	Water heated, oil cooled	S, D	L, M	20–200
		Water chiller	Refrigerant boiled, water cooled	S	L, M	30–150
		Brine cooler	Refrigerant boiled, brine cooled	S	L, M	30–150
		Transformer-oil cooler	Water heated, oil cooled	S	L, M	20–50
	Vapor—liquid	Boiler desuperheater	Boiler water heated, steam desup'h't'd	S, M	M, H	150–800
	Gas—liquid	Compressor inter- and after-coolers	Water heated, compressed air cooled	S	L, H	10–20
		Internal-combustion-engine radiator	Air heated, water cooled	T	L	2–10
		Generator hydrogen, air coolers	Water heated, hydrogen or air cooled	S	L	2–10
		Air-conditioning cooler	Water heated, air cooled	T	L	2–10
		Refrigeration heat exchanger	Brine heated, air cooled	T	L, M	2–10
		Refrigeration evaporator	Refrigerant boiled, air cooled	T	L, M	2–10
	Vapor—gas	Boiler desuperheater	Flue gas heated, steam desuperheated	T	M, H	2–8
BOILING	Liquid—liquid	Hot-liquid evaporator	Waste liquid cooled, water boiled	S	L, H	40–150
		Liquid-sodium steam generator	Sodium cooled, water boiled	S	M, H	500–1000
	Vapor—liquid	Evaporator (vacuum)	Steam condensed, water boiled	S	L	400–600
		Evaporator (high pressure)	Steam condensed, water boiled	S	L, M	400–600
		Mercury condenser-boiler	Mercury condensed, water boiled	S	M, H	500–700
	Gas—liquid	Waste-heat steam boiler	Flue gas cooled, water boiled	T	L, H	2–10
		Direct-fired steam boiler	Combustion gas cooled, water boiled	T	L, H	2–10
CONDENSING	Vapor—liquid	Refrigeration condenser	Water heated, refrigerant condensed	S, D	L, M	80–250
		Steam surface condenser	Water heated, steam condensed	S	L	300–800
		Steam mixing condenser	Water heated, steam condensed	M	L	DC
		Inter- and after-condenser	Condensate heated, steam condensed	S	L	15–300
	Vapor—gas	Air-cooled surface condenser	Air heated, steam condensed	T	L	2–16

EXPLANATORY NOTES

Letter designations under "Type": *S*—shell-and-tube exchanger; *M*—direct-contact mixing exchanger; *T*—tubes in path of moving fluid, or exchanger open to surrounding air; *R*—regenerative plate-type or simple plate-type exchanger; *D*—double-tube exchanger.

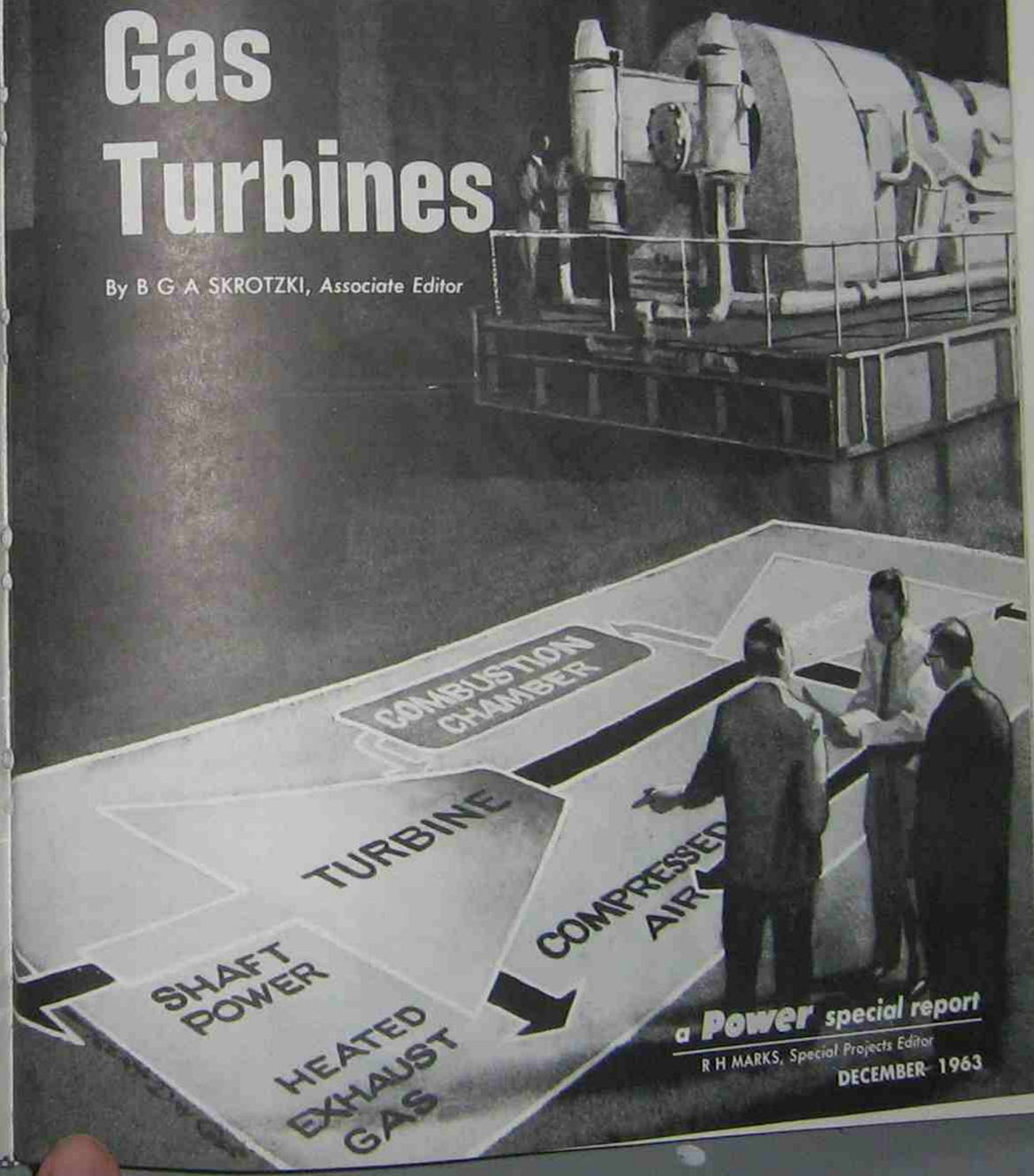
Designations under "Pressure range": *L*—highest pressure ranges from 0 to 100 psia; *M*—highest pressure from 100 to 500 psia; *H*—500 psia up.

Values of *U* represent range of over-all heat-transfer coefficients that might be expected in various exchangers. Coefficients are stated in Btu per hr, per F, per sq ft of heating surface. Total heat transferred in exchanger, in Btu per hr, is obtained by multiplying a specific value of *U* for that type of exchanger by the surface and the log mean temperature difference. DC indicates direct exchange of heat.

Thousands of gas turbines are serving daily in prop-jet and jet engines for military and commercial aircraft with hundreds more found in rail, marine and automotive service as prime movers or auxiliary generators • Versatility of the gas turbine is also demonstrated by its growing acceptance in a wide variety of stationary energy systems for processing, power generation and mechanical drives • Recent developments include adaptation of standard jet engines to base-load generation and peaking service; interest in gas turbines as the heart of on-site generating systems continues at a high level • In this 24-page special report we look at gas-turbine equipment varying from 25-hp capacity to over 100,000 kw • Fuels range from natural gas to residual oils, with coal use largely experimental

Gas Turbines

By B G A SKROTZKI, *Associate Editor*

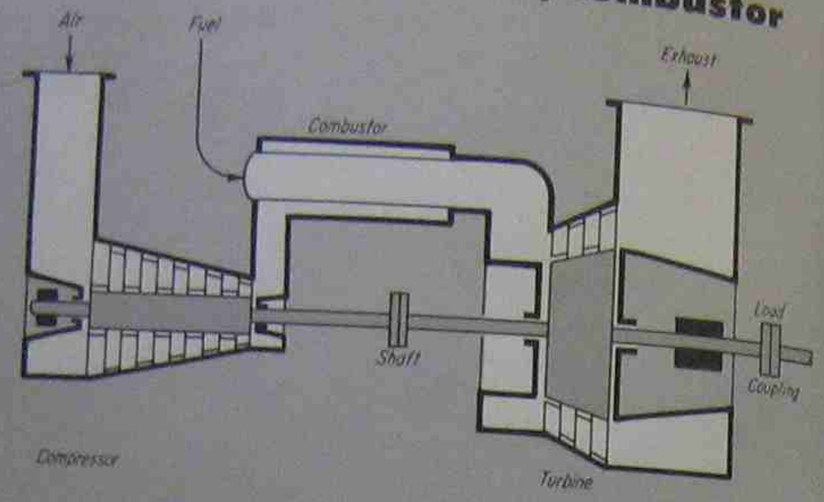


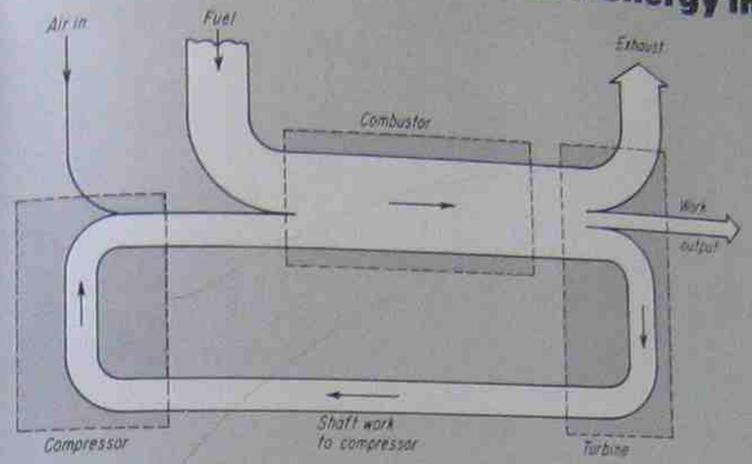
a **Power** special report

R H MARKS, Special Projects Editor
DECEMBER 1963

Open cycle system employs compressor, combustor and turbine to convert fuel energy into work output

Basic equipment for a simple gas-turbine system includes a compressor, combustor and turbine. Rotating compressor sucks in atmospheric air, pressurizes it, and forces it into the combustor or furnace in a steady flow. Fuel forced into the air burns, raising temperature of the mixture of air and combustion products. This high-energy mixture then flows through the turbine, dropping in pressure and temperature as it does work on the moving blades. It leaves at atmospheric pressure and high temperature. The turbine drives the compressor rotor through a shaft and also an external load through the load coupling.





Energy flow diagram shows how heat energy moves through the cycle. Starting with the compressor we can arbitrarily call internal energy of entering air zero since it plays no part in the energy conversion. Shaft work into the compressor is transferred to the air as it's pressurized to give it an energy load entering the combustor. Here burning fuel releases thermal energy, further raising air temperature to develop the maximum energy load for the cycle. In the turbine, part of this energy develops mechanical work, most of which goes to drive the compressor. Residual energy leaves with the air as it exhausts.

How gas turbines use thermal energy

To know how gas turbines behave we need to clearly understand the basic steps in the cycle. Simple gas-turbine plant (above) consists of a compressor, a combustion chamber and a turbine. The aim is to convert heat energy of fuel into mechanical energy. Compressor and combustion chamber produce a high-energy working fluid that can be expanded in the turbine. This develops mechanical energy just like expanding steam in the more familiar steam turbine (*Steam turbines*, POWER, June, 1962).

Volume of the working fluid is smallest at the compressor outlet, though its temperature is higher than at the compressor inlet. High excess-air ratio in the combustor keeps air and gas temperatures below a maximum limit. At turbine outlet gas volume is a maximum. Main elements of the gas turbine plant must be proportioned to handle the flow of working fluid with minimum pressure loss through the system.

Energy flow diagram (facing page) shows how fuel input divides between useful output and exhaust losses. For a simple cycle plant the fuel represents net energy input. Work output (net useful output of the cycle) plus exhaust energy equals the fuel energy input.

Compressor shaft input work simply circulates within the cycle. In a sense this is the catalyst that makes the gas turbine cycle workable. The turbine must always be capable of generating the mechanical energy needed to drive the compressor and pressurize the air. Whatever it generates above this is available to drive an external load. Of the total shaft work developed by the turbine, roughly two-thirds goes to drive the compressor and one-third to drive the load. This may seem like a high proportion of mechanical work to make the cycle go, but the same relation holds for any heat engine using hot gases directly to generate useful mechanical work output.

Controlling factors in gas-turbine design are best explained by first looking at the ideal simple cycle, Fig. 1, where everything works at 100% efficiency. Areas on the temperature-entropy (T-S) diagram, Fig. 2, measure heat transferred into and out of the cycle. Shaded area under 2-3 measures heat input by fuel in the combustor. Hatched area under 4-1 measures internal energy of gas leaving the turbine exhaust. This is the energy lost by equivalent cooling of the exhaust at constant atmospheric pressure to atmospheric temperature. Difference of the two areas, 1-2-3-4, measures the net mechanical work output.

Area of 1-2-3-4 can be increased by adding heat to the cycle at a higher pressure. This raises temperature range and therefore the average temperature at which heat is added to the cycle. But this depends directly on the combustor pressure. So thermal efficiency (ratio of work output to heat input) of the cycle depends on its pressure ratio (radio of compressor-discharge absolute pressure to compressor-inlet absolute pressure). Fig. 3 shows how thermal efficiency rises with increasing pressure ratio.

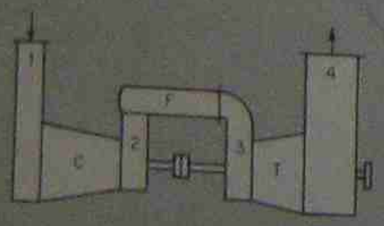
Here 100% machine efficiency means: (1) turbine works at 100% engine efficiency, it converts all available gas internal energy to mechanical work and (2) compressor converts all its mechanical work input to increased internal energy in the air at 100% compression efficiency.

But an actual gas turbine cannot work at ideal conditions. Fig. 3 indicates what happens at 70 to 90% machine efficiencies when T_1 = 60 F, T_3 = 1500 F and there are no pressure losses in the cycle. For machine efficiencies much below 70% the plant cannot work at all.

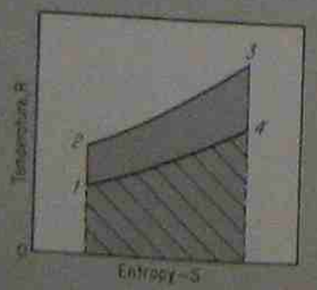
Regenerative cycles make use of exhaust heat. Fig. 2 indicates a large amount of energy under 4-1 leaving cycle with the exhaust gas. If this could be reduced we'd improve plant thermal efficiency. A basic thermodynamic rule states that cycle efficiency can also be improved by adding heat at the highest possible temperature. These conditions can be approached by using a regenerator *R* hooked up as shown in Fig. 4.

T-S chart, Fig. 5, shows that regenerator cools turbine exhaust in an ideal cycle from T_4 to T_5; transfers this

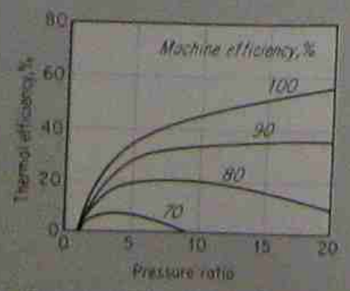
Simple cycle has fewest elements, lower thermal efficiency



1 Flow diagram numbers steps in gas turbine cycle. Air is compressed (C) from 1 to 2. Combustor (F) heats air at constant pressure from 2 to 3. Gas then expands in the gas turbine (T) from 3 to 4

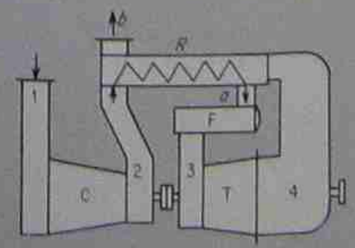


2 Temperature-entropy (T-S) diagram for ideal cycle gives net work output

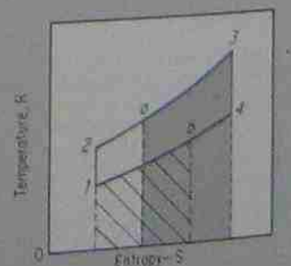


3 Thermal efficiency rises with pressure at machine efficiency of 90% or above

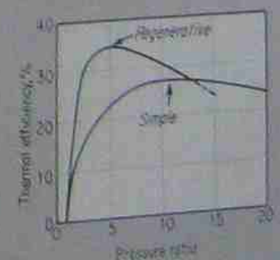
Regenerator for exhaust heat recovery improves performance



4 Regenerator (R) receives turbine exhaust gas on one side to heat pressurized air from compressor. Hotter air entering combustor needs less fuel to reach maximum temperature before entering turbine

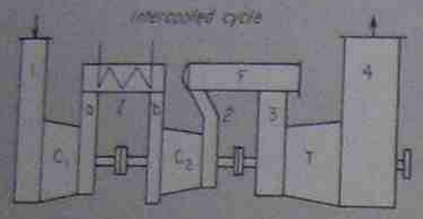


5 In ideal cycle regenerator heats air from T_2 to $T_{2'}$; then fuel heats it up to T_3

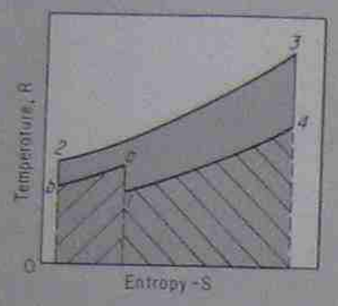


6 Thermal efficiency drops if pressure exceeds optimum for regenerative cycle

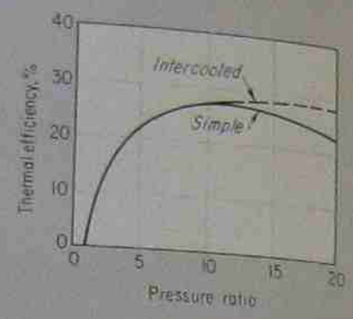
Intercooling ups output by reducing compressor work



7 Separating the compression into two processes with an intercooler in between reduces shaft input to compressor. This increases portion of shaft work developed and available for net cycle output



8 T-S chart shows intercooling tends to lower the average exhaust temperature



9 Intercooling only has marked effect on thermal efficiency at the higher ratios

heat to the air before exhaust wastes to the atmosphere. Average temperature of heat addition to the cycle (shaded area under a-3) then rises and average temperature of heat rejection (hatched area under b-1) falls. Net area, 1-2-3-4, still measures net work output. Compared to Fig. 2 there is a marked improvement in efficiency.

Fig. 6 gives thermal efficiency of practical cycles at various pressure ratios when $T_3 = 1500$ F, $T_1 = 60$ F, machine efficiency = 85% (for compressor and turbine) and regenerator effectiveness is 70%. The latter means the regenerator raises air temperature through 70% of the maximum theoretical range for the particular cycle.

Regenerative cycles have higher efficiency at lower pressure-ratio than the simple cycle. But if pressure ratio is carried too high the regenerator will cool compressed air entering the combustor instead of heating it and the regenerative cycle becomes less efficient.

Intercooling. Fig. 7, 8, and 9, offers the advantage of reduced air flow through the cycle for a given capacity with less compressor work input needed. Physical size and cost of basic equipment is smaller, although this is partly offset by extra investment for the intercooler.

Reheating, Fig. 10 and 11, raises average temperature of heat addition so that we can get more capacity or higher efficiency from the cycle. Use of high-pressure ratios is critically important since reheating at lower pressure-ratios actually lowers thermal efficiency, Fig. 12. Reheating, like intercooling, reduces air flow through the cycle so that less compressor shaft input is needed. This reduces size of some equipment elements at the cost of an extra combustor and a more complicated turbine.

Compound cycle. Fig. 13, achieves maximum efficiency. Physical size of the plant is larger than for the simple cycle, Fig. 1, because of the added elements. But when fuel costs are high it may pay to use all these cycle improvement schemes.

T-S chart, Fig. 14, is more complicated because of the added number of processes. Shaded area under c-3-d-e measures fuel-energy input. Hatched area under a-b measures heat rejected in intercooler and under f-1, the heat rejected in the regenerator exhaust gas.

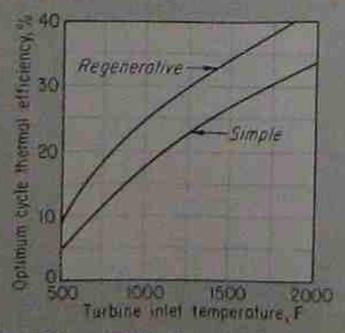
Thermal efficiency of simple, regenerative and compound cycles are compared in Fig. 15 for a wide range of pressure ratios. This is based on an actual cycle with $T_3 = 1500$ F, $T_1 = 60$ F, machine efficiency 85% and regenerator effectiveness 70%. As before, the regenerative cycle has much better thermal efficiency than the simple cycle at lower pressure ratios. But the compound cycle performs much better than either of these at all pressure ratios. In addition, intercooling and reheating reduce air flow and shaft work output to compressors.

Where more than one turbine and compressor are used,

Turbine inlet temperature and pressure ratio affect performance level

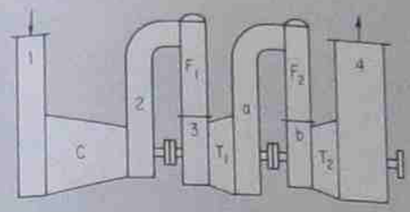
Graphs at right review some major variables affecting gas-turbine performance. In ideal cycles thermal efficiency depends only on pressure ratio. But in actual cycles turbine inlet temperature, Fig. 16, is important. This chart is based on 60 F outside air, 85% machine efficiency and 70% regenerator effectiveness. Fig. 17 shows how cycle efficiency varies with regenerator effectiveness when $T_1 = 60$ F, $T_3 = 1500$ F and machine efficiency = 90%. Best efficiency is developed at lower pressure ratios.

Inlet air temperature to compressor also has a marked effect on efficiency. Fig. 18 and 19 are based on 1500 F turbine inlet, 85% machine efficiency, and 70% regenerator effectiveness. Compression efficiency is assumed constant for all inlet temperatures. Since compressors fall off in efficiency when not running at design conditions, actual variations are not as great as shown.

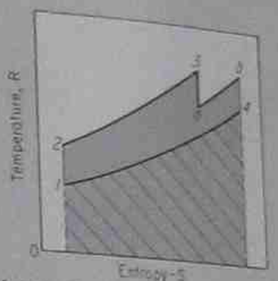


16 Efficiency of simple and regenerative cycles rise with inlet temperature

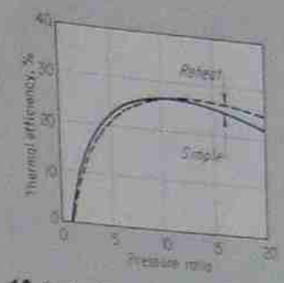
Reheating combustor improves performance or boosts capacity



10 Heated gas from combustor F_1 is expanded in turbine T_1 to an intermediate pressure above atmospheric. Then it's reheated in combustor F_2; expanded in turbine T_2. Both drive the same shaft

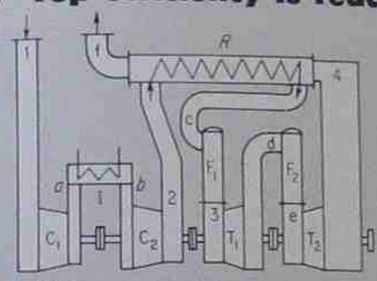


11 Reheating after partial expansion ups average temperature of heat added

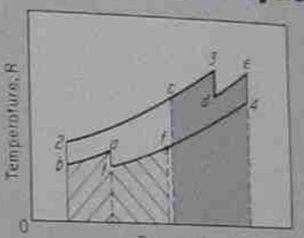


12 Compared to simple cycle, reheating lifts efficiency only at the higher ratios

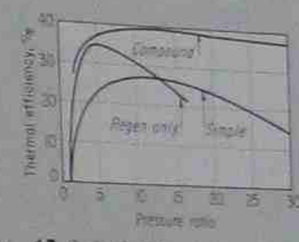
Top efficiency is reached by using all cycle improvements



13 Compound cycle has regenerator, intercooled compressor, 2-stage heating



14 Loop 1-b-2-c-3-d-e-4-f on T-S chart measures net mechanical work output



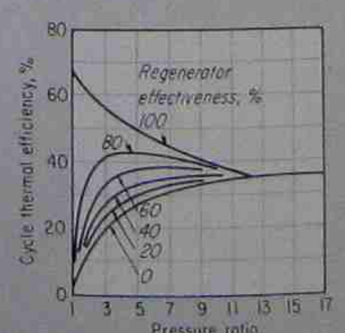
15 Combined cycle outperforms simple and regenerative cycles at all ratios

they are often grouped on two or more shafts for better part-load efficiency and more flexible control. Several stages of intercooling and reheating are apt to be found only in large high-load-factor plants.

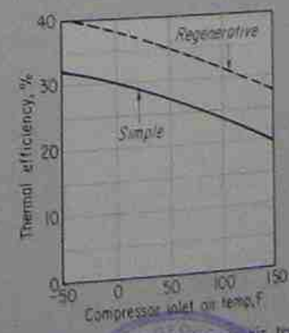
Turbine temperature (below) is a major factor in plant performance. Fig. 16 helps explain the persistent drive to develop materials that can withstand high-temperatures. In Fig. 17, as regenerator effectiveness increases, best efficiency occurs at even lower pressure ratios. Curves all converge at a pressure ratio of about 12—maximum at which a regenerator can be used for performance gain. At higher pressure ratios, compressed-air temperature exceeds that of turbine exhaust so a regenerator would actually cool the air.

Compressor inlet air temperature, although assumed constant so far, does influence plant efficiency and capacity. Fig. 18 and 19 show that the turbine performs more economically in winter than in summer.

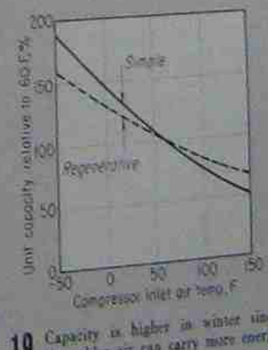
Sometimes it may even pay to cool air entering the gas-turbine compressor. Plant capacity is also higher in cold weather since denser air can carry a higher energy load and develop more output.



17 Regenerator effectiveness curves cross 0% (simple cycle) line at ratio of 12

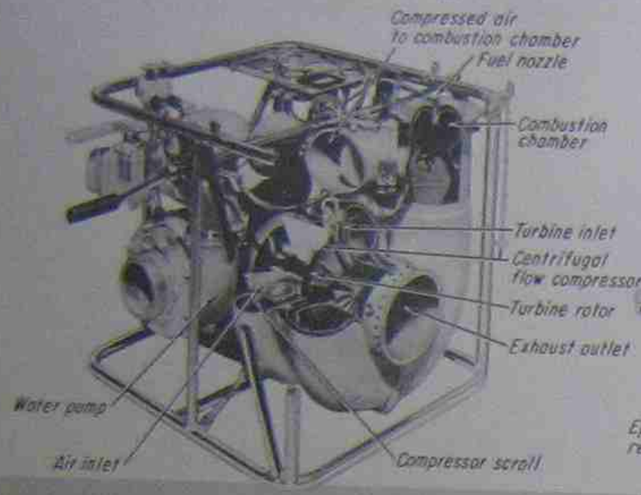


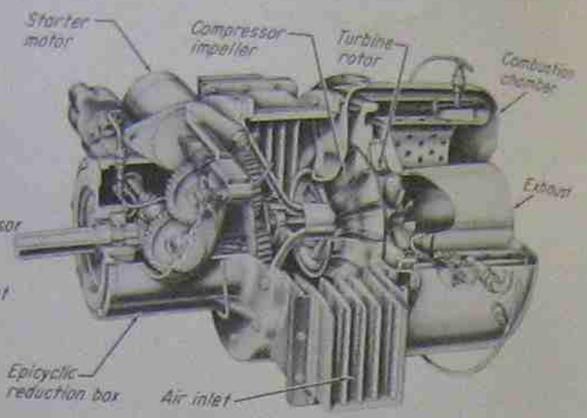
18 Thermal efficiency rises as air temperature entering compressor drops



19 Capacity is higher in winter since the colder air can carry more energy

For shaft power of almost any capacity . . .





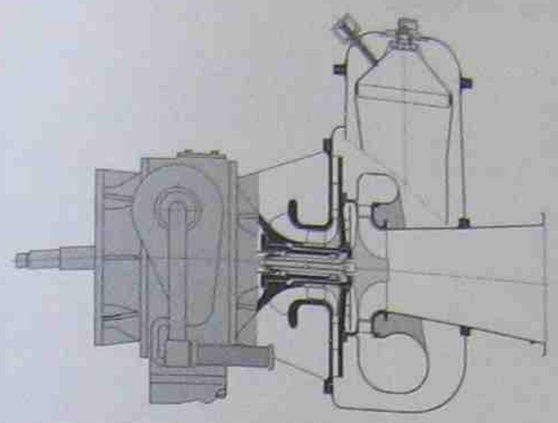
Small, portable simple-cycle gas turbine drives a water pump

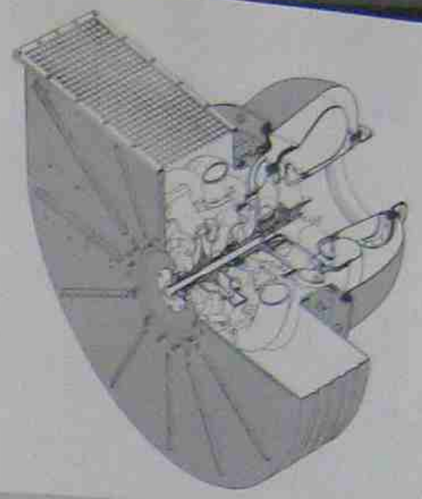
This 50-hp gas turbine uses a centrifugal compressor driven by a radial-inflow single-stage turbine at 38,250 rpm. The centrifugal pump is driven through a gear at 4428 rpm. The combustor burning a distillate oil supplies the turbine with power gas at maximum of 1300 F; turbine exhaust reaches maximum of 1050 F. This unit can be started by two-man hand cranking through a step-up gear set.

Compact unit features annular reverse-flow combustion-chamber

Gas turbine's continuous rating is 70 brake hp with an intermittent rating of 90 bhp. Single-stage centrifugal compressor develops up to 3.1 pressure ratio. Single-stage radial in-flow turbine drives compressor at 41,000 rpm. As an option compressor inlet may be fitted with venturi-type silencers, shown above. Maximum rating uses inlet gas temperature over 1500 F, but lower temperature lengthens operating life.

. . . there's a gas turbine





Portable turbine employs single vertical combustion-chamber

Like most small-capacity gas turbines this one also uses centrifugal compressor and radial-inflow turbine on a common shaft. A 90-hp unit, it develops a 2.7 pressure ratio at 50,000 rpm shaft speed. Gear box drops output shaft speed to 4300 rpm. Unit may be hand started by crank, or motor started where power is available. Weight is 139 lb without fuel tanks making this unit easy to move.

Two-stage compressor unit produces shaft power and air

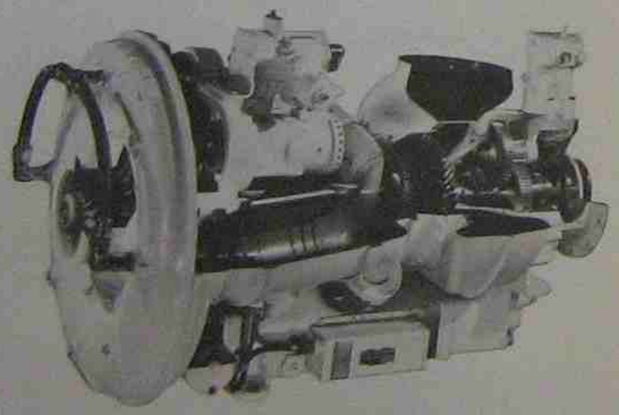
Gas turbine's double-entry first-stage compressor feeds its discharge to a single-entry second-stage centrifugal compressor. The pressurized air at 4.02 pressure ratio flows to a single combustion chamber (not shown) mounted above turbine inlet volute. Design can deliver 315 bhp and zero air flow or 134 lb per min pressurized air and zero bhp, or any combination of these two types of energy output.

Applications, sizes span wide range

Gas turbines have found a place in every field requiring shaft-power and heat, separately or in combination. We use them to run aircraft, marine vessels, automotive road vehicles, locomotives, road-building equipment, etc. In the energy systems area, gas turbines power compressors, pumps, fans and electric generators. Their exhaust heat is used for steam generation, process energy, drying, space heating and air conditioning. Combined with steam turbines, they form electric generating plants that work at higher efficiencies than either one alone. The following pages (S · 6 through S · 10) present a cross section of current gas-turbine equipment and typical applications.

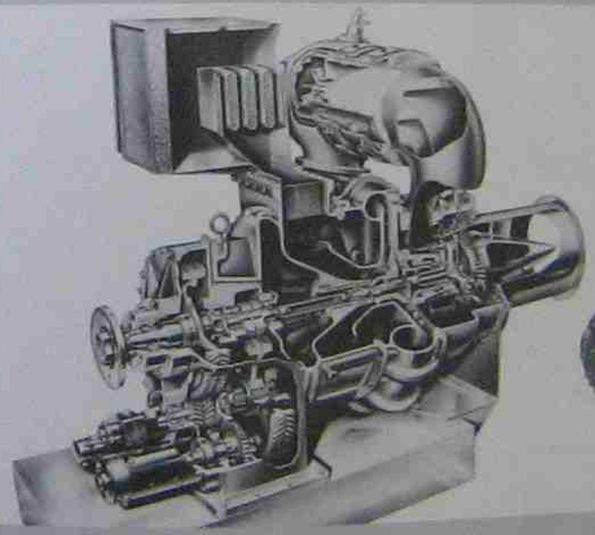
Natural gas, distillate oils and residual oils fuel most turbines. Some burn a treated residual oil processed in the plant. Coal and nuclear fission are being used as heat sources on an experimental basis.

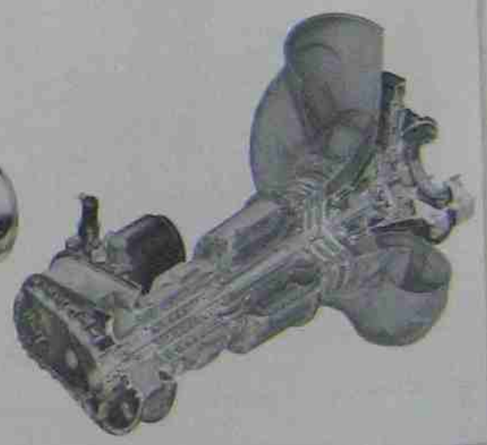
In size, turbines range from 25 hp to over 100 mw, with promise of larger future units. This equipment may be: (1) permanently installed (2) packaged for fast installation with infrequent later moves and (3) truck mounted for fast handling of emergencies.



Free-turbine unit's horizontal combustors work in parallel

Continuous rating of this gas turbine plant is 200 bhp when burning natural gas in the two combustors. Centrifugal compressor (above) is driven by single-stage axial-flow h-p turbine to develop 4.45 pressure ratio. H-p turbine exhaust flows directly to in-line single-stage axial-flow l-p free power turbine. This allows compressor to run at varying speeds with changing shaft output and gives better part-load thermal efficiency. The 26,000-rpm output shaft speed can be geared down as needed. Unit has 290-hr [illegible] rating.





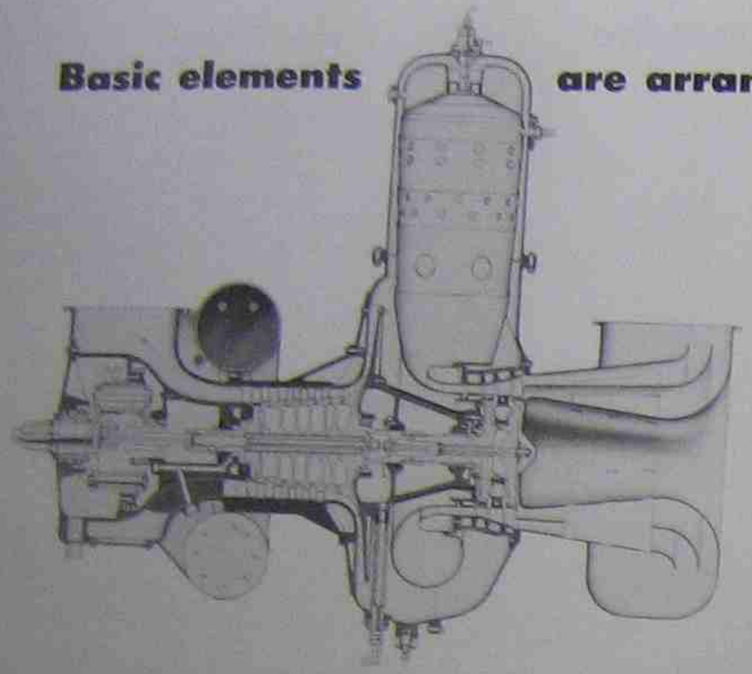
Two-stage axial-flow turbine drives single-stage compressor

Two-stage axial-flow turbine in this design drives the single-stage centrifugal compressor at 29,000 rpm to develop a pressure ratio of 3.5 at combustor inlet. At full load the combustor supplies 1470 F gas to the turbine's first stage. Air bled from the compressor outlet cools the turbine disks and blade roots. This plant develops 220 hp at 80 F and 30 in. Hg abs inlet air conditions. Like all the units on this page, the rotor turns in antifriction ball and roller bearings using liquid oil lubrication, helping to cool shaft. High main-shaft speed can be geared down to any speed needed by load.

Single-shaft design has axial-flow compressor and turbine

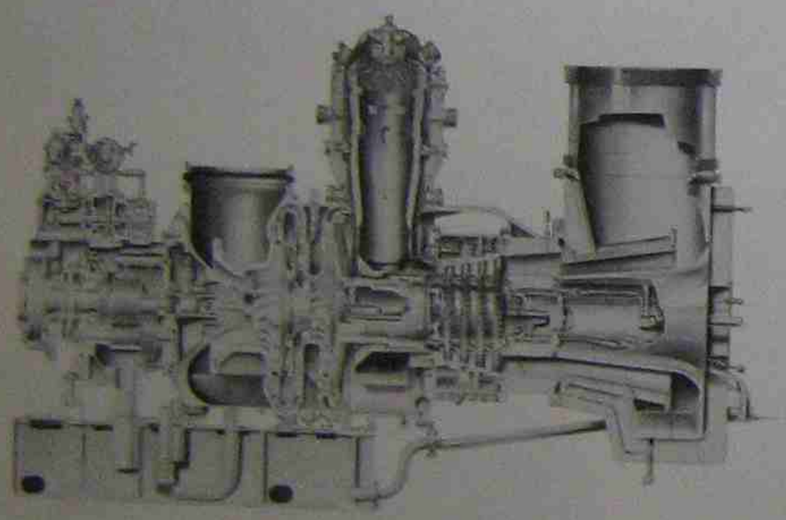
A three-stage axial-flow turbine drives the 8-stage axial-flow compressor at 22,000 rpm. Axial compressor operating efficiency is 86% with turbine inlet temperature at 1450 F for a full-load rating of 1100 hp. Thermal efficiency at this point is 22%. The annular combustor in this design can burn distillate oils or natural gas. Weight of the unit is less than 1.1 lb per hp. Like all small plants it can be started in seconds and fully loaded immediately. This unit is also built in a free power-turbine version giving better thermal efficiency at partial load operation of the plant.

Basic elements are arranged to match the operating conditions



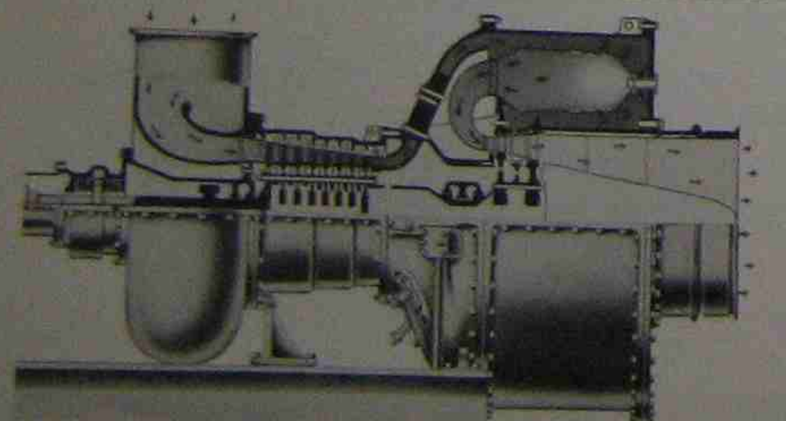
Single-shaft design uses combination compressor

This 600-bhp plant has five axial compressor stages and one centrifugal stage. Axial stages develop a 2.45 pressure ratio and the centrifugal 1.95 for an overall 4.78. Efficiencies of different plant elements are: compressor 80%, turbine 87%, combustor 98%. Turbine inlet temperature is held at 1427 F and shaft speed at 22,000 rpm. About 4% of the pressurized air is bled to cool turbine parts. Design thermal efficiency for 59 F and 14.7 psia inlet air is figured at 15.8% overall. Single combustion chamber uses the reverse-flow principle. The flame tube expands at its lower end into the neck of the turbine entry volute; cooling air flows through joints.



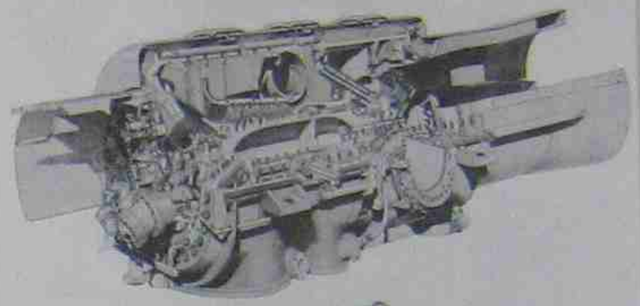
Axial-flow turbine drives centrifugal compressor

Here we have a four-stage axial-flow turbine driving a two-stage centrifugal compressor to develop a 6.5 pressure ratio. Net output of the plant is 1060 bhp at a shaft speed of 13,000 rpm. All the turbine-rotor disk faces are cooled by air bled from the h-p compressor outlet. Single combustion chamber is canted from the vertical and uses the reverse flow principle. Flame-tube outlet connects directly to the turbine inlet. An auxiliary gearbox drives the lubricating oil pump, governor, tachometer and liquid-fuel pump. Two starter motors mount on the gearbox and drive the output shaft through a gear ring. Unit has 18,600-Btu-per-kwhr heat rate (HHV).



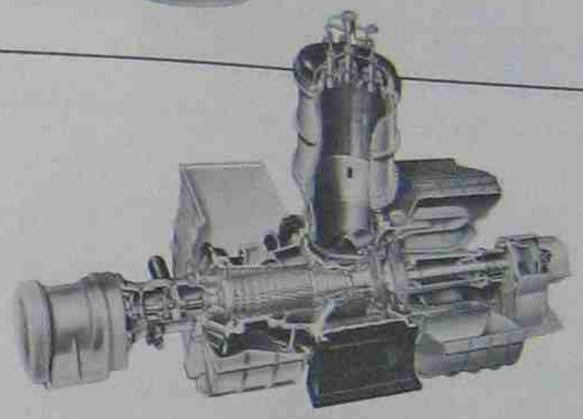
Gas turbine employs eight reverse-flow combustors

Developing net output of 1615 bhp, this unit has a two-stage axial-flow turbine driving an eight-stage axial compressor at 13,000 rpm. Eight combustor flame tubes are arranged around the main shaft in an annular combustion chamber. The unit has an overall pressure ratio of 4. Rated-load heat rate for the unit is quoted at 15,360 Btu per bhphr. Lubrication system uses an electrically-driven starting and standby pump, and an engine-drive[illegible] be pump.



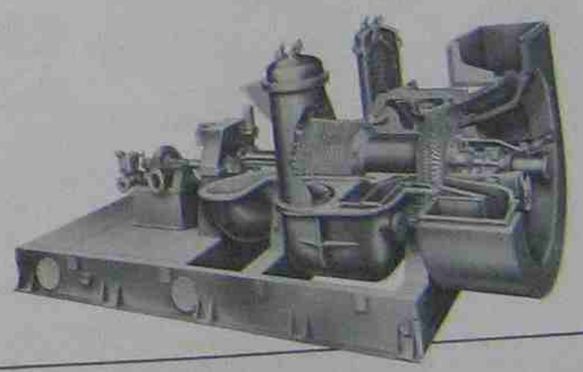
Compact design can be transported as a unit

This gas turbine develops 3200 kw at 7300 rpm with a thermal efficiency of 17.4% when burning natural gas. Two vertical combustors (not shown) fasten to the sides of the casing. Turbine inlet temperature runs about 1400 F and outlet at 840 F, with a pressure ratio of 4.3. Hydraulic motors start the unit.



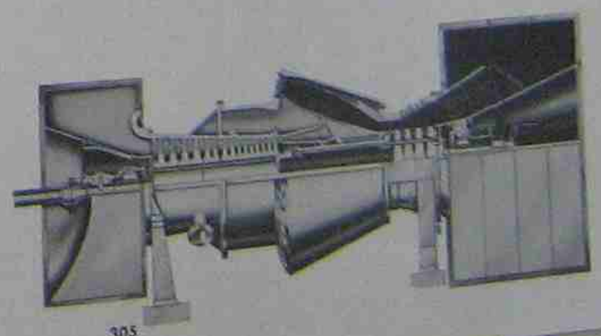
Two-shaft unit has single large combustor

Two-stage h-p turbine drives 12-stage axial-flow compressor to develop a 6.0 pressure ratio. The two-stage l-p turbine drives load at 4900 rpm to develop a net output of 8000 bhp. Plant runs at about 12,800 Btu per bhphr (HHV). Air bled from compressor cools turbine casings, rotor disks, bearing housings and packs some glands. Flyball-type governor controls fuel to single combustor.



Turbine frame size delivers 9000 to 12,000 hp

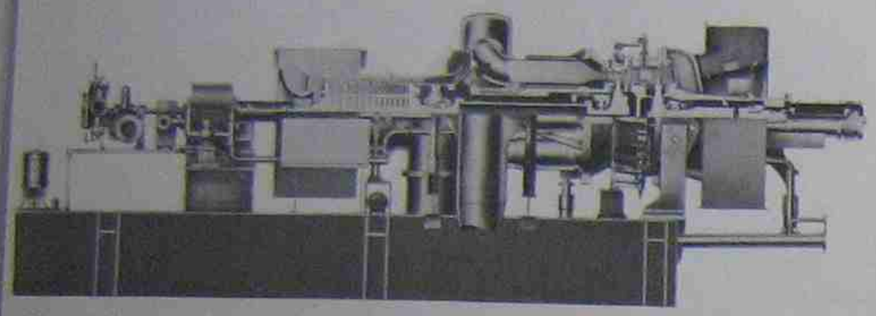
Single-shaft unit of two-bearing design delivers 12,000 bhp in largest size at rated speed of 5000 rpm. A 3-stage turbine drives 15-stage axial compressor to develop a 6.5 pressure ratio. H-p air passing through intermediate case minimizes radiation and assures low skin temperature of outer case. Bleed air cools the turbine disks and the blade roots they carry. Labyrinth seals on the shaft minimize leakage of air and gas.



Twelve combustors power large unit

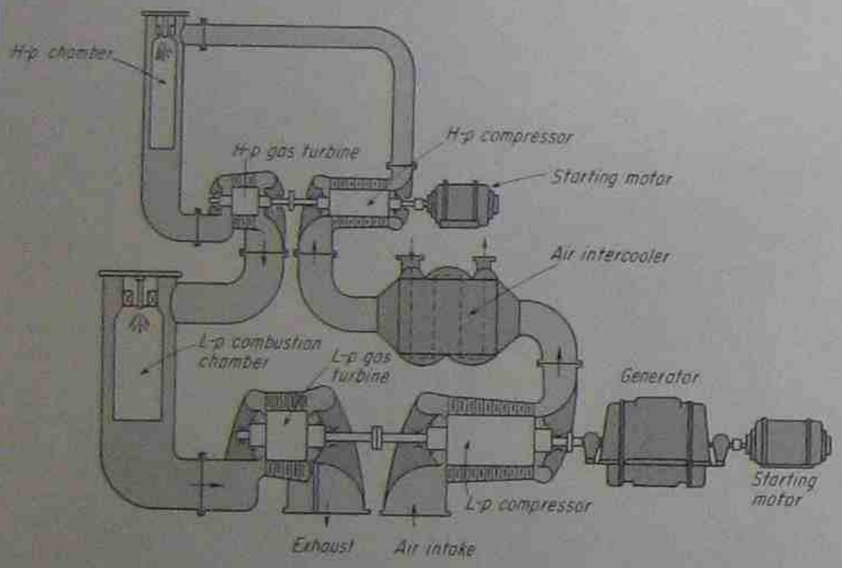
Despite its 27.5-mw base-load rating this unit is a single-shaft two-bearing design. Compressor and turbine rotors are solidly connected through a wide-diameter torque tube. At normal rating the unit develops a 6.5 pressure ratio when turning at 3600 rpm. Its heat rate runs at 13,700 Btu per kwhr (LHV). Canting of combustors shortens length of overall unit. Four-stage reaction-bladed turbine drives the 15-stage axial-flow compressor.

Larger units make economical use of complex cycles



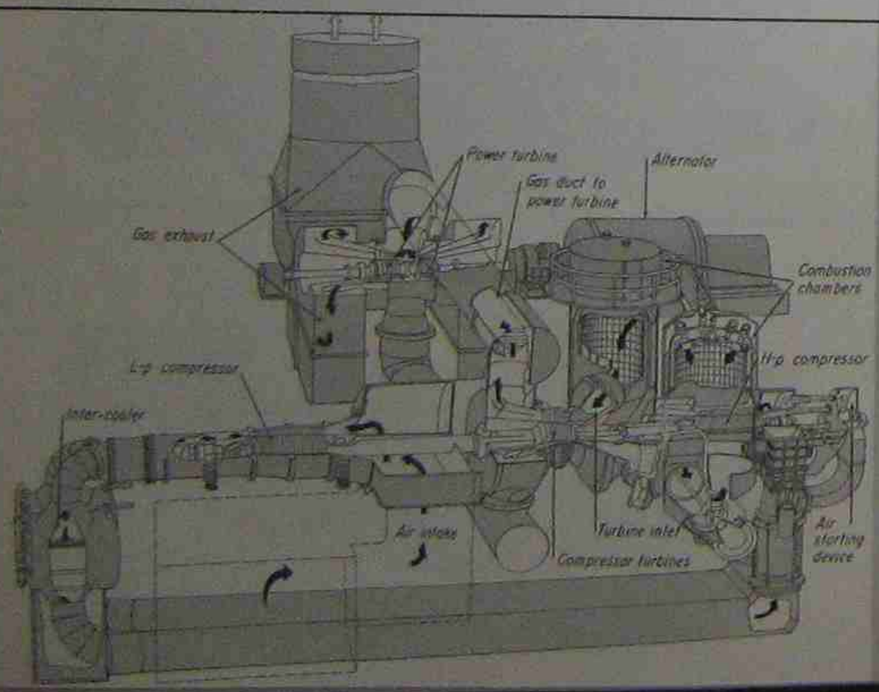
Regenerative-cycle unit has single baseplate

Two-shaft 8000-hp design has single-stage h-p turbine driving 14-stage axial-flow compressor at 7000 rpm. Single-stage l-p turbine drives the load at 5500 to 6000 rpm. Compressor exhaust goes to regenerator (not shown) then enters 6 combustors clustered around shaft. Unit heat rate is 8640 Btu per bhphr with 1550 F maximum turbine inlet temperature, 955 F outlet.



Intercooled, reheated cycle has two shafts

This peak-carrying system generates 25 mw at 25-F air inlet. When ambient rises to 70 F, capacity drops to 21.6 mw. Maximum turbine inlet temperatures are held to 1200 F. The 7-stage l-p gas turbine drives both l-p compressor and the generator at 3600 rpm. The 5-stage h-p turbine driving only the h-p compressor varies its speed from 3600 to 4500 rpm. Combustors burn either natural gas or heavy fuel oil; overall pressure ratio of the cycle at full load is 15.5, one of the highest used. Combustion chambers stand at the side of each set in the cycle. Each shaft has its own starting motor. Unit can carry full load from cold in 20 min.



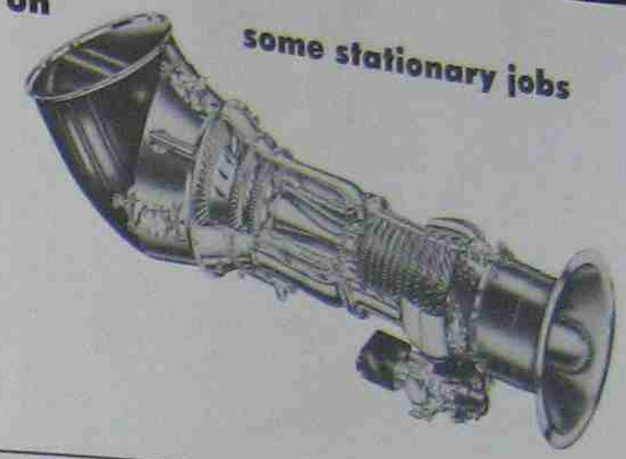
Largest operating plant carries peaks

System generates 40 mw at 41-F air inlet and turbine inlet of 1290 F. Thermal efficiency (LHV) is 26.9% and pressure ratio is 12. In this 3-shaft cycle the l-p 2-stage turbine drives the l-p compressor; the 2-stage h-p turbine drives the h-p compressor; the 2-stage double-flow power turbine drives the load. Gas circuit starts at l-p compressor inlet, partly pressurized air flows through intercooler to h-p compressor, then through paralleled vertical combustors for heating. From here, gas then flows through h-p and l-p turbines in common casing to cross over and enters power turbine before discharging to the stack. The h-p and l-p turbines are overhung from their single bearings. Unit burns residual fuel oils for on-and-off peaking.

Jet engines take on some stationary jobs

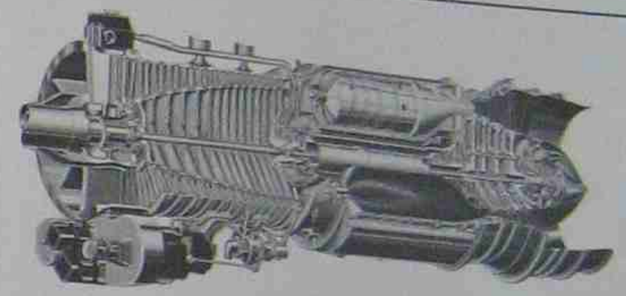
Modified jet engine produces shaft-power

Jet engine working as a gas generator has 2-stage h-p turbine driving a 10-stage axial compressor at overall compression ratio of 8. H-p turbine exhausts into single-stage l-p turbine turning at 19,500 rpm and developing full load of 1000 hp. Thermal efficiency with 1500-F in the annular combustor outlet is 21.4%.



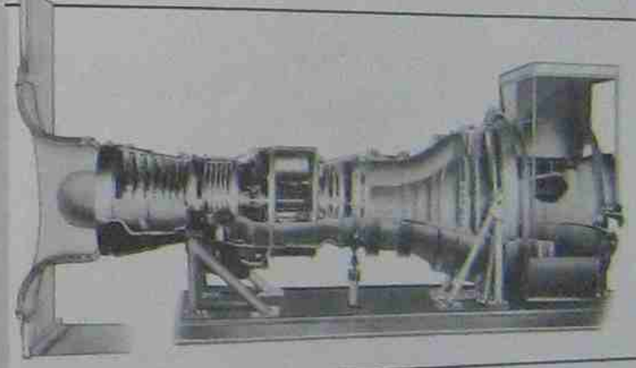
Single-shaft jet engine generates 2600 hp

Four-stage turbine drives 14-stage axial compressor and load shaft at 12,850 to 14,500 rpm to produce 2600 bhp. When air inlet is 80 F, 1000 ft elevation and turbine inlet is 1570 F the thermal efficiency is 22.5% (LHV). This unit uses 6 combustors in an annular chamber to burn distillate oils or natural gas.



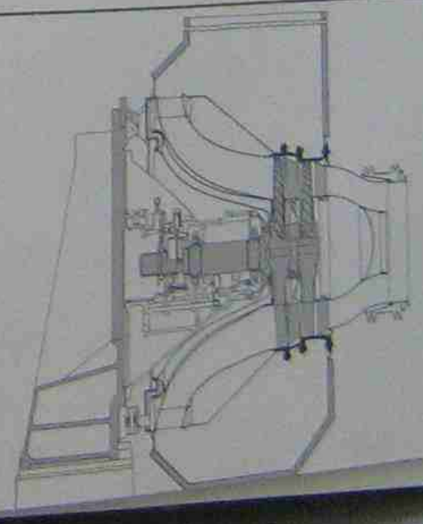
Three-shaft design gives high efficiency

Jet engine generator (left of center support) feeds 2-stage load turbine at right. In jet, 1-stage h-p turbine drives 7-stage h-p compressor and 2-stage l-p turbine drives 8-stage l-p compressor. Eight burners mount in annular chamber. Unit produces 10-mw max at 1500-F temperature, 3600-rpm shaft speed for the load.

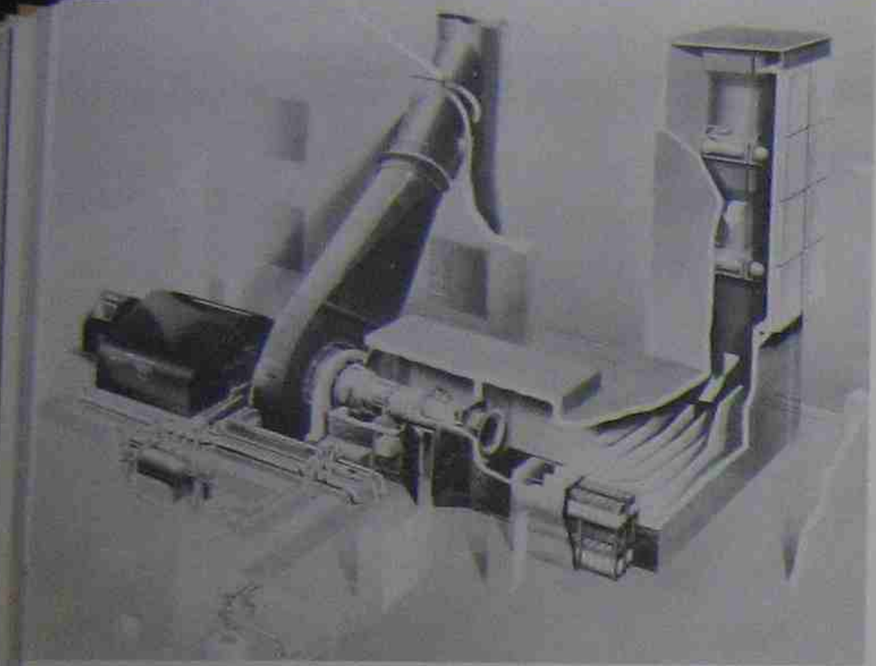


Power turbine serves jet engine generator

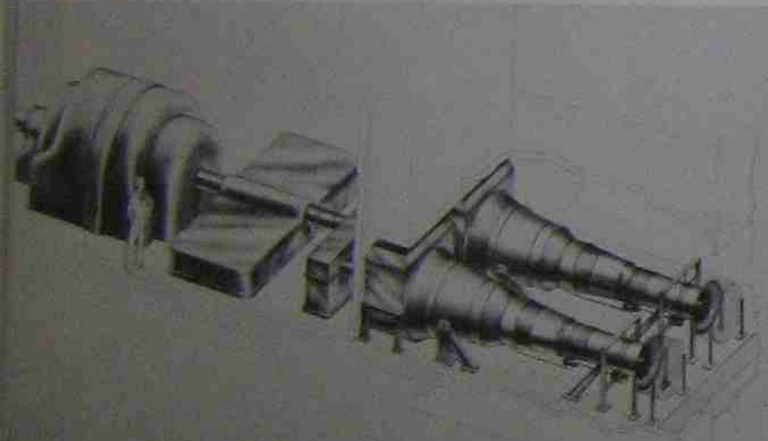
Free power turbine has been built to work with jet engine (shown above) as its power gas generator. This 2-stage turbine develops 10,500 bhp continuously when receiving power gas at 865 F. Shaft turns at 5000 rpm. Estimated thermal efficiency using LHV of distillate oil is 25%. Exhaust gas temperature is 680 F and may be used for water heating or l-p steam generation. Jet gas generator feeding this turbine can be changed out in four hours when needing repairs or general inspection.



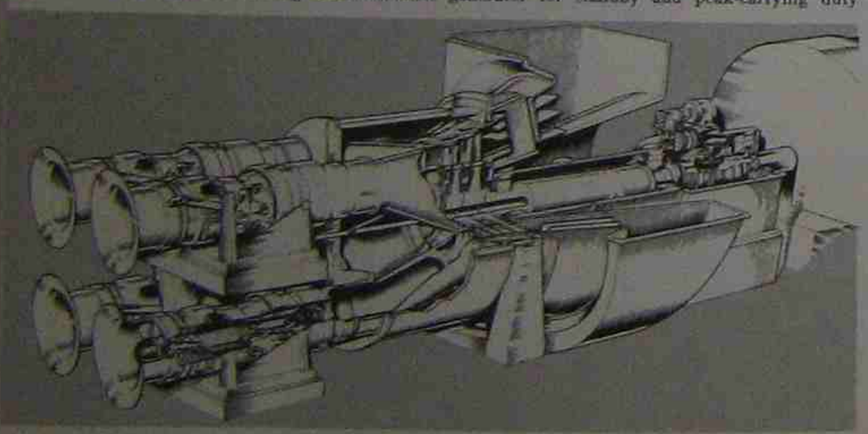
Jet-engine unit



1 Single gas generator consisting of modified aircraft jet engine drives 2-stage 17.5-mw free-turbine wheel. Jet takes in air through filter-silencer at plenum entrance



2 Two jet gas generators, each driving their own load-turbines, act on a common gear to drive an existing 20-mw electric generator for standby and peak-carrying duty



3 Four jet engines feed power gas to nozzle boxes of two-stage free turbine to drive a 55-mw electric generator. Unit can run with any number of jet gas generators

Adaptation of the aircraft jet engine to economical stationary service has been one of the most significant developments in the growth of the gas turbine. Compact design, light weight, good thermal efficiency and mass production give the jet engine some advantages as a power-gas generator.

Compact design, a major criterion for any transportation prime mover, can be used to advantage in stationary plants for any kind of service. Light weight reduces foundation needs, eases installation problems and maintenance handling. High thermal efficiency comes from the use of high-pressure ratios and turbine inlet temperatures of 1500 F and above; jets, though, are more critical about the fuel they'll burn.

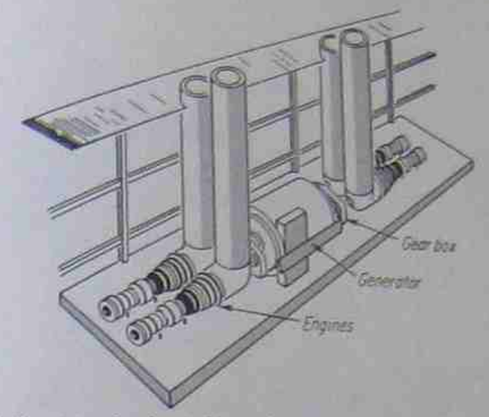
Mass production implies that they can be built for less investment and their overhaul can be done at the factory instead of the field. Also they offer the advantage of interchangeability, meaning less down time for the main prime mover and higher use factor for the overall plant.

Jet engines have been run in pipeline service with encouraging results. Normally built for many starts and stops with continuous runs of less than six hours, they have performed remarkably well in 8000-hr continuous runs with little trouble. Designers believe they will compete with heavy-duty designs in length of service life and costs. Actual use will tell.

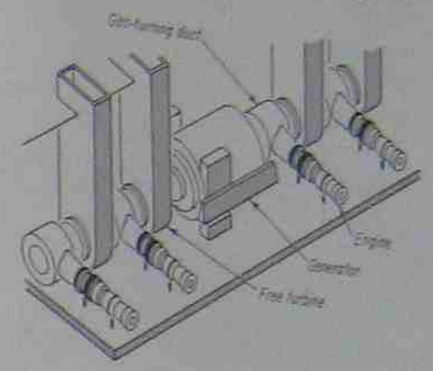
With the ability to start from cold and carry full load in less than two minutes, they make good peaking and emergency generating units. Coupled with favorable investment they offer one answer to the electric utilities' dilemma in servicing short-time annual peaks. Ability to group gas generators as in Fig. 2 to 8 makes it possible to build large peaking units, an urgent need to meet today's zooming load growth.

In the 100-mw unit being built for Cincinnati Gas & Electric Company (Fig. 8) each of the ten gas generators feeds its own nozzle box. These essentially give full-circle admission to the single-stage load-turbine buckets. The wheel is over 20 ft. in diameter and the buckets are 42-in. total length with about 22 in. being active in handling gas flow. Bucket design accounts for operation with as many as three gas generators out of service. Buckets

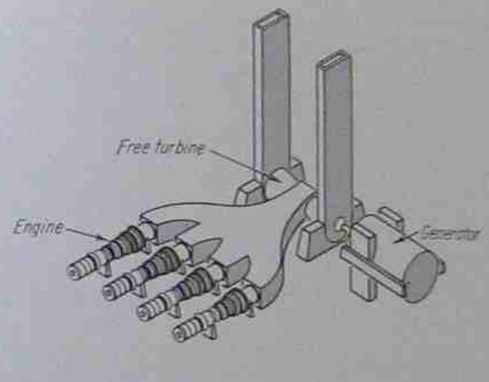
generators combined form large-capacity plants



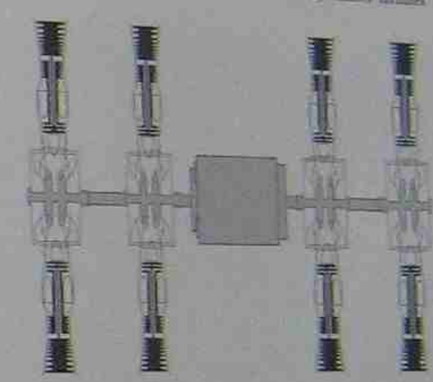
4 Four jet-engine free-turbine units can drive one 53.5-mw electric generator through gear boxes at both ends of load element



5 Another 4-turbine arrangement places free load turbines in tandem on common shaft. Unit can run with any number turbines



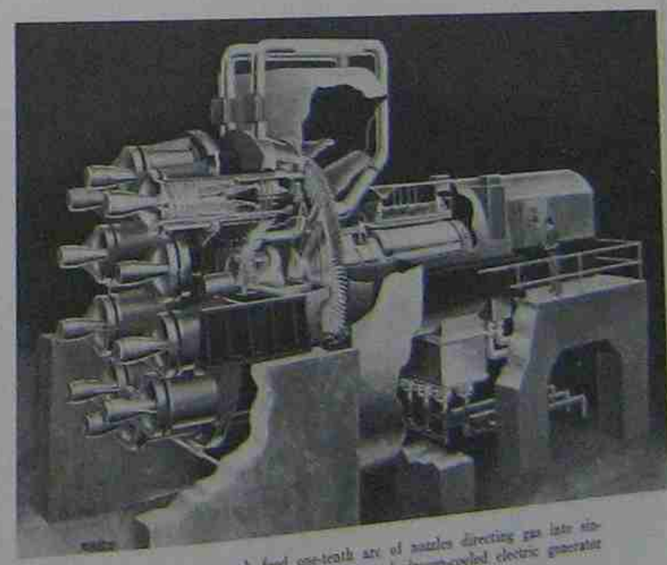
6 A possible arrangement of four gas generators would be to feed one large double-flow free turbine through common duct



7 In 111-mw unit layout, two gas generators would feed one free turbine: one the upper nozzle box, the other the lower box

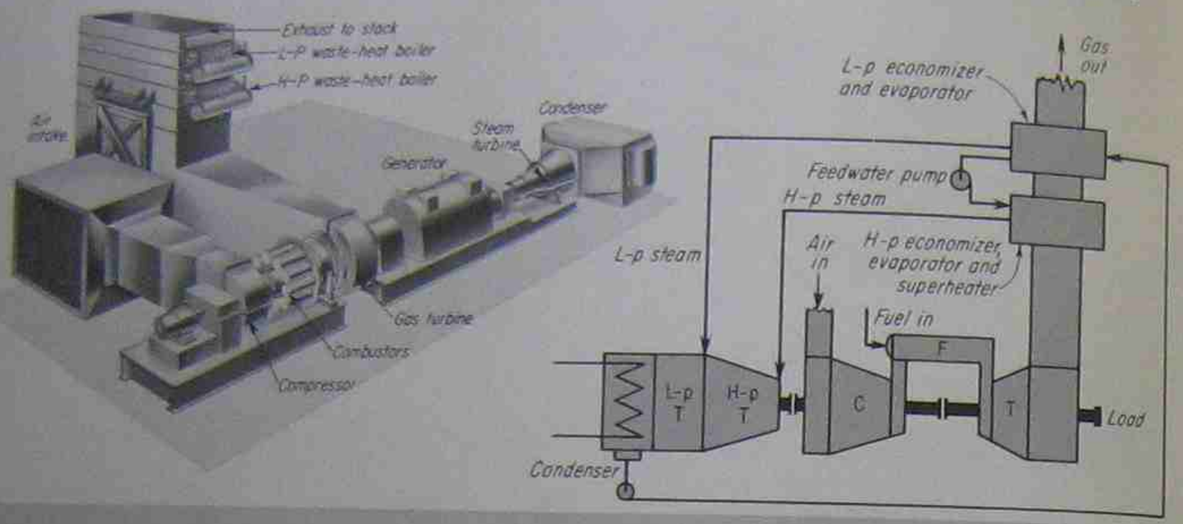
must withstand the thermal cycling of many startups and shutdowns. Full load generation from cold start will take about 20 minutes.

The hot-gas nozzle boxes and transition sections are thin walled and shaped to withstand rapid temperature transients. The individual gas generators are designed for quick removal and replacement. A spare gas generator will be supplied with this plant for increased reliability. A gas generator can be changed out in less than four hours—designers hope to reduce this to two hours eventually. Central control system runs the ten gas generators as one through common fuel valves and a common governing system for the entire plant.



8 Ten jet gas generators each feed one-tenth arc of nozzles directing gas into single-stage impulse turbine wheel driving 100-mw hydrogen-cooled electric generator

Combined cycles build on gas turbine's ability . . .

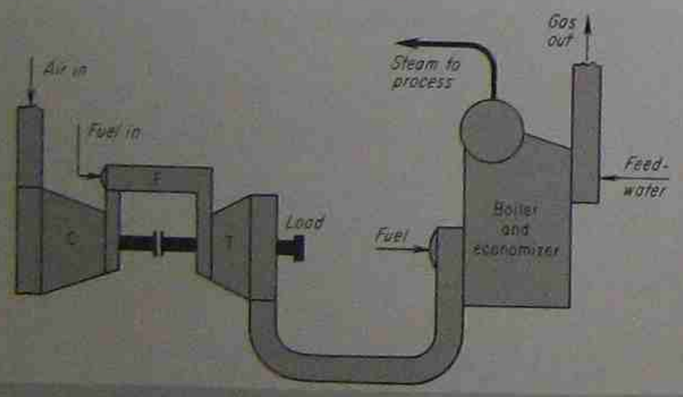


Gas-turbine steam-turbine plant offers low-cost power at medium capacity

High-temperature energy in the gas-turbine's exhaust gas offers both challenge and opportunity. Designers strive to reduce it by seeking ever higher engine efficiency in the turbine—today they have reached near the upper limit. The alternative would be to apply the abundant exhaust energy usefully.

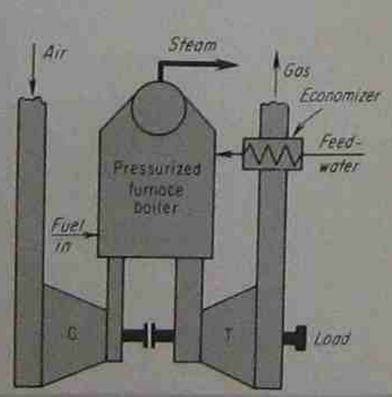
The plant above does this by passing exhaust through two exhaust-heat boilers in series. The first produces superheated steam 400 psia, the second saturated steam at 104 psia. The h-p steam enters the inlet valve of a mixed-pressure steam turbine mounted on the same shaft with the gas turbine and compressor. The l-p steam enters the steam turbine at an intermediate stage. Both steam flows pass through the turbine to the main condenser.

In this plant both the steam turbine and the gas-turbine element drive the compressor (as an integral part of the cycle) and the generator as the useful load. A feedpump returns the condensate to the l-p waste heat boiler drum. This forced-circulation heat exchanger with horizontal extended-surface tubes produces the l-p steam. A second feedwater booster pump draws water from the l-p boiler drum to pass it to the h-p boiler drum, also a forced-circulation heat exchanger. This generates the h-p superheated steam. The builder offers this 20-mw plant at an installed cost equalling the better steam turbine cycle for this capacity range. Performance when burning gas is predicted at 10,000 Btu per kwhr based on HHV. Steam turbine produces about 42% of plant capacity.



Supplementary firing gives added flexibility

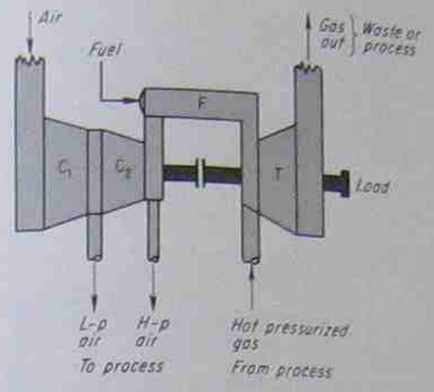
Turbine exhaust gas usually has an oxygen content of about 17% because of the high excess air needed to cool combustion gases entering the turbine. In addition to recovering internal energy of exhaust in a heat-recovery boiler, we can use this gas as a highly preheated air for a boiler furnace. By injecting fuel with the air, variable amounts of steam can be generated. This can be used for economical process or space heating, or to power a conventional steam turbine or engine to generate additional shaft output.

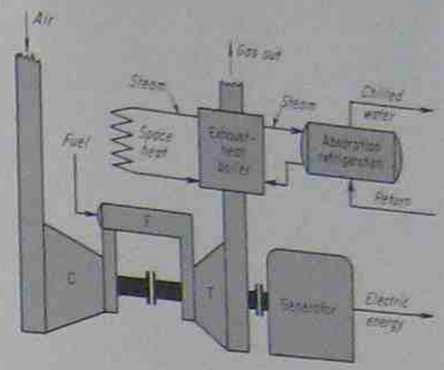


Pressurized furnace cuts boiler size

Improved compressor and turbine efficiency makes it possible to have supercharging gas-turbine set for the boiler furnace produce shaft power output as well as pressurized air. Compact boilers result from smaller air specific volume and higher heat-transfer rate. Economizer recovers heat in exhaust. This was earliest application of gas turbines to power generation technology.

. . . to produce shaft power or heat from many fuels





Complex process needs are served

Gas turbines reach their peak of versatility when made a part of complex processes. In addition to generating shaft power they can produce several levels of pressurized air with an oversized compressor. When the process produces pressurized hot gases, the turbine can use these as power gas, the combustor supplying supplementary power gas as needed by the shaft load. The exhaust can supply heat for steam raising, or be used directly in drying processes. Ultimately the exhaust will be wasted to atmosphere especially if temperature is too low. In some processes the turbine may be used without a compressor or combustor, being driven entirely by hot, pressurized process gas; in this situation the turbine is called an expander though turbine principles govern design.

Interest mounts in on-site generation

The high exhaust energy of gas turbines is used to advantage in supplying multiple services in a variety of public, commercial and industrial establishments. The energy generates steam at a convenient pressure. This may be done in a simple exhaust-heat boiler, or in a supplementary-fired boiler, depending on energy balance between service demands at each particular plant location.

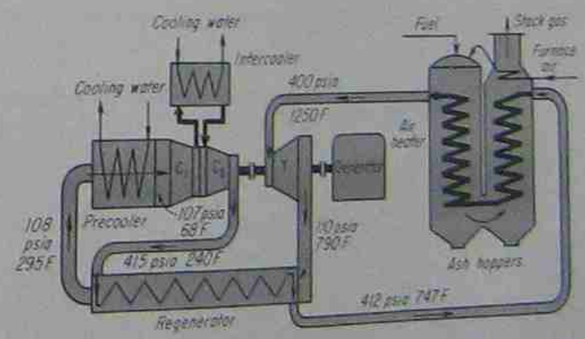
The shaft power produces electric energy. The steam supplies space heating, hot water and an absorption refrigerating system. The latter produces chilled water for air conditioning, and storage refrigeration. The electric energy supplies lighting and motors for driving elevators, escalators, fans and auxiliaries for the heating, boiler, and refrigerating systems of the building. Standby unit gives load protection.

Closed cycle gas turbines are smaller in size

By connecting the exhaust of an open-cycle gas turbine to the compressor inlet we form a closed cycle. But we still have to get rid of the unusable energy leaving the turbine, so we put a heat exchanger called a *precooler* in the line between turbine and compressor inlet.

In addition we replace the combustor with a surface heat exchanger, similar to a boiler, passing cycle working air through the tubes. Air flowing through tubes of the *air heater* can then be heated by burning any fuel in the furnace.

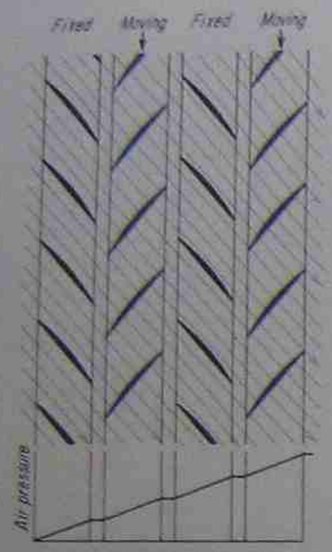
Now we are at liberty to pump up cycle air to any desired level in the precooler. This will be the lowest pressure in the system (107 psia in the cycle above). Then for a pressure ratio of 3.88, air pressure out of the h-p compressor will be 415 psia. From here pressure drops as air flows through regenerator, air heater, turbine and



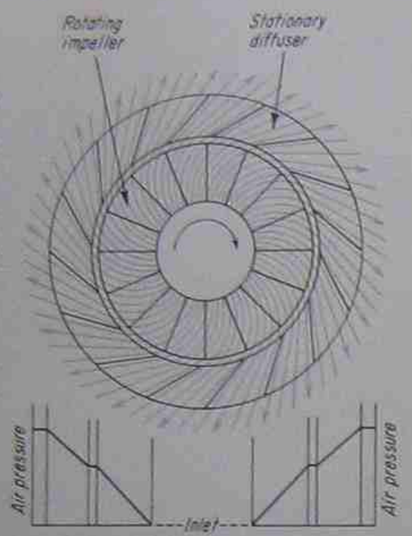
back to precooler, to be continuously circulated through the plant components and piping.

Using higher pressure air means that all components of the cycle need smaller cross-sectional passages. So the size of compressor, intercooler, regenerator and turbine are smaller. But the air heater will be larger than a conventional combustor. In addition, the precooler adds bulk to the system. Big advantage of this approach lies in the ability to use any fuel as a heat source, including uranium in atomic fission. About eight of these plants run outside of the U.S.

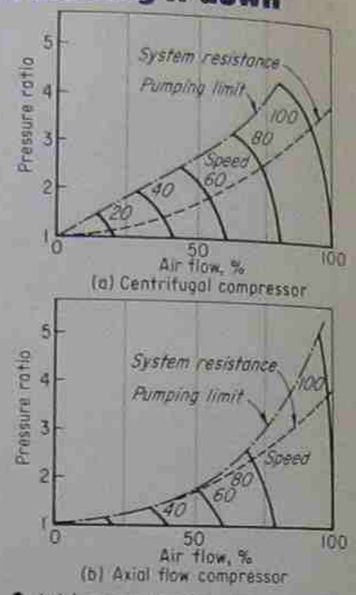
Air is pressurized by first speeding it up, then slowing it down



1 Air speeds up in moving blading and slows in fixed blading by diffusion



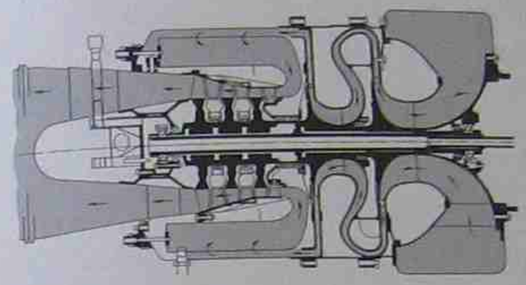
2 Centrifugal impeller speeds up the air flow, diffuser pressurizes by slowing it



3 Axial compressors have lower pumping or surge limits than centrifugal units



4 Axial compressor rotor carries 8 stages of air-foil shaped blades to accelerate air flowing into similar fixed blades



5 Small gas-turbine unit uses two stages of centrifugal compression to pressurize air before forcing into annular combustor

Combination impellers are used



6 Medium-sized high-speed compressor has first stage of axial compression followed by second and final stage of centrifugal

COMPRESSORS put air in working trim

Efficient compression of large-volume flow of air is the key to a successful gas-turbine cycle. This has been achieved in two types of compressors, the axial-flow (Fig. 1 and 4) and the centrifugal (Fig. 2 and 5).

In the axial-flow unit, blades on the rotor (Fig. 1) have air-foil shapes similar to those on aircraft propellers. These "bite" into the air flow, speed it up and push it into the following stationary-blade passages. These are shaped to form diffusers that slow up the incoming air to make it compress and pressurize itself by "catching up with the air ahead of it" in smooth fashion.

In passing through both moving and stationary blade passages direction of air flow changes slightly. As a whole the air follows a helical path through the compressor passages. Blades of the axial compressor (Fig. 4) are twisted to accommodate the vortex-flow pattern of the air (higher circumferential velocity nearer the inner edge of the annular passage), and different speeds of blade sections.

Blade shapes must be precise and clean to achieve compression efficiencies in the high 80's to low 90's. Surface fouling quickly tears down high performance.

Each stage has a compression ratio of about 1.125, so 16 stages must be used to develop an overall pressure ratio of about $6.6 = 1.125^{16}$. Blade heights shrinks as air flows through the compressor because of diminishing specific volume of the air at higher pressures.

Centrifugal compressors (Fig. 2) take in air at the center of the bladed impeller. Centrifugal force of the blades acting on the air forces it out radially at high speed into the stationary diffuser. Here the slowing action pressurizes the air. Rotor blades and diffuser passages have varying shapes depending on the pressure characteristic the designer wants with changing rotor speed.

Both types of compressors have pumping limits (Fig. 3). When air flow drops below this limit at any rotor speed, the flow becomes unstable because of secondary circulation created in the blade passages. This causes the flow as a whole to pulse and may damage the blading. Axials are more liable to surge at low flows, so they are often bled at an intermediate stage during starting to induce a higher air flow and prevent damage. The air bled from an intermediate stage is wasted to atmosphere.

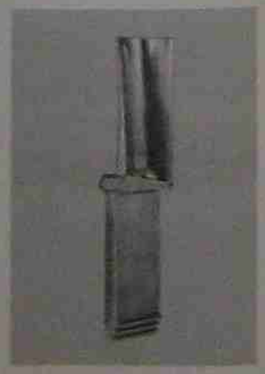
Both impulse and reaction blading produce shaft power



7 (a) For high internal-energy drop, some gas turbines use impulse nozzles and buckets. (b) Reaction-bladed turbines may have two or more stages



8 Radial inflow turbine looks like centrifugal compressor



9 Long-shank turbine bucket has [illegible]-running dovetail

TURBINES convert gas energy to shaft output

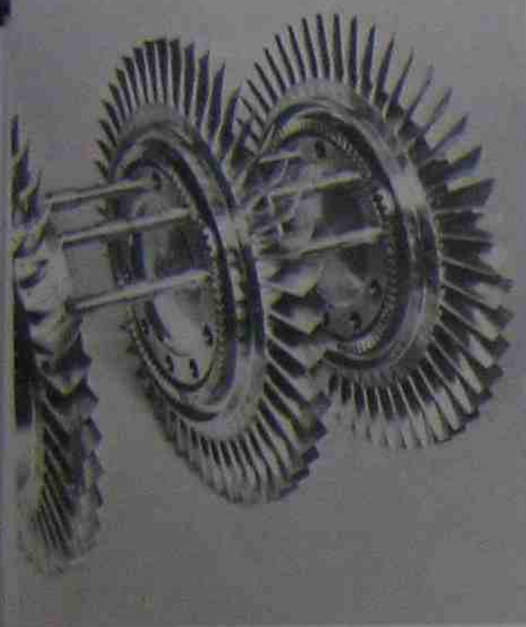
Gas turbines, like steam turbines, use familiar impulse and reaction principles (Fig. 7). Because they work with lower pressure drops they have fewer stages, and less change in blade height from inlet to exhaust.

For small capacities, radial-inflow turbines (Fig. 8) may be used. Inlet gas flows through peripheral nozzles to enter the wheel passages in an inward radial direction. The speeding gas exerts force on the wheel blades and then exhausts in an axial direction to atmosphere. These wheels are well suited for lower range of specific speeds and work at relatively high efficiency.

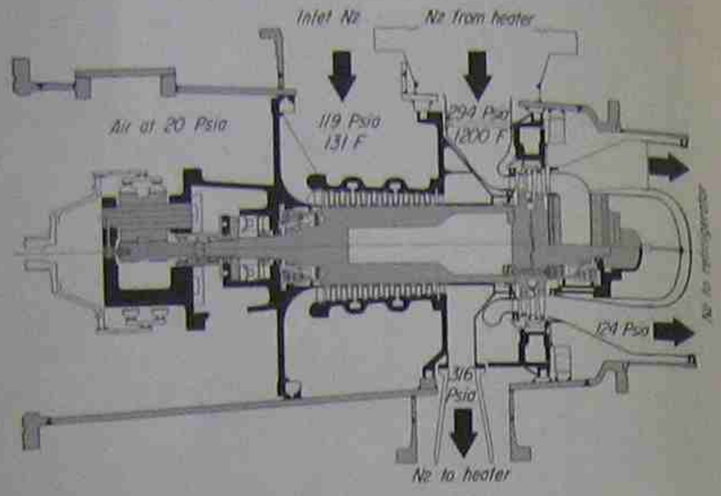
For best performance the gas turbine must work with high inlet-gas temperatures. This poses severe materials problems that must be overcome by ingenious design. One approach is to cool the parts subjected to highest temperatures and highest stresses. The most critical are the first stage moving buckets and the disks carrying them. Fig. 12 shows one design where air bled from the compressor outlet is led over disk surfaces and blade roots to give film cooling, protecting the metal from the main gas flow temperature which could severely damage the rotor.

Fig. 9 shows an impulse bucket with a long shank between the base of the active blade section and the fir-tree root fastening to the disk edge. This design creates resistance to thermal flow from bucket to root, so the latter's temperature is over 500 F cooler than that

High temperatures pose problems



10 Individual disk construction avoids problem of making one large high-alloy steel forging



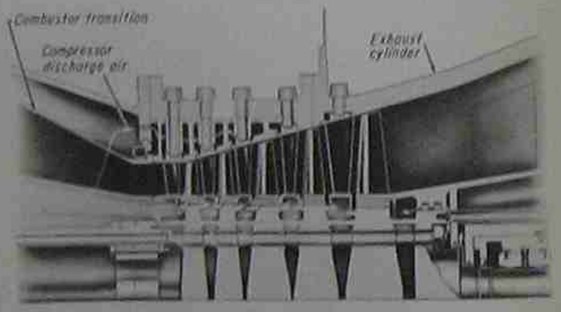
11 Turbine and compressor set for closed-cycle nuclear power plant produces over 400 kw and turns at 22,000 rpm. Nitrogen is the cycle working gas or fluid

of the gas flowing past the bucket at the working section.

Building up the turbine rotor of sections as in Fig. 10 and bolting them together makes it possible to avoid complex casting and forging problems.

Fig. 11 shows a 2-stage turbine and 11-stage axial compressor built for a closed-cycle plant fueled by an atomic gas-cooled reactor. The gas is nitrogen with ½% oxygen. This unit turns at 22,000 rpm to generate a net of about 400 kw. Special care had to be used to prevent bearing oil entering the gas circuit of the plant.

Some processing cycles yield a hot pressurized gas that can't be used at other points in the plant. Modern practice passes this gas through a turbine expander to produce shaft power for compressor or pump drive.



12 Turbine blade roots and disks are cooled by bleeding air from compressor outlet. Air flow at exhaust prevents gas leakage

COMBUSTORS power the gas-turbine cycle

Combustors burn fuel in the pressurized air after it leaves the compressor. Today's metallurgy limits the exit temperatures to about 1550 F for base loading of the turbine. Since fuels burn with a flame at about 3000 F, careful design is needed to insure complete combustion. Only about 25 to 30% of the air takes part in oxidizing the fuel. The remainder acts as a film coolant to preserve the combustor basket (Fig. 13 to 15) and as a diluent to cool the gas going to the turbine nozzles and buckets.

Combustors must be built to work with a low pressure drop of the working air, from compressor outlet to turbine inlet. This needs adequate passage flow areas and minimum number of changes in flow direction. Various arrangements of large single combustors (Fig. 14) to paralleled multiple combustors (Fig. 13, 15) are used to achieve this aim of complete combustion and pressure-loss.

Insuring continuous flame action depends largely on fuel nozzle design and proper circulation of combustion air to and through the burning zone. For turbine protection the combustion gas must be thoroughly mixed with the remaining excess air to avoid large temperature differentials across flow passages and consequent destructive thermal stresses. In multiple combustor units cross flame tubes between combustor baskets insure burning stability in the high-speed or flow.

Combustors must have igniters to start gas turbine

Combustors burn the fuel for energy input

from cold. Once stable ignition is achieved the igniters are shut off and retracted from the burner. Persistent research in combustor performance has led to improved temperature distribution in the gas flow: where older designs had variations from 1300 to 1580 F across flow passages, improved arrangements reduced this spread to the range of 1430 to 1480 F.

Fuels for combustors range from natural gas to distillate and residual oils. Coal is still the subject of experimental investigation, disposal of the ash and its effect on blading being the primary problems.

Gas turbine builders specify fuel characteristics to insure trouble-free operation. For example, solid materials in a fuel gas should not exceed 30 ppm by weight. Size and density distribution of the dust must fall within certain limits. Water in the gas above saturation should not exceed ¼% by weight.

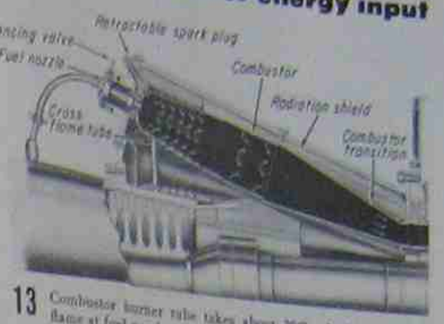
The gas should not have more than 0.1 gal liquid-equivalent of gasoline vapor in 1000 cu ft of the gas. Heating value must be in range of 300 to 5000 Btu per cu ft, and not vary by more than ± 10% from the design value. Fuel gas contaminants must be known to anticipate effects on turbine materials.

Flammability limits must be known to insure operating safety. Fuel-flow range of a gas turbine from full load to lightoff may be as high as 20:1; the range at given air flow may be 5:1. Limits of flammability of a fuel indicate how well the fuel will burn in a combustor; experience shows that the minimum ratio for many combustors is 2.2:1 to insure flame stability.

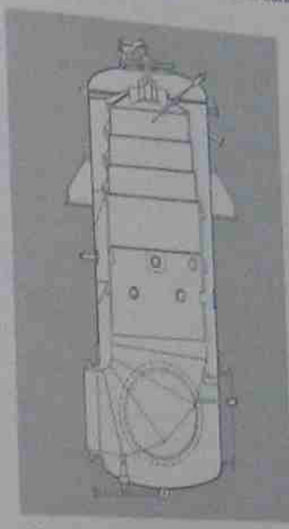
Oil specifications for gas turbines have been developed during considerable operating experience. Chemical properties of an oil become critical when turbine-inlet temperatures exceed 1150 F. Sodium, sulfur, vanadium and lead form corrosive compounds. Alkaline earths promote blade deposits in varying degrees. Ash forming substances in the oil may be adjusted to reduce corrosion and to allow deposits that will shed after a few hours shutdown of the turbine.

Specifications limit sodium content to inhibit attack by sodium sulfate and minimize deposits. Magnesium is used as an inhibitor against vanadium corrosion and to form deposits that are easier to remove.

Sodium content of an oil can be reduced by any oil desalting method such as washing, centrifuging, filtering or electrostatic precipitation. Residual oils must generally be treated by one of these methods and often pays off in low overall fuel costs for the gas turbine plant.



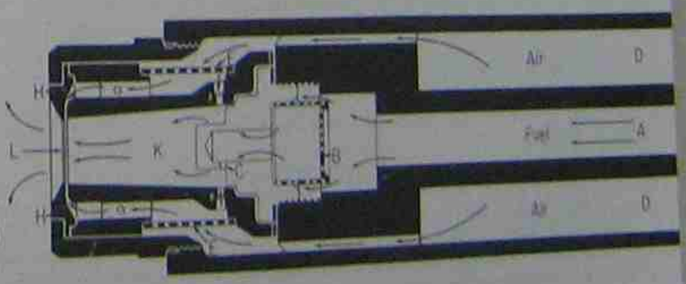
13 Combustor burner tube takes about 30% of air to support flame at fuel nozzle, rest of air cools burner and gas to turbine



14 Air enters large combustor through bottom circular opening, flows up annular space, down the central burner tube



15 Reverse-flow multiple combustor takes in air through annular space to support flame and cool burner tube and leaving gas



16 Oil-fuel nozzle gets oil through central tube, air through annular space. Passages mix oil and air in *K* with final mixing and atomization at circular slot *L*

Heat exchangers boost efficiency of gas turbine system

To produce shaft power, the gas-turbine plant needs the two rotating components, turbine and compressor, and a relatively simple container, the combustor. In its simplest form, no heat exchanger is needed, but usually a lubricating-oil cooler proves practical for reliable operation.

Regeneration. When an application demands economy, the first step is to reduce fuel consumption. The designer casts an eye on the large exhaust loss and dreams up ways to route a large part of this to the combustor, Fig. 6, the point of energy input. This is done through a regenerator—a heat exchanger that can take a variety of forms. In its simplest form it may be a shell-and-tube exchanger with the hot gas flowing through the tubes and the air through the shell. Or it may be a plate type exchanger with hot gas and pressurized air flowing oppositely in alternate passages. Either form needs an extended-surface design to achieve a practical heat-transfer flow. Fig. 3 shows the type of fins used on tubes, and Fig. 4 the fins used on plates.

Balance of fuel savings against investment in heat-transfer surface usually dictates the size and type of regenerator used in a given application. Gas passages must be designed to minimize pressure drop, yet have adequate turbulence to promote good heat-transfer rates. Materials must withstand corrosion.

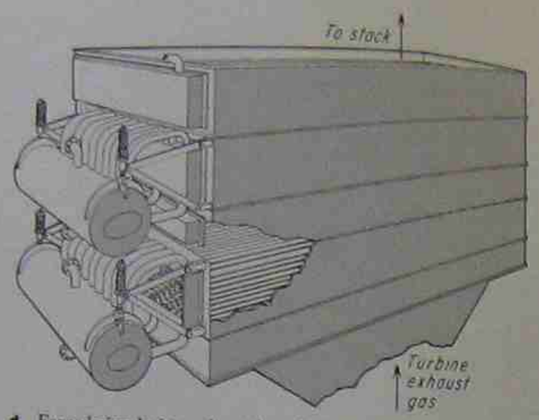
Exhaust-heat boilers offer another path to salvaging exhaust energy. Where the prime output of the gas-turbine plant is shaft power, the steam can be used to drive steam turbines, Fig. 5. Or the steam may be used for process or space heating where there is concurrent demands for both shaft power and heating service.

One plant (see top of p S·14) uses the steam from the exhaust-heat boilers to drive a steam turbine on the same shaft with the gas turbine. Fig. 1 shows the two exhaust-heat boilers used in this plant.

Each boiler is a horizontal, finned-tube heat exchanger with a drum and forced-circulation pump. The lower unit receives the turbine exhaust which flows over the finned surfaces and then through the upper unit and finally to the stack. The upper unit produces l-p saturated steam, the lower one produces h-p superheated steam.

Condensate from the steam-turbine condenser first enters the economizer section of the l-p boiler. It then flows to the drum; a forced-circulation pump passes the water through the horizontal tubes. In the drum 109-psia steam goes to the l-p section of the steam turbine. A booster boiler-feed pump picks up drum water to force it through an economizer section of the h-p boiler below. This water is then pumped through the horizontal tubes of the h-p boiler back to the drum. Steam at 413 psia separates in the drum and flows through a superheating section receiving hottest exhaust gas from the gas turbine. Superheated steam then enters the steam turbine inlet.

Boilers reclaim turbine exhaust heat



1 Forced-circulation exhaust-heat boilers in series produce steam at two pressures; h-p steam is superheated, l-p steam saturated

This heat recovery system indicates low plant investments and high thermal performance that offer advantages for power generation.

Steam generation realized from gas-turbine exhaust may be boosted by supplementary fuel firing, Fig. 2. All or part of the exhaust (with about 17% oxygen content) can be passed through burners of a fired boiler to generate and superheat steam.

If there is more exhaust gas than needed for combustion in the boiler furnace, the excess can be diverted to flow over separate convection surface and then into the gas pass of the finned-tube economizer. An auxiliary stack at the gas turbine exhaust can pass any excess gas to atmosphere that cannot be used by the boiler.

The gas turbine, in effect, supplies highly preheated, slightly pressurized air to the boiler furnace. So it would appear that no fans are needed by the boiler. But if separate operation of the boiler is anticipated when the gas turbine is shut down, a forced-draft fan must be installed. When the fan is provided, it can also be used to supercharge the gas-turbine compressor and so increase the shaft output of the gas-turbine plant.

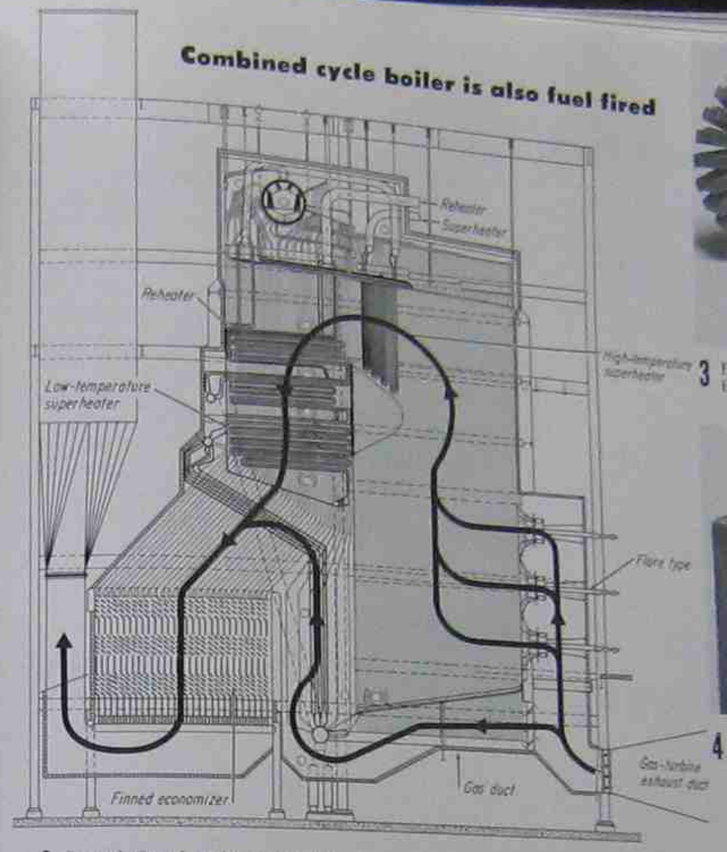
During warmup of the steam cycle there is enough energy in the exhaust gas to produce superheated steam at low load without firing any fuel.

Special consideration in design of the boiler must be given to maintaining a low draft loss. Among other factors this leads to using a finned-tube economizer in the boiler of Fig. 2. The fired boiler can produce about six times the steam that a simple unfired waste-heat boiler would generate, using the same flow of gas-turbine exhaust.

Rotary regenerators, Fig. 7, are being primarily developed for automotive gas turbines. They work like a Ljungstrom regenerative air heater, but have the added problem of handling h-p air which blows down to atmospheric pressure at the rotor seals.

Since regenerative cycles work at the lower pressure ratios, around 4, the blowdown problem is somewhat mitigated. Close packing of heat-carrying matrix also raises problems of pressure loss and possible fouling.

Combined cycle boiler is also fuel fired



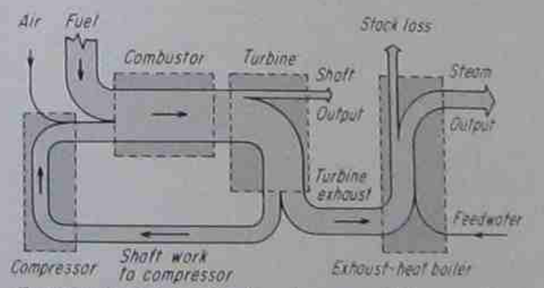
2 Steam boiler of combined cycle takes in gas-turbine exhaust (lower right), passes part through gas burners; rest flows over convection surface to finned economizer



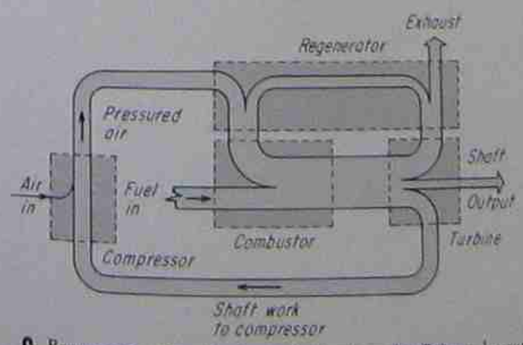
3 Heat-recovery boilers use extended-surface tubes with fins on the gas side



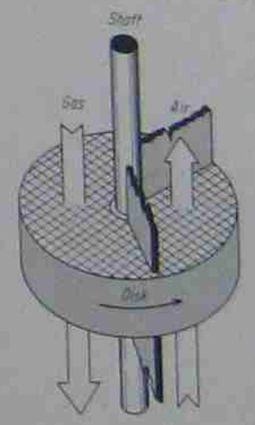
4 Regenerators have gas on both sides of surface and so use extended surfaces

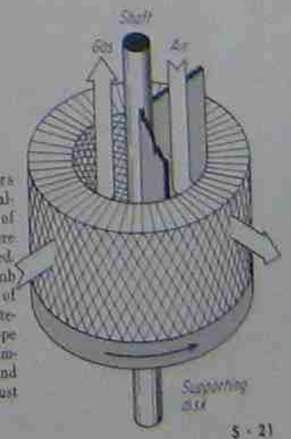


5 Exhaust-heat boilers handle a large part of the energy input to a gas-turbine cycle, need careful engineering for application



6 Regenerator makes direct contribution to cycle efficiency by cutting fuel input to combustor through salvaging exhaust energy





7 Rotary regenerators offer method of salvaging exhaust energy of small gas turbines where compactness is needed. Heat-carrying honeycomb of rotor may be made of metals or ceramic materials. Design must cope with problems of compressed-air leakage and blowdown of air to exhaust

Controls, accessories supervise overall system operation

Up to this point we have been looking at the main components of gas turbine plants. Now let us look briefly at the many supporting elements that enable us to run, control and protect the main parts of the plant.

Bearings used depend on the system type and size. Most designs use oil-lubricated sleeve bearings. Some smaller units and jet-engine type gas generators use anti-friction bearings of the roller and ball types. Light weight and compactness of these bearings and their lubricating system favor the use of these types. Reactions between gas flow and blading of compressor and turbine make it necessary to use thrust bearings to keep the shaft properly aligned axially to maintain adequate clearances.

Lubrication system often ties in with the plant's governing system. As a lubricant, the oil not only reduces turning friction, but carries away heat from bearings to dissipate it in air- or water-type coolers. Pumps, filters and strainers, Fig. 1, must be used to run and protect this all important auxiliary system.

Reduction gear usually ties together the main turbine-compressor shaft and the load shaft. Turbo machinery can usually run at better efficiency at speeds higher than that suitable for the load. In addition, smaller reduction gears are used to run fuel pumps and compressors, tachometers, oil pumps, governor weights, and other small auxiliaries needed by the total plant.

Fuel supply to the combustor is simplest when it is gas—natural, manufactured, blast furnace, etc. Then a centrifugal compressor, with strainers and governor-actuated controls may be all that's needed. If natural gas is supplied at high pressure, a reducing valve in place of the compressor may be used for simpler overall design.

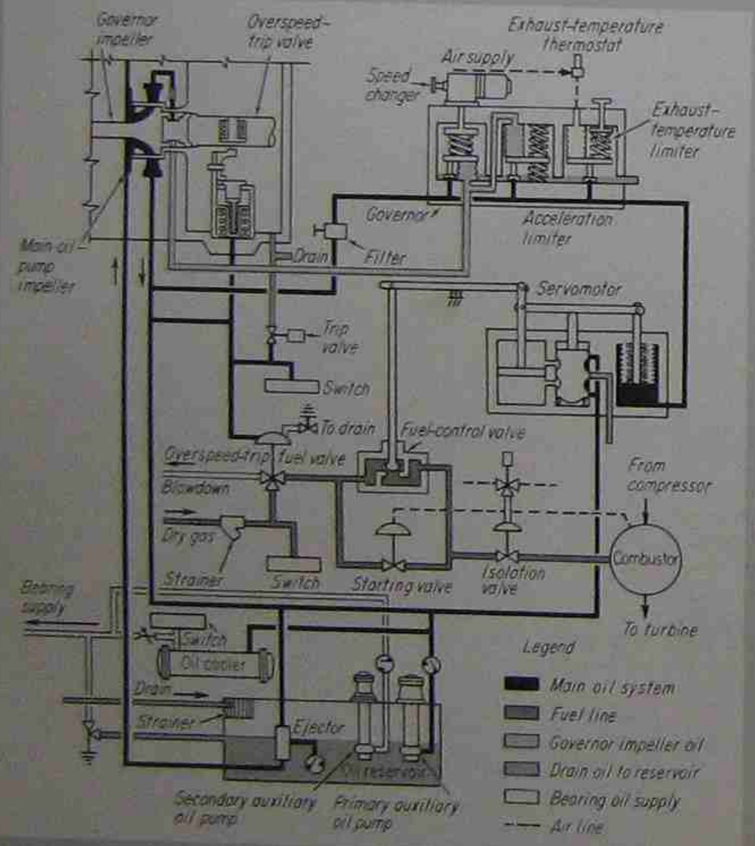
For liquid fuels a variable-stroke reciprocating pump would be used in place of the compressor. The fuel oil would be stored in large tanks, supplemented by smaller day tanks in the plant for safety reasons.

Fuel nozzles are carefully engineered components designed for proper atomization of the fuel. They must properly mix the fuel with the air to insure complete and efficient combustion in a properly shaped flame. Strainers preceding the fuel nozzles prevent clogging of fuel system valves and nozzle openings.

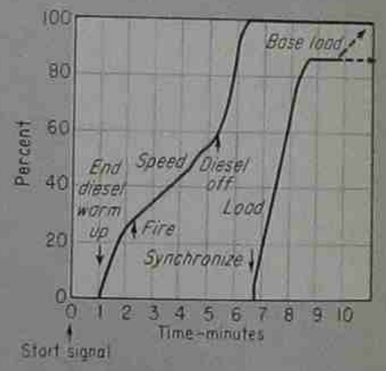
Governing of the plant usually depends on load-shaft speed sensing to control the rate of fuel flow into the combustor. This is done by varying pump or compressor speed or pump stroke. In some systems, fuel flow is controlled by valve as in Fig. 1.

Speed sensing in some units is by fly-ball governor, governor-oil impellers or electric generator. These actuate oil servomotors or electric transmission systems to control the regulating valves or pumps.

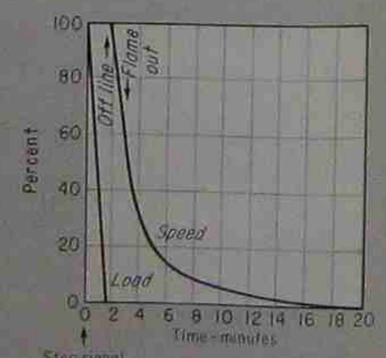
Gas turbines need many auxiliary systems for normal operation and safety



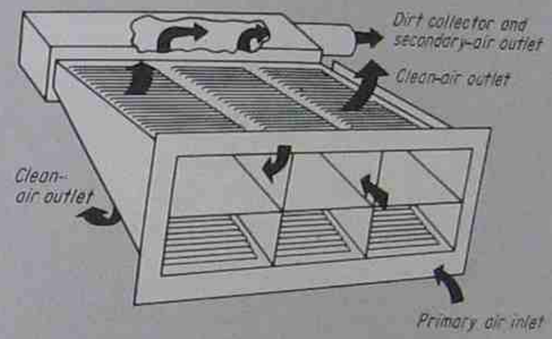
1 Pump on turbine shaft supplies oil for lubrication and governing, auxiliary pumps work during startup and shutdown. System automatically limits several variables



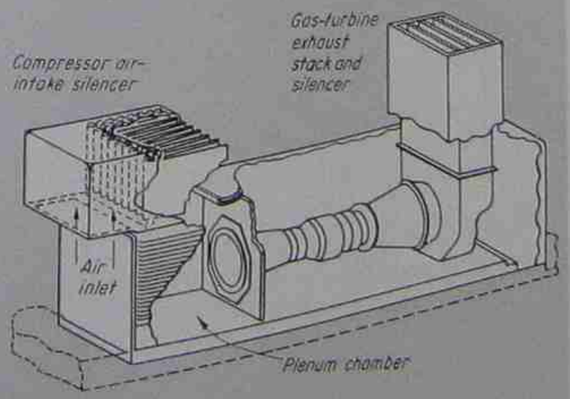
2 Starting sequence for gas turbine, cold to full load, takes only a few minutes



3 Shutdown sequence for larger turbines may also be controlled automatically



4 When gas turbines work in dirty atmospheres, separators must be used to remove contaminants from entering air



5 To make the gas turbine plant a good neighbor, silencing baffles must be used at the air inlet and gas outlet

Overspeed governors cut off fuel supply automatically when shaft speeds exceed about 115% normal. Turbine exhaust or inlet temperature also actuates a trip to cut off fuel supply when exceeding a safe level.

In some two-shaft turbines the gas-generator shaft speed and turbine exhaust temperature automatically adjust setting of nozzle-blade angles of the load turbine. These two factors set the blades to give best performance for off-design ambient conditions and part loads and to yield a higher output and quicker response to load changes. Proper nozzle angle also reduces the amount of starting power needed.

Automatic controls have been designed for many gas-turbine plants to make simple pushbutton starts and stops with minimum operator supervision. Many of the units will automatically alarm or stop, or both, on malfunction of any part of the plant during starting, running or shutting-down phases.

Those units driving electric generators can have systems that automatically regulate speed and voltage. They synchronize the unit with the line before automatically closing the switch and bringing load up to a predetermined level. Plant controls can include local or remote, automatic or manual regulating systems.

Starting equipment can take a variety of forms. It may be compressed-air driven turbines, steam turbines, gas expanders, reciprocating gasoline-fired or diesel engines, or electric motors. The type chosen depends on energy service available at the site. These drivers turn the air-compressor shaft to initially pressurize the combustor.

Together with the turning apparatus there must be an ignition system in the combustor to start the flame when fuel and air conditions are right. This may be a high-tension sparking system or an electrically heated glow rod next to the fuel nozzle. The igniter must be withdrawn to protect it after the fuel starts burning.

Fig. 2 shows a typical starting sequence for a medium-capacity turbine fitted with a starting diesel. At time 0, the diesel engine is started. After 1 minute it is clutched into the main shaft and the speed is steadily raised for another minute. Then the fuel in the combustor is admitted and immediately fired. For the next three minutes the diesel steadily increases main shaft speed until the gas turbine is self supporting. Fuel flow is then increased and the diesel declutches with the turbine coming up to speed and synchronizing 6½ min after starting. In the next two minutes the unit may be fully loaded.

Fig. 3 shows the stopping sequence of this unit which can be controlled automatically or manually. Plants with jet-engine type gas generators can fully load from a cold start in less than two minutes.

Air-filters, Fig. 4, are essential for gas turbines working in contaminated atmospheres. Compressors are very sensitive to deposits on their blade and nozzle surfaces so dust, vapors, bugs, etc must be removed to maintain top efficiency. Filters usually cause a small pressure drop of the entering air. Washers may be used in place of filters: these offer the advantage of evaporative cooling of the air during high ambient temperatures for higher efficiency and capacity.

Silencers, Fig. 5, in the form of sound-absorbing baffles at compressor inlet and turbine exhaust, help reduce plant noise. Housing usually controls the direct machinery noise. Silencer design must avoid too great a pressure drop to maintain plant efficiency and capacity.

Plant performance varies with system capacity and design

When talking about gas-turbine-plant heat rates or thermal efficiencies we have to specify several things: (1) air temperature entering the compressor (2) elevation of the plant above sea level (3) heating value of the fuel—lower (LHV) or higher (HHV).

On page S-5 we showed how both thermal efficiency and plant capacity depended on air temperature—the colder the air the more dense it becomes and more mass flows through the plant giving it higher capacity.

We know that air pressure drops with rising altitude. For constant temperature this makes the air less dense and so the plant loses capacity and efficiency as temperature rises. To put comparisons between plants on a uniform basis, builders quote the performance of their plants on the NEMA standard—80 F ambient air temperature and 1000-ft elevation above sea level. They supply correction factors to figure the plant performance for other conditions that may exist at the actual plant site.

Quoting heat rates on LHV or HHV of the fuel burned is an arbitrary choice. Make sure you know which is being used. The difference depends on the hydrogen content; if H_2 is zero, HHV equals LHV. But as H_2 grows, the LHV shrinks because of the growing H_2O in the combustion products that carries off energy to atmosphere. Actual ratio of HHV/LHV for a fuel depends on its fuel element composition. For rough rule-of-thumb corrections you might use for natural gas, HHV/LHV = 1.11; for distillate oils, HHV/LHV = 1.06.

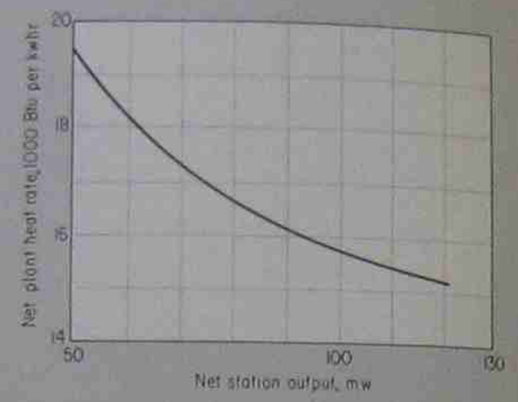
Heat rates for various types and sizes of gas turbine plants are given in Fig. 1 to 3. These are based on HHV of the fuels burned, at NEMA ratings.

Fig. 1 shows the heat rate for a large 10-gas-generator peaking unit. By modern levels of central-station performance this heat rate is poor, but the shorter hours of operation of this type unit make thermal performance relatively unimportant. The installed cost of 60 to 70% of high-efficiency base-load units makes a place for this gas turbine on an economic basis.

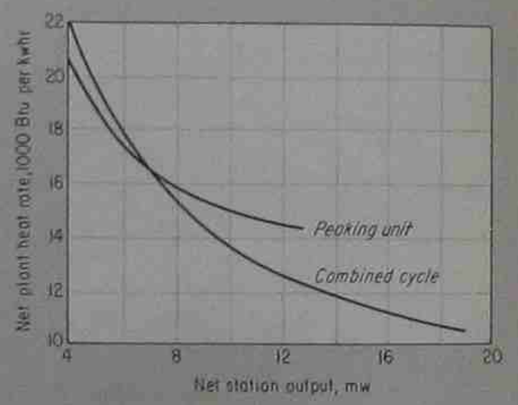
Fig. 2 compares the performance of different types of gas-turbine plants. The combined cycle shows the marked improvement achieved by the additional components.

Fig. 3 shows the dependence of variable-speed mechanical-drive gas turbines on load, speed and air flow in determining their thermal performance. The thermal efficiency of this turbine is based on burning distillate oil in the plant at NEMA standards.

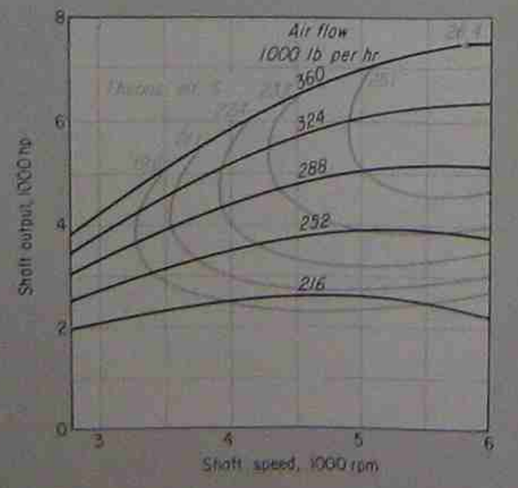
Heat rate and thermal efficiency are best at full load



1 Large peaking unit with multiple jet-engine gas generators has fast-rising net heat rate as the load drops towards zero



2 Base-load combined-cycle plant has markedly lower heat rate than comparably-sized peaking plants, but higher investment



3 Mechanical-drive gas-turbine performance depends on the load and shaft speed as well as air ge[illegible] through the compressor

OIL and GAS ENGINES

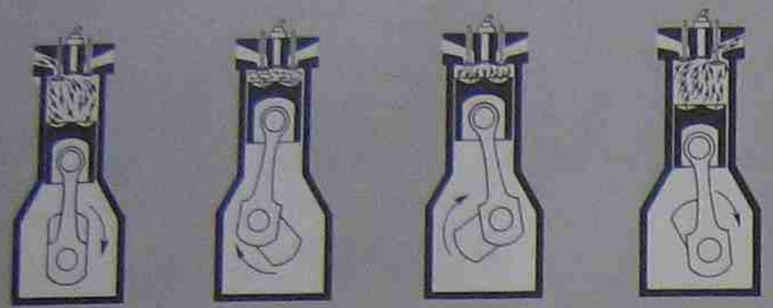
a **Power** special report



Today's oil and gas engines, like thoroughbred horses, derive their abilities from a blending of the best in a number of blood lines—an ancestry that includes such famous names as Lenoir, Beau de Rochas, Otto, Hornsby-Ackroyd, Diesel. More than a century of development has given us a team of prime movers of major importance for a broad range of stationary and mobile uses.

Under the increasingly analytical attack of modern designers, recent years have seen advances in efficiency, reliability and, most notably, specific output. The results of these efforts are evident in the pages that follow—a condensed, practical report on the current state of an art of key importance to those who design and manage energy systems. It was written by a team of POWER editors working closely with a recognized expert on oil and gas engines—Consultant Edgar J. Kates.

4-STROKE CYCLE: One power stroke out of two revolutions



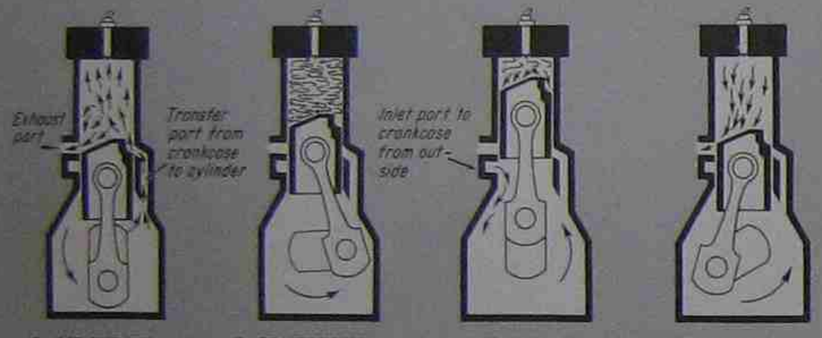
1. AIR INTAKE
In 4-stroke diesel engine, descending piston draws air through open inlet valve, thus filling cylinder space

2. COMPRESSION
Rising piston compresses air against closed valves. Injection of the fuel starts near the end of compression

3. EXPANSION
The burning mixture expands, forcing the piston down. This is the one stroke of the four that delivers power

4. EXHAUST
With the exhaust valve open, the rising piston forces products of combustion out of cylinder. Cycle repeats

2-STROKE CYCLE: One power stroke out of each revolution



1. AIR INTAKE
With transfer and exhaust ports open, air under slight pressure in crankcase flows into engine cylinder

2. COMPRESSION
Rising piston covers ports, compresses air in cylinder, creates suction in crankcase. Fuel injection starts

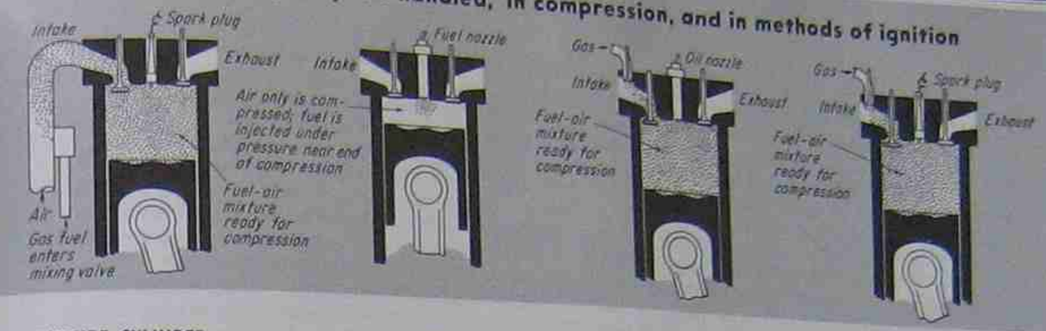
3. EXPANSION
Burning fuel expands, pushing piston down. Air flows into crankcase, to be compressed as the piston descends

4. EXHAUST
Descending piston uncovers exhaust. Slight pressure builds up in crankcase, enough to move air into cylinder

Engines differ in...

DIAGRAM OF ENGINE OPERATION
WHEN AND WHERE FUEL AND AIR MIX
COMPRESSION
IGNITION METHOD
OUTLINE OF ENGINE'S CYCLE OF EVENTS

... fuels and the way they are handled, in compression, and in methods of ignition



OUTSIDE CYLINDER, BEFORE COMPRESSION	INSIDE CYLINDER, AT END OF COMPRESSION	OUTSIDE CYLINDER, BEFORE COMPRESSION	OUTSIDE CYLINDER, BEFORE COMPRESSION
LOW	HIGH	HIGH	HIGH
SPARK	COMPRESSION	COMPRESSION PLUS PILOT OIL	SPARK
GAS ENGINE	**DIESEL ENGINE**	**DUAL-FUEL ENGINE**	**HIGH-COMPRESSION GAS**
1. Mixing valve introduces gas into air in a "perfect" ratio 2. With inlet valve open, suction stroke fills cylinder 3. Compression stroke raises pressure of the mixture 4. Spark ignites mixture near end of compression stroke 5. The fired mixture expands, pushing the piston down 6. Exhaust valve opens; rising piston clears cylinder NOTE: Gasoline engine operates in similar way but uses a carburetor to vaporize fuel	1. Suction stroke fills the cylinder with air 2. Compression stroke raises air to high level of pressure and of temperature 3. Fuel injection starts near end of compression 4. Hot air ignites oil fuel 5. Burning fuel expands, and pushes the piston down 6. Exhaust valve opens; rising piston clears cylinder NOTE: Gas can be injected and ignited in same way with pilot oil to stabilize burning	1. Suction stroke fills cylinder with air and gas fuel 2. Compression stroke raises mixture pressure to high level 3. Near compression end, pilot oil injects for ignition 4. Compression heat ignites pilot oil, then gas mixture 5. Resulting expansion pushes piston down on working stroke 6. Exhaust valve closes; rising piston clears cylinder NOTE: Engine can operate on gas, oil, or combination. Gas operation is outlined above	1. Gas fuel enters inlet air under valve control 2. With inlet valve open, suction stroke fills cylinder 3. Compression raises mixture pressure to a high level 4. Spark ignites mixture near end of compression stroke 5. The fired mixture expands, pushing the piston down 6. Exhaust valve opens; rising piston clears cylinder NOTE: Denser mixture resulting from high compression requires higher spark voltage

Fundamentals

Here's your refresher on basic elements of oil- and gas-engine operating cycles and modern engine types

The oil and gas engines with which this report deals operate on the *internal-combustion* principle—the fuel burns *inside* the engine and the products of this combustion form the *working fluid* that generates mechanical power. This sets them apart from engines and turbines that use a working fluid—steam, for example—developed outside the power-producing unit.

Family characteristics. As you would expect, all oil and gas engines bear a strong family resemblance. They have these basic mechanical features: a *cylinder* in which fuel is fired, a *piston* to receive the resulting expansive force and convert it to mechanical motion, a *connecting rod* and *crankshaft* (or their equivalent) to turn line motion of the piston to rotating motion suitable for turning electric generators, driving machinery, or spinning propellers. In addition, suitable *valves* or *ports* control flow of air and exhaust gas. Finally, there must be reliable means for *introducing* fuel in controlled amounts and *igniting* it.

All oil and gas engines operate in the same general way. Each *cycle*, or series of events taking place in the cylinder involves these steps: (1) Cylinder is charged, (2) cylinder contents are compressed, (3) burning charge expands, pushing on piston, and (4) products of combustion are exhausted so cylinder can be recharged. As diagrams above show, a piston stroke can be used for each of the four steps of intake, compression, expansion and exhaust. In this *4-stroke cycle* there is thus one power stroke to each two full revolutions of the crankshaft.

By using air at pressure slightly above atmospheric to blow the exhaust gas out of the cylinder and fill it with a fresh charge, the complete cycle can be accomplished with two strokes. This *2-stroke cycle* yields a power stroke for each full revolution. In the diagrams, the air used to *scavenge* and fill the cylinder is obtained by using the crankcase and underside of the piston as an air compressor. This is called *crankcase scavenging*. Other methods of scavenging, and *supercharging*, which should not be confused with it, are described later in this report.

Basic types. Although alike in major mechanical aspects, oil and gas engines differ in the fuels handled, when and where fuel and air are brought together, how much the charge is compressed and how it is ignited. There have been many variations of these elements but the four examples diagrammed above will serve to illustrate the basic considerations involved and to provide a firm basis for understanding today's engine types.

Gas-engine operation. As in the familiar gasoline engine in your automobile, the low-compression gas engine mixes fuel and air outside the cylinder, before compression. With natural gas as fuel, a mixing valve may replace the carburetor used with liquid fuel.

The gas fuel is proportioned to the air to produce a nearly *perfect* mixture—that is, just enough air to burn the gas completely. This mixture flows into the cylinder and is compressed. Near the end of compression, an electric spark ignites the inflammable mixture, which burns explosively. Cylinder pressure rises rapidly and acts on the piston to move it down on its *power* stroke.

The familiar fact that compressing a gas raises its temperature works against us here; the mixture may get hot enough to self-ignite before end of compression. Such *pre-ignition* (and the *detonation* or "knocking" familiar to the motorist, one cause of which is too-high compression pressure) causes loss of power. It can be seen that compression must be limited in this type of engine. Is that good or bad? Let's take a look at the business of compres-

sion ratio, which is a major factor in establishing what the compression pressure will be.

Compression ratio is volume of cylinder at beginning of stroke, divided by volume at the end. Pressure at end of compression is roughly proportional to compression ratio, and, in general, the higher the compression ratio, the higher will be the maximum pressure reached during combustion. Thus compression ratio is important for two reasons: (1) Theoretically, the higher the expansion ratio, which in most engines corresponds to the compression ratio, the more efficient the engine, and (2) the higher the compression ratio, broadly speaking, the stronger and heavier must be the engine.

Thus, although it is desirable to employ a high compression ratio, the nature of the fuel imposes limits in engines where a near-perfect mixture is compressed. With natural gas, for example, compression ratio might run about 5 to 1, for a compression pressure of some 120 psi. By changing the nature of the fuel, as was done in development of high-octane "anti-knock" gasolines, compression ratios in automotive engines have been raised from about 6 to 1 to as much as 10 to 1, or more.

Diesel principle. In contrast to engines in which fuel and air mix before compression stand those in which only air is compressed and fuel enters near the end of compression. In the diesel, prime example of this class, heat of compression is used to ignite the fuel.

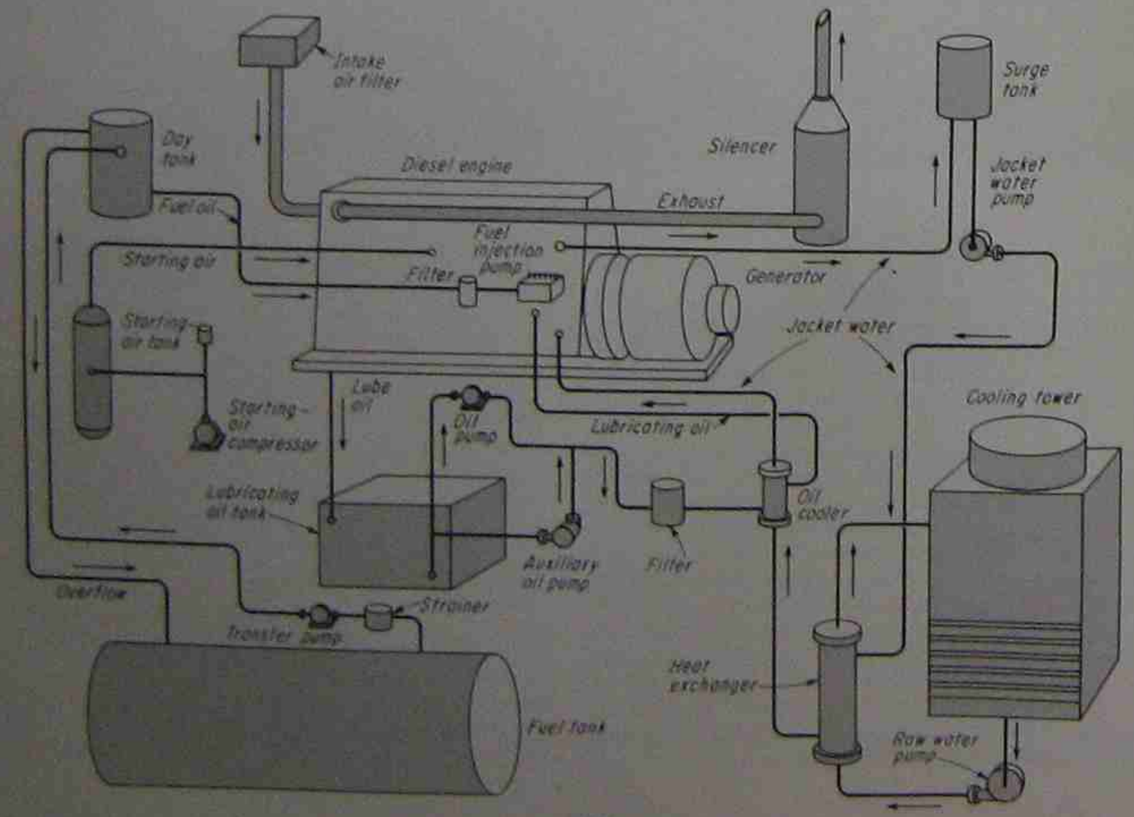
In a typical diesel, air is compressed to about 450 psi, which brings it up to about 1000 F. When finely atomized oil is sprayed into this "red-hot" air, it ignites and burns. Thus, in the diesel, the high compression ratio necessary for reliable ignition means inherently high efficiency.

Because, in practice, compression ratios above those needed for ignition give little gain in over-all efficiency, it is customary to go no higher. Pressure and temperature resulting from a given compression ratio depend on engine speed, cylinder size, and other design factors. Typical compression pressures in diesels range from 450 to 600 psi, or more, with small, high-speed engines generally having higher compression pressures than large ones.

Burning gas at higher compression. About 25 years ago, interest began to focus on means for burning increasingly available natural gas, and such waste products as sewage gas, at higher efficiencies and in engines that could be converted readily from oil to gas operation.

First successful step in this direction was to inject gas into a diesel cylinder at high pressure, just as oil is injected into compressed air in the conventional engine. It was found that the gas fuel would be ignited by compression heat but, to insure stable combustion, it was desirable to inject a small quantity of oil fuel (called pilot oil). Diesel efficiencies could be obtained when burning gas; conversion from oil to gas or vice versa required only a matter of hours. Engines fitted for such operation were initially designated as *gas-diesels*.

The immediate postwar years saw the introduction and rise of the *dual-fuel* engine, capable of operating on oil, gas, or any combination of the fuels simultaneously (POWER, May 1945, pp 64-70). In these engines, gas fuel mixes with air before compression, which is to full diesel



levels. How can this be accomplished without the preignition that seemingly limits pressure?

Dual-fuel operation. It is important to remember here that the low-compression gas engine, where preignition is a problem, operates with a near-perfect fuel-air ratio. In the diesel engine, however, there must be a relatively large amount of excess air so that each sprayed-in particle of oil fuel will readily find the oxygen it needs for burning in the limited time available.

Since natural gas has about the same heating value per lb as does fuel oil, if we were to operate a diesel engine at the same output on natural gas instead of on oil, we would charge the cylinder with a weight of gas about equal to that of the oil we had been burning. And we would thus wind up with a *lean* mixture. In fact, the mixture would be so lean that it would not self-ignite at the temperature reached by the end of compression.

Thus, in dual-fuel engines a small quantity of oil is injected near the end of compression. This is ignited by the compressed mixture and burns like the oil fuel injected into a standard diesel. Its burning supplies enough heat to ignite the gas-air mixture. This pilot oil may be supplied by the same pump and nozzle used for injecting fuel during oil operation. For precise control, however, two sets of pumps and nozzles, or duplex designs, may be employed.

Gas admission. In 4-stroke cycle unsupercharged engines, gas may be admitted to the main air manifold or, more commonly, to the individual air passages into each cylinder. In 2-stroke cycle designs and supercharged 4-stroke units, air enters the cylinder while exhaust valves or ports are still open. It is therefore necessary to use a gas valve timed to delay admission until there is no chance of losing fuel out the exhaust. This may be done with a separate valve, as diagrammed on the preceding page, or with a second disk on the inlet valve stem.

Because quantity of air admitted remains the same at all loads, fuel-air mixture tends to become extremely lean at partial loads—so lean as to result in incomplete combustion and poor fuel economy. Thus most dual-fuel designs employ some means of reducing air quantity at partial loads, to maintain desirable mixture ratio.

Spark-ignition at high compression. Where operation is solely on gas, it is desirable to gain the good fuel economy of high compression, without the cost of pilot oil. By using higher intensity ignition systems and slightly richer mixtures with slightly lower compression ratios than in dual-fuel engines, modern gas engines can yield performance close to that of dual-fuel engines, without pilot-fuel.

Brake mean effective pressure. In discussions of engine development, the term *brake mean effective pressure* (*bmep*) is frequently used. Because output for an engine of known cylinder dimensions and speed is directly proportional to bmep, we should know what this term means. We know that pressure on the piston during the power stroke varies from instant to instant and that some of the power produced is eaten up by engine friction. Bmep may be visualized as *average* pressure on the piston, reduced by the amount needed to overcome friction losses. It may be calculated if we know *net* shaft output, or brake horsepower, and the engine's cylinder dimensions and speed.

These typical auxiliaries serve the engine in a complete plant

Diagram at left shows auxiliary equipment serving engine in typical stationary plant. Auxiliaries for units intended for mobile or portable service are usually mounted on the engine or its base, to make it self-contained. Functions of auxiliary systems may be outlined as follows:

Fuel system for oil engine provides storage space for supplies of fuel oil, pumps required to transfer oil from delivery point to storage, and from tanks to engine, plus strainers and filters needed to insure clean fuel. It may also include special equipment for preparing heavy oil. Fuel system for a gas engine would include a pressure regulator.

Intake system supplies air for combustion, consists of piping from a source of fresh air to the engine manifold, with a filter to remove dust and other harmful impurities. It may also include a silencer to subdue pulsation noise.

Exhaust system, in simplest form, consists of piping from engine to a point where exhaust gas may be discharged without danger or annoyance. It usually includes a silencer to reduce noise from pulsations and may also include a device to recover some of the heat from the exhaust gas.

Starting system provides motive power to turn engine through several cycles until firing starts and unit runs on its own power. Diagram shows system using compressed air; cranking motors powered by storage batteries are also used, particularly on mobile and portable engines.

Lubrication system delivers lubricant to rubbing surfaces of engine. It usually includes a sump or storage tank of some kind, pumps for delivering oil to the engine and for circulating it under pressure to points needing lubrication, and strainers and filters to remove foreign matter that might damage wearing surfaces. Full-flow filter is shown; in optional bypass hook-up only a portion of the oil is filtered continuously.

Lubrication system may also include an oil cooler to keep lubricant at desired temperature, and a purifier or reclaimer to remove contamination that occurs in operation.

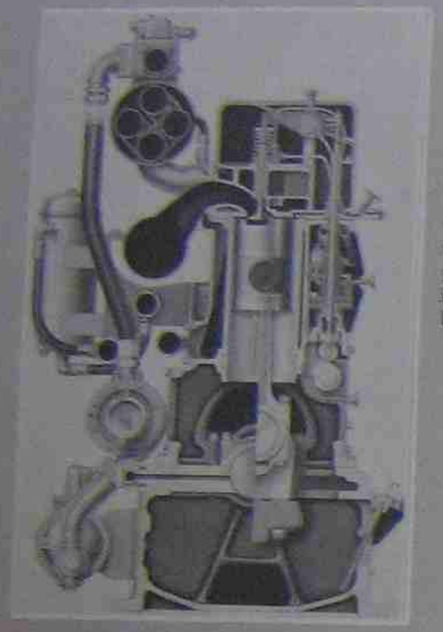
Cooling system removes part of heat of combustion from engine cylinder, keeping metal temperatures in and around combustion space at a reasonable level. A pump circulates water through cylinder and head jackets to carry heat away.

Simplest cooling system thus needs only a water source, a pump, and a place for disposal of heated water. Since it usually proves uneconomical to throw water away, arrangements are made to cool water leaving the engine, so it may be re-used. This involves such devices as radiators, evaporative coolers, cooling towers, and spray ponds.

The system illustrated is of the closed type recommended in modern practice. Only pure water circulates in jackets, thus avoiding scale formation.

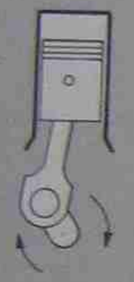
Other auxiliaries frequently met in stationary plants include: (1) some form of drive, such as V-belting, gears, chains, clutches, hydraulic or magnetic couplings, etc, to effect satisfactory transmission of power from engine crankshaft to driven machinery, (2) controls to regulate engine operation, and (3) instruments to indicate engine and record behavior.

In-line, vee and opposed piston are basic types

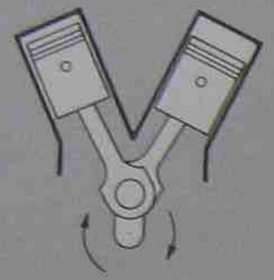


IN-LINE DIESEL ENGINE

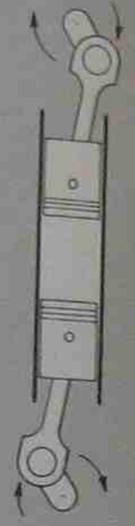
In the usual form of internal combustion engine, cylinders are arranged vertically as shown at left and below. Up to 16 cylinders can be placed in-line, one after the other. Vee configuration, an increasingly popular type, is employed in 8, 12 and 16 cylinder combinations. Engine length is reduced by almost one half. Lines of cylinders, known as cylinder banks, range 30 to 75 deg apart. If the vee is increased to 90 deg. we have the right angle type. Where a flat engine is desired, vee can be opened to 180 deg. yielding the opposed-cylinder type, facing page. This should not be confused with opposed piston type sketched at right. Here two pistons operate in what is essentially a single vertical cylinder with combustion chamber in the center between pistons and a crankcase at each end.



VERTICAL IN-LINE



VEE TYPE



OPPOSED PISTON

Engine Construction

Shape, size and materials of both stationary and moving elements depend on performance demands and exact nature of each task

Broadly speaking the engine structure includes all fixed parts. It supports and keeps in line reciprocating and rotating parts while resisting the forces produced by engine operation. It also holds auxiliaries, provides jackets and passages for cooling water, a sump for lubricating oil and a protecting enclosure. Moving parts include pistons, connecting rods, bearings and crankshaft.

Firing pressure tries to push cylinder heads and crankshaft bearings apart, setting up tension in the frame. Motion of the moving parts tends to twist and bend the frame and move the engine off its foundation. Each engine structure must be strong and rigid enough to economically contain all these forces.

Cylinder and piston configurations are many and varied. Seven basic arrangements described above include: (1) vertical in-line (2) V-type (3) opposed piston (4) horizontal (5) radial (6) delta and (7) rotary.

Main engine structure usually consists of a base, frame and cylinder heads. In medium and low speed engines the base is generally a heavy cast or welded structure which supports the engine and collects or stores lubricating oil. Most bases are constructed of a good grade cast iron or welded steel plate and castings. Welding saves weight while giving the same strength and rigidity. In higher speed ranges the engine may be supported by a frame which also holds the crankshaft. The base then becomes just an oil pan.

Frames of most in-line engines contain both crankcase and the cylinder block. This construction is more rigid than one with separate crankcase and individual cylinders or bolted on cylinder block. Joint between frame and base may be above, below or directly at center line of the crankshaft. Illustrations, page S • 8, show: (1) frame bottom on crankshaft centerline, (2) frame extending well below crankshaft, and (3) base completely enclosing the crankshaft. Most frames are made of a good grade of cast iron or of weldments fabricated from steel plate and steel forgings and castings. Through bolts are sometimes used to ease firing loads on base, frames and cylinders. Extending from base to top of the frame, they carry load directly between main bearing caps and the cylinder head.

Most large stationary engines are provided with spring-loaded manhole covers at sides or ends of the crankcase. These open to relieve pressure in the event of a primary crankcase explosion and then close to block inward air flow supporting a secondary or more violent explosion.

Cylinder liners may be classified as: (1) dry, (2) wet, or the (3) integral water-jacket type. A dry liner never

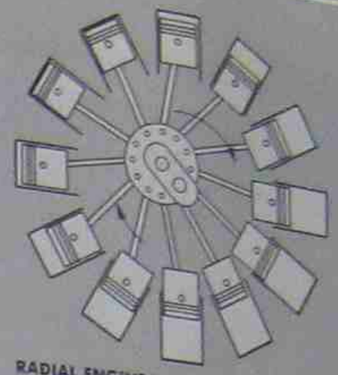
Horizontal, special designs play important role

Horizontal configuration produces a flat engine of single or opposed-cylinder design. Single-cylinder units are generally slow speed with rugged construction and heavy flywheel. Horizontal units, widely used in Europe, develop up to 3500 bhp.

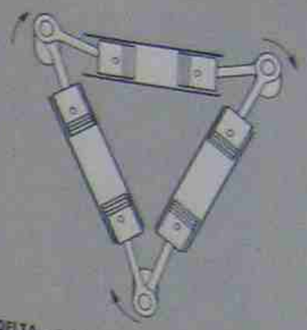
Most sophisticated horizontal type is the radial engine. Firing order is consecutive around the circle. Balance is achieved by actual convergence of combustion pressures and inertial forces at one focal point on the crankshaft axis. Inner ends of connecting rods are secured by knuckle pins equally spaced around a master bearing mounted on the crank pin. Reciprocating motion of each piston converts into rotary motion at the crankshaft through connecting rods.

Delta cylinder is a compact design with three sets of cylinder blocks forming the sides and three crankcases, one at each apex of the triangle.

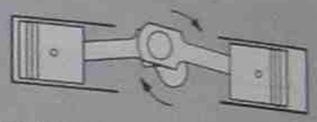
Rotary engine is a four cycle, high speed (3000 to 8000 rpm), lightweight, spark-ignition gasoline engine. Adding rotors is the equivalent of adding cylinders to reciprocating engines.



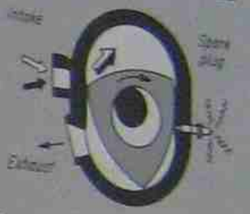
RADIAL ENGINE has axis of crankshaft in vertical plane with a single crank at the top



DELTA unit has opposed pistons reciprocating in 3 cylinders driving the 3 crankshafts

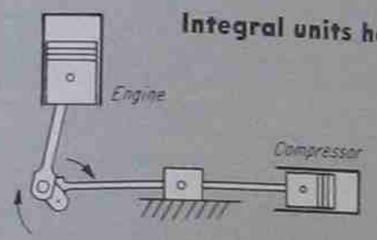


HORIZONTAL type, used where headroom is a problem, can be of multicylinder design

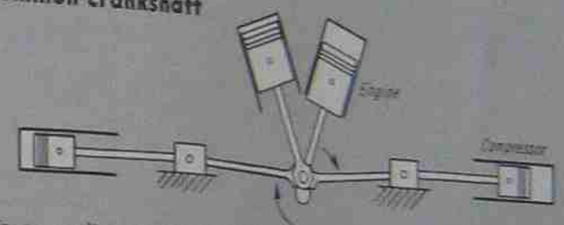


ROTARY engine has three-sided envelope rotor which oscillates as it revolves in unit

Integral units have common crankshaft



INTEGRAL GAS-ENGINE COMPRESSOR has in-line power cylinders with compressor pistons connected to the engine's crankshaft



V-TYPE INTEGRAL DESIGN has compressor cylinders on both sides with each tied to the engine crankshaft through a crosshead

contacts the coolant but fits as a sleeve inside an already complete cylinder. Wet liners form not only the cylinder wall but also inside of the water jacket. When the liner contains an integral water jacket it becomes an individual cylinder assembly held in place by the cylinder block and head or may be flanged and bolted to the engine frame.

Dry liners can be made relatively thin since they merely transmit pressure to the cylinder wall. Fit in the cylinder need not be tight. When engine heats up, liner will then expand tightly against cylinder wall. Temperature on the inside surface will be higher than on a corresponding wet liner since heat must travel through two layers of metal before reaching the coolant. Close contact between liner and cylinder is absolutely necessary; if it is missing, considerable resistance to heat flow is the result.

Liner sealing. Liner must be free to expand and contract with temperature changes. Lower end usually makes a sliding fit with cylinder using O-rings for sealing. With wet liners, a water seal must be provided at both ends. Top flange of the liner is sealed with O-rings or a neoprene or composition gasket. Bottom water seal must allow for slight axial movement of liner and still provide a water-tight joint. Two or more neoprene O-rings are commonly used. In two-cycle engines with one or more ports in cylinder walls, joints above and below must also be sealed.

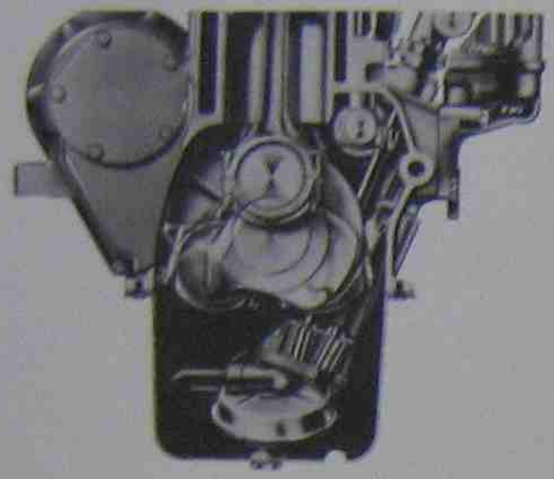
Liner materials. Most liners are made of alloy cast iron containing small percentages of nickel, chromium, molybdenum and titanium. For small, high-speed engines many are induction hardened. Liners are usually produced by centrifugal casting which yields a denser, more uniform product than sand casting. Bore is precision machined, ground, and in many cases, honed. In large, slow speed engines, cast iron and alloy cast iron are used. For longer wear many liners are porous chrome plated, finely honed.

Cylinder heads. To withstand firing pressure and heat of combustion, cylinder heads must be strong and carefully

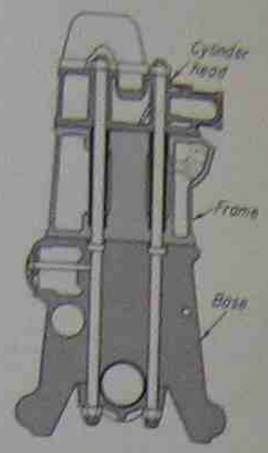
Stationary engine components include base, frame, cylinders and cylinder heads



VERTICAL A-FRAME employs through bolts running from engine base to cylinder heads



DEEP FRAME, internally ribbed for extra strength and rigidity, supports crankshaft



UNDERSLUNG BEARING is supported by through bolts joined to the cylinder head

cooled. Design provides for one or more valve openings and sometimes an auxiliary combustion chamber. Heads are usually made of alloy cast iron. Composition varies widely and may include small amounts of nickel, molybdenum, chrome-nickel and chrome-nickel molybdenum. Special alloy irons such as Meehanite and nodular iron are also employed.

Cylinder heads for two-cycle engines are usually simple and nearly symmetrical. The four-cycle head structure is more complicated because of the need for inlet and exhaust valves and their port passages, besides the injection nozzle and sometimes air-starting or relief valves.

Water jackets. Nearly always, cooling water enters pockets at lower end of the cylinder where temperature conditions are less severe. Water passes from cylinder jacket to head and flows out coolant discharge header.

Critical cooling area lies at top of cylinder around the combustion chamber. Various means are adopted to maintain positive and rapid circulation of coolant. One wet liner design, facing page, has spiral flutes cast on outer surface of the liner to direct cooling water flow up and around the cylinder. Flutes are covered with a tubular sleeve to contain coolant immediately next to the liner.

Pistons and their rings seal the cylinder and transmit gas pressure to the connecting rod. Piston absorbs heat from the gas, but this heat must be carried away to hold metal temperatures within safe limits. Normal escape path runs through piston side walls, rings and cylinder walls to the jacket water. Larger pistons, and those in engines operated at high ratings, require additional cooling.

Constant reversal of piston travel sets up inertia forces which become greater at higher rotative speeds. For this reason designers try to keep piston weight low.

Top section of piston is called the crown, lower section the skirt. External shape depends largely on combustion chamber design. Crown section of the piston is usually thicker to withstand gas pressure without distortion and provide a good path for heat flow from head to ring area.

Practically all new engines have trunk pistons. Crosshead construction is now rarely used. With trunk design the connecting rod fastens directly to the piston. Resulting side thrust causes piston to press against cylinder wall, first on one side, then on the other. At top of stroke, when cylinder pressure is greatest, angle made by connecting rod is so small that side thrust is negligible. Most wear from rod thrust occurs in lower part of the bore.

Piston materials. Ideal material would be light and strong, conduct heat well, expand only slightly when heated, resist wear and be low in cost. In the past almost all pistons were made of cast iron. Today aluminum alloys and various alloys of cast iron are usually employed. With a heat transfer rate roughly three times that of cast iron, aluminum alloy pistons can be made fairly large without need for cooling. But high thermal expansion rate must be considered when determining piston clearance.

Piston cooling needs depend on size of piston and bmep of engine. Almost all two-cycle and all medium and large four-cycle engines require some form of cooling. Basic methods include: (1) shaker, (2) circulation, and (3) spray. The shaker method, normally applied with cast iron pistons, delivers oil through connecting rod to a compartment in the piston head. Oil shakes around inside the piston and then discharges to crankcase.

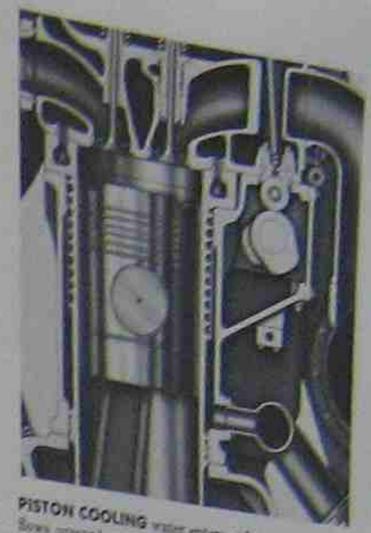
Circulation method, used for some aluminum pistons, runs oil through a series of grooves beneath the ring belt or circulates it through coils of tubing cast in the piston. Spray cooling is generally applied on small sizes of both cast iron and aluminum pistons. As shown above, a jet of oil sprays against underside of the piston crown. Used oil collects in the crankcase, is pumped through coolers and returned again to the piston.

Piston rings. Typical piston carries a wide band of rings at the top and a few on the skirt. Their job is to: (1) seal gas pressure, (2) provide a path for heat flow

Connecting rod and piston pin are connecting links between piston and crankshaft



CONNECTING ROD AND PISTON assembly for opposed-piston engine has hard steel insert for eye. Floating bushing for wristpin ups the bearing capacity



PISTON COOLING water enters at lower right; then flows upward and around piston through spiral flutes



CRANKSHAFT usually has main-bearing journals between each successive pair of cranks with counterweights for high-speed units

from piston to cylinder walls, and (3) control cylinder wall lubrication. Most rings are made of cast iron. Steel, stainless steel and chrome plated steel are also employed.

Connecting rod, essentially a strut with a bearing at each end, transmits piston thrust to crankshaft and visa versa. It must be strong without excessive weight, because of inertia forces. Rods, above, are forged from medium steel or alloy steel.

Wristpin, usually made of hollow steel, links connecting rod and piston. It can be secured in the piston with bearing in the rod or fastened to the rod with bearing in the piston. Most are installed with bearing surface in both the piston and the connecting rod. This so called "full floating" design prevents piston distortion caused by expansion of wristpin when it is fastened on the piston.

Crankshaft must resist bending action of connecting rod thrust when piston is at top center. Maximum gas pressure then acts straight down on the crankpin, tending to bend the shaft between supporting bearings. Crankshaft must also withstand twisting or torsional forces from the connecting rod angular thrust. Most are made of carbon steel and alloy steel with some alloy cast iron used.

In extremely large engines, two separate forgings may be bolted together. It is customary to heat-treat forged shafts to relieve internal stresses. Induction hardening or nitriding give journals a hard skin over a tough inner core.



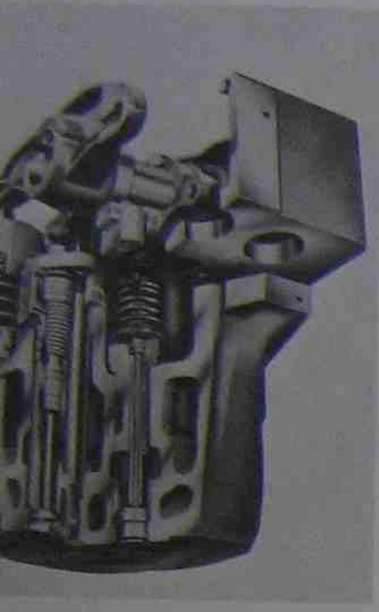
CONNECTING ROD piston-pin eye is generally a solid part of the solumn with cap bolting to the crankpin end. Joint can be horizontal or angular with serrated surfaces or employ the tongue and groove joint



SPRAY COOLING of small size cast iron and aluminum pistons employs jet of oil directed against underside of piston crown. Telescopic oil cooling used on larger engines carries oil directly to the piston crown



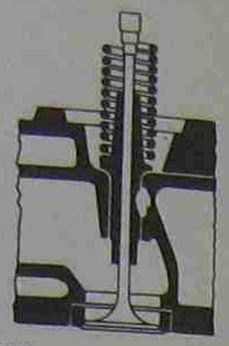
ARTICULATED connecting rods for V-type engine handle two cylinders on a common crankpin. Side-by-side or fork and blade mounting can also be used. Connecting rods shown are high-strength steel forgings



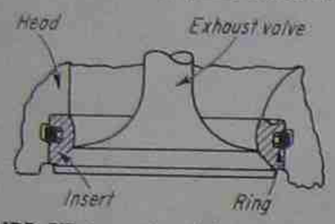
CYLINDER HEAD, with its valves, seats, guides, and mechanism, is interchangeable



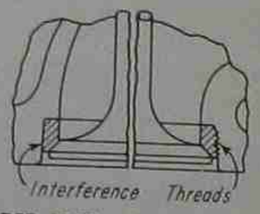
ONE-PIECE VALVE mounts in a removable guide. It seats directly against cylinder head



SEAT RING, of a wear-resisting material, is inserted into the head in this valve design



SLIDE FIT is employed in typical insert design. The snap ring locks it into place



THREADED SEAT at the right runs hotter. Interference fit, shown at left, lasts longer

Getting air in and exhaust out

For high volumetric efficiency, combustion products must be removed completely and the cylinder fully charged with fresh air

We're now ready to take a look at the engine's breathing system — the mechanics of charging the cylinder and removing products of combustion. In the 4-stroke cycle, separate piston strokes fill and discharge the cylinder so we need only valves and actuating gear to control flow. But in 2-stroke engines we must use fresh air to push out exhaust gas. This is the job of the scavenging system.

Volumetric efficiency. In practice, this breathing system isn't perfect—the weight of air or air-fuel mixture the cylinder actually receives is less than it can theoretically hold. We measure breathing-system performance by *volumetric efficiency* — volume of air drawn in per stroke, divided by the volume swept by the piston.

Valves. Most current engines use the mushroom-shaped poppet valves familiar from automotive practice. With good cooling to offset exposure to combustion heat, inlet valves offer no great problems and carbon steel ordinarily serves. But in addition to being exposed to combustion heat, exhaust valves are swept by hot gas instead of cool air. Special materials and constructions are thus usually required for successful, long-life operation.

Many engines employ a single inlet and exhaust valve per cylinder. Making inlet valve larger decreases resistance to air flow and thus ups volumetric efficiency; on high-speed engines inlet valve may run 25-35% larger than exhaust. At the expense of extra complexity, use of two inlet and two exhaust valves offers advantages: (1) larger valve area within same head space, (2) less lift because valves are smaller, and (3) cooler operation.

Valve construction. One-piece construction shown above is simplest. Springs hold valve against in-the-head seat; rocker arm opens it against spring pressure. Conduction through stem guide and seat surface cools valve; every effort is made to bring cooling water close to these points.

Both valve and seat must resist severe mechanical wear and, in the case of exhaust valves, high temperatures. Thus, valves may be made in two parts with a steel stem welded to a heat-resisting alloy head, or seating surfaces may be faced with an alloy that retains hardness at high temperatures. Inserted seats are also used (sketches above). Here, every effort must be made to maintain good heat transfer.

Valves for larger engines may be assembled in cages (photo, top left). The cage, which is removable from the cylinder head as a unit, carries seat, stem guide, springs and spring guide. Usually made of cast iron, cage may have a renewable seat and be watercooled for exhaust service.

In gas and dual-fuel engines, as we have seen, 2-stroke and supercharged 4-stroke designs require timed admission of fuel gas. This may be done with a separate gas valve or, as shown above, with a 2-element inlet valve.

Valve gear. In most designs, valve gear consists of rocker arms which actuate the valves, push rods connecting rocker arms to cams on camshaft, and some form of drive linking camshaft and crankshaft.

Rocker arms swing on steel fulcrum pins in bronze bushings, or on needle bearings. A roller may be fitted at the valve end, but some form of set screw is more usual. If no adjustment is provided where rocker and stem meet, it is needed on push-rod side. Clearance required by temperature difference between idle and running engine may be eliminated by automatic, mechanical or hydraulic adjusters.

For rigidity without excess weight, push rods are often tubular. In simplest arrangement, a hardened mushroom-shaped head at lower end rides the cam and a similar head at upper end fits into a cup on the rocker. In many engines a hinged follower transmits cam action to push rod; the follower usually carries a roller that rides the cam.

Camshafts. In addition to cams for actuating inlet and exhaust valves, camshaft may carry those for fuel-spray valves, fuel pumps, gas, or air-starting valves. Some engines have two camshafts; one for inlet and exhaust, the other for auxiliaries.

Camshaft may be forged in one piece with integral cams; it may consist of a steel shaft with forged-steel or cast iron cams keyed on; or it may be made up in sections, with either integral or separate cams. In latter design, each section usually handles a cylinder or group of cylinders and enough sections are bolted together to make desired length. For good support, camshaft bearings are usually located between each pair of cylinders. These may be bushings or split sleeves to permit ready shaft withdrawal.

Camshaft drives. In 4-stroke engines, camshaft speed is one-half crankshaft speed; in 2-stroke units it equals shaft speed. Because speed relationship must be exact, connecting drive must be positive, using gears or chain or a combination. Drive chosen depends to a large extent on camshaft location and whether an auxiliary camshaft is included. Camshaft may be at upper crankcase level with long push rods, at upper cylinder level with short rods, or at cylinder level with no rods. General trend is to complete enclosure of camshaft and push rods.

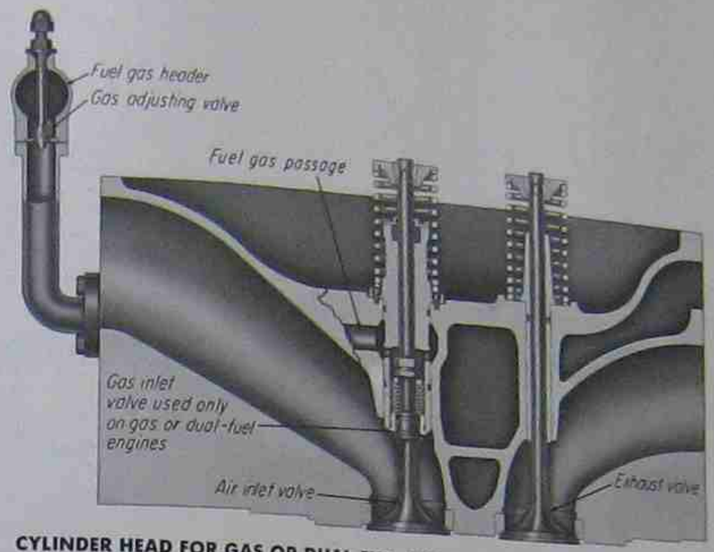
Gears for camshaft drives must be accurately cut and heat-treated to resist wear. Helical teeth are frequently used for greater quietness; a fiber or other nonmetallic gear may be placed in the train for the same reason. Chain drives are of roller or silent type. Provision is usually made for adjustments necessitated by wear.

Scavenging. In an ideal 2-stroke engine, *scavenging air* would act like a piston, pushing all the combustion products out of the cylinder without mixing with them. There would be no loss from short circuiting and no contamination of the incoming fresh charge. In practice, this has to be accomplished in the very short time interval when the piston is near bottom dead center (see p S • 2). It is easy to see that the completeness with which this is done has an important effect on the power developed.

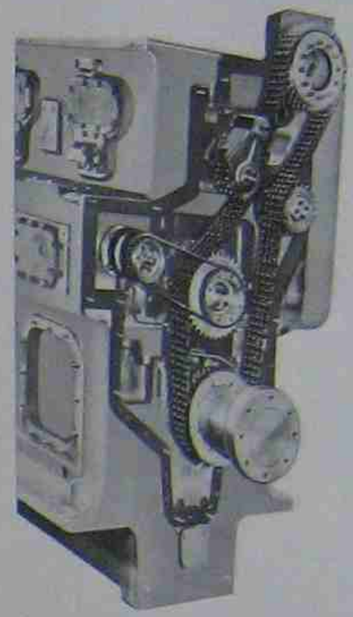
There are three basic methods of supplying air under pressure for scavenging. The diagrams on p S • 2 illustrate *crankcase scavenging*, in which the crankcase and the underside of the piston act as an air compressor. In *power-piston scavenging*, which is similar, a separate chamber is provided under the piston and air drawn into it on the piston upstroke is compressed on the downstroke. Most common, however, is *blower scavenging*.

Ports and valves. Many 2-stroke engines employ *port scavenging*, that is, air enters and exhaust leaves the cylinder through ports alternately covered and uncovered by the piston. In *valve-scavenged* engines air usually enters through ports and exhaust leaves under valve control.

Designers give careful attention to path of scavenging



CYLINDER HEAD FOR GAS OR DUAL-FUEL ENGINE has a pair of exhaust valves and a pair of inlet valves. Latter consist of two elements: an air-inlet valve and gas-inlet valve



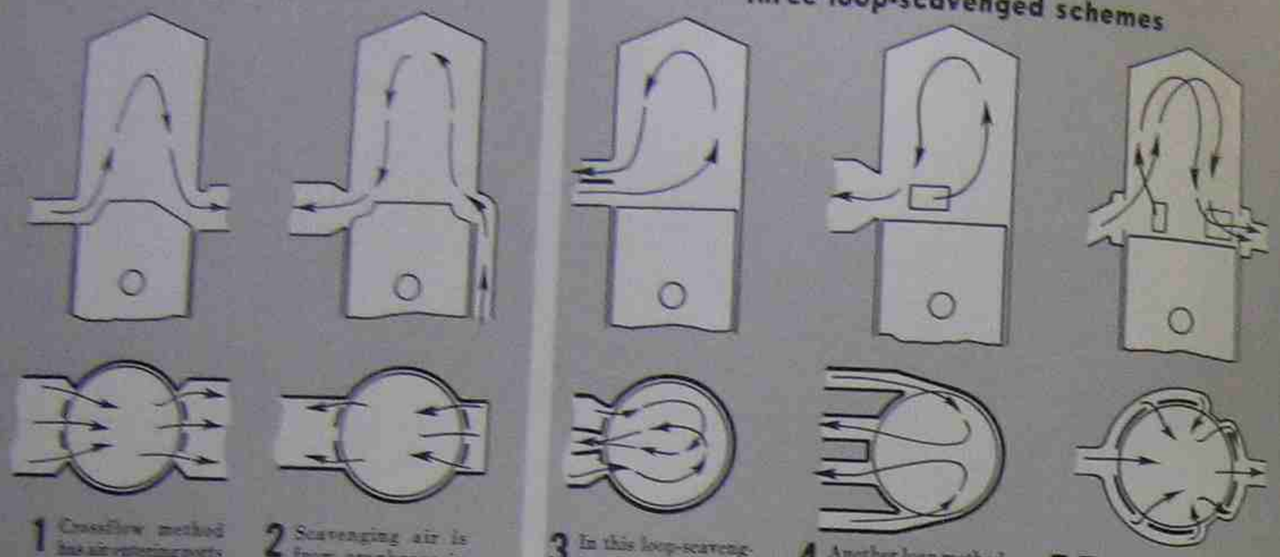
CHAIN OR GEAR DRIVE holds exact speed relation between camshaft and crankshaft

Seven methods of scavenging combustion products from an engine's cylinders and charging them with fresh air

Two crossflow

three loop-scavenged schemes

two uniflow



1 Crossflow method has air-entering ports on one side of cylinder, exhaust leaving on opposite side. Piston-crown shape directs air upward

2 Scavenging air is from crankcase in this crossflow design. Crankcase is partitioned between cylinders; piston does compressing

3 In this loop-scavenging design, air is admitted in a transverse plane across piston, is forced to leave through ports above inlet ports

4 Another loop method directs the air upward through inclined inlets on two sides. Gas leaves by exhaust ports between the inlet ports

5 This loop layout has air ports that vary in inclination. Air ports farthest from exhaust ports have the greatest inclination, as is shown

6 Uniflow scavenging brings air in at ports around lower end of the cylinder, pushes burned gas up and out through poppet valve at the top

7 Opposed-piston unit has intake and exhaust ports at opposite ends. One-way air flow passes straight through, pushing exhaust ahead

air flow from inlet to exhaust and have developed many detailed refinements. These can be classified into three broad categories: (1) crossflow scavenging, (2) loop scavenging, and (3) uniflow scavenging.

Cross scavenging (diagrams 1 and 2 above) uses a deflector piston crown to direct air upward to help avoid short circuiting. While not considered as effective as some of the other arrangements, crossflow is widely used on smaller engines, because of its simplicity.

Loop scavenging has many variations, as indicated by the diagrams above, but primary concept in all is to induce air to flow upward and then loop back to exhaust ports either level with or slightly lower than the inlet ports. If piston uncovers both sets of ports simultaneously, automatic air check valves are used to prevent exhaust gas flowing out through inlet ports while cylinder pressure is above scavenging air pressure. They remain open while piston travels to bottom of its stroke and begins to move upward, until cylinder pressure equals manifold pressure. In this way the cylinder is filled at the beginning of compression with air at a pressure somewhat above atmospheric. As we'll see a little further on, this constitutes a slight degree of supercharging.

Uniflow scavenging (diagrams 6 and 7, above) moves air and exhaust gas through the cylinder in only one direction. This reduces chances of short circuiting or excessive mixing between fresh air and exhaust gas. The air inlets, controlled by the piston, may be in the lower end of the cylinder, with a poppet exhaust valve at the top.

In the opposed-piston engine, uniflow scavenging is accomplished with exhaust ports controlled by the lower piston and inlet ports controlled by the upper one. To permit exhaust gas to discharge its pressure before scavenging air is admitted, the lower crank "leads" the upper one by 12-14 deg. Thus exhaust ports uncover ahead of the inlet ports and close before them, and cylinder pressure can build up to scavenging air pressure by time inlet ports close and compression begins. Some supercharge results.

Supplying scavenging air. The term "blower" scavenging covers use of reciprocating pumps, eccentric-vane compressors, and centrifugal blowers as well as the lobed positive-displacement blowers so widely used today. In these lobed blowers (see illustration above), meshing action of the rotors transports air to a region of higher pressure where it is compressed by backflow effect.

These blowers deliver air at a rate approximately proportional to speed. Since they operate at relatively moderate speeds, they are usually driven from the engine.

In contrast, centrifugal blowers, which operate best at relatively high speeds (upwards of 5000 rpm), are usually driven by a separate motor or turbine.

Supercharging. In simplest terms, the chief purpose of supercharging is to cram more air into the cylinder so more fuel can be burned and engine output increased. It is accomplished by supplying intake air at a density above atmospheric and retaining this increased density in the cylinders at the start of the compression stroke.

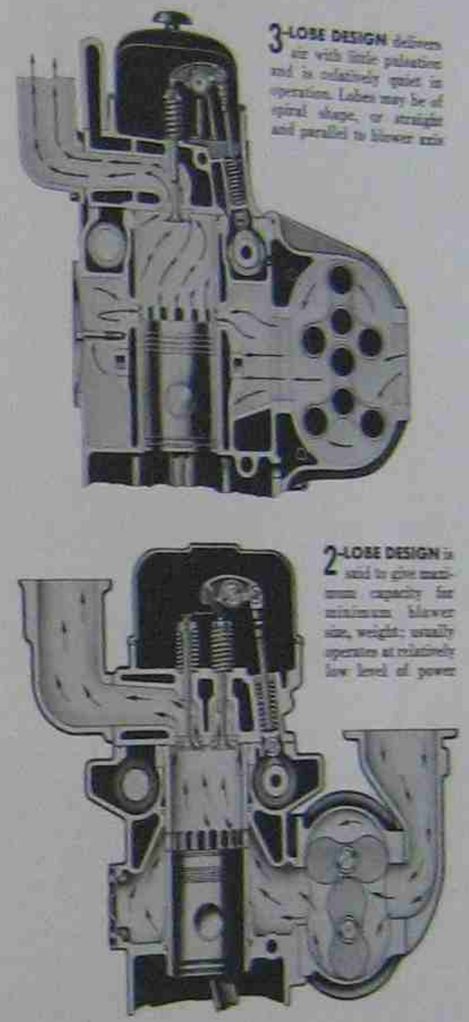
Here we see the difference between supercharging and the scavenging we have been talking about. Scavenging air is supplied to a 2-stroke engine at a density greater than atmospheric but this does not supercharge unless arrangements are made to retain the increased density in the cylinder after exhaust ports or valves close. We've just seen how this may be done to yield a slight supercharge effect; later on we'll look further into supercharging 2-stroke engines to higher levels.

Supercharging methods. Although a variety of means have been investigated for creating the higher intake pressure needed, common practice today uses some form of blower. This may be driven by the engine, by an electric motor, or by a turbine powered by engine exhaust. In the first two cases, power needed to drive the blower represents a loss and must be deducted from the gross engine output to measure useful output. As mentioned earlier, engine-driven positive-displacement blowers are widely used. Centrifugals are usually separately driven.

The basic idea of the gas turbine is an old one, and so is the thought of passing the exhaust of an engine through such a turbine to recover enough energy to drive a supercharging blower. With improved efficiencies for gas turbines and centrifugal blowers, and development of the Buchi (or blowdown) system, *turbocharging* began to have commercial application in the early 1930's.

Turbocharging systems. In the 4-stroke engines to which turbocharging was first applied, designers saw an opportunity not only to increase output by cramming more air into the cylinder, but to reduce heat stresses and improve scavenging. This could be done by increasing the *overlap* between intake-valve opening and exhaust-valve closing -- say to about 140 degrees. In this interval, when both valves are open, pressurized air sweeps out combustion products remaining at the end of the exhaust stroke and cools cylinder walls, pistons and valves.

Two configurations of positive-displacement blowers



3-LOBE DESIGN delivers air with little pulsation and is relatively quiet in operation. Lobes may be of spiral shape, or straight and parallel to blower axis

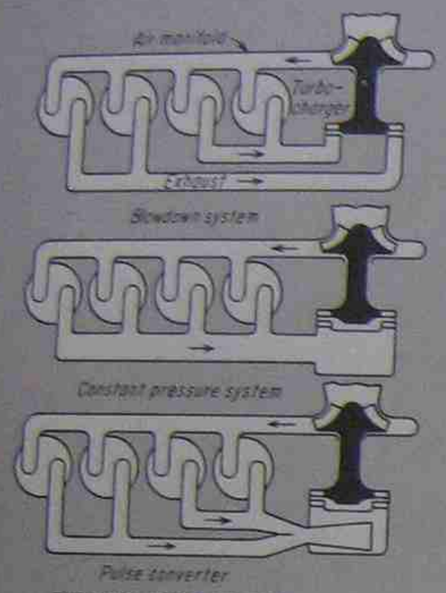
2-LOBE DESIGN is used to give maximum capacity for minimum blower size, weight; usually operates at relatively low level of power

To permit this, intake pressure must be significantly higher than exhaust pressure. But exhaust pressure must be high enough to drive the turbine, and unless turbocharger efficiency is high, it is difficult to obtain pressure from the blower sufficiently higher than that of the exhaust.

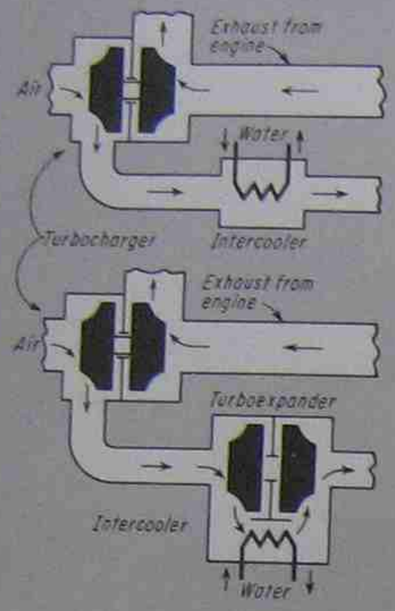
Blowdown system. Instead of operating the turbine on the more or less constant pressure that results when all cylinders discharge into a common manifold, the *blowdown system* divides the manifolds to take advantage of inherent pulsations in exhaust pressure.

At the beginning of exhaust stroke, there is an initial pressure surge. By carefully proportioning the manifold and turbine nozzles, this pressure can be converted into kinetic energy in the turbine. As exhaust stroke nears end, manifold pressure drops nearly to atmospheric. With essentially constant air pressure from the blower, there is thus

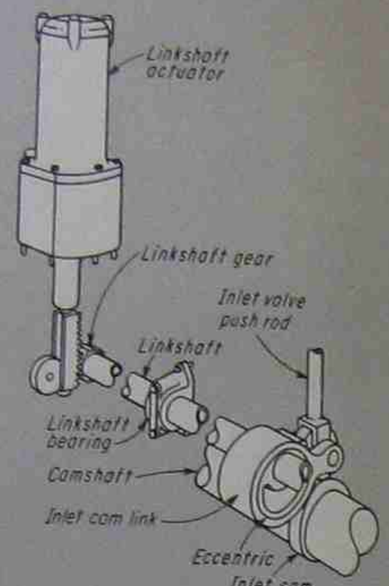
Exhaust energy is used in several ways to supercharge; cooling boosts effectiveness



TURBOCHARGER SYSTEM may use exhaust pulsations (top) or, with high pressure ratio, may operate at constant level (middle). System at bottom combines ideas



AFTERCOOLING, or intercooling as it is also known, uses a heat exchanger to remove heat of compression. In lower diagram, part of the cooling job is done by turboexpander



COOLING WITHIN CYLINDER is accomplished in one case by closing intake valve before end of intake stroke, so air expands. Mechanism adjusts valve timing to load

a substantial pressure differential when intake opens. Manifolds must be so divided in relation to firing order that exhaust pulsations do not cancel each other out. The manifolds connect to separate nozzle compartments in the turbine, which operates on partial admission. This system usually produces air pressures around 5-6 psig.

Constant-pressure system. In recent years, increases in turbocharger efficiency made possible much higher pressure ratios. At higher ratios, energy in exhaust pulsations is a smaller fraction of total exhaust energy and a common manifold may be used. Turbine can then operate on constant pressure and full admission, which contributes to higher efficiency. With such a constant-pressure system, inlet air pressure can be upwards of 30 psig and greater increases in engine output become possible.

Pulse converters. In some cases it may be desirable to combine steady-flow advantages with utilization of pulse energy. As diagrammed above, each pair of cylinders with noninterfering pulsations exhausts into a separate manifold. At any one moment, fluctuating pressure in one branch hits a peak and is converted into high velocity in a nozzle. This exerts an eductor effect on other branch. In the next instant conditions are reversed. These momentum transfers between gas flows maintain a fairly uniform high velocity in the mixing section, which is converted to a pressure rise. This augments output of turbine, which operates at steady flow and full admission.

Aftercooling. Compression of intake air, an essential of supercharging, raises air temperature. This lessens air density, increases engine heat stress, and, in a gas engine, may cause detonation. It is thus increasingly common to cool air between supercharger outlet and intake manifold. This *aftercooling*, or *intercooling* as it also known, often needs only addition of a heat exchanger.

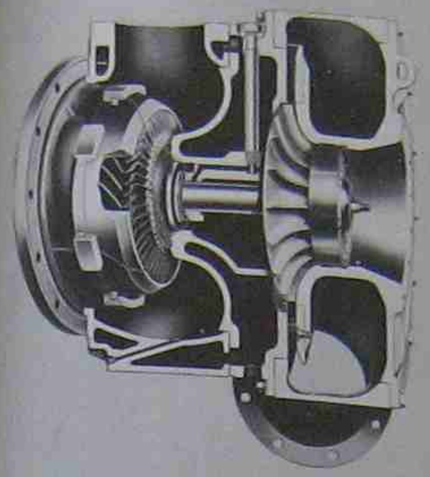
On gas-fuel engines, one builder employs a *turbocooler* — a centrifugal blower on the same shaft with an expander turbine. As diagrammed above, air from turbocharger is further compressed in centrifugal blower of turbocooler. It is then cooled by a heat exchanger and further cooled by sudden expansion in the turbine driving the blower.

Cooling within the engine cylinder is a feature of the Miller system. In a turbocharged and intercooled engine, intake valve is closed before end of intake stroke. Air in the cylinder expands to lower pressure and temperature, while doing useful work on the piston. Part of compression stroke is needed to bring air back to temperature it had when intake valve closed. Thus air in cylinder at end of compression is cooler and denser than normal.

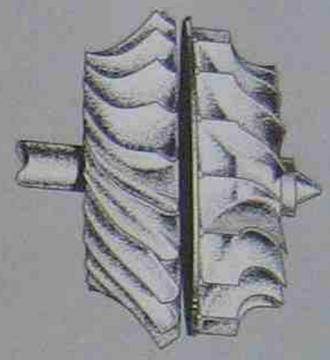
Drawing above shows mechanism that controls timing of intake-valve closing in accord with intake manifold pressure. At part load, valve closes with normal timing but as load and manifold pressure increase, control acts to close valve earlier for more expansion of air in cylinder.

Supercharging 2-stroke engines. The 2-stroke engine presents a different supercharging problem from 4-stroke engines we have been discussing. It does not have the separate charging stroke which permits the 4-stroke engine to start even when the charging blower is at rest. Balance

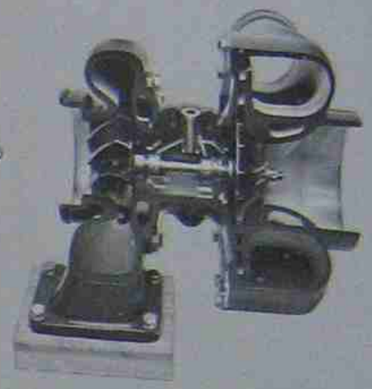
Today's turbochargers employ a variety of turbine and compressor wheel designs



AXIAL TURBINE, at left, and centrifugal blower, at right, mount on a common shaft, with support for precision sleeve bearings between wheels. Entire rotor assembly is statically and dynamically balanced. Blower and turbine casings can be removed from the intermediate casing without disturbing the rotor assembly and the rotor's bearings



CENTRIPETAL TURBINE WHEEL and mixed-flow blower impeller combine in a single rotor structure separated by a stationary partition plate. In addition to simplicity, this design aims to eliminate parasitic losses such as turbine and blower leakage. Overhung rotor is at end of shaft, which is journaled in two bearings on cold side of rotor



INWARD-FLOW TURBINE, at left, receives exhaust gas from casing surrounding periphery of the rotor. Entering rotor radially and inward, gas flow changes direction in passing through blading, leaves axially through opening at left. Air enters axially at right; discharges radially through diffuser vanes which act to convert kinetic energy

between air needs and exhaust energy available is also a problem because of scavenging air needs, which are essentially constant at all loads, and the usually greater combustion-air excess. This all adds up to need for more air per hphr, higher full-load air pressures and lower full-load exhaust temperatures with which to drive a turbine.

Thus early designs of supercharged 2-stroke engines used mechanically driven blowers. Continuous effort to realise, either partially or fully, the advantages of recovering exhaust energy in a turbocharger has led to a variety of combinations of mechanically driven and turbine driven units, in parallel and in series. In some cases, the turbocharger takes over after a given load is reached; in others both units remain in operation.

Full turbocharging. With suitably efficient turbocharging units, it is possible to supercharge the 2-stroke engine even during startup. This proved easier to do with the blowdown system and units of this type were developed first. However, the constant-pressure system seemed to offer advantages, and recently means have been found to use this without mechanical assistance. Auxiliary starting means are provided — usually jets of starting air to spin the turbine until the unit becomes self-sustaining. Supplementing this "jet assist" starting is a simultaneous purging of the cylinders by main air supply. If assist action is applied to the impeller blower, air used for accelerating the rotor can enter the cylinder for combustion. Spark may be retarded at starting and part load to raise exhaust temperature.

Supercharging advantages. Thus far we have talked mainly of supercharging as a means of increasing amount of fuel that can be burned in a given cylinder and thus boosting engine output. Without increasing engine heat stresses, output of 2-stroke engines can be increased as much as 50% or more, and in 4-stroke engines up to 150% of normally aspirated ratings. Greatest increases are usually obtained with aftercooling and on low speed engines.

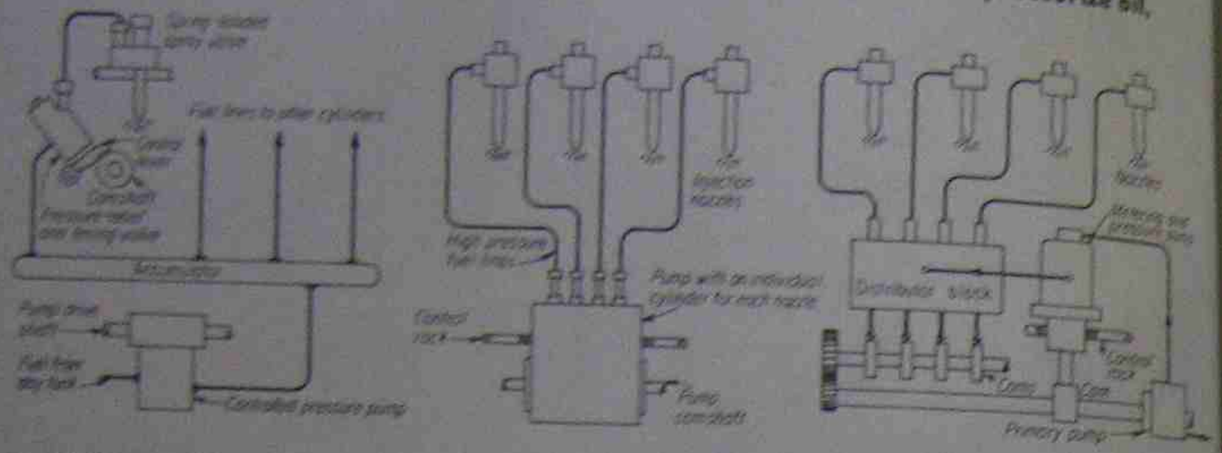
Supercharging also improves fuel economy and engine performance. Since friction horsepower increases only slightly with increased load, added horsepower from supercharging carries only a small friction penalty. In other words, proportion of engine output used to overcome friction becomes a smaller percent of the total.

Increase in air density at end of compression stroke tends to cause a decrease in the auto-ignition temperature of diesel fuel and a reduction in ignition lag. The result is a more gradual rate of pressure rise during combustion and generally quieter operation.

Although more heat is liberated in the cylinder of a supercharged engine, there may be little or no increase in cooling-system requirements. This comes about because increased air flow cools engine parts and a greater proportion of engine heat goes out in the exhaust.

Design for supercharging. Supercharging can, of course, be applied to existing engines with relatively few modifications. In designing for supercharging, particular attention would be paid to valving and timing. Clearance volume may be increased to reduce maximum pressure. Obviously, greater fuel-injection capacity must be provided.

Common-rail, pump, distributor, pressure-time and unit injector systems pressurize oil,

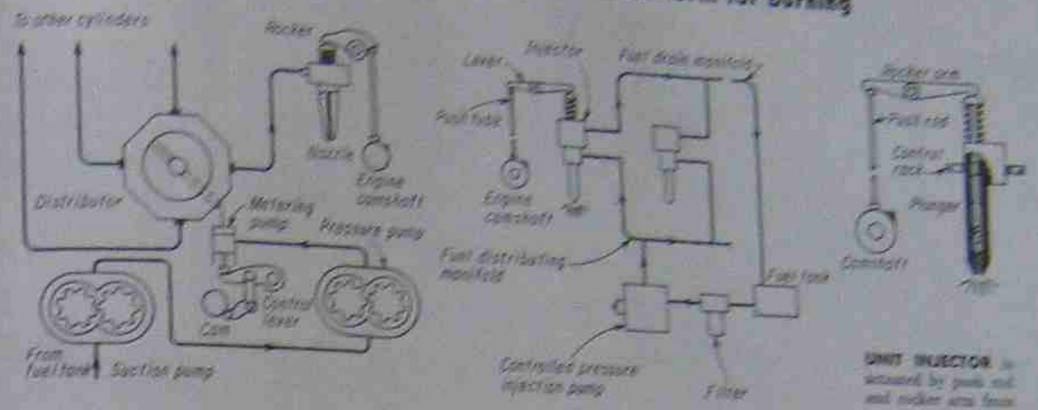


COMMON-RAIL injection pump maintains header at set pressure. Pressure relief and timing valves control injection time, flow rate of fuel. Spring-loaded spray nozzles also act as check valves to insure tight closing

PUMP-INJECTION system has an individual pump or pump cylinder connected to each fuel nozzle. Pump raises pressure, meters charge and controls injection timing. Fuel oil pressure actuates the spray nozzle

DISTRIBUTOR-INJECTION system uses pump to pressurize and meter fuel, time injection. Fuel is distributed to cylinders in right firing order by cam-operated popper valves which open to admit fuel to nozzles

meter and time its admission into cylinder in atomized form for burning



ALTERNATE DISTRIBUTOR hookup employs gear pumps to deliver low pressure fuel through metering pump in distributor assembly. Still at low pressure, fuel is directed to cylinder where mechanically-actuated nozzle raises pressure, controls injection time

PRESSURE-TIME injection system gear-pump and controls deliver fuel to distribution manifold; discharge pressure varies with engine speed. Injectors set each cylinder meter, pressurize and inject fuel. Pump provides continuous circulation through all the injectors

UNIT INJECTOR is actuated by push rod and rocker arm from camshaft. Tip pump plunger raises fuel pressure level, meters quantity, controls injection timing. Spill the valve is actuated by change in pressure

Injecting fuel and burning it

Basic job of fuel injection system is to bring fuel into the engine cylinder and mix it with air for rapid and complete combustion

Having seen how the engine is charged with air, let's look at the equally important job of bringing fuel into the cylinder for efficient combustion. With natural-gas fuel the job is fairly simple. Air and gas inlet valves, pp 5-10, 11, control flow of gas and air needed to provide a combustible mixture for spark ignition. In the case of fuel oil, the injection system is more complex.

The fuel injection system must perform five essential jobs: (1) deliver oil from storage to fuel nozzle, (2) raise fuel pressure to level needed for atomization, (3) measure and control amount of fuel admitted during each cycle, (4) control time of injection, and (5) spray fuel into cylinder in atomized form for mixing and burning.

Pumps and fuel nozzles form the basic elements of every mechanical injection system. They meter fuel, raise its pressure, and spray it into the cylinder at the right time. These elements are combined in many ways, but most systems fall into three basic categories: (1) common-rail, (2) pump injection, (3) distributor. All are shown above.

Common-rail system features pump with built-in pressure regulation which adjusts pumping rate to maintain the desired injection pressure. Fuel enters control valve through a ball-check isolating valve and flows to spring-loaded injection valves. These are lifted by tappet motion actuated by a cam. Between tappet and cam there is a lever mounted on a governor-operated eccentric shaft. Governor action then changes lever position, valve lift and timing. Since fuel pressure is fixed, this controls the quantity.

When injection valves seat, a passage through the injection valve stem connects discharge chamber to atmospheric pressure and a pressure-relief drain to the storage tank. This relieves spray valve of constant header pressure between injection periods, giving a sharp cutoff to injection and preventing any possibility of "dribbling." Since control of injection timing and quantity is placed in a separate valve, the spray valve need only be a spring-loaded check valve. When injection valve lifts to admit high pressure fuel to spray valve, its needle rises against the spring. When pressure is vented to atmosphere, the spring then snaps the valve shut.

Pump injection system depends on pump to carry out bulk of the control job. Typical pumps and nozzles employed in this widely used method are described later.

Distributor arrangements meter fuel at a central point and then direct it to cylinders in proper firing order. Alternate distributor design shown consists of a rotating disk and a stationary cover from which fuel lines run to individual ejectors. Disk and cover carry a series of holes, which, when properly indexed, form passages from fuel supply pump to metering pump. This occurs when metering plunger moves down on its suction stroke permitting oil to fill the pump barrel. Disk continues to rotate and lines up with correct discharge hole in cover just as metering plunger rises. This movement of the plunger forces correct amount of fuel into the proper injection line.

Metering pump is a closely fitted reciprocating unit, with driving linkage so designed that pump-stroke controlling quantity pumped, can be adjusted by the engine governor. In actual units gear pumps, distributor, metering pump and governor are combined in one housing.

Although this type of distributor system is still in use, it has been largely superseded on new engines.

Pressure-time injection depends on pressure of fluid and how long orifice is left uncovered, which in turn, is a function of engine speed.

Fuel pump assembly consists of a supply pump, a governor assembly to vary pump discharge pressure with engine speed, a throttle to control pressure of fuel delivered by pump to injectors and a shutdown valve.

During operation fuel is pumped through the system by a positive-displacement gear pump and delivered to fuel groove on the governor plunger. A bypass circuit runs from this groove, through an axial hole out the end of the plunger, back to inlet of the pump.

Fuel pressure produced is determined by the resultant of governor and spring forces acting to close gap between end of governor plunger and the pressure-control button. Fuel pump discharge pressure is independent of throttle position but is a function of engine speed. All fuel not delivered to injectors is discharged through gap between end of governor plunger and the button.

At idling speed, fuel passes through idle governor port to injectors. Throttle controls fuel flow in range between idling and maximum governor speed. Pressure at inlet to each injector provides enough fuel in given time.

Amount of fuel metered into the injection cavity through the fixed metering orifice is controlled by fuel-pressure differential across orifice and by total time orifice is open, fixed by cam-operated plunger and engine speed. After injection, plunger remains seated until the next metering and injection cycle. Although fuel doesn't reach the injection cup, it does flow freely through the injector and returns to the fuel tank. This helps to cool the injector and warm fuel in the supply tank.

Unit injectors combine pump, fuel valve and nozzle in a single housing, eliminating discharge tubing. Each engine cylinder then is served by an injector, actuated by push rod and rocker arm from the camshaft. Injector unit contains a pump plunger, which raises fuel pressure, meters charge and times injection; a delivery valve and a nozzle tip to give desired spray pattern.

Injection pumps must be capable of producing high pressures and measuring small quantities of fuel with a high degree of precision. Most operate with a constant stroke, although variable-stroke pumps are also used.

In constant-stroke pumps, the quantity pumped is usually adjusted by opening a bypass at some point before stroke is complete. Designs differ mainly in whether the bypassing is done by ports or by a valve.

Multiplunger pumps have a separate pumping element for each engine cylinder. They usually have a port and helix metering system and a self-contained drive. Camshaft, tappets, bearings and the governor may be lubricated by engine oil or by a self-contained system. Design, p 5-18, has constant-stroke plungers operating in barrels with intake and spill ports for port and helix metering.

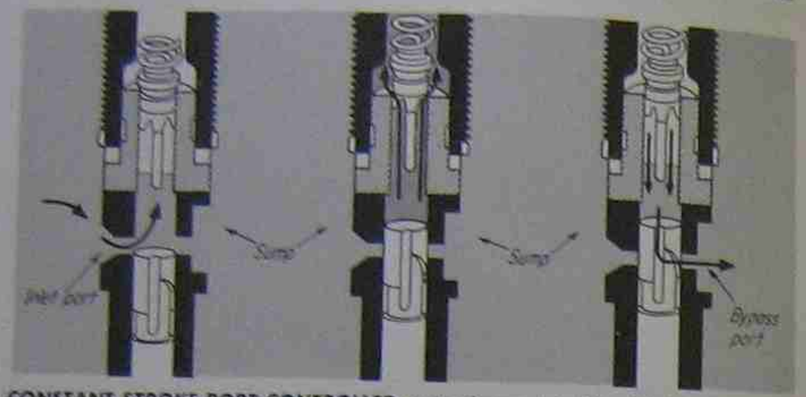
Distributor type pumps handle fuel oil for all cylinders and are most commonly found on small multicylinder engines. Design on p 5-19 has inlet metering, built-in governor, transfer pumps and automatic speed advance.

Individual pumps are mounted on each cylinder and actuated by an engine-mounted camshaft and tappet arrangement. While used on some smaller engines, they are more generally found on larger models since they can

Fuel injection pumps must produce high pressures



MULTIPLUNGER PUMP has self-contained drive, port and helix metering system, pump element for each cylinder



CONSTANT-STROKE PORT-CONTROLLED pump plunger, left, fills with fuel at bottom of travel. As plunger rises, oil pressure opens delivery valve. As stroke continues, helix opens bypass port to drop pressure and snap delivery valve shut. Turning plunger changes delivery time

be spaced along the engine near each cylinder. This permits use of short high-pressure injection lines of equal length. Pumps range in size from 25 to 3800 cu mm per stroke.

One typical design, p S·19, with output regulated by rotation of a helically-grooved plunger, is actuated by a rack which receives governor indications through a lay shaft and a spring-loaded individual arm along the engine bank. Individual pump adjustments can be made and a latch engaging on a groove in the rack makes it possible to isolate each pump and hold it in the "no fuel" position.

Duplex pump, p S·19, is used on dual-fuel engines that operate on either fuel oil, or gas and pilot fuel. Pump receives fuel oil at low pressure, measures correct amount for injection and delivers it at high pressure to the injection nozzle. Pump is of the two-plunger type. The lower or pilot-fuel pump is of small diameter to insure precise delivery of a constant small amount of fuel each stroke. When engine runs on gas, this serves to ignite the gas. In operation, valves in each cylinder control rate of gas admission from a common header. Typical gas-timing valve and a metering arrangement are shown below.

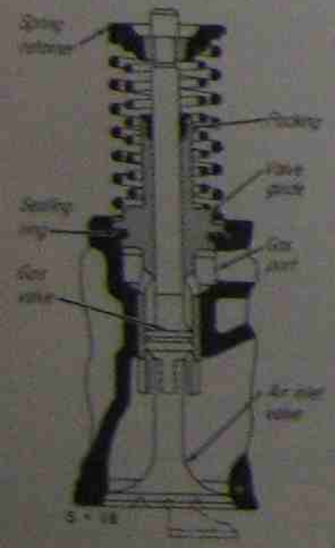
Spray valves and nozzles open and close passage to cylinder space and convert high-pressure oil into a spray of desired pattern. Typical common-rail injection systems use mechanically-operated needle valves. A spring holds the valve closed against fuel pressure until rocker, actuated by push rods from the camshaft, lifts valve in proportion to amount and duration of injection needed.

In pump injection systems, pressure rise created by the pump discharge stroke can be employed to actuate the valve hydraulically. These spray valves are usually the differential-area type.

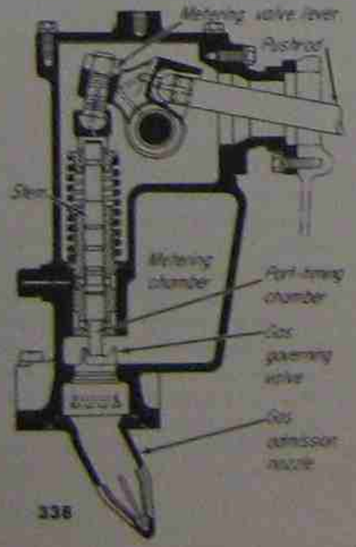
Nozzle tips. Most fuel valves consist of a nozzle holder or body which contains the valve mechanism and a nozzle tip which forms the spray. Design depends largely on the shape of spray pattern required. Common nozzle types, p S·20, are single or multihole and pintle.

Single-hole nozzles offer advantage of a fairly large

Gas control valves aim for lean ratio of air to fuel and right timing of admission

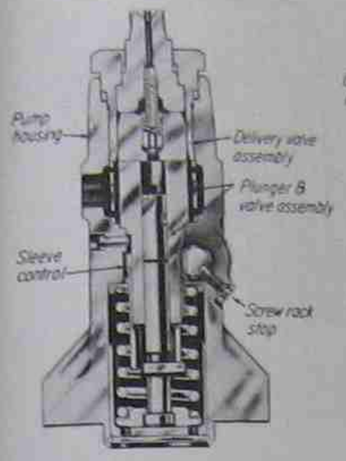


GAS TIMING VALVE can be an integral part of the air intake valve. Gas is admitted when gas valve uncovers ports in sleeve. Gas valve opens after air intake valve is partially opened and closes ahead of it. Some engines have a conical-seating gas valve floating on air-intake valve stem. Admission of gas in supercharged engines must be timed to occur after scavenging is completed and exhaust ports or valves closed

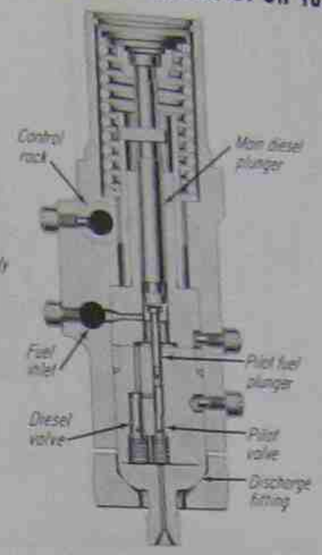


DUAL-FUEL METERING valve at each engine cylinder introduces enough gas to insure a balanced load on all cylinders. Actuated by an extension arm on the air valve lever, metering valve moves only when air inlet valve opens or closes. With air valve closed, metering valve is at position shown. Gas at controlled pressure then flows into metering chamber. Amount accumulated there depends on dimensions of chamber

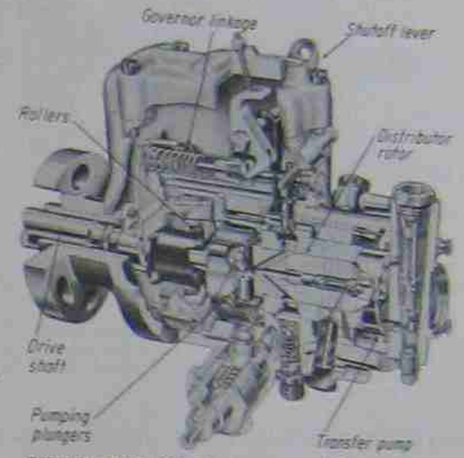
and measure extremely small quantities of oil fuel with the greatest precision



FUEL INJECTION PUMP of the constant-stroke type is regulated by rotation of helically grooved plunger



DUPLEX INJECTION pump for dual-fuel engine measures and pressurizes both fuel oil and pilot oil



DISTRIBUTOR-TYPE PUMP has two sets of plungers, shoes and rollers converging on common central pumping chamber. Top capacity is 200 cu mm per stroke at average pressures

opening even in small high-speed engines, which usually means less clogging trouble. They are also used in engines where combustion chamber shape creates turbulence and spray need not be so finely atomized or widespread.

Multiple-hole nozzles are popular for open chamber designs, p S·20, where it is necessary to distribute fuel spray to all parts of a wide shallow chamber. The more spray openings, the smaller each becomes. This makes it even more critical to keep the fuel oil clean.

Pintle nozzles are fitted with valves with ends carrying a shank or pin shaped to form spray pattern wanted. The pintle reaches into the nozzle orifice to form an annular space. By shaping the pin, designer obtains either a hollow cylindrical jet of high penetrating power or a tapered spray with an angle up to about 60 deg.

Combustion. In the case of fuel oil the engine handles the entire job of vaporizing, igniting and mixing inside the cylinder in an extremely short time. Successful combustion requires: (1) fine atomization, (2) high temperature for prompt ignition, (3) high relative velocity between fuel and air particles, and (4) good mixing of fuel and air.

Atomization, penetration and dispersion of fuel depend largely on the fuel injection system. Compression ratio, cylinder dimensions and cooling arrangements determine temperature conditions. Mixing depends on proper relation of injection pattern, air intake system and shape of combustion space formed by cylinder head, walls and piston crown.

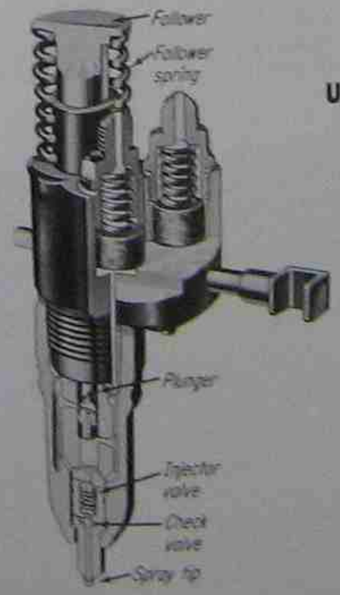
Combustion chambers. Simplest design is the open type, p S·20. It can be defined as one in which the fuel is injected directly into the entire air charge confined between the piston crown and cylinder head. Oil sprayed in this shallow space has to meet all the air without impinging too heavily on piston or cylinder walls.

While both air and fuel move in all engines, fuel motion predominates in an open chamber and greatly affects nature of combustion. Fuel is injected in a number of jets located to give best possible coverage of the space. Top of the piston crown is often made concave and shaped to make combustion space roughly hemispherical.

Mixing is improved by having air currents cut across oil sprays to disperse particles in turbulent fashion. Mixing is also helped by the motion of air entering the inlet port and any motion set up during compression. By coordinating shape and arrangement of piston crown, inlet port and valve, desired turbulence can be produced.

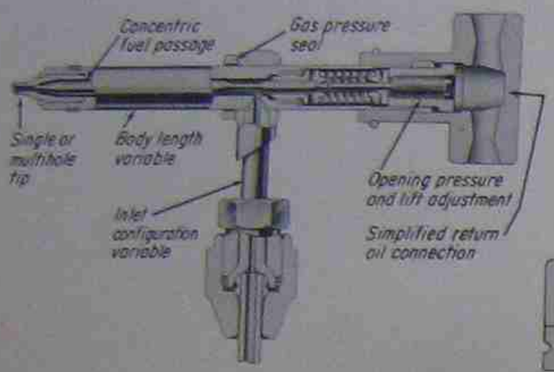
Open combustion chambers are widely used in medium

Unit combines fuel pump and nozzle

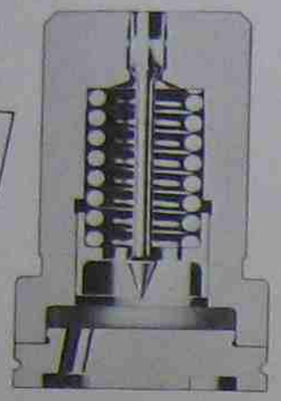


UNIT INJECTORS combine pump, fuel valve and nozzle in a single housing. Design, left, consists of a hollow steel body with high-pressure pump and a nozzle below. Injector mounts in a water-cooled copper tube that passes through cylinder head. Top of nozzle projects slightly below lower surface of the head

Injection nozzles may be hole or pintle type

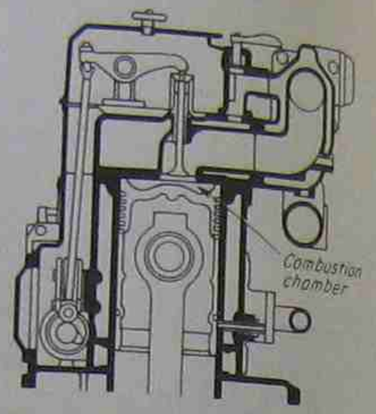


SINGLE OR MULTIHOLE NOZZLE, commonly used in the open or direct injection type of combustion chamber, usually produces a spray of uniform and compact pattern

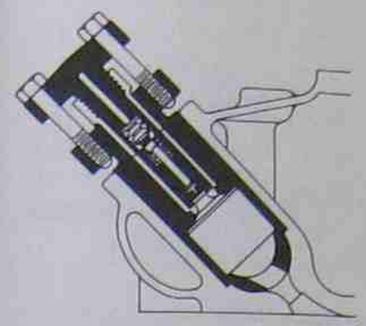


PINTLE TYPE poppet valve nozzle, used on opposed-piston design, provides conical spray

Combustion chamber design varies with engine size and speed



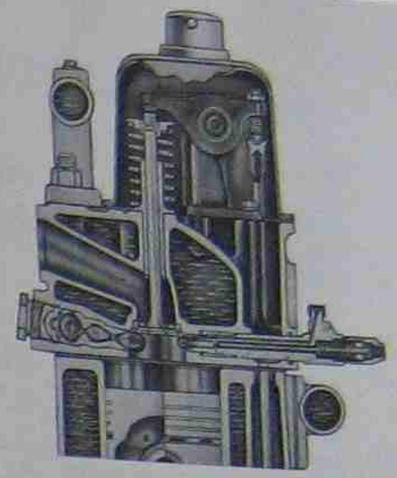
OPEN-TYPE combustion chamber contains all air at time of combustion. Nozzle sprays fuel directly into the cylinder



TURBULENCE CHAMBER holds virtually a full cylinder charge at end of compression. Shape creates highly turbulent conditions



PRECOMBUSTION chamber provides space where fuel burns with insufficient air, throws unburned fuel into main chamber



ENERGY CELL containing air burns entering fuel, blows products of combustion into main chamber to create desired turbulence

and large bore engines for low and medium speeds. Performance, particularly at constant speed, is good.

Special designs. Difficulty is encountered when both high maximum speed and a wide speed range are desired. Correct proportioning of the spray is critically important and speed change unbalances it. Overcharging only a small part of the combustion chamber can cause incomplete combustion and a dirty exhaust.

These limitations on open chambers for small-bore high-speed engines have led to development of some specialized designs. One spherical open-combustion chamber employs abnormally high-velocity air turbulence. This is created by a combination of either directional-port or masked-valve-induced air swirl and a very high velocity piston-induced squish. High-velocity air then sweeps over fuel deposited on chamber walls, temperatures of which are closely controlled, vaporizes it and mixes it with air for combustion. The result is smooth, controlled combustion with low-peak combustion pressures and quiet operation.

Other special designs can be grouped into four main classes: (1) turbulence chambers, (2) precombustion chambers, (3) air cells, and (4) energy cells.

Turbulence chamber, p S•21, is an auxiliary space separated from the cylinder by an orifice or throat. During operation piston forces air charge into the chamber setting up a rapid rotary motion. Velocity though the throat increases as piston rises, reaching a peak somewhere before top center. Nozzle then injects fuel into the turbulent air currents and good mixing results.

Precombustion chambers look like turbulence designs, but their basic principle differs markedly. Precombustion chamber holds only a part of the air charge with remainder contained in the cylinder space. Fuel injected in auxiliary chamber starts to burn with insufficient air. The mixture tends to explode, throwing unburned fuel into the main chamber, mixing it thoroughly with remaining air.

Air cell is a space provided in the piston or in the cylinder head where air is trapped during the compression stroke. This air is at close to maximum pressure when the piston starts down and pressure in the main space starts to drop. Pressure difference between air cell and cylinder causes air in cell to expand and flow out into main combustion space where it creates additional turbulence.

Energy cells, above, and air cells are often confused. With an energy cell, fuel is actually blown into the cell and burns there using air in the cell. Products of combustion then blow back into the main combustion space where they create the desired additional turbulence.

Gas-engine ignition demands maintenance of the correct air-fuel ratio and application of the spark at the right instant. For gas engines using compression pressures no greater than 140-150 psi, conventional automotive battery or magneto ignition system, p S•20, is quite acceptable.

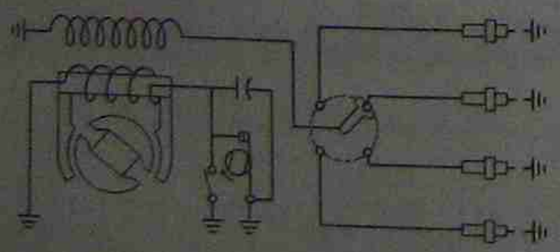
Later development of high-compression gas engines with pressures as high as 625 psi has led to radical changes in ignition systems to provide the high voltages needed for spark formation. Conventional battery or magneto ignition system has long leads from distributor to spark plugs. Increased voltage in these leads produces leaking, arcing, corona losses and generally erratic engine performance.

Today's high voltage ignition systems, p S•20, embody individual transformer coils located on each cylinder. This permits use of very short high-voltage wires to spark plugs. Distributor, instead of being in the high-voltage circuit, is in primary circuit. Resistors are often used to reduce burning of spark-plug points. Elimination of breaker points, always a weak feature in conventional ignition systems, is achieved by the pulse generator, below, in which a magnetic rotor replaces familiar rotating cam.

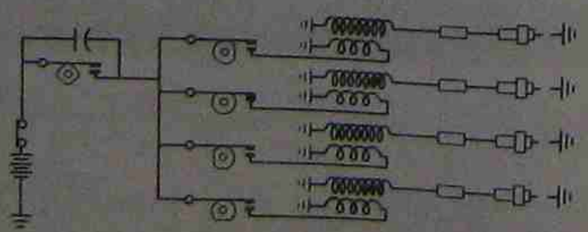
Electronic-ignition circuits, below, are now available using transistors to trigger the primary circuit. Transistor may be actuated by conventional breaker points. Since only transistor triggering current flows through breaker points, their useful life is extended many times. Systems of this type can also be installed on existing engines using their present breaker points and distributor.

Ignition systems for gas engines provide high voltages needed for spark formation

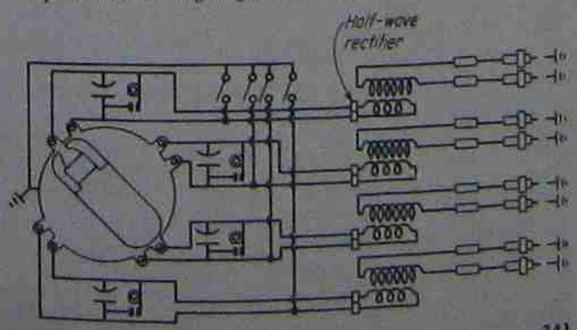
HIGH-TENSION MAGNETO supplies high-voltage current to distributor which then delivers high-tension current to the spark plugs



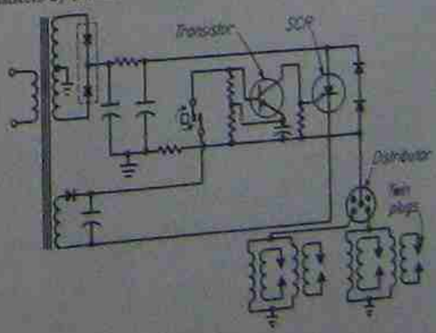
LOW-TENSION BATTERY distributor has four-lobe cam to interrupt current for all cylinders. Four cams distribute current to coils



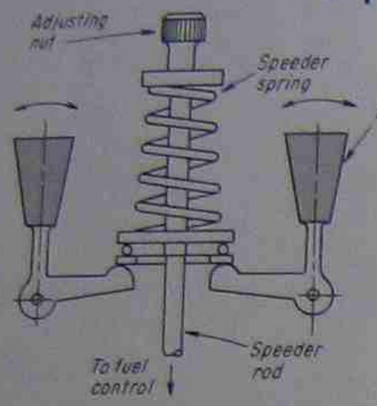
PULSE GENERATOR does not depend on interruptors for normal operation. Revolving magnetic rotor replaces the conventional cam



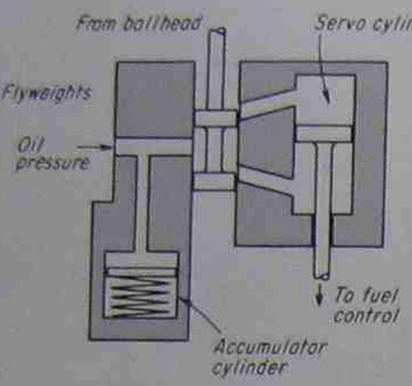
ELECTRONIC IGNITION-SYSTEM using 110-volt supply actuates transistors by normal breaker points which trigger primary circuit



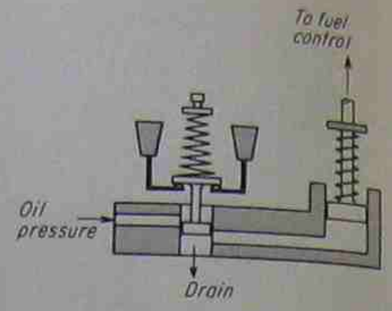
Simple mechanical governor using flyweights to adjust fuel flow



HEART OF GOVERNOR SYSTEM consists of revolving weights driven from flywheel end of crankshaft. In steady state, flyweight arms are vertical; speed change causes centrifugal force to move weights, so actuate throttle

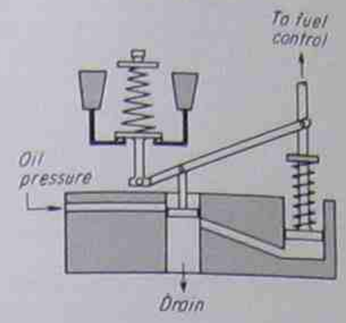


HYDRAULIC GOVERNOR uses same rotating flyweights as mechanical, but instead of actuating throttle linkage directly, the speeder rod controls oil flow to servo cylinder. Servo piston then operates fuel control

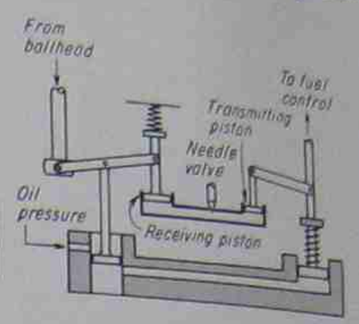


SERVOMECHANISM in simplest hydraulic governor has only one equilibrium position, when valve is fully closed. But since inertia of rotating parts prevents instant response, governor is unstable, causes severe hunting

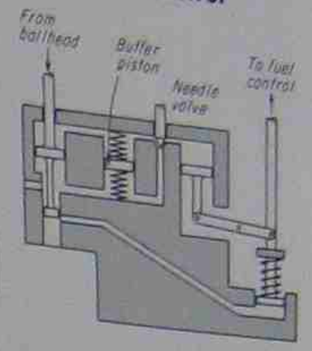
has developed into today's isochronous governor for precise generator control



STABILITY can be obtained most simply by connecting speeder rod, pilot valve stem and servo piston. This introduces speed droop, reduces over-travel of the piston and prevents hunting. Speed droop is adjustable



ISOCHRONOUS GOVERNING is essential where speed is critical, as in engine-generator sets. Rigid link is replaced by twin links. The needle valve controls oil leakage and gradually removes the speed droop



BUFFER PISTON complements needle valve in isochronous governor. Buffer produces pressure differential across a receiving piston connected to pilot valve, reducing or increasing force which flyweights must balance

Governing and instrumentation

Advances in engine power output have been matched by development of control equipment to ensure safe, efficient operation

Having seen how an engine is constructed and fed, let's look now at how it is controlled. Heart of any prime mover control system is a speed-governing device—in an automobile that device is the driver's foot, trying perhaps to maintain a certain speed by controlling the gasoline supply.

Governor development. But use of the human governor is not very satisfactory, especially when the prime mover is driving a generator or other machinery requiring precise speed control. As a result, some sort of automatic speed control is needed. The drawings above show how the simple mechanical governor, using centrifugal force and suitable linkage as a means of controlling fuel flow, has developed into today's hydraulic governor. It operates through a pilot valve to regulate flow to a servo cylinder. This in turn controls the fuel valve.

Basically both mechanical and hydraulic governors depend on the movement of spring-loaded flyweights driven by gearing from the engine crankshaft. These spinning weights produce a centrifugal force balanced by a spring-loaded thrust bearing which actuates linkage either to the engine throttle or, in a hydraulic governor, to the hydraulic servo mechanism. We will now take a closer look at a governor's function in controlling engine speed.

Speed regulation and *speed droop* are two terms often confused. Regulation is the variation in an engine's steady or sustained speed when load is changed without governor adjustment, expressed as a percentage of speed at full load. Therefore, if full load speed is 1200 rpm and rises to 1250 rpm when load is removed, speed change is 50 rpm and speed regulation 4%. Speed droop, on the other hand, is the change in speed resulting in complete governor-actuated throttle movement from fully open to fully closed, and vice versa. Some measure of speed droop is built into every governor, both mechanical and hydraulic, to prevent over-correction and hunting.

Mechanical governors. With a mechanical governor, an increase in load and consequent fall in engine speed reduces rotational speed of the flyweights. The speeder spring then overcomes reduced centrifugal force on the speeder ring, moves the ring down and in turn opens the engine fuel valve. Engine speed increases, but *not* to its previous value—if it did the throttle would not be open wide enough to supply the increased load. Conversely, when load is reduced and engine speed rises, centrifugal force on the flyweights causes speeder ring to rise and close the fuel valve—again, not to its original position, since a smaller fuel opening is needed for reduced load; the flyweights must be further displaced from the vertical, resulting in higher speed than before the load change.

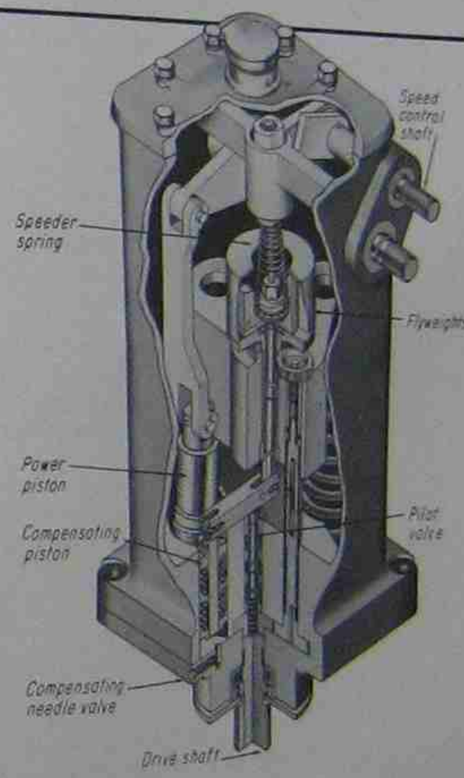
Thus the mechanical governor has inbuilt, permanent speed droop; steady speed on an engine fitted with this type of governor falls when load is applied, rises when load is reduced. Also, corrective action of any governor depends on its sensitivity—the more sensitive a governor is to engine speed changes, the less the corrective action needed and the faster its response. Engine speed deviation under load changes is dependent on both the time needed to correct fuel injection rate to correspond with the new load, and the time required for the engine's power output to respond to this change in fuel rate. Precise speed control, therefore, demands a prompt, sensitive governor, attributes not easy to provide in a mechanical device.

Hydraulic governors fulfill requirements of sensitivity, speed of operation and, most important, true isochronous control; they have largely superseded mechanical governors in most present-day operations. Instead of using the flyweights' centrifugal force to act directly on the fuel control mechanism, the speeder ring is linked to a small pilot valve controlling oil flow to and from the fuel control servomotor. Force needed to move the pilot valve is small, and so small flyweights can replace the large weights required on a mechanical governor. Friction in ballhead, speeder rod and pilot valve is kept to a minimum, often by continuous rotation of either the pilot valve or its sleeve.

The servomotor in a hydraulic governor may be double-acting, single-acting with spring return, or have differential areas. Function is the same in each case. To obtain stability, speed droop is built into the hydraulic governor by providing a link between speeder spring and servo piston. Then as fuel flow is increased, speed setting is reduced. Amount of speed droop depends on linkage ratio provided and is usually adjustable.

Growing use of duel-fuel engines has led to introduction of hydraulic governors able to control both compression-ignition and spark-ignition cycles. Governing of a gas engine is more critical than that of a diesel, due to the very small variation in air/fuel ratio which can be tolerated, and also to the lag both in power response after a fuel increase, and in supplying extra air to match this fuel change until a cycle or more later. If the engine overspeeds, on the other hand, a quick reduction in fuel will cause misfiring, a condition particularly critical with 2-cycle engines. Governor response therefore must be sufficiently slow to ignore speed variations caused by misfiring, and respond only to sustained speed changes resulting from variation in load.

Isochronous governing—control of speed to precise limits—is essential for diesel or gas engine generator sets.



MODERN ISOCHRONOUS GOVERNOR is suitable for use on diesel, gas or dual-fuel engines driving alternators or dc generators. Example shown provides a high degree of accuracy in a compact unit. A relatively short floating lever connects speeder rod with spring-loaded receiving piston, which in turn is open to the compensating needle valve adjustable from outside the governor casing. If no leakage occurred from the compensating oil system between receiving and transmitting pistons, the receiving piston would move as if rigidly connected to the power or servo-piston and permanent speed droop would result. To make the centering spring effective, therefore, controlled leakage past the needle valve returns receiving piston to its equilibrium position independent of the servo-piston movement

It is generally obtained by a compensating system which removes the stabilizing speed droop as soon as it is no longer needed. When the servo piston starts to move, a differential pressure acts on a piston connected to the pilot valve to cause speed droop. Simultaneously, a needle valve begins to relieve this pressure and fully removes speed droop by the time the new fuel setting has been reached and engine speed has returned to normal.

Design and construction of most hydraulic governors is based on the foregoing principles. Several companies manufacture governors embodying speed droop alone; many other units are isochronous. More elaborate types provide manual adjustment for speed droop, compensation and load limit. Frequently hydraulic governors are modified to suit special applications such as the variable speed operation of engines driving pumps or compressors in pipeline service. The pipeline pressure, working on a diaphragm, adjusts compression of the governor speeder spring and thus alters engine speed to maintain the desired pressure.

Electric governors find application in power generating sets where precise frequency control is needed. They may be sensitive either to speed change or to load change; in the latter case, correction in fuel setting starts before load changes appreciably affect the engine speed. In a load-sensing system, signals from the generating set's potential and current transformers are converted to a direct current corresponding to wattage. This current is applied to a solenoid, in turn connected to the oil pilot valve.

Engine starting and controls. Most engine installations will have at least some automatic controls or safety devices. These may be quite simple—automatic shutdown devices to stop the engine in the event of low oil pressure or high coolant temperature, for example, or a limit switch to prevent the engine being started with clutch engaged. More complex controls are used to start and stop the engine automatically or vary its performance as needed.

Selecting controls for a given installation depends on required performance, environment and the anticipated degree of human supervision. But before discussing automatic controls, let's look at typical starting mechanisms.

Large engines, both diesel and gas, are usually started by supplying compressed air directly to the engine cylinders. It is common practice to install two compressors, one engine-driven and the other with individual motor drive to provide for emergency operation. Air storage capacity depends upon the air storage pressure, usually between 250 and 450 psi, and the number of starting attempts made before recharging the air tanks. One rule of thumb is to provide a receiver capacity of some 30 times the engine cylinder volume. Minimum compressor capacity should enable the receivers to be fully replenished within one hour of reaching their lowest working pressure.

Smaller engines often use a separate motor, electric, air or hydraulic, geared to the flywheel; a small gasoline engine, too, may be used. Actual firing of the compression-ignition engine depends on the development of high enough temperature on the compression stroke to ignite the fuel. Since the temperature varies with compression pressure, and so in turn with cranking speed, a diesel engine will require cranking at some 15% of its operating speed before ignition temperature is reached.

Protective devices. Improvements in governor design have been matched by development of engine protection and safety devices. Alarms and shutdowns may be initiated by abnormal operating conditions such as high coolant temperature, low oil pressure or engine overspeed. Modern sensors and circuitry provide almost any combination of alarms enabling automatic, unsupervised control of entire diesel or gas engine plants. Extension into automatic operation involves starting and shutdown procedures; these functions may be initiated by low-voltage relays, frequency sensors or by pressure-sensitive controls.

One protective device monitors both water temperature and lube oil pressure using wax-type temperature-sensing elements. Inserted in the engine water jacket, the unit combines a bulb-mounted temperature sensing element with a lube oil pressure switch wired to the alarm system. When engine water temperature rises, wax contained in the bulb expands and causes a diaphragm-mounted needle valve to restrict oil flow, so actuating the pressure switch. Low lube oil pressure resulting from any other cause, such as a blocked filter, operates the switch in the same manner.

Speed protection is often provided over and above that of the governor. Overspeed protection in particular is given by a speed-sensing mechanism similar to that of the hydraulic governor but actuating engine shutdown. Capability of running for long periods without attention has been extended by devices which maintain crankcase oil level. Sump level in large engines is commonly monitored by a float valve regulator mounted on the crankcase and supplied from a gravity-feed oil tank. As well as insuring that the proper oil level is maintained, this arrangement adds a measure of protection against possible contamination compared to manual filling.

Automatic control. Widespread use of all these monitoring devices has greatly increased the reliability of unattended oil and gas engine plants. Degree of automatic control varies with application; service may vary from ensuring uninterrupted power for military radar networks, to simple standby service for, say, emergency hospital lighting. Single-engine installations are the simplest of all; such units can be arranged to start automatically in response to demand, or by remote control.

In the first case, starting may be triggered by low power line voltage, for example, or low water main pressure in a pumping installation. If the engine fails to start after a set number of cycles, the system is shut down and an alarm sent out. Risk of failure to start is often reduced by incorporating a timing cycle into the control system—set to start the engine periodically even when no demand exists. Similar provision is often made in low temperature conditions as a means of keeping the engine warm at all times; it may consist of a simple timing mechanism or a thermostatically controlled starting switch.

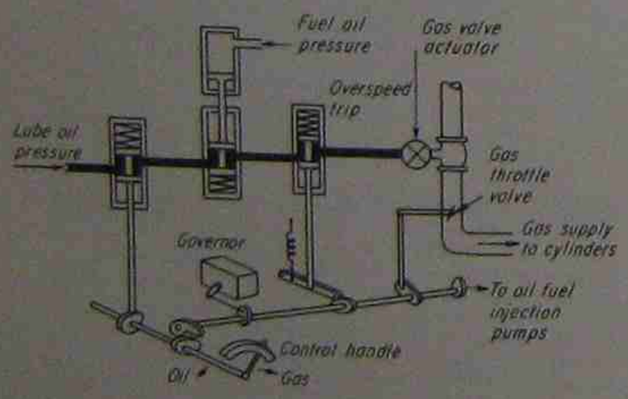
As engines become larger, and where more than one engine is involved, automatic control requirements become more complex. Starting procedures have more steps, and provision must be made for their correct sequencing. In power generation use, the need for speed-matching, synchronization and circuit breaker operation must be met. A typical compressor plant would require four basic control circuits — engine starting circuit, valve positioning, alarm and shutdown circuits. The control panel can be set for automatic or manual operation.

On automatic control, operation of the starting switch actuates a sequence of controls, each timed and interlocked to prevent continuation of the cycle if any phase should malfunction. First the auxiliary pumps, for engine cooling and lube oil cooling circuits, are started. When pressures reach a predetermined level, the compressor piping is purged through a blowdown valve. Discharge valve is then opened and starting air applied to the engine cylinders. After 8-10 sec rolling time, ignition is established and the gas valve opened. At this point engine fires, starting air is turned off and speed comes under governor control.

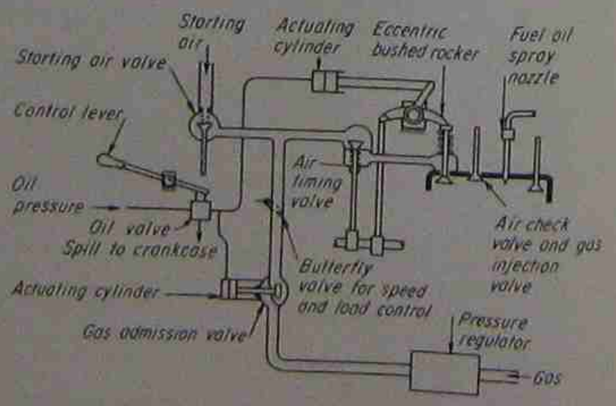
Unattended plants are usually equipped with a wider range of protective instrumentation than would be necessary in a manned installation. Some control instruments provide dual-sensing ranges to provide both alarm and shutdown functions in a single instrument. For example, jacket water temperature control might be arranged to give alarm signal at 190 F, shut down the engine at 200 F. Other dual-sensing instruments may monitor engine-bearing temperature, water and oil temperature and pressure, engine overspeed and crankshaft vibration. Points monitored for alarm only include lube oil filter differential pressure, sump oil level, manifold air temperature and engine exhaust temperature.

Engine-generator plants are provided with an additional safety feature in the form of a dead bus starting circuit. In the event of a multi-engine plant losing its only operating engine, say at a time of low load, all station power will be gone. The dead bus starting provision immediately trips out the station line feeders, signals another engine into operation and restores the line feeders in a predetermined sequence, avoiding overload on newly started engine.

Dual-fuel governors must handle transient speed changes

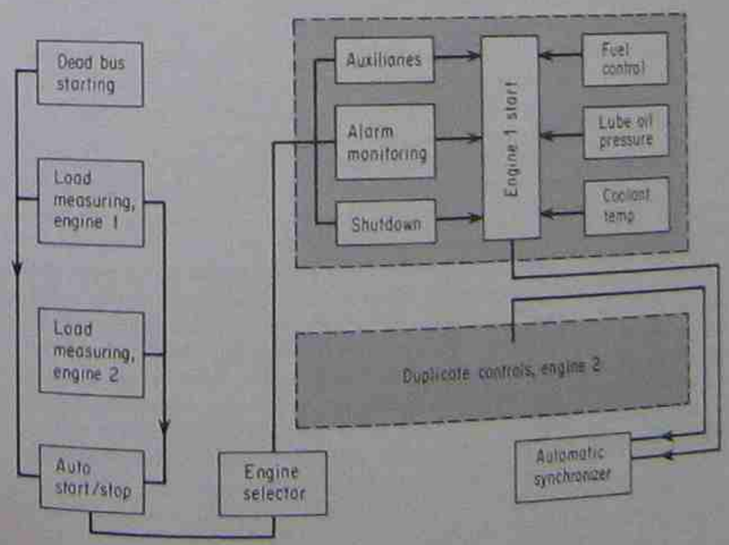


CONTROL SYSTEM provides independent control of gas throttle and oil fuel injectors. Lube oil pressure actuates the safety devices



AIR-STARTING VALVE in this dual-fuel system also serves as gas valve. Control lever prevents the functions occurring simultaneously

Automatic plants require rapid alarm and shutdown monitoring

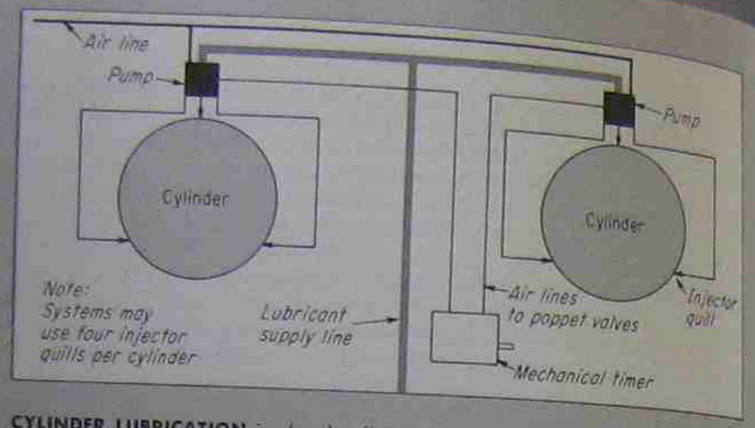


Complete automation of an engine-generator set and standby unit is a frequent requirement for, say, military or hospital use, or pipeline pumping. Sequence control system for a large critical installation has provision for engine selection and load-sharing, as well as automatic synchronization before the selected generator is put on line. Each engine-generator unit has its own control panel containing starting, alarm and shutdown relays, auxiliary equipment controls, temperature and pressure monitors. On receipt of starting signal, the individual engine control system is activated and prelubrication carried out. Valves and control devices are positioned for the start, and the engine then rolls on air. After start-up period, the change is made to fuel.

The modern lube system

An engine's main lubricating system supplies oil to bearings, valve gear, pumps, attached accessories. It also provides for piston cooling. Because of increased oil-flow requirements, engines larger than 2000 bhp generally have a separate oil sump. There is no firm pattern for locating oil entry point to journal bearings. Some designers feel there is advantage to bottom entry since oil passages may be rifle drilled and main oil line cast in bedplate, thus eliminating some oil piping. The system oil pump is generally driven from the free end of the crankshaft.

A separate lube system is often incorporated for engine cylinders having bores 16-in. and above. Separate system permits use of heavier oil in cylinders which is especially important for high temperature water-jacket designs. Also, alkaline reserve type oils may be adopted readily where conditions warrant.



CYLINDER LUBRICATION is often handled by a separate system designed to supply a measured quantity of lubricant at specific intervals. Air operated system, shown highly simplified above, will inject a metered amount of oil at high velocity onto ring belt of piston as it passes the lubricant inlet ports in cylinder. Cycling of lubricant system may be controlled by a mechanical timer which is controlled, in turn, by engine timing. In one specific design, the mechanical timer consists of adjustable cam-operated poppet valves, so spaced that one cam will trip one poppet valve every 36 deg of shaft rotation. Oil supply here may be from crankcase — off downstream side of oil filter — or through a separate fresh-oil feed. Some makers recommend that oil supply be filtered to eliminate particles above 10 microns. Alarm system responds to any lubricant or air supply failure

Lubrication

How the engine lubrication system functions to reduce wear and carry off heat

Reduced to bare fundamentals, job of the engine lubricating system is to reduce friction, to cool, to keep moving parts clean. This job is done, for most engines, in a pressurized system made up of four basic elements.

System parts of a pressure-lubricated arrangement include the *sump* for oil storage, a *pump* to supply pressure, an *oil cooler* to remove heat picked up by the oil, *oil conditioning equipment* to remove dirt, sludge, moisture. The system is completed with piping, valves and gages.

In the typical system, oil is supplied under pressure to a header and from there fed to each main bearing. Some oil enters passages in the crankshaft journals to supply the connecting rod bearings. A portion may be passed up through the drilled rod to lubricate piston pin bearing.

Single pressure generating-source cylinder lubricating system (not illustrated above) is widely used. Here a divider is provided to deliver the lubricant from pump proportionately into as many as 16 points. The 16 output points from this block are provided by assembling a "block package" which consists of inlet and outlet blocks and up to eight intermediate blocks with plungers.

Engine lubricants do their job, and for longer periods, in spite of: ever higher engine ratings, problems brought about by fuel impurities, the higher bearing loadings, the higher speeds and widening range of operating temperatures. The single problem of corrosion can be stubborn. Low operating temperatures, long idling periods, cold weather operation, water leakage, are some contributors to today's corrosion problems.

Lubricant additives are supplying many of the answers. Additives, protecting the lubricant in service by limiting chemical change or deterioration, also protect engine parts from corrosive effects of outside contaminants, improve the lubricants' physical properties (pour points, viscosity index, etc), help reduce surface wear.

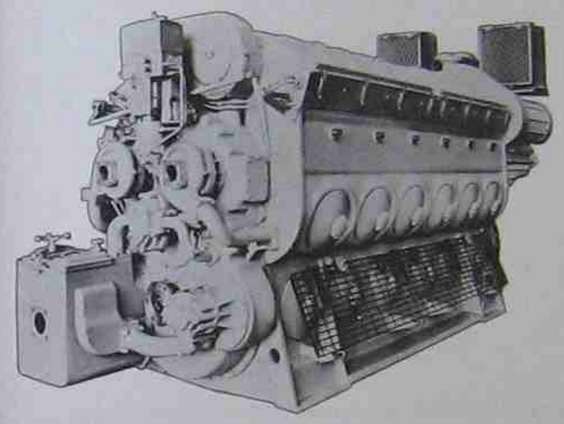
Operating temperatures are worth special note. Many designers consider an engine cold if jacket water is below 140 F or just below the dew point of combustion gases. Since blowby increases at the lower engine temperatures, sludge formation will be accelerated. Fuels containing even moderate amounts of sulfur, tend to form acids which pit and corrode when blowby is significant. True, the modern lubricant is formulated to cope with these problems, but they will do their job over a reasonable period only if teamed with oil conditioning equipment.

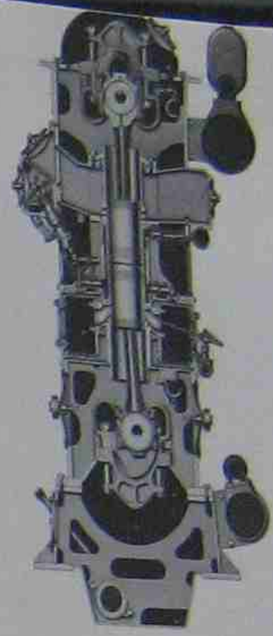
Oil conditioning means cooling, filtering, centrifuging, reclaiming. Heat of friction plus heat picked up by oil-cooled pistons, must be carried off to an external oil cooler. Quantity of heat removed by an oil cooler varies widely.

Filters are basically mechanical strainers or adsorbent devices. Mechanical straining is done by screening, metal-edge filters, cartridges of felt and cellulose: latter work by entangling solids as oil flows through. Adsorption filters work by attracting the foreign matter to its surface through molecular polar attraction. Adsorbent materials include fuller's earth, bentonites, activated alumina. They will remove dissolved acids, colloidal sludge — and some additives. Reclaiming uses filtration plus heat.

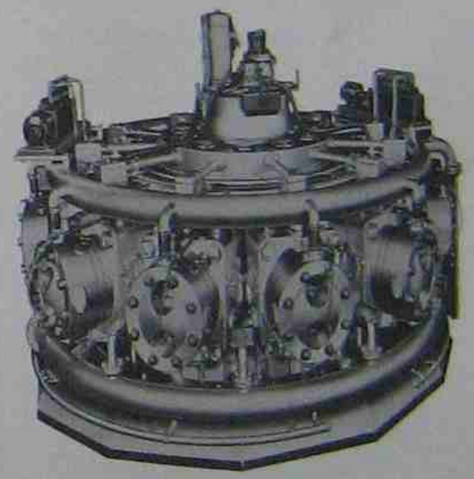
Typical modern engines

Starting with 2-cycle designs on this page, the following highlighting of construction features is made without attempt to separate engines on basis of rating, speed or duty

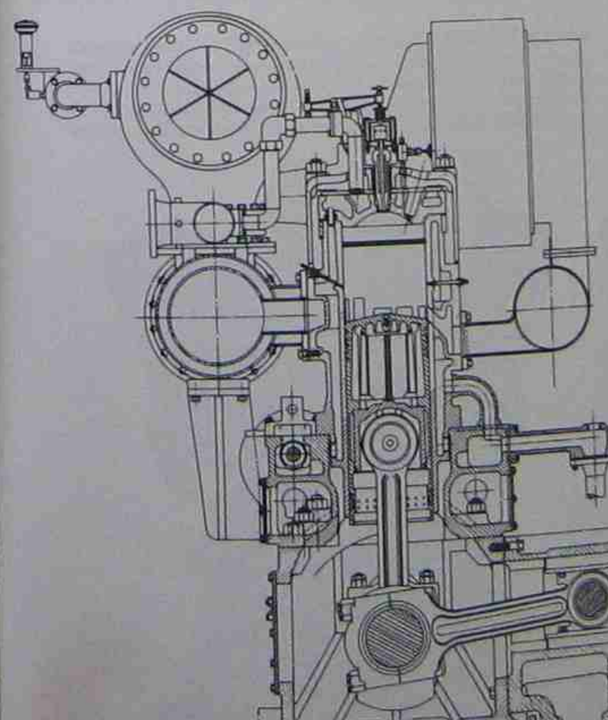




OPPOSED PISTON design has a crankshaft on top and bottom. Two pistons form a nearly spherical combustion chamber as they converge midway. Scavenging air enters upper ports, flows downward



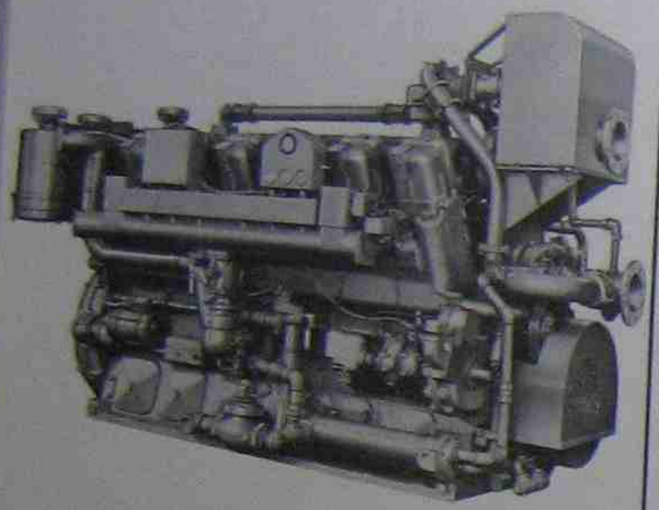
LIGHTWEIGHT ENGINE averaging about 20 lb per bhp; an important consideration for mobile generating sets. This non-supercharged, uniflow scavenging design requires no derating to 4000 ft



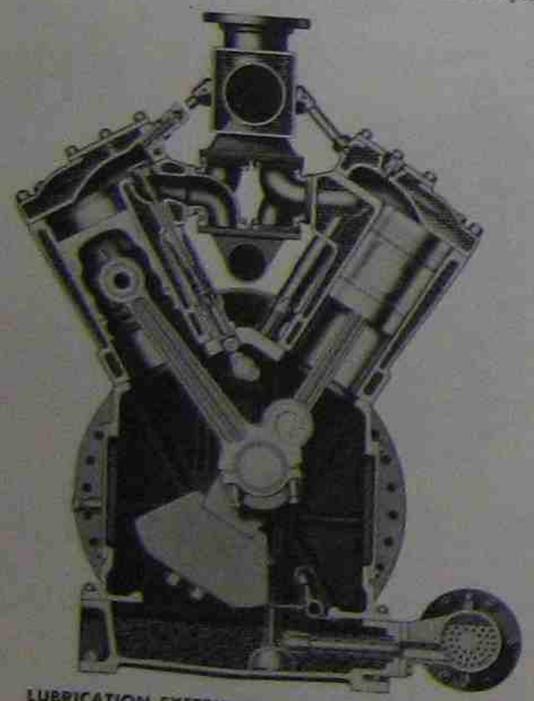
RADIAL DESIGN saves space: Cylinders are in horizontal plane with crankshaft rotating about a vertical axis. This 12-cyl unit built for gas, oil or dual fuel is rated 3200 bhp at a speed of 450 rpm

ENGINE-COMPRESSOR using a 14 x 14-in. bore and stroke is built with six or eight cylinders; top bhp rating of 1100 and 1440. Turbocharger is accelerated on startup with intermittent jets of air

Engines designed for gas fuel using the 4-stroke cycle

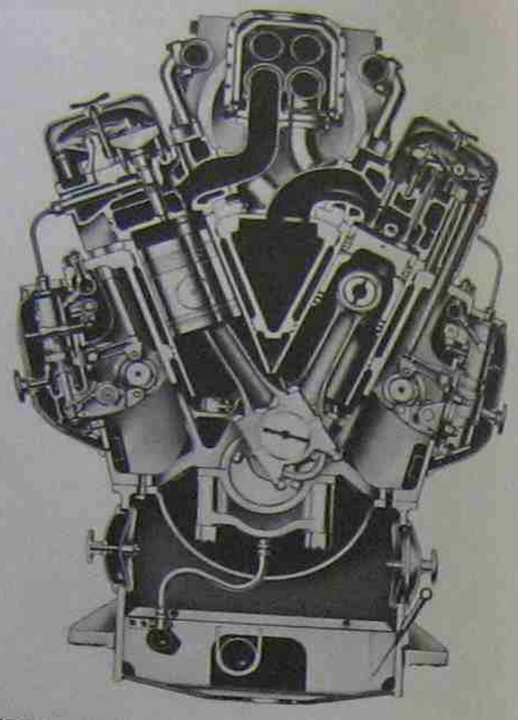


STELLITE-FACED VALVES seat on stellite inserts in this 12-cyl, overhead valve, heavy-duty engine. Piston is a 4-groove aluminum-alloy design. All major parts are interchangeable between right and left banks. Ignition is through dual low-tension magnetos, one spark plug and coil per cylinder. Instrument panel monitors coolant temperatures, oil pressure, vacuum and speed



LUBRICATION SYSTEM starts from an oil header having individual lines to each main bearing. Shell-and-tube oil cooler (lower right) is mounted on frame to simplify piping. Articulated forged-steel connecting rods have rifle-drilled passages for the lube oil. Camshaft in the crankcase, driven from crankshaft by heavy-duty roller chain, is lubricated by an oil spray

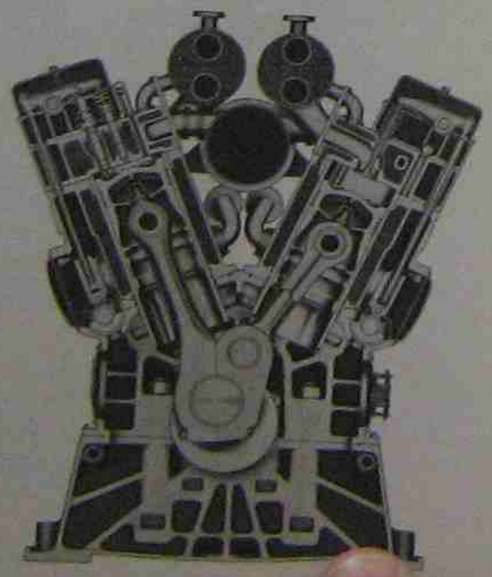
Developed primarily as oil engines,



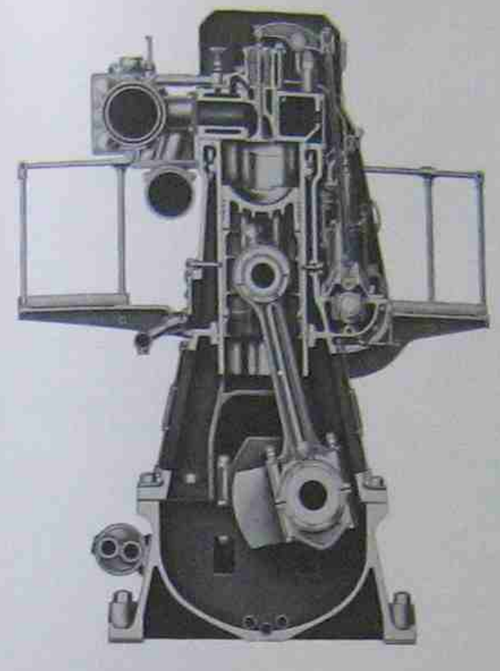
PISTONS are fitted with removable ring carriers which can be replaced when worn. Piston cooling done with oil circulating through inner passages: Oil feed is from openings drilled in connecting rods. Main and crankpin bearings are tri-metal: steel back, lead-copper layer, lead-tin face. Serrated fit used between bearing cap, block

Dual-fuel features of 4-cycle engines

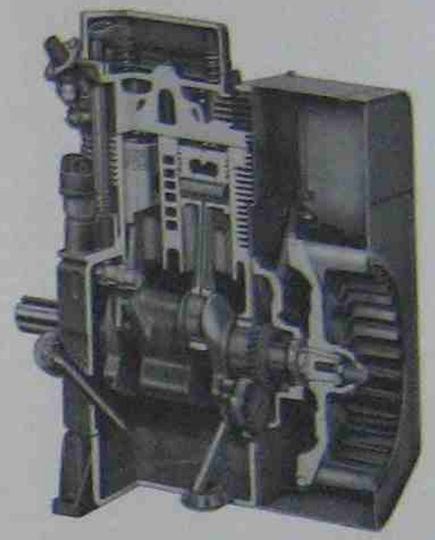
COMPACT DESIGN is stressed in this engine. Connecting rods of opposite cylinders are in same plane to reduce engine length and simplify the job of removing rod and piston assembly as a unit. Complete piston and connecting rod can be removed through cylinder by releasing six bolts. The liners are of high-strength cast iron



these 4-cycle units span a wide range of ratings and cover a number of applications



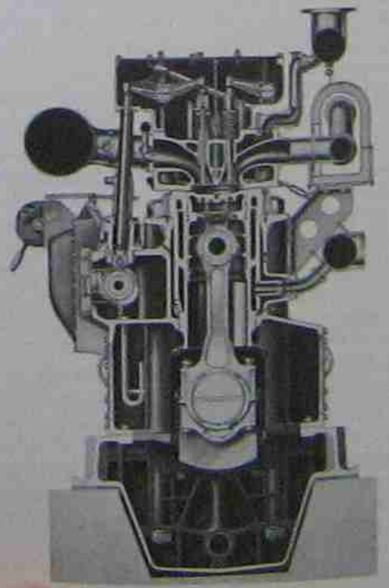
REMOVABLE CAGES house the inlet and exhaust valves, helping to ease checking, inspection and reconditioning. Exhaust valve cage is watercooled. Water-jacketed exhaust manifold (top, left) prevents heat stresses while protecting operator from hot-surface contact. Positive 2-point cylinder lubrication provided by force-feed



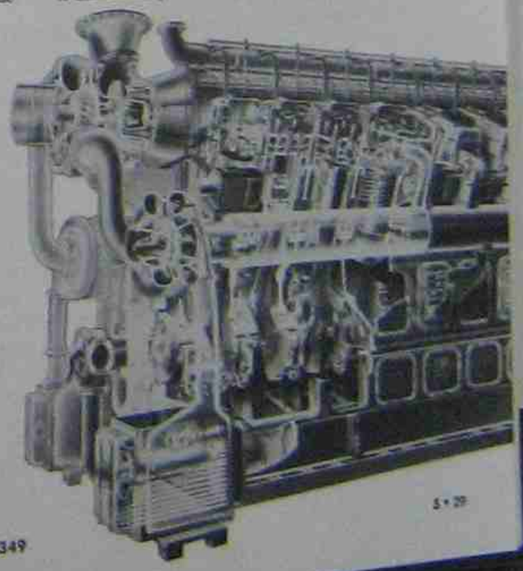
AIR COOLED ENGINE in the 7- to 40-bhp range follows in-line construction, overhead valves. Hand primer used for bleeding air from fuel system on initial startup, after long shutdown. Crankcase is vented to engine air intake and is kept at slight vacuum to prevent oil leakage at joints. Glow plugs and air heater are standard

permit operation with a variety of fuels, offering a measure of flexibility

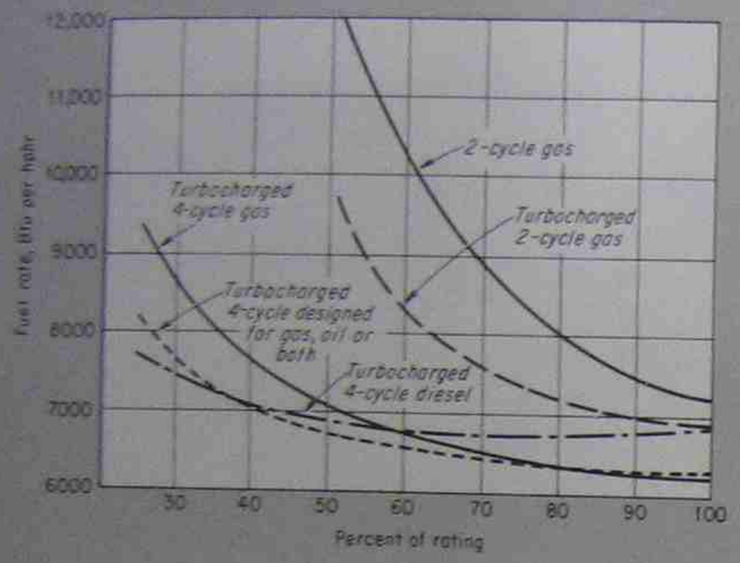
CYLINDER COOLING here is accomplished with cast-in water jacket, eliminating need for sealing rings, glands. Piston tops are not cutout since cylinder heads are recessed. Connecting rods interchangeable with maker's V-line. Rods drilled for pressure lubrication of wristpin and for piston cooling. Lube oil manifold cast in base



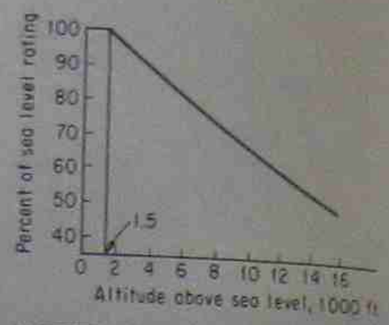
TURBOCOOLER lowers temperature of air leaving turbocharger. This raises engine load-pulling ability by increasing detonation level. Turbocooler, a centrifugal blower and expander turbine on a common shaft (shown left, below turbocharger), reduces sensitivity to ambient. Air pressure drop while expanding reduces temperature



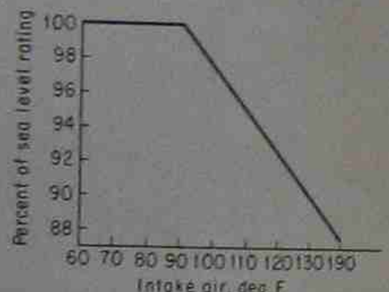
When analyzing economics of various engines, consider effect of derating and heat recovery from exhaust gas and jacket water



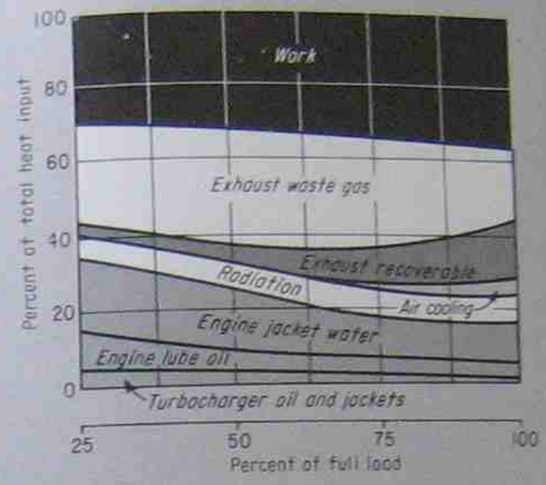
FUEL-RATE CURVES FOR LARGE ENGINES reveal the influence of a number of factors. For example, effect of turbocharging on fuel economy becomes evident when the 2-stroke-cycle gas engines are compared. And, as might be expected, all three of the turbocharged 4-stroke-cycle engines—gas, dual-fuel, and diesel—show better fuel rates than the turbocharged 2-stroke-cycle gas engine. Characteristically, the diesel engine has the flattest turbo-rate curve, with performance at partial loads approaching that at full. On the other hand, the gas engine, while excellent at 100% load, suffers at loads below 50%. It should be noted that, in accordance with customary practice, the gas and dual-fuel engines have their fuel rates based on the lower heating value of the fuel, while the diesel fuel rate is based on the higher heating value. The difference this makes in the economics of operation for the various engines is clearly evident in the higher load portions of the fuel-consumption curves



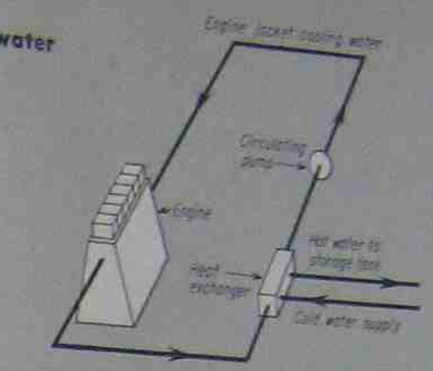
ALTITUDE RATING is charted as percent of sea level bhp. Derating is needed because atmospheric pressure drops with altitude; therefore cylinder holds less air by weight



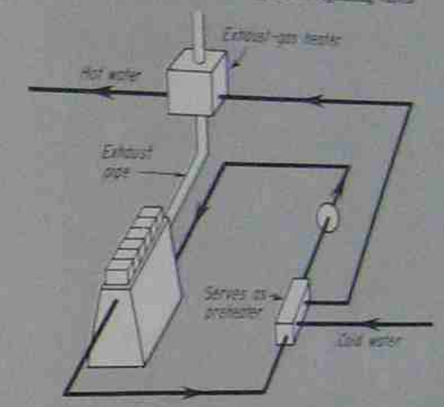
AIR TEMPERATURE also affects unit rating, since air density decreases with an increase in temperature. Result is less oxygen actually available for combustion in cylinder



HEAT DISTRIBUTION, shown above, is for a typical 4-cycle turbocharged heavy-duty diesel of about 1500 hp. At full load, the assumed engine thermal efficiency of 36.5% corresponds to a specific fuel consumption of 0.360 lb per bhp per hr, based on 19,350 Btu per lb of fuel. The heat rejected by engine jacket water and lubricating oil combined, will total 16.8% and can be reclaimed completely. Here the exhaust heat that can be recovered comes to 18.3%, yielding an overall plant thermal efficiency of 71.6%. Estimated cost for complete heat recovery equipment needed to yield above results from exhaust gas, lubricating oil and jacket water might well run less than 5% the cost of engine and generator. The engine jacket water alone is often used to produce steam in the 15- to 35-psi range for space heaters



JACKET HEAT may be recovered in heat exchanger to generate hot water. Sketch does not show the temperature-regulating valves



JACKET AND EXHAUST HEAT both contribute to heating of water here, with the jacket-water heat exchanger serving as a preheater

Putting engines to work

Effective application requires an understanding of engine performance and of ways to utilize its byproduct heat

Efficiency and capacity are perhaps the first considerations that come to mind in putting oil and gas engines to work. There are others, but let's look first at these two, and some of the factors that influence them.

Efficiency. The percentage of fuel heat converted to useful work is the *thermal efficiency*. For oil and gas engines as a class, it runs high—generally above 30% and sometimes above 40% at full load. An important asset of this type of prime mover is the fact that efficiency is relatively independent of unit size. In general, large, low-speed engines tend to be more efficient than small, high-speed units, but the difference is usually slight.

Fuel consumption rates represent another means of expressing efficiency. The curves above give fuel rates for several types of large engines and indicate, among other things, the value of turbocharging in improving fuel economy as well as increasing engine capacity. They also show that the diesel engine, in particular, maintains its efficiency over a wide range of loads. This can be an important consideration for some applications.

Conditions under which fuel consumption figures are derived and guaranteed by members of the Diesel Engine Manufacturers Association are spelled out in their publication "Standard practices for stationary diesel and gas engines." Prospective purchasers would be well advised to consult this informative book.

What price efficiency? Thermal efficiency is, of course, but one element in an equation that must include such other factors as fuel cost and the required investment in equipment. For example, high efficiency is clearly more valuable, and hence worth added investment, in areas where fuel is expensive. Where fuel is cheap, the economical answer may well be a less costly type of engine even though it may have a higher fuel consumption rate.

It is equally evident that greater investment for high efficiency can be justified more readily for applications where load factor is high—pipeline pumping, for example. In contrast, for standby and peak-load applications, where operating hours may be few, it is customary to seek low first cost, with efficiency receiving only minor consideration. Other factors in this particular equation might be quickness and reliability of starting.

Engine capacity. When it comes to capacity, we are primarily concerned with *brake horsepower*—the net power available at the engine output shaft. This accounts for power taken by auxiliaries that are engine driven but net output of the complete installation will, of course, be reduced by the power needed for plant auxiliaries.

For essentially self-contained units such as are used in mobile and portable application, *net hp* would be the output of the engine equipped with all necessary auxiliaries, while *gross hp* would be output of a stripped unit.

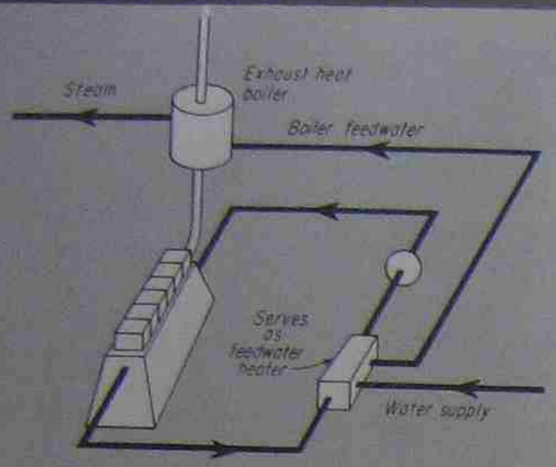
Maximum brake hp may be defined as the highest output the engine can develop at a given speed, while staying within permissible smoke limits. *Rated bhp* is horsepower specified for a given speed and type of application. In this matter also, the prospective purchaser would be wise to consult the DEMA "Standards" mentioned earlier.

For a specified cylinder size and stroke, engine output depends on speed and mean effective pressure (defined on p S • 5). Up to a point, increasing quantity of fuel burned increases the bmep and hence the output. Beyond this, combustion will be incomplete and injection of additional fuel results in smoky exhaust and greater heat stresses.

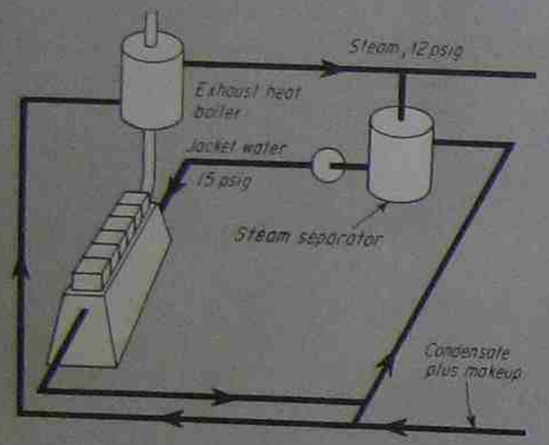
Derating. The capacity of an engine depends in large measure on the *weight* of air its cylinders will hold and this, in turn, is influenced by barometric pressure of the intake air, and its temperature. To avoid need for altitude or temperature corrections in the majority of installations, standard sea level ratings apply to altitudes up to 1500 ft and temperatures up to 90 F. For higher altitudes or temperatures, the engine is generally derated in accordance with the DEMA curves shown on the preceding page.

Supercharging can be used to offset the effect of altitude and intake air coolers can reduce high ambient air temperatures. Because of the variables involved, no simple formula is available for making derating calculations on a supercharged engine. Altitude ratings for these units are generally provided by maker for specific conditions.

Operating costs. In addition to the cost of fuel, these

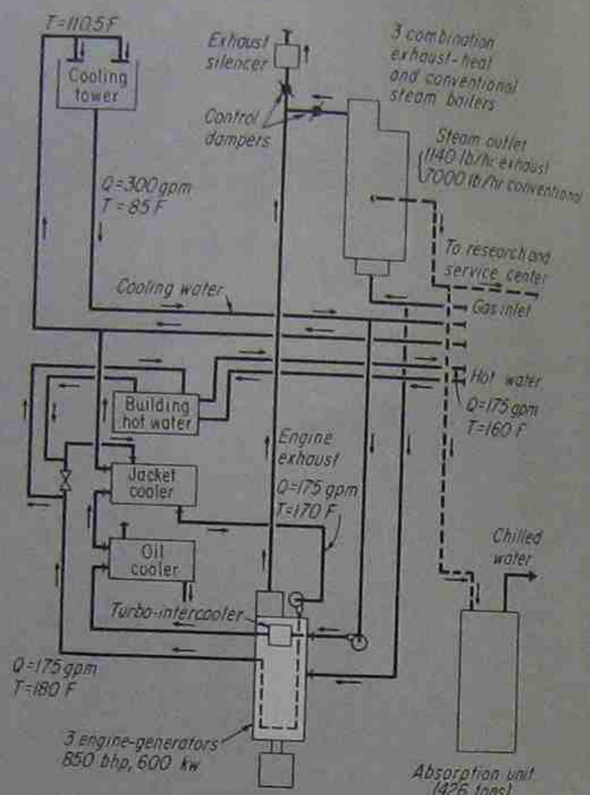


LOW PRESSURE STEAM may be generated in an exhaust-heat boiler, with jacket-water exchanger serving to heat boiler feedwater



VAPOR-PHASE SYSTEM generates steam. Higher and more uniform jacket temperatures help reduce corrosive cylinder wear

One way to use recovered engine heat



TOTAL-ENERGY CONCEPT is applied here through utilization of jacket and exhaust heat for hot water and building heating, cooling

include lubricating oil, operating labor, maintenance and repairs and fixed charges. Because data in this area was hard to come by, the Oil and Gas Engine Power Costs Subcommittee of ASME has published for many years an annual report giving actual cost experience of typical installations. The latest such report presents data collected from 95 plant operators throughout the U.S. for the year 1962. The subcommittee aims at fact finding and makes no attempt to establish conclusions or interpret the facts.

Applications. Oil and gas engines see service in the generation of electric power in municipal and privately owned stations and in industrial plants. Many find use as direct drives for pumps, compressors and other machinery in industrial plants, pipeline stations, etc.

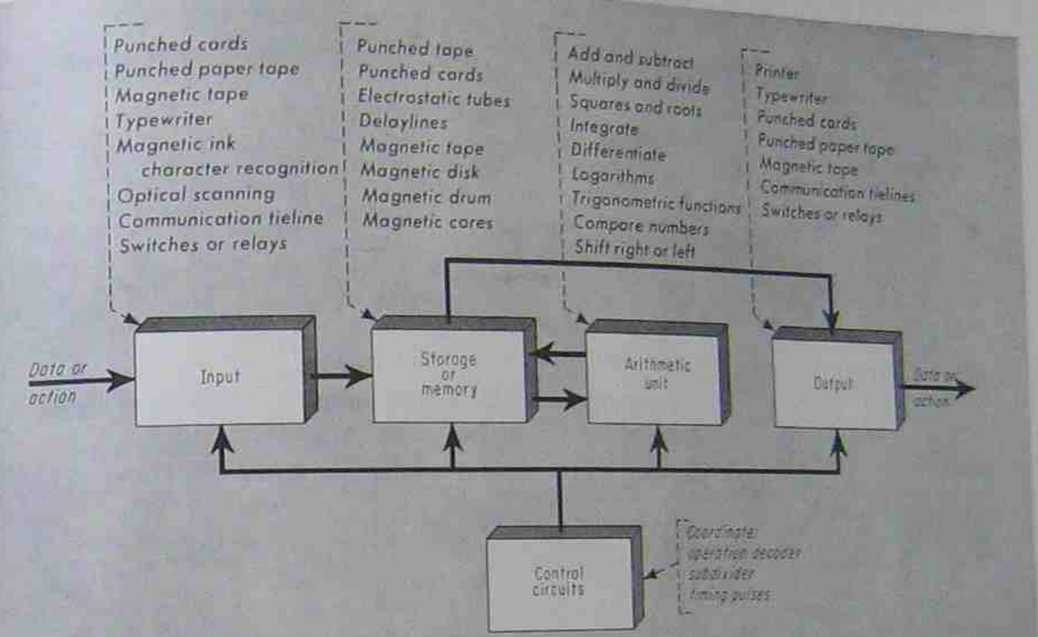
As peaking units on electric utility systems, the inherent compactness and flexibility of oil and gas engines permits locating them in key load center areas, aiding the development of a planned, economical system growth.

Engines continue to serve needs for standby power in industrial, commercial, institutional and military installations. In recent years, critical demands of some electronic equipment—microwave and computer installations for example—have led to increased interest in engine-generator sets able to take over with essentially no loss in electrical wave shape, frequency or voltage. Standby equipment of this kind has proved a practical answer to problems posed by electrical transients from switching, system faults, start-up of major in-plant equipment, lightning strikes, etc.

Heat recovery in engine installations has taken on added significance in recent years. Need for process and space heating has always presented an opportunity to recover some of the 60% or more of fuel energy not converted to brake hp. Sketches above and on preceding page outline some typical heat-recovery hookups.

Total energy concept is simply the application of oil or gas engines (or steam or gas turbines) to drive electric generators, with byproduct heat serving climate-control or plant-process needs. A strong factor favoring total-energy installations is the growth in year-around climate control. This, plus gas utility incentives makes many shopping centers, housing developments, commercial buildings and industrial plants prospects for total energy.

By B G A SKROTZKI, Associate Editor



1 Digital computers made up of thousands of elements have them grouped in five major sections. Input group loads the computer with data and instructions; memory stores the data; control circuits carry out instructions; arithmetic unit works with memory to carry out computations or comparisons under direction of the control circuits; output records answers or initiates actions

Automatic computer control: a time of trial

- Generating stations were probably the first to use automatic open- and closed-loop control systems
- Continued development of analog and digital computers point the way to achieving a fully automatic pushbutton energy-process control system and generating plant
- First approaches to automatic energy control superpose computers on more conventional intraplant control loops
- Ultimate automatic system is visualized as less complex control layout with both energy system and controls designed as compatible overall unit
- Unexpected problems and rising costs tax the control-designer's ingenuity to prove the computer in automatic control systems

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Increasing use of arithmetic and its descendant, mathematics, and the growing mountain of data to be processed led man to develop easier ways of doing the job. So were born the abacus, the adding machine, the slide rule, the calculator. These relieved man of the boring chore of repetitive figuring, sped up the process and proved more accurate.

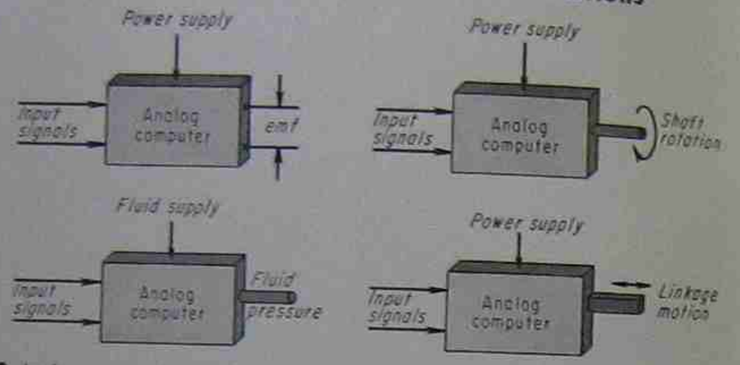
Analog computers. In the 1920's efforts were made to speed up the processes of more complex mathematics by putting electrons to work. Various electrical networks of resistances, inductances and capacitances and applying voltages at input terminals provided answers to complex equations by measuring voltages and currents at output terminals. The facility of this approach was expanded by developing various electromechanical and mechanical elements, Fig. 2, and answers could be produced in graphical form. In energy control systems this type of computer is called the special-purpose analog computer.

It does a wide variety of jobs by instantaneously figuring boiler efficiency, heat-transfer rates, mass flows, compressor efficiency, power demand, pump efficiency, viscosity, pressures, temperatures and liquid levels. Many of our familiar energy-system instruments can be classed as analog computers. For example, a flowmeter basically measures the pressure drop of a fluid passing through an orifice and by mechanical cams or by electrical resistance across a mercury manometer "computes" the flow and draws a line on a flow-vs-time graphical chart.

Analog computers and instruments have the virtue of being fast and relatively inexpensive. Generally they are special-purpose devices designed for one specific application. They are precision limited, the highest usually being on the order of one part in 10,000. With time, instrument accuracy may drift, and the computer may need periodic calibration. All analog computers are not necessarily electrical; some use hydraulic, pneumatic or mechanical components exclusively. This depends on the application and economics involved.

Analog computers often have hardware components not too different from conventional energy-system instrumentation. This means that generally no new maintenance skills need be developed. Also being less complex they are usually less expensive than digital computers.

Analog computer controls add, subtract, multiply, divide, generate logarithms and trigonometric functions



2 Analog computers were the first type of electronic calculators developed. Their variety of elements finds special applications in closed-loop energy control systems

1—Comparison of number systems

DECIMAL SYSTEM					BINARY SYSTEM					
Weights					Weights					
Powers of base	10^3	10^2	10^1	10^0	Decimal number	2^3	2^2	2^1	2^0	Equivalent no. Binary	Decimal
Decimal value	1000	100	10	1		8	4	2	1		
	0	0	0	0	0	0	0	0	0	0000	0
	0	0	0	1	1	0	0	0	1	0001	1
	0	0	0	2	2	0	0	1	0	0010	2
	0	0	0	3	3	0	0	1	1	0011	3
	0	0	0	4	4	0	1	0	0	0100	4
	0	0	0	5	5	0	1	0	1	0101	5
	0	0	0	6	6	0	1	1	0	0110	6
	0	0	0	7	7	0	1	1	1	0111	7
	0	0	0	8	8	1	0	0	0	1000	8
	0	0	0	9	9	1	0	0	1	1001	9
	0	0	1	0	10	1	0	1	0	1010	10
	0	1	0	0	100	1	0	1	1	1011	11
	0	8	7	6	876	1	1	0	0	1100	12
	3	5	7	9	3579	1	1	0	1	1101	13
	8	7	5	3	8753	1	1	1	0	1110	14
	9	9	9	9	9999	1	1	1	1	1111	15

Digital computers. Fig. 1, were born in the 1940's. They were another electronic approach to the high-speed processing of mountains of data with complex equations. The first ones used electrical relays or vacuum tubes to apply the very simple system of recognizing two states of an object: go or no-go, yes or no, true or false, 0 or 1.

The last-mentioned two alternative states are the basic tools of binary arithmetic, a counting system based on the number 2. The one we ordinarily use is the decimal system based on the number 10. Our decimal system is largely an arbitrary form of counting, probably derived from the fact that we have ten fingers, our handiest counters. Table 1 shows how binary and decimal counting systems correlate with each other.

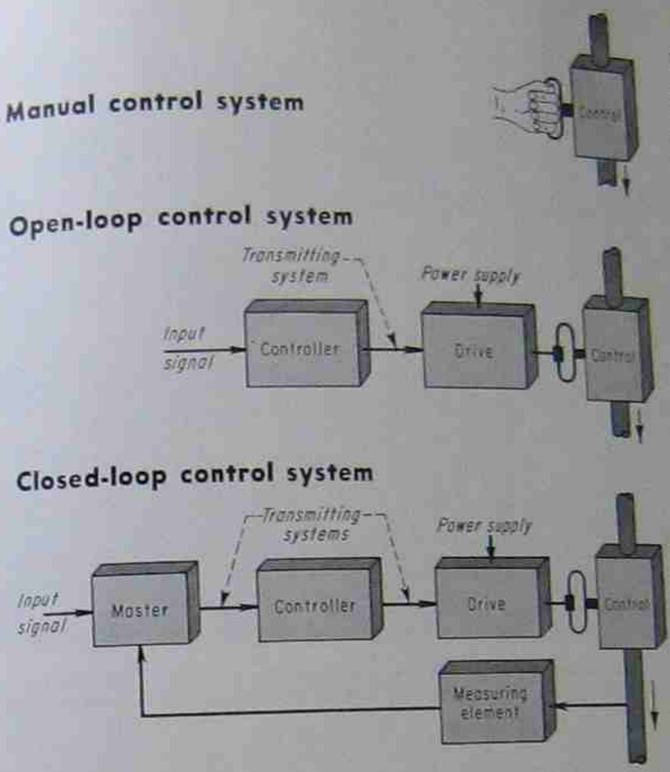
The digits in a decimal number are the coefficients of the various powers of 10, the base of the decimal system. For example, the number 876 really means $8 \times 10^2 + 7 \times 10^1 + 6 \times 10^0$. The placement of each digit in the number tells how many hundreds, how many tens and how many units are in the total.

The binary system follows an analogous arrangement, each digit (which can only be 0 or 1) tells how many of each power of 2 is in the total. Thus the binary number 1010 means $1 \times 2^3 + 0 \times 2^2 + 1 \times 2^1 + 0 \times 2^0$. Since most of us are strangers to binary arithmetic the number gives us no "feel" for the total value. Translating this into decimal arithmetic (see table) we find $(1010)_2 = (1 \times 8 + 0 \times 4 + 1 \times 2 + 0 \times 1)_{10} = (10)_{10}$.

This seems a cumbersome method of expressing numbers, but limiting the digits to 0 and 1 is the key to high-speed data processing. Computers designed in early days to handle decimal digits (0 to 9) always proved ponderous in size and slow in operation. Fortunately, in the modern digital computer, data can be fed in in decimal form, but the computer automatically converts this to binary, does binary arithmetic, and converts the answer to decimal form before discharging it as the result or output.

Each binary digit is called a "bit" in computer technology and the design and size of the machine depends on the number of bits it can handle in any one operation. In a computer, a bit can be represented by an electrical pulse or the absence of a pulse. The pulse can be a momentary voltage or current of very short duration, on the order of microseconds.

Pulses in a computer circuit: (1) establish basic timing (2) indicate information (3) control sequence of operations. A timing oscillator generates the basic pulses that control the sequential and repetitive operations through the control circuits.



3 Operator sets control to change the flow in manual control system. Open-loop control system holds control at set point. Closed-loop system compares actual flow with master input signal to hold flow or variable at the needed level through control

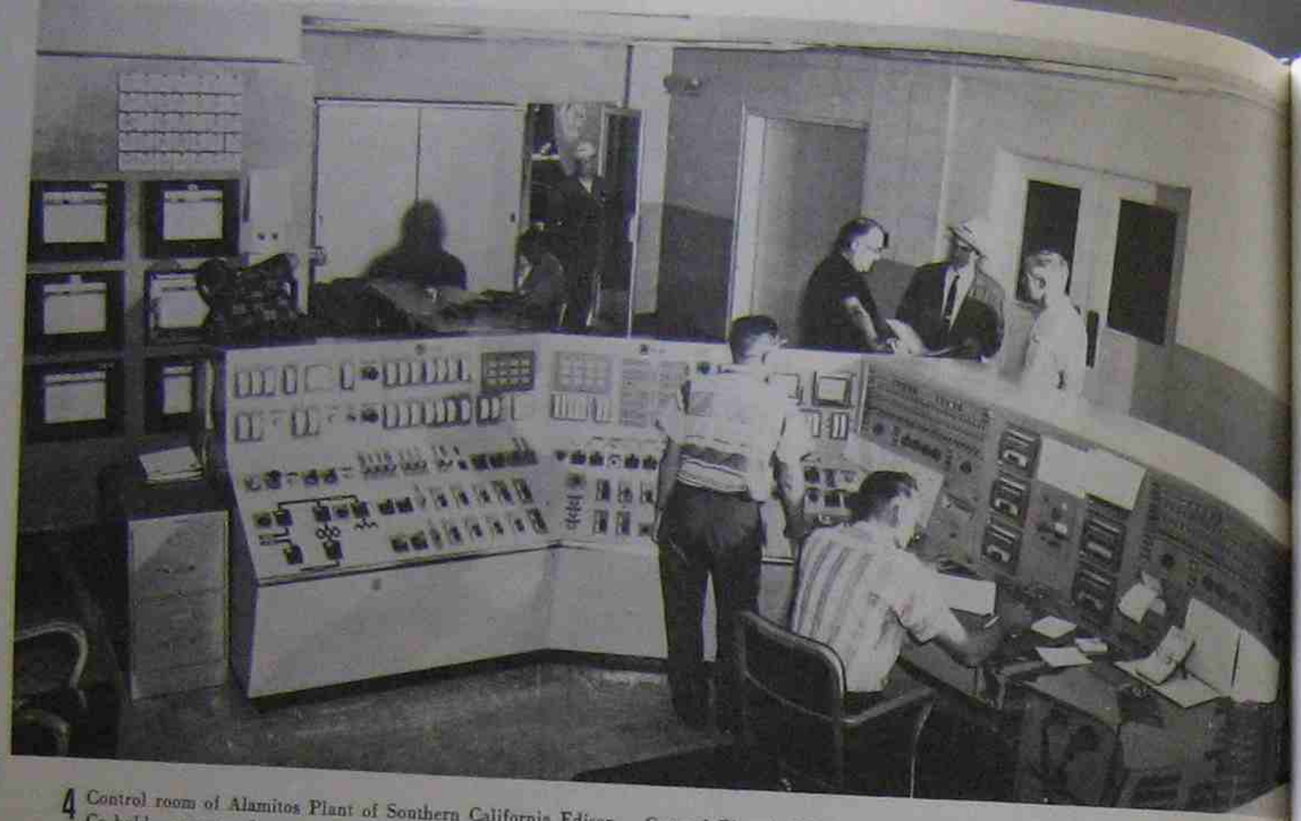
The pulses representing bits in turn may represent characters which are numbers, letters or symbols, according to the code and combinations established for the computer.

Grouping characters forms "words" that are the working form of the data processed by the computer. For instance, computers may have binary-coded decimals that use 4-bit groups to handle the range of digits from 0 to 9. To handle the alphabetic characters (26) they use 6-bit groups. A computer designed to work with a maximum of 48 bits per word can then handle 48/4 = 12-digit decimal numbers or 48/6 = 8-letter alphabetic words.

Computer layout. Fig. 1 shows the essential divisions of a digital computer and lists the type of equipment involved or the duties performed. The input section receives the basic data to be worked with and the instructions of what's to be done with the data. During the receiving process it converts the data to binary form. The *memory* receives the binary form of both data and instructions and as the list shows may use a wide variety of devices. Location of data in a memory is given by an address. Magnetic cores give a limited memory capacity but highest access speeds. On the other hand, magnetic tapes have highest capacity but low-speed access. Punched cards have the lowest access speed of all the devices.

The *arithmetic unit* consists of adders, registers, complemeters and transfer networks. They may operate with pulses given in series through one circuit or by several circuits in parallel, usually the latter. Fig. 1 lists the functions that can be done by this division of a computer, by working in conjunction with the memory. In most computers after the results have been worked out in the arithmetic unit they are transferred to the memory for storage and eventual output.

The *control circuits* have elements known as program counter, ring counter, control gates, instruction and address registers and others. The power input, basic-timing-pulse generator and miscellaneous control signal elements are other important parts of the control circuits. The control circuit puts the computer through three instruction steps that are repeated continuously until all data is



4 Control room of Alamitos Plant of Southern California Edison Co holds computer for supervising its Units 3 and 4. These are General Electric 325-mw 3600/1800 rpm turbine generators using 2400-psi 1050/1000 F steam from Combustion Engineering boiler

processed: (1) selection (2) evaluation or decoding (3) execution.

Computer *output section* equipment takes much the same forms as the input section. For the record type of output the binary-form signals from the memory are first converted to decimal or alphabetic form, though they may be stored in binary form on magnetic or punched paper tapes. When the computer acts as a control circuit, the binary-form signals from memory are first converted to analog form to work the controls of the governed system.

Operation of a computer is governed by the *programing* prepared for it. This is a skill that demands an intimate knowledge of both the computer's capabilities and all aspects of the problem to be investigated or the process to be controlled. Programing is a time-consuming function. When prepared for automatic process control, the cost of programing can easily equal the first cost of the computer hardware.

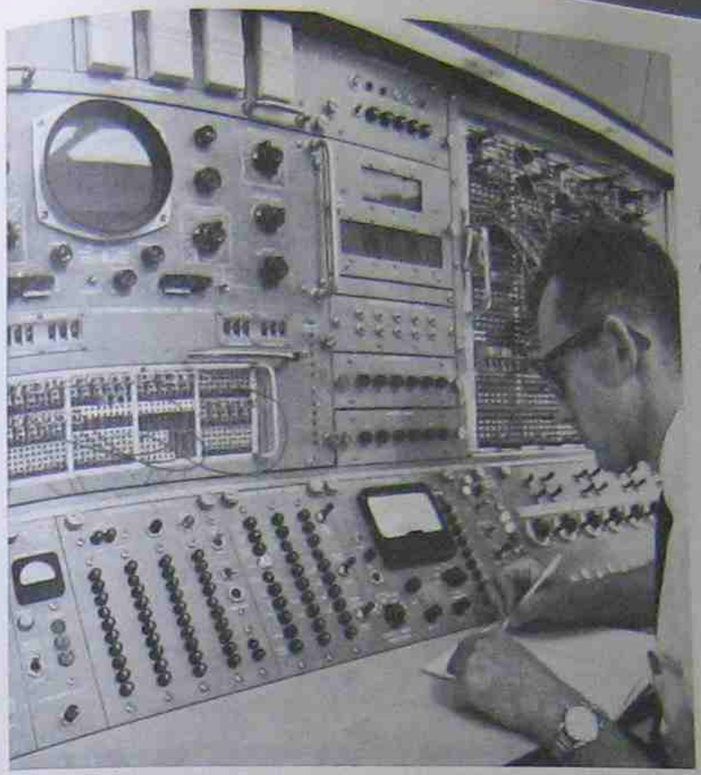
Computer uses have a wide range. Perhaps the primary use is engineering and scientific calculation, for which computers were first designed. Computers can do a wide variety of mathematical manipulation as shown in Fig. 1 in the listing above the arithmetic unit. The particular utility in this application is the high speed with which data can be processed through complex equations. Parameters in an equation can be readily changed to study the effects on results. The scientific computer is generally classified as the general-purpose computer, because it can be adapted (though not always economically) to any type of data-handling problem.

The largest application for digital computers is in the electronic data processing (EDP) field. Here the computer is used for compiling payrolls, customer billing, sales posting, inventory control and general high-volume bookkeeping activities. The high investment or rental cost of the computer is usually more than offset by the reduction in costs of clerical labor and volume of files.

Electric utility systems for several years have been showing high interest in using computers. General-purpose computers are used for payroll preparation, customer billing, inventory accounting, financial control, engineering problem solving. Among the latter are system design and planning studies, forecasting future cost trends and fuel needs for individual generating units.

On-the-line computers do automatic data logging, scanning and alarming of equipment operation, performance calculations, limited automatic machine control, and automatic system-load dispatching accounting for cooling-water temperature and other factors. The ultimate aim is to have computers control generating plant operation completely from startup to shutdown. Limited runs have been made on a few units, but more work needs to be done before the automatic generating plant comes of age.

Success of on-the-line computers depends on the reliability and accuracy of the basic measuring instruments and transducers. Failure here is as fatal as man-failure in making the wrong move. Many of the pioneer efforts have found that computer



5 Complex industrial processes are simulated on analog computer at Minneapolis-Honeywell Special Systems Division, Pottstown, Pa., to develop automatic control systems

programs needed were much more extensive and costly than anticipated.

One approach to plant automation depends on building a mathematical model of the dynamic behavior of the individual components of the plant. The computer program may then be based on this model initially. Field testing of the computer in the plant then shows program modifications needed to conform to actual behavior. This is not as simple as it may sound because an error corrected in one variable must be accompanied by corrections in other dependent variables to keep all factors in the proper overall balance.

Operating experience with automatic on-line computer control has been limited to a few plants. Little Gypsy No. 1 of the Louisiana Power & Light Company was the first to run. The 233-mw unit uses a Daystrom Model 46 computer with a 21-bit word and an 8000-word core memory supplemented by a 100,000-word drum memory. The computer was used for logging prior to unit startup in 1960. Only six tests of automatic control were made, at last report, with only two lasting more than two days. Tests are expected to be completed before the end of this year. Low computer speed limits the response of the system for automatic control.

A computer to be installed with 400-mw Unit 2 at this plant in 1965 will have a speed 15 to 20 times faster than that for Unit 1. The new computer will have a 15-bit word, 28,000-word core memory and 131,000-word drum memory. The system will include 350 thermocouple inputs, 188 analog inputs, 600 contact closure inputs, 6 pulse inputs, 12 analog outputs and 321 contact closure outputs.

Huntington Beach Unit 3 of Southern California Edison Company was another of the first units designed for on-line computer control to aid the operator; the computer has direct control over some plant equipment but it mainly monitors and supervises conventional sub-loops.

The computer scans, alarms, computes and logs performance data; it prints on-demand data; it controls startup, normal operation, normal shutdown and emergency shutdown; it also performs corrective actions.

Computer startup routine includes starting the feedwater system, lighting burners and warming up the boiler, accelerating, synchronizing and loading the turbine-generator to one-third load. For higher loads the operator transfers unit control to the system-wide automatic dispatch sub-loop control.

The original 16,000-word memory of the computer was expanded to a 52,000-word drum ultimately of which 40,000 words are used. A major problem proved to be lack of detail data on sensors, recorders, supervisory instruments and control devices. Grounding of some instruments required modifying the computer input section.

Other problems that plagued the computer and plant shakedown included: 60-cycle noise on thermocouples; poor common-mode noise rejection; sneak circuits in output relay matrix; read-write head malfunctions; noise and timing malfunction in processor circuitry; sensitivity to interruption in feedwater flow through once-through boiler requiring revision of programing; poor reliability of limit switches, relays and other components of the computer.

The numerous program changes led to lack of adequate program documentation. To straighten out this difficulty, the computer was reprogramed and a documentation system set up. Trials showed that using the power plant as the test medium for control suitability was inefficient. So complete simulation tests were run on all computer programs to prove out the logic and sequence.

Experience at Huntington Beach leads to several conclusions for successful computer application: (1) Simulation testing in the computer factory is imperative. (2) Program debugging and documentation should be complete before shipping. (3) On-line process control programs must be flexible and easily changed. (4) Dynamic testing and installation time must be minimized. (5) Extensive customer training must be given before the computer is shipped.

Scanning is a typical duty performed by on-line computers in generating plants and energy-processing systems. Generating plants may have

Survey of digital computers installed in steam-electric central stations

2—Digital computers installed annually

Year	Data only	Control plus data	No. of units over 50 mw	% units with digital computers
1958	2	0	—	—
1959	0	0	—	—
1960	3	1	47	8.3
1961	7	5	44	27.3
1962	8	3	38	29.0
1963	15	11	41	63.5
1964	3	2	46	10.9
1965	0	6	39	15.4
Totals	38	28	255	25.1*

Note—After survey in Jan 1963 an added 8 computers were ordered for probable 1964-65 installation
*—Averaged on 1960-1965

3—Expected benefits

Benefit	Number of installations
Fuel savings	30
Manpower utilization	15
Increased safety	32
Better records	28
Service experience	6
Space economy	3

4—Data processing applications

Data process	No. of computers	No. of units
Periodic logging	40	62
Demand logging	40	62
Startup logging	19	30
Alarm logging	40	62
Sequential alarm logging	11	23
Performance calculations	40	58
Special records	32	46

5—Control applications

Description	No. of computers	No. of units
Startup sequence monitoring	13	18
Startup sequence control	13	20
On-line control:		
Auxiliary equipment	12	13
Burners	5	6
Shutdown sequence monitoring	10	16
Shutdown sequence control:		
Normal	11	14
Emergency	10	12
Direct digital control	13	20

6—Analog inputs per generating unit

Scan rates, points/sec	Units	Thermocouples	Units
1- 4	1	0- 99	23
5- 9	20	100-199	9
10-14	5	200-299	10
15-20	4	300-399	10
Over 20	9	400-499	2
		Over 500	2

Mv or ma	Units	Resis elements	Units
0- 24	12	0	2
25- 49	14	1- 9	11
50- 69	6	10-29	12
70- 99	5	30-49	23
100-149	5	50-69	1
150-199	4	70-99	4
Over 200	1	Over 100	1

Transduced pneumatic	Units	Slide wires	Units
0	24	0	22
1- 9	9	1- 4	9
10-29	7	5- 9	5
30-49	7	10-19	0
		20-39	2

7—Digital inputs per generating unit

Total inputs	Units	Alarm contacts	Units
0- 49	28	0	16
50- 99	9	1- 24	6
100-299	7	25- 49	7
300-499	4	50- 74	1
Over 500	8	75- 99	8
		100-499	6
		Over 500	8

Pulse accum	Units	Control inputs	Units
0	8	0	32
1- 9	28	1- 99	8
10-19	16	100-199	3
20-29	2	Over 200	7

Scan rate, pts/sec	Units	Scan rate, pts/sec	Units
0	7	100-499	6
1-24	3	500-999	5
25-49	1	Over 1000	6
50-99	3		

300 to 600 analog points to measure important cycle conditions, about 100 to 300 may be in the boiler and furnace. These measurements are made by temperature, pressure, flow and level transducers that pose problems in signal cabling, shielding practice, signal noise and filtering and calibration.

As many as 600 contact closures may be monitored in a plant using automatic sequence control. For simple scanning and logging computers there may be as little as 50. Problems to be coped with include contact reliability, bounce and noise.

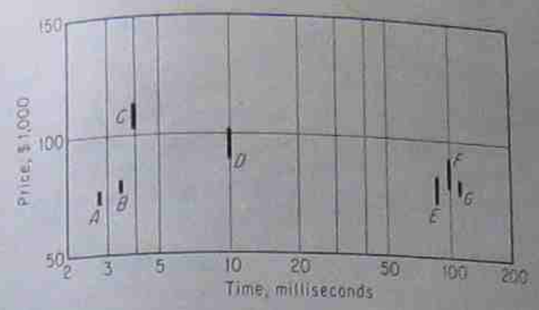
Alarm and logging functions for an on-line computer may vary from 200 for a small system to 400 on a completely automated system. Studied effort must be made to avoid logging too much data. All points scanned need not be logged, even for historical information. Only the data needed by an operator to make decisions should be logged. Performance indices and operating guides can be calculated and displayed. These indices may be alarmed when they are useful guides.

Simpler forms of computers for plant control stop at the alarm that signals the operator of off-normal conditions. The next step would use the alarm pulse to start corrective action in the energy system being monitored. This step involves a sharp rise in computer cost because of the great expansion in hardware needed to implement such a system.

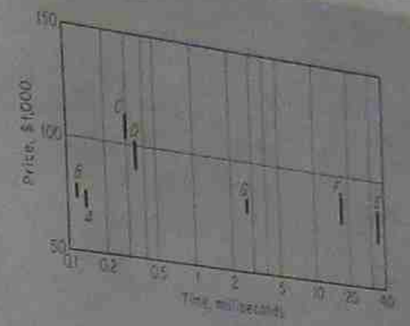
Pre-engineered or standardized computer systems and programs are practical because of less system engineering, greater reliability, reduced lead time and installation time. But this saving in investment is realized at the cost of less flexibility in choosing number of points, type of sensors and functions to be fulfilled.

Sequence monitoring by computers becomes critically important during plant startup and shutdown operations. Here again the computer may just alarm when an improper step is taken by the operator, or take action itself to correct the deviation under a fully automatic system.

For either arrangement the computer must be completely programed to assure safe operating procedures. Three phases make up sequence monitoring: (1) identifying the next step or noting an operation omitted by



6 Execution time for an arithmetic benchmark problem shows wide variation of ability in different makes of digital computers



7 Execution time for logical benchmark problem shows no clear relation to price as for the arithmetic problem in Fig. 6, left

printouts (2) checking turbine acceleration and generator loading to guide the operator in correcting deviations from program (3) monitoring manual operations and alarming any misoperation.

Computer programing to perform startup and shutdown sequence monitoring may need about 4000 instructions. But for automatic sequence control, as many as 20,000 instructions are needed. Details of operating procedures, unit characteristics and plant instrumentation must be thoroughly known. Each plant is unique, and little work done on other plants can be applied. Only the overall principles of programing appear useful as general guides.

Performance calculations useful to a plant operator include: boiler efficiency, turbine efficiency, feedwater heater performance, condenser performance, overall cycle heat rate. Whenever any of these performance indices deviate, the operator may investigate the cause. The analog or digital computer may be programed to perform these calculations at stated intervals or on demand.

To achieve acceptable accuracy in performance calculations, instrument accuracy, location and calibration must be of a high order. Any deviation in accuracy correspondingly degrades the accuracy of the answer and may raise concern about main equipment performance unnecessarily. Flow stratification in pipelines and ducts can have important effects on pressure and temperature transducers. So these must be placed to minimize any deviations from average values over the entire load range. Sensors should be calibrated after installation in the plant cycle, to include the effect of the entire measuring circuit. Performance measurements should generally be made with the energy cycle in a steady state. Transients during load changes do not stay in phase and so would give misleading performance results.

Evaluating control computers is critically outlined by C C Hendrie and R W Sonnenfeldt, The Foxboro Company, in their paper presented before the 6th National Power Instrumentation Symposium of the ISA at Philadelphia, Pa., on May 15, 1963. Computer performance should be rated according to: (1) reliability or consistency of performance (2) speed margin—how the computer copes with the worst-case time combination of events (3) memory storage margin—provisions for worst-case data storage, retrieval and working space.

Computer speed depends on the overall actions needed to perform a calculation. These may take anywhere from 10 to 100 times longer than the time needed to simply add two numbers, often quoted by manufacturers. In addition a drum or disk memory with 150 microsecond add time may have memory access time of 16,000 microseconds; this obviously is the controlling factor on computer speed.

Word length also affects computer speed. One with 24-bit words and another with 12-bit words seem to have identical operation rates and memory access times. But there will be as much as a 2:1 variation in the speed at which they do a group of arithmetic operations to the same degree of precision. Overall, problem-solving speed should be compared to estimate the relative usefulness of computers.

The number and power of the operations in the machine's instruction complement may not all be useful in a given application. These features should be critically balanced against the control needs in an energy processing system or generating plant.

Bench-mark problems should be used to compare computers for relative suitability to solving specific control problems. Each computer should be programed for a given application to reach a conclusive choice. Unfortunately this attack is very expensive, so a good compromise test uses shorter typical trial problems with representative arithmetic and logical manipulations to tryout the computer.

One bench mark problem to test arithmetic problem-solving capability consists of a pair of simultaneous equations in two unknowns. This problem took account of word length. Fig. 6 relates the speed for several machines against their cost.

In some control applications the logical-problem-solving ability may be more important than the arithmetic aspect. In the logic function the computer uses information transfers, manipulations and comparisons all of which use time. Fig. 7 relates logic speed for some computers against their cost, for a specific test problem.

Memory size. An on-line control computer cannot deal with a real-time problem unless all instructions defining the action are stored and available when needed. Distribution of storage between high-speed random-access memory sections and lower-cost lower-speed cyclic access sections, such as drums and disks, influence computer speed. Good practice stores an image of the high-speed working memory in one of the slower speed backup memories.

In machines with 12- to 15-bit words more than one memory word may be needed to store an instruction or data item. Comparing bench mark problems will show the relative need of memory addresses between different computers. Experience has shown urgent need for machines with expandable memories. The tendency has been to completely underestimate the capacity needed on first approach to an application.

Reliability of computers should be evaluated on actual field experience, but little of this information is available. Another few years of shakedown of these new devices should yield representative data. Critical appraisal of design conservatism can help in judging computer reliability. The mean time between failure (MTBF) should be in the thousand-hour-plus category. Ambient temperature specifications should permit operation in the 50-to-120-F range.

The computer should be protected against incidental power failure. Special attention must be given to protecting data stored in the memory.

The shape of control computers is given in a survey made by the Power Industry Division of the ISA reported by R A Russell of Black & Veatch at the 6th National Power Instrumentation Symposium in Philadelphia, Pa., May 13, 1963. Tables 2 to 7 list some results of the survey which covered only digital on-line computers in central steam stations on utility systems. The results cover about 90% of the installations.

These include 42 computers serving 66 generating units. See also POWER, October 1962, p 148 for a survey of central-station data loggers and computers. Tables 2 to 7 show that computers are limited to larger generating units. About 75% of the utilities feel that anticipated fuel savings, increased safety and better records justified installation of the computers. Almost all computers have periodic, demand and alarm logging as well as performance calculations incorporated. About 11 of the computers provide full startup and shutdown control.

What's in the future? Past rapid development of computers may seem to make a look into the future cloudy at best. But demands of modern and future technology assure that development momentum will carry on into the next decade.

Purely mechanical computers have been with us for many years, usually needing a human brain to direct each action. First attempts at automating the computing process to speed it up, and handle more complex and greater quantities of data, used electromechanical relays. Individual actions of components of the computer needed milliseconds to complete.

Introduction of the vacuum tube shrank the physical size of computers and speeded up their operation to the order of microseconds, 10^{-6} or millionths of a second. Minimum memory cycle times were about 10 microseconds, transfer times one microsecond and switching about 1/3 microsecond.

Today's computers use semiconductor junctions instead of vacuum tubes for rectification, amplification, capacitance variation and now tunneling as the latest development. Transistor action (control and amplification) is realized by combining two junctions and in the laboratory speeds of the order of nanoseconds, 10^{-9} or billionths of a second, have been achieved. Intensive investigation now going on with tunnel diodes show they have a time constant of less than 10^{-12} second or 0.1 picosecond (10^{-12}).

Thin films of ferromagnetic materials, iron, nickel, cobalt and their alloys, promise a significant speed up in computer actions. Using these for memory and register, their state can be changed in nanoseconds.

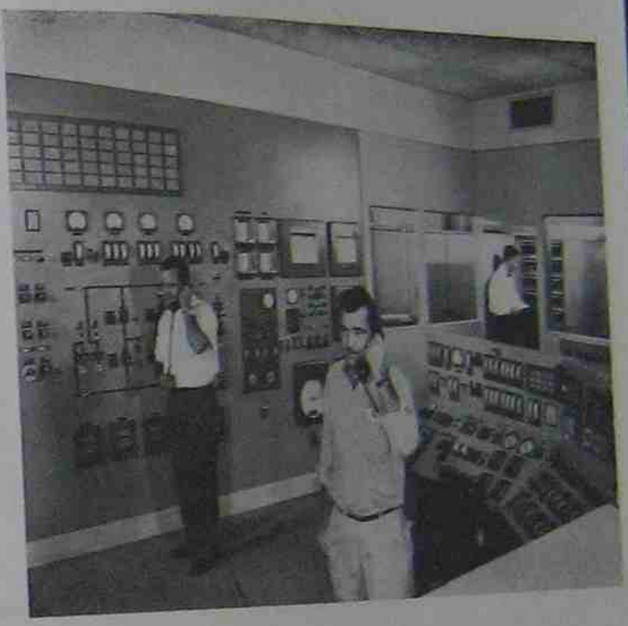
Cryogenic techniques using the association between magnetic fields and superconductivity at temperatures near absolute zero may be used in future computers. Magnetic time constants are on the order of 10 picoseconds and thermal time constants about 1 nanosecond.

With high-speed phenomena we run into an interesting restriction—the speed of light. The well-known 186,000 miles per second is equal to 11.8 inch per nanosecond. In computers the speed of information along the electrical circuits will be about 1/2 to 2/3 of this speed. This means that circuit lengths will be a vital factor in limiting computer operational speed. The high frequencies involved in these compact circuits raise the need for special design techniques and the need for using distributed constants instead of the more familiar lumped constants.

Programing still uses the most time of any phase of total computer operation for problem solving. So even if computer time were cut to zero the saving would not be significant in overall time needed. On the other hand saving in computer time is important in control applications because processes can be held more closely to optimum levels. In fact, in some missile-guiding applications, computers prove to be too slow for successful solutions; the nanosecond speeds may be the answer.

For problem solving applications, efforts are being made to reduce preparation time by automated programing techniques and better computer organization.

Nanosecond techniques will probably be used in serial computers, in which a series of pulses over one circuit will transfer all the information between components. Our present "megacycle" computers are largely parallel machines using parallel circuits to handle simultaneously all the bits in a word. The serial computer would be a more compact machine with significantly less hardware. It's expected this design would be more reliable, have lower power consumption and adapt more easily to controls.



CONTROL ROOM of modern thermal power plant houses computer, print-out units

COMPUTER CONTROL:

Power plants join industry-wide advance

With more than 400 industrial process computers ordered or in use, central-station engineers are leading the way to a new appreciation of automatic control technology

By R K EVANS, Assistant Editor

Evolution of electronic computers can be divided into five-year periods, each characterized by some significant development or trend. From 1945 to 1950 there was a period of fundamental electronic design which gave birth to today's computer "hardware." From 1950 to 1955 attention was focused on the solution of scientific and engineering problems, and the next five years saw a great upswing in commercial data-processing applications. Today there is comparable activity in the field of real-time, on-line computer control of paper and steel mills, power plants and refineries.

What problems have been encountered in today's computer applications? What developments will take place in the next few years? On the following pages, as we study two typical "case histories," we will discuss the lessons learned and the trends established in modern process plant control.



GEORGIA POWER COMPANY'S McDonough plant uses digital computer to monitor two 250-mw units. Operator inserts fuel analysis data to obtain continuous record of heat rate

First requirement...

When Georgia Power Company planned two 250-mw coal-fired units at its new McDonough plant, a decision was made at the design stage to incorporate digital computer monitoring. Behind this decision lay three compelling reasons: (1) Existing boiler control problems increase with size of unit; continual adjustment of reset, rate and proportional band settings of conventional subloop control systems may be necessary to obtain stable control conditions. (2) Cracking of turbine metals, failure of boiler tubes and maintenance problems can often be attributed to wide and frequent variations in steam pressures and temperatures, both of which can be held within narrower limits under computer vigilance. (3) To obtain maximum usefulness from the Southern Company's Early Bird computer, controlling dispatch and transmission over the four interconnecting systems of which Georgia Power is one, more accurate loading information had been found necessary from each of the system's thermal and hydro generating plants.

The resulting analysis of boiler-turbine system dynamics has served as a model for many subsequent computer-monitoring installations. At the time that work on McDonough started, little was known of boiler dynamics. Both analog and digital computer simulation was developed to establish primary and second-order effects and determine what data is relevant in deriving basic constants. For instance, drum pressure is not solely a function of fuel rate, but also of feedwater flow, burner position, gas recirculation, superheat spray water flow, waterwall slagging and other factors. Extensive study was therefore made of the cross-effects between these variables and of the best way to incorporate them into an overall control system.

Most far-reaching of the findings was the need for much greater accuracy in critical sensors and transducers when their signals form the input to an on-line digital computer. The four major types of measurement—pressure, temperature, flow and power output—were found to require a maximum error of ±0.25% of the measured variable if input error to the computer was to be held within acceptable limits.

...increase the accuracy of plant instrumentation

Primary flow measurement selected was that of condensate to the deaerating heater. A flow section with removable throat-tap flow nozzle calibrated over a Reynolds Number range from 2×10^6 to 6.5×10^6, enables differential pressure across the flow nozzle to be measured by a manometer with a servo-system following the mercury level. Latter is indicated by digitizer attached to a rotating shaft in the servo system; computer senses this as various combinations of contact closures.

Pressure measurement is through accurate pressure transducers with a long-term accuracy of ±0.15%. Input to the computer is digital in binary-coded decimal form; pressure is read in 300 milliseconds with a resolution of one part in 2500.

Temperature readings are the only critical measurements requiring analog-to-digital conversion. Chromel-constantan thermocouples are duplicated where temperatures have greatest influence on results. Reference junctions and thermocouple elements are made of selected and matched wire, and are controlled to within 0.1 deg of set point.

Power measurement is through a three-element watt-hour meter system using calibrated current and potential transformers. Three-phase calibration minimizes the effect of mutual induction between coils when currents and potentials have phase relationships 120 deg apart, insuring the desired accuracy.

On-line computer selected for monitoring the McDonough units is a General Electric GE-412 digital stored-program unit, with a 256-input, 20-point memory event recorder directly coupled to the computer to monitor sequence of events during abnormal operation. Under normal conditions memory is available for alarm storage.

In operation, fuel analysis and similar data are inserted via the operator's console. Results of performance calculations (boiler efficiency, heat rate, and divergence from reference cycle) together with continuous pressure, temperature and flow readings are typed out on the console typewriter. Information, such as boiler and turbine efficiencies, is also available for visual display and trend recording, affording a continuous check on operation.

Analysis of plant operation precedes choice of computer

Today's engineers are finding greater justification for installing computer systems. Multiprogramming, long under development, is now established and available in many computers. Thus, an on-line system can handle data-processing or perform calculations during pauses between its real-time control activities.

More important, users are gaining in knowledge and sophistication in their choice of equipment. No longer entirely dependent on the computer hardware manufacturer for system design, a user finds it easier to apply computer control techniques to the requirements of his particular plant, whether it is a steel mill or bakery, sugar refinery or boiler-turbine unit.

First step following the decision to streamline plant operations by installing computer control is a searching analysis of the process itself. Many of the early failures of loudly-heralded computer-controlled plants were due to neglect of this fundamental requirement. One approach is to build a mathematical "model" of the individual plant components and their dynamic behavior. This can serve as a basis for the proposed computer program.

But success of an on-line computer depends very largely too on the accuracy and reliability of the basic measuring instruments, sensors and transducers. Many pioneer efforts were unsuccessful because of the accumulation of errors as instrument readings were converted to digital form for processing by the computer and later reconverted to analog input to pneumatic or electric actuators. Account of McDonough plant above emphasizes the importance of recognizing sensor and instrument limitations *before* considering a computer program.

From data obtained during this preliminary plant analysis, the potential user can specify the tasks which a control-computer installation must be able to perform. Such criteria as cost, reliability, ease of programming, and life expectancy must all be taken into account. So must "maintainability"—too often, in the past, diagnosis and location of a fault have lengthened computer down time to an unnecessary and uneconomic degree.

Expensive result of neglecting these criteria was experienced by Southern California Edison at its Huntington Beach power plant, which, like Louisiana Power & Light Co's Little Gypsy, was one of the first units designed for on-line computer control. Plagued by such fundamental problems as inaccurate sensors and recording instruments, poor reliability of computer components, and need for frequent program changes, Southern California Edison's experience there has led to a major revamping of computer-system requirements.

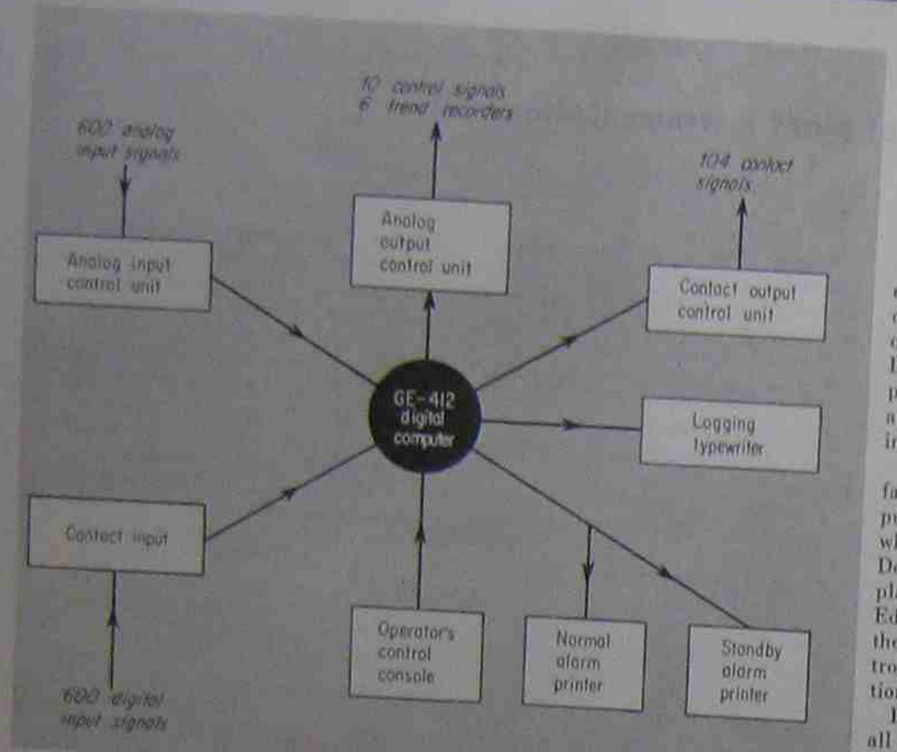
Success of subsequent installations at Alamitos and Etiwanda can be attributed largely to lessons learned at Huntington Beach. The five most important are:

(1) Complete analysis of system must be carried out before specifying computer requirements.
(2) Accuracy of critical measuring and actuating devices (pressure, temperature and flow) should be no less than ±0.25% of the measured variable.
(3) Simulation testing must be carried out in the manufacturer's works; program debugging and documentation should also be complete before installation.
(4) Control programs must be flexible and easily changed.
(5) Extensive personnel education and training pays dividends far greater than its cost.

Two contrasting approaches to this latter need are illustrated by recent installations of Westinghouse PRODAC 510 computers; Georgia Power Co, whose operators are already familiar with previous installations, felt that no major training program was necessary. Pacific Gas and Electric, on the other hand, with no comparable experience to draw on, insured that all operators at its Contra Costa plant took part in a full training program—amply justified when units 7 and 8 made their initial roll under computer control.

Importance of adequate customer education cannot be overemphasized. If they have not been fully trained in its use, operating personnel can make or break any computer system, particularly at a time of emergency or plant malfunction. The aim of all computer manufacturers is complete automatic control without human intervention. Nevertheless, the guiding rule, "When in doubt, let the operator run the plant," still applies, especially in such hazardous conditions as power plant operation or steel-making. The computer, therefore, in addition to its monitoring functions, must provide the operator with information on plant status and trends. Only in this way can he be continuously aware of minute-by-minute plant conditions, readily able to override or assist the computer.

Winning operator's confidence has often proved an unexpected problem. Experienced plant operating personnel, trained to master the vagaries of a complex process plant, are often unable to understand how a newly-installed computer functions. Input signals from faulty plant equipment can cause a shutdown which, in the operator's eyes, is computer malfunction. Many off-normal data input signals are given unrealistic limits in the program. Consequently, the computer gives erroneous alarms and may even shut down the plant. Experience has shown that careful review of such variables enables non-valid alarms to be eliminated or the limits widened, increasing operators' confidence in the computer system.



BLOCK DIAGRAM of computer control system installed at McDonough plant. Computer receives 1200 input signals from sensors and transducers, sends out 120 control signals

Etiwanda unit 4 . . . 12 months of successful computer control

Ultimate aim in application of process-control computers is to have the computer solely responsible for all plant operations from startup to shutdown. Despite complexity of modern thermal power plants, central-station computers approach this ideal more closely than in comparable industrial applications.

On previous page we outlined the factors to be considered before a computer installation can be specified. But while Georgia Power limits its McDonough computer system largely to plant monitoring, Southern California Edison's 310-mw Unit 4 at Etiwanda is the first to be under full computer control from light-off to line synchronization at operating load.

Based on previous installations (not all successful) at its Huntington Beach and Alamitos plants, Southern California Edison has concentrated much experience into the new Etiwanda control system. Using a GE-412 digital computer basically identical to that installed at McDonough, the automatic control system

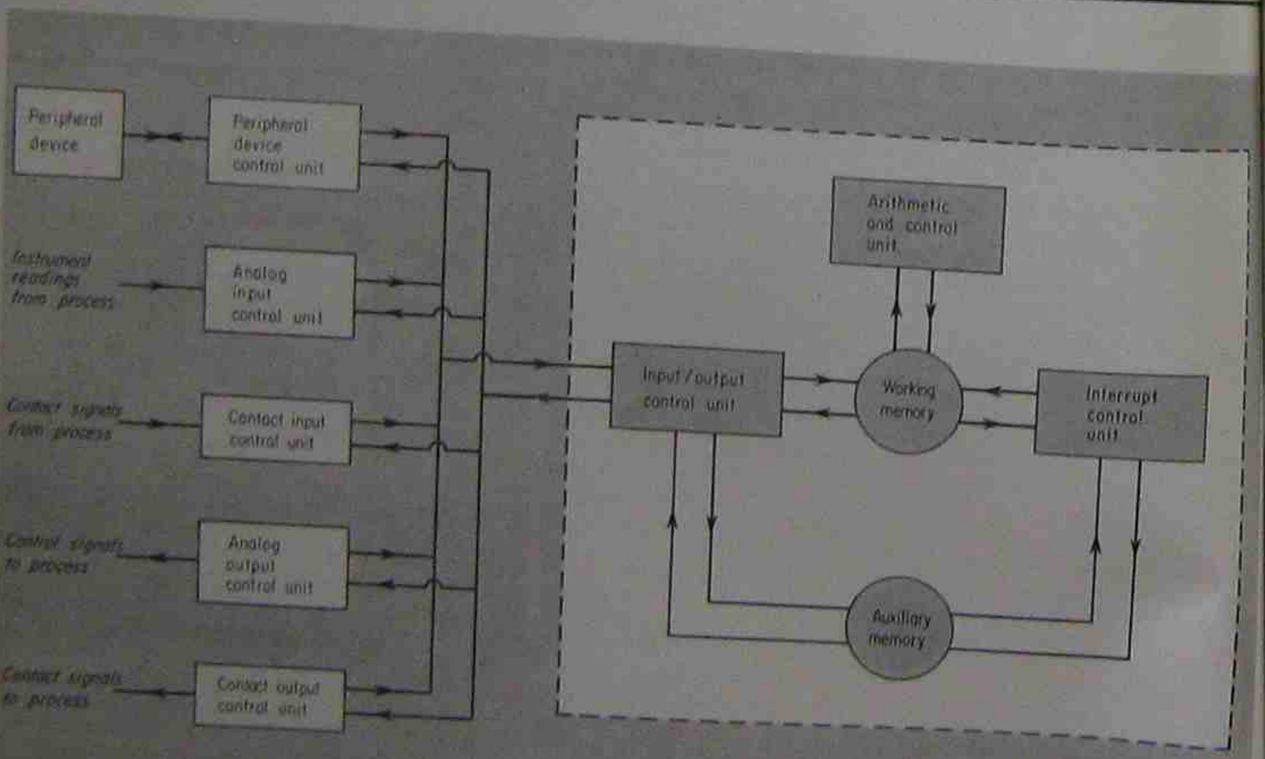
- confirms that prestart conditions (temperatures, water levels, valve settings, furnace condition and water treatment) are in accordance with programmed settings
- performs turbine trip tests
- establishes water circulation and air flow through the furnace
- lights and monitors burners
- phases turbine h-p and l-p shafts
- accelerates turbine up to 3600 rpm, synchronizes unit to system frequency, and loads generator to 65 mw.

During operation the computer continuously scans 1084 functions for possible alarm conditions, logs 56 values every half-hour or on demand, and makes 22 performance calculations which vary in complexity from simple totalization to determining net heat rate. Operator is thus relieved of most routine responsibilities and has more time to optimize plant performance. Should he require a continuous trend recording of any of the major plant functions, he can monitor it by putting the particular input on one of six trend recorders in the control room.

Should the computer fail, the operator can run the plant with conventional subloop controls; all computer outputs are automatically returned to "normal." Two most complex dynamic control functions handled by the computer are boiler warmup and turbine speed control. Experience with the latter at Huntington Beach, where it was controlled as a separate subloop, suggested that the Etiwanda speed control be handled as a closed loop directly through the computer, with contact outputs operating the turbine stop-valve and bypass valve motors to raise or lower turbine speed.

Boiler warmup is computer-controlled from light-off to full rated pressure. One analog output regulates fuel-valve opening while another adjusts the steam pressure set point after turbine synchronization. Six fuel-change motions are also programmed into the computer to initiate and monitor transfer from gas to oil firing and vice-versa. A battery diagnostic and control routine handles emergency transfer to oil firing if gas supply should fail.

Emergency shutdown routines include reinitiation of the scanning program after a trip to remove scan points that could cause false alarms. Considerable extra capacity is available for future refinements dictated by experience. Normal and backup power supplies to the computer are provided by its own ac motor and battery-powered dc motor/ac generator set. At present Etiwanda 4, with only routine maintenance, has been under successful computer control for some twelve months.



LOGIC CAPABILITY of process-control computers requires some combination of all the units shown above. Computer itself consists of equipment within dotted line; peripheral devices include tape and card readers and logging typewriters, all aiding the operator

Modular concept insures computer-system flexibility

Typical process-control system includes a wide variety of electronic equipment, as shown in the block diagram at left. Generally considered as part of the computer are arithmetic/control unit, working and auxiliary memories.

Arithmetic and control portion of the digital computer provides the logic and calculation capacity needed to evaluate and control output signals to the process plant. Working with instructions from the memory unit and data from sensors and transducers measuring plant conditions, the arithmetic unit performs calculations according to programmed instructions and transmits the results to the input/output control unit.

Memory unit contains instructions, usually as magnetic signals on core or drum, which cause computer to perform the required functions. Storage is also provided for data required to solve calculations, normally programmed into the memory, and for data transmitted from instrumentation within the plant.

Interrupt control unit provides the necessary signals to the arithmetic and control unit when plant situation warrants interruption of the program for priority action. This unit stops normal sequence of instructions within the arithmetic unit and, after noting the point of interruption, triggers entry to the higher priority routine. Normal sequence is resumed automatically.

Many peripheral devices may be linked with the computer. These include magnetic tape, paper tape and card readers, teletype printer, line printer and typewriter. Use is self-explanatory; each has access to a control unit containing the circuitry necessary to transmit information to or from the working memory.

Contact-input control unit provides circuitry to transmit the status of contacts located throughout the plant (limit switches, pressure switches, etc) into the computer memory. This input is in digital form, suitable for immediate use in the computer.

Analog/digital converter selects input signals in analog form (voltages representing pressures and temperatures, for example), amplifies and converts the signals to digital form, then transmits them to the computer memory in the same way as contact-input unit.

Output-control units are similarly either analog or digital (contact). The latter transmits signals to control on/off equipment and certain peripheral devices. Analog control sends out variable-voltage signals to set electrical controllers throughout the plant or to position valves, thus providing closed-loop capability of the computer control system. Analog outputs are also used for trend recording and other noncontrol functions.

Direct digital control (DDC) is at present much in the news as a likely replacement for analog control. Major advantage is that DDC would abolish need for digital/analog converters and give computer more direct control over plant equipment, as well as remove one more source of spurious signals. However, until we have plant equipment which will respond to DDC signals, analog control will continue to be the principal medium for transmitting computer commands to implant actuators.

Computer programming can make or mar control system

When specifying a computer-control installation, an important consideration is to insure that hardware and software are complementary. Inclusion of certain hardware features may save much work when programming the computer. Conversely, their absence may render certain instructions impossible to program. By properly weighing the cost of hardware against likely future programming requirements, proper balance can be established between the two sets of costs.

For example, in a situation where large memory capability is required, most economical solution is often to supplement the expensive high-speed "working" memory with a lower-cost auxiliary memory. This combines the advantage of high-speed arithmetical operations with relatively low overall memory cost. Typically, working memory would be magnetic core, and the auxiliary memory either disk, drum or magnetic tape.

Anticipate future expansion

Future needs must be forecast as accurately as possible when specifying a computer system. In many early process-computer installations, programming costs were extremely high because of hardware limitations. Memory was often too small, arithmetical operation slow, and input/output capability limited. Today's computer hardware has helped reduce programming costs considerably, but program changes and possible future expansion should still be taken into account before finalizing design.

In process-control work certain aspects of programming warrant extra consideration. These include real-time operation, memory capability and operator misuse. As a process computer functions in a real-time environment, a certain amount of "free" time must be available to allow for emergency reactions and special operator requests. A good rule of thumb is to allow 40% of free time within the computer; any less may cause the computer program to fall out of step with the operating situation.

Choose memory system with care

Memory capability, as mentioned previously, needs careful balance between working and auxiliary store capacity. System employing fast-working memory, supplemented by large but slow bulk storage memory, is economic compromise but presents problem of data transfer from one to the other. In such a system care must be taken in deciding which functions should remain in working memory at all times and which should be called in from store, as required.

Choice of program language is limited in practice to three: COBOL, ALGOL and FORTRAN. The first, Common Business-Oriented Language, was developed largely as a means of communicating computer functions in the field of business data processing.

ALGOL (Algorithmic Language) is a symbolic language independent of the particular computer structure. A program written in ALGOL is sufficiently legible for a programmer to read visually, yet, at the same time, may be translated automatically into any particular machine code by a suitable translator program.

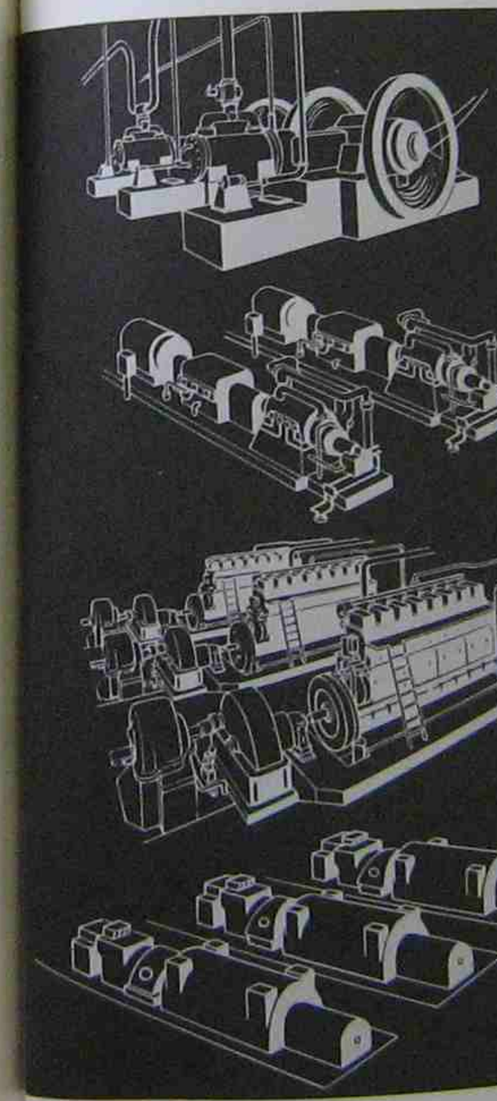
Most process-control computers today use one of the variants of IBM's original FORTRAN. Prior to this, writing commands for a computer was a manual process. FORTRAN is, in fact, a compiler or program generator which produces a program automatically suited to the computer in use. Disadvantage is that any compiler-produced program requires about double the space needed by a carefully hand-written program. Thus, a boiler/turbine startup program can be written by hand in some 2000 words but takes 4000 words when produced by a compiler. FORTRAN finds principal applications in relatively infrequent procedures, such as plant startup and shutdown. Minute-by-minute scanning, on the other hand, is handled by a standard "scan, monitor and alarm" program filled in manually for the particular scanning sequence dictated by operating requirements.

Check validity of input signals

Self-checking program is important feature of process-control computer system. Unlike a scientific program in which the results obtained are printed out for perusal by an engineer, closed-loop control system utilizes the computer's calculations to act directly on the process plant itself. Should either input to the computer or data-handling within it be in error, the resulting calculated control points and output signals will be incorrect and could result in hazardous operation. Double and triple checks may be necessary to insure that operating data is valid. As more and more input signals are utilized, the programming necessary to provide such validity checks becomes increasingly more complicated. Continuous calculation of, say, heat balance can be useful in determining the validity of input information, since an extensive range of input data figures in the calculation.

Knowing the process itself is an important attribute of the system programmer. He can observe the overall relationship between program and process more easily, to establish the optimum frequency of data-logging, for example. Also, he can incorporate such aids to efficiency as fixed-point programming where this will speed up a repetitive loop function. For this reason, the present tendency among users is to train their own engineers as programmers rather than rely entirely on the computer manufacturer. To this end manufacturers provide comprehensive training courses—the Westinghouse Computer Center, for example, includes a self-contained school where customers' personnel may spend up to a year studying programming techniques.

Utilities, in particular, have found it essential that programmers be completely familiar with the power plant and its operation. Most of them now assign temporary potential programmers to the manufacturers' works, both to study and also to assist the manufacturers' own staff in an advisory capacity as problems arise.



By B G A SKROTZKI, Associate Editor

Energy system economics...

getting the most energy for the fewest dollars

How are your dollars best spent to meet your growing energy demands? There's a wide variety of equipment and hookups available today, and you want to select the best for your system, whether it be central refrigeration, steam supply, fluid handling, compressed gas, chilled water or electric power.

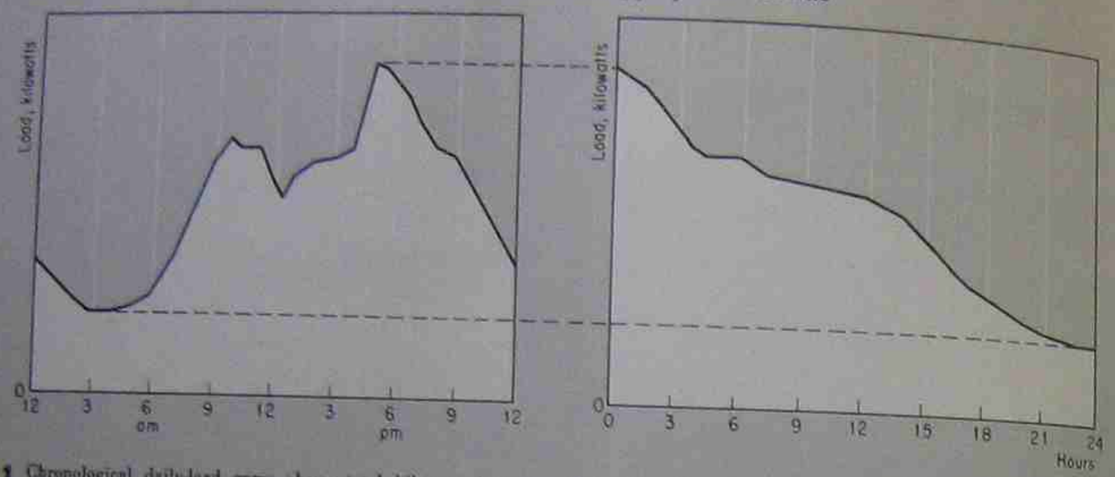
With all investment and operating-cost data in hand, how do you go about choosing the best system? Here you must apply principles of engineering economics to the special problems of energy supply.

The energy systems handle media of radically different character, but for financial operating comparisons they are evaluated by essentially the same methods. We've picked electric power generation to illustrate the practical use of energy-system economics. These 24 pages show how to evaluate electric energy systems, but you can translate these methods to other energy-carrying systems by substituting lb per hr, cfm, Btu per hr, gpm or any measure used in other systems for kw and kwhr. Your aim: find the arrangement that promises lowest total annual cost of operation and capital charges. This will be one of the important factors in making the final choice of system layout.

Once your energy system is built, do you run it for best economy? To do this you must know your incremental costs. "Doing it by ear" on the basis of average performance curves only wastes fuel or energy if you don't know the actual cost of every energy unit. Here POWER shows the importance of the incremental rate in scheduling your equipment operation for best overall plant performance.

a Power special report • December 1961

Chronological and duration curves define energy-system loads



1 Chronological daily-load curve shows total kilowatt demand on a system at every moment of a day. Area measures kwhr

2 Load-duration curve is simply a rearrangement of daily-load curve with loads set up in descending order of magnitude

First look at today's and tomorrow's load and energy demands

To design a plant for maximum economy we must know the nature of the load it will have to carry. Easiest way to describe this load is by graphs—either chronological or duration curves, Fig. 1 and 2.

Chronological daily load curve, Fig. 1, shows total load at every moment of the day. Since the curve plots kw vs time in hr, area under the curve measures product, kw × hr = kwhr of energy for the day.

This curve holds information important to plant operators. It lets them know what loads to expect on given types of days, so they can prepare the engines or units to take on load at given hours, be ready to take off engines when load drops to maintain system economy.

Load-duration curve, Fig. 2, is simply a rearrangement of the chronological curve of Fig. 1. To get it, we cut the daily load curve into many vertical strips and then arrange them in descending order. Here, too, area under the curve measures kwhr of energy for the period.

The load-duration curve offers the advantage of summarizing loads for a day, week, month or year. This is a great help in plant design: in one simple curve a whole year can be summarized, showing peak demand, all variations in demand down to the minimum, length of time they existed and total energy involved.

Curve factors help measure the load and its relation to the plant. Fig. 3 shows a typical load-duration curve for one year in the life of a typical city or regional system. Line above the curve gives installed capacity of the power plant serving this load.

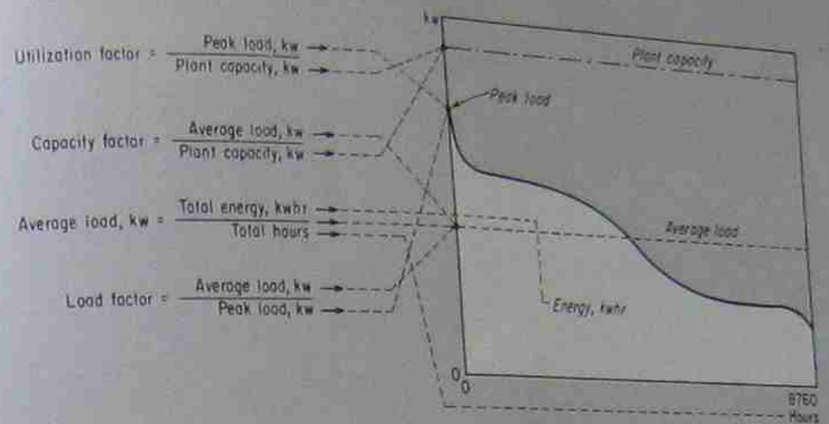
Utilization factor shows the extent to which the plant capacity is used to meet the peak demand. As this approaches 1.0 it may signal the need for additional capacity. On the other hand, in some interconnected systems the plant utilization factors may rise to 1.1 and even 1.2, meaning that the plant carries 10 or 20% more than its rated nameplate capacity. In other words, plant's capability is higher than its rating because of the conservative design of its components. Most plants, in fact, have capabilities exceeding their ratings. But it's wise to check with the equipment builders on advisability of using this built-in reserve as regular operating capacity.

Capacity factor shows how near the plant runs to its full rating. When there are several plants on a system, the most efficient usually runs close to 1.0; least efficient acts as a peaking plant and may barely top zero. Notice the difference between *capacity* factor and *load* factor—the two are often confused needlessly.

Average load is easy to understand; it's the average height of the load curve. If the plant ran continuously at the average load, it would generate the same amount of energy that the actual load curve shows.

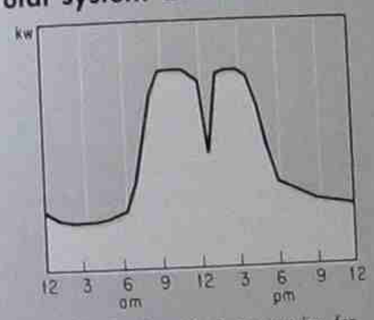
Load factor measures variability of the load-duration curve. As it approaches 1.0 the curve is nearly rectangular, but at 0.5 it can take myriad shapes. For instance, it could be at peak load for half the total time, or it could be at half peak load all the time with the exception of one short sharp peak lasting only one hour in the whole year. More often it's a tapering curve as in Fig. 3, with variable loads during the year.

Component loads. Most all municipal, regional and industrial loads are made up of components: their sum at any given moment creates the total demand. It's unlikely

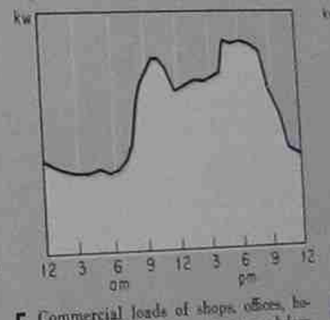


3 Annual load-duration curve variations and how they relate to the capacity of the generating plant can be measured by a variety of ratios or factors. This type of information must be available to the designer if he is to plan an efficient overall energy system

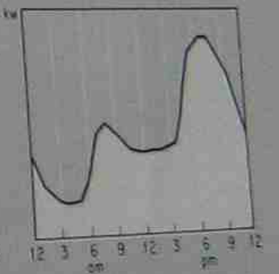
Total system demands are combined from many separate elements



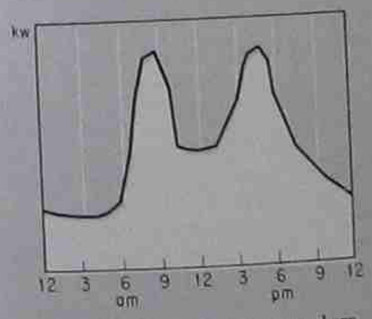
4 Groups of industrial plants running for one shift have high loads during the day



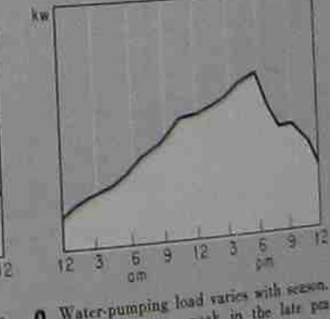
5 Commercial loads of shops, offices, hotels persist into late evening on weekdays



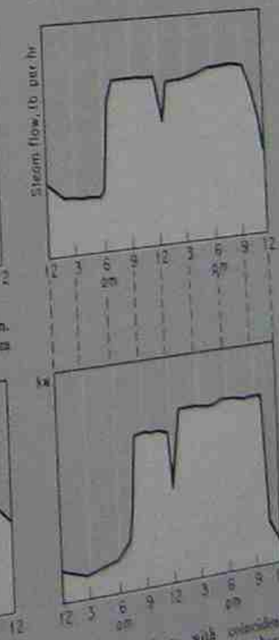
6 Residential loads feature broad evening peak demands on every day of the week



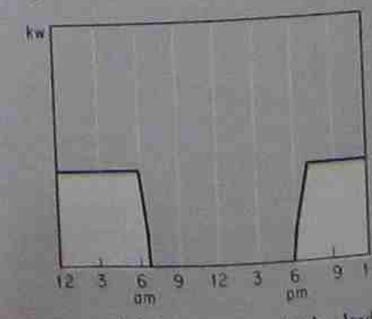
7 Urban electric roads have two sharp peak loads on every working weekday



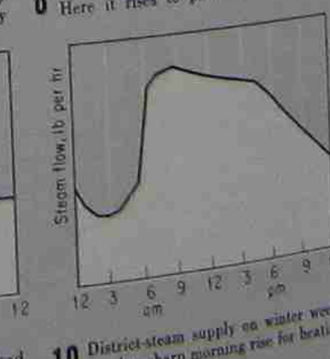
8 Water-pumping load varies with season. Here it rises to peak in the late pm



11 Industrial plants with coincidental steam and electric loads run cheaply

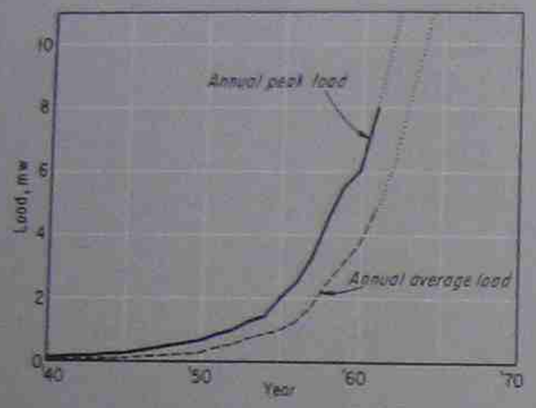


9 Street lighting features steady load during darkness. It's all off during day

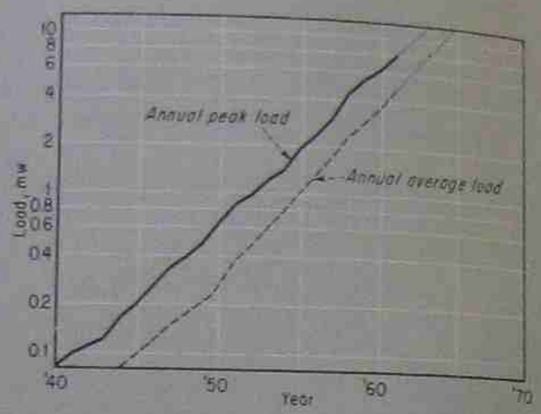


10 District-steam supply on winter weekday has sharp morning rise for heating

Past growth of energy system hints at its future growth pattern



12 Historical variation of peak and average system loads gives clue to future loads you can expect and new capacity needed



13 Extrapolation of load trends often can be made easier by plotting the kw on a semi-logarithmic chart (see Fig. 12)

that component demands will peak at the same time. This diversity of peak demand helps make central-station generation an economical energy system.

Fig. 4 to 9 show the character of typical daily-load curves for various load groups. With the exception of street lighting, most of them sink to the minimum level during early morning hours. Each individual curve varies with the type of day, weather and season. The percentage distribution of these load types on a central-station system determines shape of the system load curve as in Fig. 1, 2 and 3. Diversity usually flattens the load curve.

Fig. 10 is a typical winter-day load curve for a district-steam system. Most of the steam is used for space and hot-water heating; a small part may go to electric-generator and other drives. Sometimes the steam is supplied by backpressure turbines or automatic-extraction turbines on the central-station electric system, instead of directly from boilers. This economical arrangement contributes to keeping down overall operating cost.

Fig. 11 shows steam-demand and electricity-demand curves for a private industry that needs both steam and electric energy. These could be typical of a plant running on a 2-shift basis. If there is reasonable coincidence of steam and electric demands, backpressure or automatic-extraction turbines generate the electric energy with great economy. If there is little coincidence, electric energy may be purchased from the local utility system.

Load growth is the common worldwide experience of energy-supply systems. This raises another problem: expanding power-plant capacity to meet the growing peak demand. To do this effectively we must know at what rate the peak load is expanding year by year.

This can be found by plotting the yearly peak load on a graph, as in Fig. 12, for as far back as data is available. But often we come up with a sharply rising curve when plotting the data on arithmetical coordinates. Such a curve is difficult to project with any confidence, even for a short span like a year or two.

Our job is usually easier if we plot the same data on semi-logarithmic coordinates, Fig. 13. If the data still does not suggest a straight-line trend, at least it will produce a much flatter curve, easier to extrapolate for several years into the future.

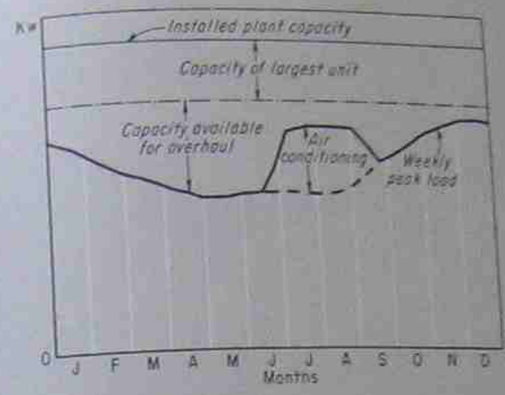
To get the complete story, it's best to plot yearly average loads on the same curve. This gives an idea of where the load factor is trending over the years. If the peak-load and average-load curves tend to approach each other the load factor is rising, and vice versa. Fig. 13 suggests a rising load factor—the national experience. Projection of straight-line growth shown by the dotted lines in Fig. 13 was plotted on the arithmetic coordinates of Fig. 12.

Peak-load studies ought to be supplemented by data on the trends of separate components as in Fig. 4 to 9. Important changes in these individual demands, that could have a vital effect on power-plant planning a few years later, may be masked for several years in the total load trend for the entire energy system.

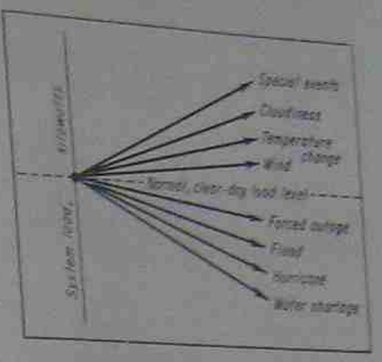
For most systems a plot of the weekly peak loads throughout a year may show a trend like the one in Fig. 14. Historically, peaks arose in early winter at the time of shortest daylight. But in the past decade, availability of room air conditioners for summer cooling has changed the traditionally low peaks of the summer season; in some systems the yearly peak now appears in the summer! So if you suspect that this or some other type of energy-using equipment is experiencing rapid growth, try to measure this growth and project its future magnitude—avoid a major planning headache later. This situation is also important in private industrial energy systems; here, too, keeping tabs on the energy needs of all departments will put you in a position to supply power to grow.

Whatever type of energy system you're responsible for, it's wise to keep analyzing all parts of it to make sure it can handle present and future demands. This means adequate instrumentation conscientiously used.

To return to Fig. 14 for a moment, the trend to growing summer loads brings up another problem in plant planning: creation of double peaks in one year. Systems with many generating units are hard-pressed to find a time to take them out of service for periodic inspection and overhaul. Sometimes this has meant installing extra capacity to allow adequate overhauling time for all units on the system. Moral: keep on top of your system needs to assure smooth service for the future.



14 Weekly peak loads vary through the year. Many annual peaks rise in winter, but air conditioning may make summer peaks



15 Variety of conditions may change the load from its usual level, either up or down. Some causes affect plant planning

Load variations are always possible if there's a basic change in the need for a particular service. But energy demand can be influenced by other factors that have a system-wide effect. The designer must prepare for them in his equipment, but more important, system operators must be aware that these influences exist.

Fig. 15 illustrates factors that can cause the total system load to rise or fall. Industrial-power systems might be affected by similar situations. Operators should be alert so they can make adequate preparations.

Some special event like an important political broadcast or a football game may bring many TV and radio receivers into operation that normally would be idle. This raises a municipal system load above normal, but it seldom, if ever, happens just at the time of the system's annual peak load.

Cloudy weather or the passing of a thunderstorm darkens building interiors, so electric lights are turned on when they would normally not be used. On systems having summertime peaks this demand might coincide with the annual peak, so extra capacity may be needed to meet the situation. Normal annual wintertime peaks usually result from early darkness coinciding with existing high industrial loads.

Atmospheric temperature changes profoundly influence electric loads. A temperature drop may cause electric heaters to be turned on, or electric motors that drive burners for steam and hot-air heaters. A temperature rise flips the switch on air conditioners and fans, with the important system peak-load effects we've just talked about.

Wind has a noticeable effect. It raises the cooling rate of buildings and so creates demand for more heating energy. In some climatic conditions the wind can be more important than atmospheric temperature change.

Hurricanes drop the load in two basic ways. They may (1) knock out part of the distribution system or some consuming equipment or (2) put generating units out of service because of flooding or other damage. Usually a few days' worth of repairs restore the system to normal, except if damage has been severe.

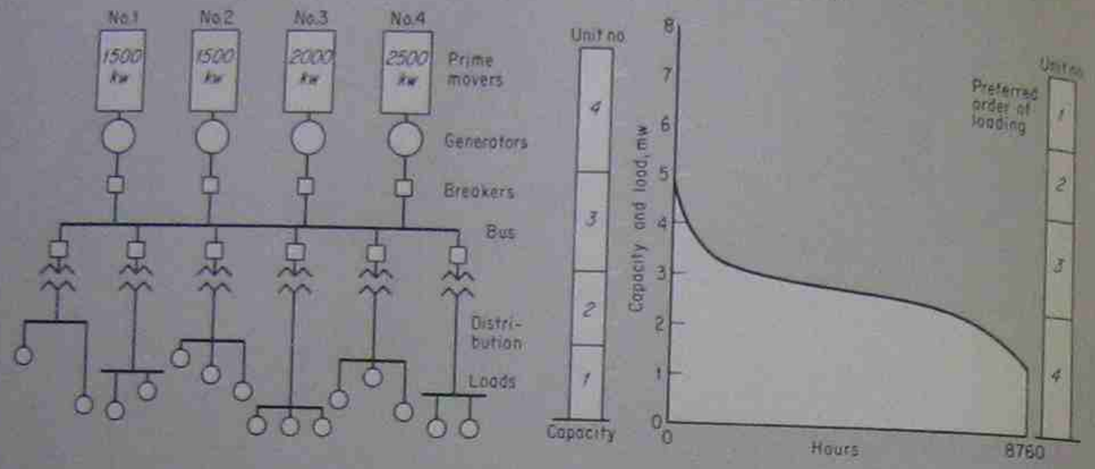
Floods may act like hurricanes in end result, but with less-widespread damage. If the plant is on a waterfront, however, it may be knocked out of service for extended periods by record floods not predicted when the plant was originally designed.

Forced outage of a major generating unit because some vital part fails may force you to dump part of the load, if reserve capacity is not available at the crucial time. Systems that serve secondary loads are able to do this without danger of customer repercussions.

When reserve capacity has been reduced to zero by forced outages, the system load can sometimes be cut by lowering the voltage at electric-generator terminals. Sometimes voltage has been cut by as much as 5% to achieve a 5% reduction in load. Filament lamps will shine less brightly and some motor drives may have trouble as current flows rise to the breaker-tripping level. Extreme reductions should be tried cautiously—only as a last resort to keep a system running.

Momentary load fluctuations may be a problem for some energy systems. Curves of Fig. 4 to 11 suggest smooth changes in demand, and they hold true where the load is lighting or motors driving fans. At the other extreme we have spot-welding operations, motors driving stamping machines, urban traction systems with vehicles drawing frequent high starting currents. Such loads take wide and erratic swings and need special treatment of generator governing systems.

Reliability of the system must be balanced against investment



1 Power plant has variety of unit capacities; growing loads encourage installing larger units to expand capacity. Installed capacity often protects you against losing largest unit at time of peak. Preferred loading order uses the newest unit most often

How much plant capacity to protect the load?

A power plant must be sized to carry the largest load you expect. Plant may be designed to handle load described by the annual-load-duration curve, Fig. 1. Here the largest-capacity unit, 2.5 mw, can be lost and the load still carried at time of peak. This is called a *1-unit reserve*. To establish service continuity, plant size must be increased substantially above the peak load.

Plant capacity can be established on one of several premises, table 1. Capacity must at least equal the expected peak load, and this can be called the *minimum need*, item 1. This might be adopted where the load is intermittent and there is enough time at no load to take units out for overhaul and inspection. In addition, losing load at times should not cause serious financial loss.

When continuity of service is needed, we must understand that no mechanical equipment is absolutely reliable to the extent that it will *always* be available at *any time* it's wanted. All types of prime movers are forced out of service about 1 to 3% of their running time. So for *minimum protection* the plant's capacity should equal peak load plus capacity of the largest unit.

For very small plants we might use the principle of *maximum protection* and supply two units, each capable of carrying the peak load by itself. This criterion may be too costly for large plants because of the high capital investment involved in doubling the capacity.

When we have a load-duration curve with a load factor near 1.0 we might adopt a policy of *conservative protection*. Here the capacity equals peak load, plus capacity of the largest unit, plus some additional capacity so units can come out for overhaul. We may have to take some capacity out of service at peak time; in effect, this often means that installed capacity equals load plus capacity of the two largest units in the plant.

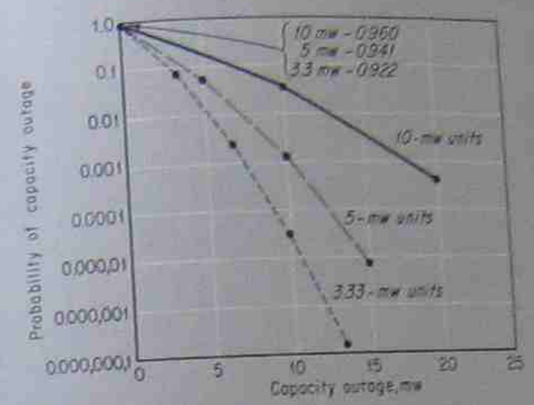
As mentioned before, most plants have an inherent reserve for *emergency protection*. This is the amount of load reduction possible through lowering the generator voltage—load is cut about proportionally to voltage.

Outage probabilities. While we have talked about protecting the load to preserve service continuity, we must realize that such protection is not absolute. As long as equipment is subject to failure we must live with the chance that at some time all units in a plant will be forced out of service simultaneously to completely shut down the energy system. As actual experience shows, this may happen at *any* time.

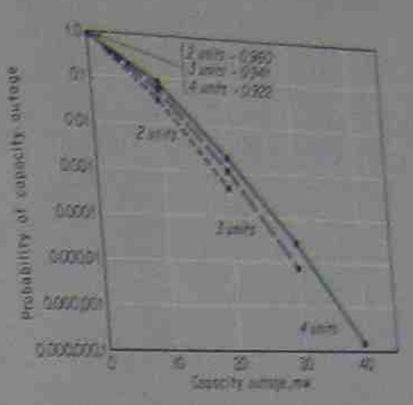
We must decide on what is a reasonable amount to invest in spare capacity. This boils down to a willingness to spend so much money to reduce probability of outages to a given level; for this we use the:

Probability theory. Here we must know what the likely availability of the units will be, based on performance of existing units like those we will install.

Usual practice surveys the operating records to establish probability of in-service time P and probability of out-of-service time or forced outage Q, as defined in table 2. Note that these definitions account only for hours of *forced* outage, not hours of idle time or hours of scheduled-overhaul outage. Probabilities are figured on the basis of exposure to active service or generation time. Presumably a unit standing idle will not be wearing out and so it won't be subject to forced outage.



2 This study compares 2-, 3- and 4-unit plants to supply load with 10-mw peak and maintain a 1-unit reserve over the peak



3 As equal-sized units are added to a growing plant, probability of given-sized outage increases to erode 1-unit protection

These probabilities are figured on an annual basis. Since they vary in magnitude from year to year, an average of several years gives us our answer.

Simple arithmetic then shows that for any one unit $P + Q = 1.0$. We can combine several units, as we do in table 2, and show that the product still equals 1.0.

When we multiply out the factors of the equation we get all the quantities listed in table 2. The various products mean the probabilities of happenings as listed in the table. For instance, if $P_1 = P_2 = P_3 = 0.9$, then $P_1P_2P_3 = 0.729$. This means that on the average—over a long period of time—all three units will be in service simultaneously 0.729 part of the time. In other words, the three units will be in service at the same time 0.729 $\times$ 8760 hr $=$ 6386 hr per year *on the average*.

Going by this assumption, $Q_1 = Q_2 = Q_3 = 0.1$ or $Q_1Q_2Q_3 = 0.001$; over a long period of time, all three units will be out of service simultaneously 0.001 part of the time, or the plant will be completely shut down 0.001 $\times$ 8760 $=$ 8.8 hr per year *on the average*. This will not happen every year; it may happen 16.7 hr every two years, 26.4 hr every three years, etc. As long as units do fail, at some time all will be out of service to completely shut down an energy system. We can only reduce outage probabilities by supplying enough units to minimize shutdown risk.

Unit capacity affects outage probabilities. Let's study three plants: two 10-mw units; three 5-mw units and four 3.333-mw units to supply a load with 10-mw peak. Each has a 1-unit reserve. All units have a forced-outage rate of $Q = 0.02$, see table 3.

The table shows that the probability of having a given capacity available is the same as the probability of having a corresponding capacity outage. Fig. 2 plots the capacity outage vs the probability of that outage. This shows that for any one plant the outage probability decreases as the outage capacity grows. In other words,

1—How much plant capacity?

1 Minimum need	Total capacity = peak load
2 Minimum protection	Total capacity = peak load + capacity of largest unit
3 Maximum protection	Total capacity = 2 × peak load
4 Conservative protection	Total capacity = peak load + capacity of largest unit + capacity for overhaul outage
5 Emergency protection	At times of reserve capacity loss, load may be shaved by dropping system voltage to cut it to capability of available units in system service

2—Probabilities of outages

$$P = \frac{\text{Hours in operation}}{\text{Hours in operation} + \text{hours forced out of service}}$$

$$Q = \frac{\text{Hours forced out of service}}{\text{Hours in operation} + \text{hours forced out of service}}$$

$P + Q = 1$

$(P_1 + Q_1)(P_2 + Q_2)(P_3 + Q_3) = 1$

$P_1P_2P_3$ = probability of three units in service

$P_1P_2Q_3$ = probability of units 1 and 2 in service, unit 3 out

$P_1P_3Q_2$ = probability of units 1 and 3 in service, unit 2 out

$P_2P_3Q_1$ = probability of units 2 and 3 in service, unit 1 out

$P_1Q_2Q_3$ = probability of unit 1 in service, units 2 and 3 out

$P_2Q_1Q_3$ = probability of unit 2 in service, units 1 and 3 out

$P_3Q_1Q_2$ = probability of unit 3 in service, units 1 and 2 out

$Q_1Q_2Q_3$ = probability of three units out of service

If all three units have same P's and Q's, then expansion of equation $P + Q)^3 = 1$ reads:

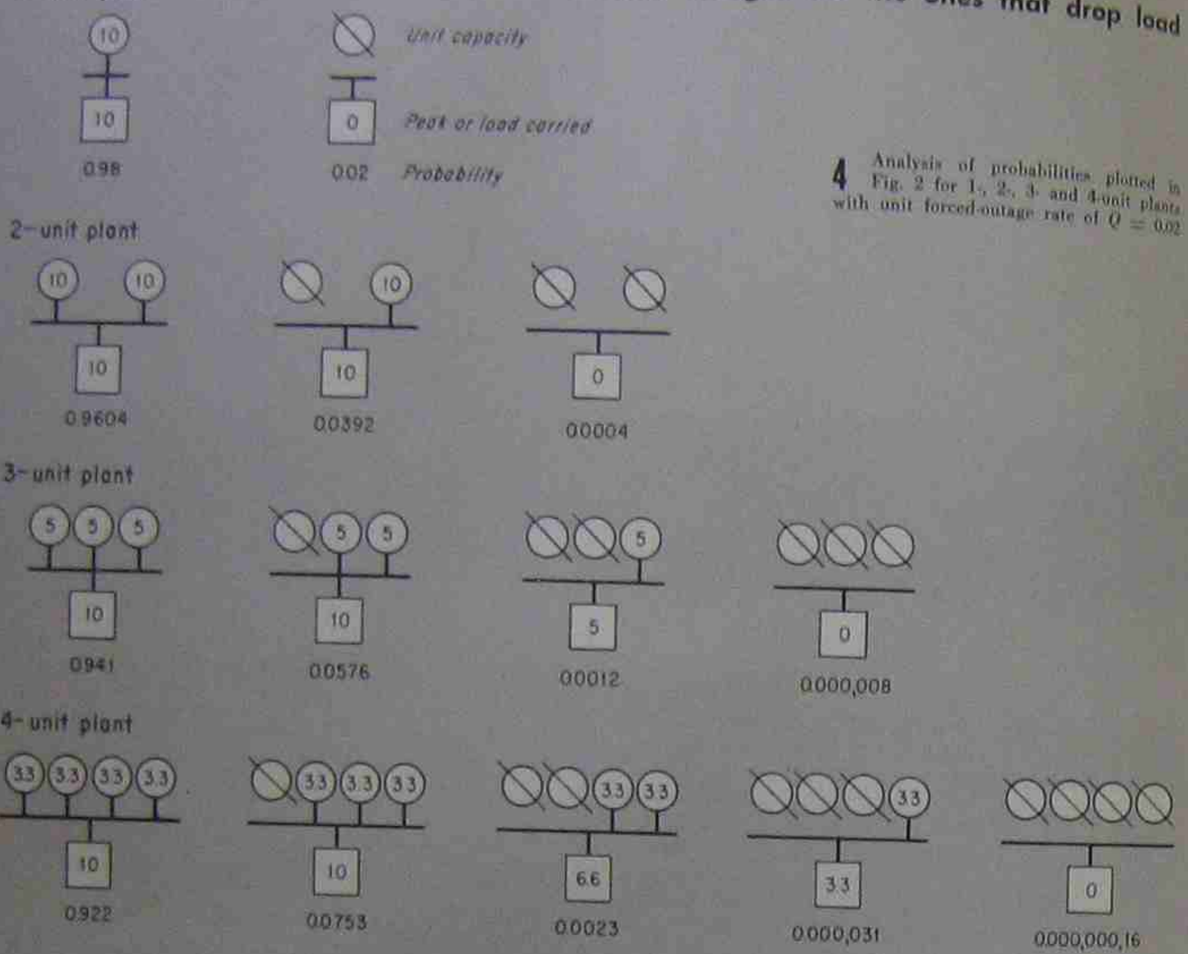
P^3 = probability of three units in service

$3PQ$ = probability of two units in service and one out

$3PQ^2$ = probability of one unit in service and two out

Q^3 = probability of all three units out of service

Critical outages are the ones that drop load



4 Analysis of probabilities plotted in Fig. 2 for 1-, 2-, 3- and 4-unit plants with unit forced-outage rate of $Q = 0.02$

large outages happen very seldom, small outages more frequently.

But what does this table tell us about the relative attractiveness of the three plants from an outage-probability standpoint? Losing more than one unit in each plant forces the dropping of load. Let us assume our load has a 1.0 load factor and find the probability of losing capacity in excess of the load, Fig. 4.

If we had a 1-unit 10-mw plant we would lose the entire plant 0.2 part of the time ($Q = 0.02$). Then the relative load loss for this plant would be 10 mw $\times$ 0.02 $=$ 0.2 mw.

The two-10-mw-unit plant must lose both units to drop any load; losing only one unit has no effect. Table 3 shows that probability of losing both units is 0.0004, giving a relative load loss of 10 $\times$ 0.0004 $=$ 0.004 mw.

The three-5-mw-unit plant drops load when losing two or three units:

Outage, mw	*Probability*	*Load loss, mw*	*Relative load loss, mw*
10	0.001,176	5	0.005,880
15	0.000,008	10	0.000,080
	0.001,184		0.005,960

The four-3.333-mw-unit plant must lose two or more units to drop load:

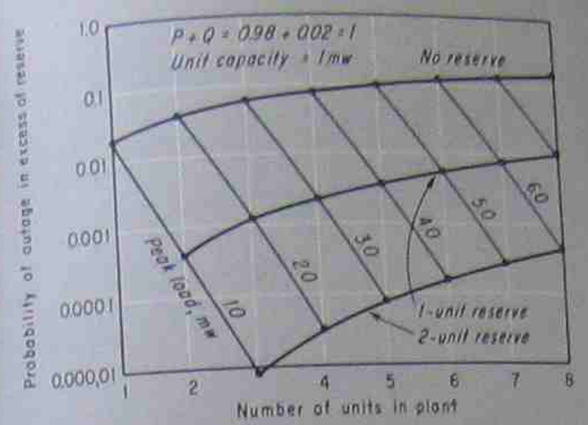
Outage, mw	*Probability*	*Load loss, mw*	*Relative load loss, mw*
6.66	0.002,304,96	3.33	0.007,68
10.00	0.000,031,36	6.66	0.000,209
13.33	0.000,000,16	10.00	0.000,002
	0.002,336,48		0.007,891

Summarizing this data for a load with a 10-mw peak:

Units per plant	*Probability of load loss*	*Relative load loss*	*Plant capacity, mw*
1	0.02	0.2	10
2	0.000,4	0.004	20
3	0.001,184	0.005,96	15
4	0.002,336,48	0.007,891	13.33

The 1-unit plant shows largest relative load loss, but lowest capacity and so lowest investment.

The 2-unit plant has double the capacity but much greater reliability. Here we double the investment to achieve improved continuity. The 3-unit plant would have about 75% of the investment of the 2-unit plant, but it suffers by a 50% larger relative load loss.



5 When a given reserve policy is followed in adding units to plant, probability of outage increases with number of units

The 4-unit plant would have about 66% of the investment of the 2-unit one, but almost doubles relative loss.

This comparison shows that as we attempt to cut investment but still maintain a measure of reliability in the form of a 1-unit reserve, we inevitably raise the probability of outage. We must make up our minds: at what point does the value of load loss exceed the saving we make in plant investment? We could express this in terms of probability of load loss or of outage.

Probability of 0.0004, for example, is the same as 8760 $\times$ 0.0004 $=$ 3.5-hr outage per year. A probability of 0.0023 is 8760 $\times$ 0.0023 $=$ 20.2-hr outage per year. From experience, we may decide that more than an average of 15 hr of outage per yr is intolerable. This becomes our standard. When the outage probability exceeds 15 hr we must install more than one reserve unit. Of the four plants above we would favor the 3-unit 15-mw plant since its outage probability is 8760 $\times$ 0.0012 $=$ 10.5 hr per year on the average.

Adding units to a growing plant also leads us to change our reserve policy in respect to the number of reserve units. Fig. 3 shows the change in outage probabilities of a plant starting with two 10-mw units and adding equal-sized units as its peak load grows (assuming all units have a forced-outage rate of $Q = 0.02$). As the plant grows, probability of all units being available at the same time decreases and outage probability goes up.

A 1-unit reserve policy, followed as the plant expands, gives us outage probability in excess of reserve capacity which grows as listed in table 4, right.

Fig. 5 charts the trends for plants built with 1-mw units, following no-reserve, 1-unit and 2-unit reserve policies. This shows clearly that as the number of units increases the outage probabilities also go up.

Outage at peak time. Outages can happen at any time; those at times of minimum plant load do not cause as large a total relative load loss as we calculated. The critical time, of course, is the peak load. If it comes 100 hr a year the probability of the peak is 100/8760 $=$ 0.0114 part of the total operating time in a year.

Assume probability of an outage in excess of reserve of 0.0012. The probability of an outage at peak time will be 0.0114 $\times$ 0.0012 $=$ 0.000,014 or about one day in 200 yr. This is a measure of the coincidence of peak outage with peak load, but it still does not alter the basic probability of having an equipment outage of 8760 $\times$ 0.0012 $=$ 10.5 hr per yr.

3—Study of supplying 1-unit protection for a 10-mw peak load with two, three and four equal-sized generating units

Probability of in-service and outage for all units
$P + Q = 0.98 + 0.02 = 1.00$

1. Plant with two 10-mw units:

$(P + Q)^2 = 1.0$

Quantity	Capacity available, mw	Capacity outage, mw	Probability
P^2	20	0	0.9604
$2PQ$	10	10	0.0392
Q^2	0	20	0.0004
			1.0000

2. Plant with three 5-mw units

$(P + Q)^3 = 1.0$

P^3	15	0	0.941,192
$3P^2Q$	10	5	0.057,624
$3PQ^2$	5	10	0.001,176
Q^3	0	15	0.000,008
			1.000,000

3. Plant with four 3.33-mw units

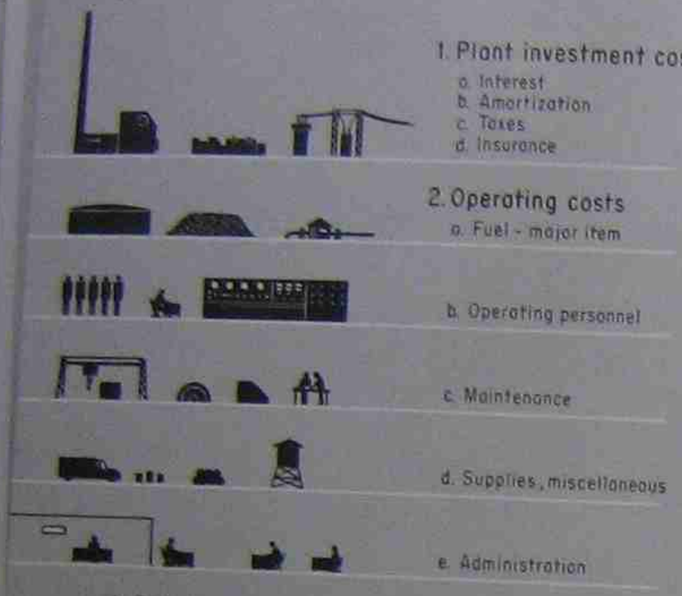
$(P + Q)^3 = 1.0$

P^4	13.33	0	0.922,368,16
$4P^3Q$	10.00	3.33	0.075,295,36
$6P^2Q^2$	6.66	6.66	0.002,354,96
$4PQ^3$	3.33	10.00	0.000,031,36
Q^4	0	13.33	0.000,000,16
			1.000,000,00

4—Outage probability changes with growth

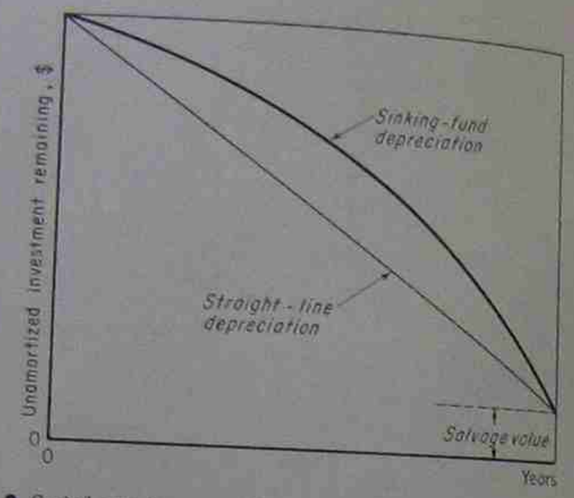
Number of units	Protected peak, mw	Probability of outage in excess of reserve
2	10	0.000,40
3	20	0.001,18
4	30	0.002,34
5	40	0.003,84
6	50	0.005,69
7	60	0.007,85
8	70	0.010,34

Operating costs and capital charges make up total you pay for energy



1. Plant investment costs
   - a. Interest
   - b. Amortization
   - c. Taxes
   - d. Insurance
2. Operating costs
   - a. Fuel - major item
   - b. Operating personnel
   - c. Maintenance
   - d. Supplies, miscellaneous
   - e. Administration

1 Cost of energy generated includes capital charges on equipment and a variety of operating costs, fuel being the biggest



2 Capital may be recovered by straight-line depreciation or by a sinking-fund accumulation—you can use either of the two

What will energy output cost?

Total price we pay for energy from power plants consists of: (1) capital charges (2) operating costs. Capital charges depend on plant investment, operating costs on the running of the plant day-by-day.

Capital costs, Fig. 1, include: (1) depreciation (2) interest (3) taxes and (4) insurance. The initial investment breeds charges that have to be met annually.

Depreciation recognizes that machines wear out or are superseded by newer designs. To maintain a profitable business in energy generation, the revenues you receive must include a component to recover the initial investment. Rate at which capital is recovered depends on estimated life of the machines, financing arrangements made to repay the investment and the method of amortization. These all vary with the type of ownership—private industrial, privately owned public utility or governmental utility—and type of industry.

When capital is raised by serially maturing bonds, an equal number may be retired each year, as table 1 shows. Here the $1-million issue has a 20-yr life and the bonds pay an effective interest rate of 6%. Each year $50,000 worth of bonds are retired and 6% interest is paid on the remaining outstanding bonds. This arrangement is analogous to straight-line depreciation. For the 20-year life, total interest of $630,000 has been paid. The equivalent annual interest on the investment is then considerably less than 6%: $630,000/20 = $31,500 or 3.15%.

When financing and equipment-life terms are about the same, annual depreciation charge for table 1 would be $50,000/$1,000,000 = 0.05 or 5%. Coupling depreciation with the equivalent interest rate: 3.15 + 5.00 = 8.15%.

For financing continuing businesses, the sinking-fund method is often used, table 2. Constant total annual payments cover both repayment of capital and interest charges. Total payments here are higher than in table 1 because capital is repaid more slowly at first. Equivalent annual interest rate works out to: $743,665/20 = $37,183 or 3.72%. Total of depreciation plus interest rate is 3.72 + 5.00 = 8.72%.

Fig. 2 shows an estimated salvage value that can be used to repay capital. Here we see the difference in unamortized capital during the life of a loan or machine for the two methods of depreciation allowance. Some designers assume the salvage value of a machine only pays for its removal, so depreciation covers full investment.

Interest rate used in evaluating a new plant depends on financing methods. For many businesses this will be a mixture of bonds and stocks. Average rate used must cover the needs of all the sources of capital.

Where all financing is by bonds, an item should be added to include objective earnings expected from the energy system. This may be called interest or profit. At any rate it should be a part of the total interest.

Insurance guards most energy systems against financial

Schedule of payments . . .

1—For straight-line amortization of loan

End of year	Amount of loan owed	Repayment on loan	Payment of interest	Total year-end payment
0	$1,000,000			
1	1,000,000	$50,000	$60,000	$110,000
2	950,000	50,000	57,000	107,000
3	900,000	50,000	54,000	104,000
4	850,000	50,000	51,000	101,000
5	800,000	50,000	48,000	98,000
6	750,000	50,000	45,000	95,000
7	700,000	50,000	42,000	92,000
8	650,000	50,000	39,000	89,000
9	600,000	50,000	36,000	86,000
10	550,000	50,000	33,000	83,000
11	500,000	50,000	30,000	80,000
12	450,000	50,000	27,000	77,000
13	400,000	50,000	24,000	74,000
14	350,000	50,000	21,000	71,000
15	300,000	50,000	18,000	68,000
16	250,000	50,000	15,000	65,000
17	200,000	50,000	12,000	62,000
18	150,000	50,000	9000	59,000
19	100,000	50,000	6000	56,000
20	50,000	50,000	3000	53,000
		$1,000,000	$630,000	$1,630,000

2—For sinking-fund amortization of loan

End of year	Amount of loan owed	Repayment on loan	Payment of interest	Total year-end payment
0	$1,000,000			
1	1,000,000	$27,183	$60,000	$87,183
2	972,814	28,817	58,369	87,186
3	943,997	30,546	56,640	87,186
4	913,451	32,379	54,807	87,186
5	881,072	34,322	52,864	87,186
6	846,750	36,381	50,805	87,186
7	810,369	38,564	48,622	87,186
8	771,805	40,878	46,308	87,186
9	730,927	43,330	43,856	87,186
10	687,597	45,930	41,256	87,186
11	641,667	48,686	38,500	87,186
12	592,981	51,607	35,579	87,186
13	541,374	54,704	32,482	87,186
14	486,670	57,986	29,200	87,186
15	428,684	61,465	25,721	87,186
16	367,219	65,153	22,033	87,186
17	302,066	69,062	18,124	87,186
18	233,004	73,206	13,980	87,186
19	159,798	77,599	9587	87,186
20	82,199	82,199	4932	87,131
		$1,000,000	$743,665	$1,743,665

loss from accidents and vandalism. Policies cover fire, explosion, windstorm, hail, flood, public liability, title, machinery and many others. Annual premiums prorated on the value of the property pay for this protection.

Taxes in all forms levied by federal, state, county and municipal governments must be paid for energy systems. The tax base may be value of the property, or revenues, unemployment, income and the like. In usual evaluating practice most of the taxes are related to the investment so calculations can be more easily handled.

Total capital charges. The capital-charge rates used for an energy system vary with the organization owning the system. Some typical rates for power plants:

	Private utility	*Governmental utility*
Interest	6.80%	2.50%
Depreciation	1.10	2.20
Insurance	0.25	0.25
Taxes	5.80	0.00
Total capital charge	13.95%	4.95%

Some governments may add a rate in lieu of taxes of 1.0 or 2.0%.

Operating costs, Fig. 1, include fuel, operating labor, maintenance, supplies and administrative expenses. The important items here vary with generation, while some minor ones stay essentially constant.

Fuel. A thermal plant burns fuel about in proportion to the load. For most plants, fuel is the largest item of annual operating cost, and depends on type of fuel, plant factor, plant thermal efficiency and fuel price.

Operating labor needed to supervise generating plants has been brought close to the minimum by increasing automatic control. Men are still required for fuel and refuse handling, to inspect and control operating machinery and for general plant security. A plant usually needs about the same number of men for any load range except when it is on cold standby.

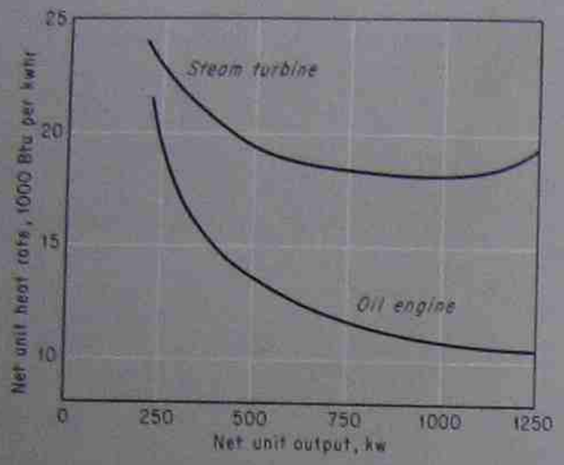
Maintenance. Most plants have their equipment taken out on a regular schedule for inspection and repairs. This helps forestall forced outages, but of course the equipment is unavailable when under repair. For an overall average, equipment appears to be available about 90% of the time. Maintenance costs involve both labor and materials—they generally vary with the plant factor.

Supplies include water, lubricating oils, water-treatment chemicals, tools, office materials, cleaning items, etc. This account is often a catchall for items not charged to any of the other categories. It is usually the smallest of the operating costs.

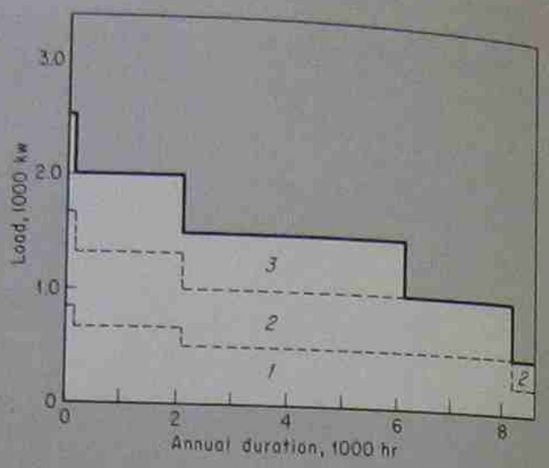
Supervision, for plants of any importance, includes superintendents, chief engineer, chemist and efficiency engineer to insure competent operation of the plant.

Choosing new equipment. Basic principle in choosing new energy equipment strives for minimum overall operating cost consistent with reliability. In the following pages we will look at several situations and learn how equipment should be evaluated in each respect. We will study the factors for choosing a new plant to serve an entirely new load; we will look at factors governing replacement of an obsolete unit; we will examine principles guiding choice of a new unit to be added to a growing system, either for base loading or peaking.

Plant heat-rate curves and load durations fix expected performance



1 Net unit heat rates compare 1250-kw boiler and steam turbine with reciprocating internal-combustion oil-engine plant



2 Expected annual-load-duration curve has 2500-kw peak. It's to be protected against forced outage by 1-unit reserve

Choosing your new power plant

Basic method of deciding between alternate plans for energy supply is to compare annual costs over the life of the system. The plan with the lowest annual costs presumably will be the economic choice. In many practical situations, however, factors other than cost play a decisive role in final selection. This is especially true if cost difference between alternates is small.

The principles we have discussed apply to plants and systems of all sizes. An example will explain these principles and how they vary:

Let us consider a new plant. An organization plans to build an entirely new power plant to run its new facilities. It can define load variation as the load-duration curve in Fig. 2. An annual peak of 2500 kw and total energy of 12,580 mwhr have a load factor of 12,580,000/ $8760 \times 2500 = 0.575$ for the year. Designers expect this load curve to last indefinitely into the future. First three columns of table 2 detail the load.

Interruption of service would disrupt operations, so a 1-unit reserve is required to guard the plant against forced outages and mitigate facilities shutdown.

After preliminary study, designers choose a plant of three 1250-kw units. This gives a total plant capacity of 3750 kw to supply a protected peak load of $3750 - 1250 = 2500$ kw. At all times enough capacity will be running on the line to let one unit be lost without interrupting service to the load imposed by the facilities.

Preliminary investigation narrows the choice to either a steam plant or a reciprocating oil-engine plant because coal at 40c per million Btu and diesel oil at 65c per million Btu are available in the area. Fig. 1 shows the overall net heat rate of the two types of units, including all plant auxiliaries, in Btu per kwhr net output.

Table 1 summarizes the capacity requirements. Let's assume a survey has shown that both steam and engine units of this size and type have a forced-outage rate of 1.5%. Item 5 checks the probability of outage in excess of the 1-unit reserve for the 3-unit plant and finds it equal to one day in 4.1 years. This is about on the edge of being acceptable. Item 6 shows outage probability for a 4-unit plant with 2-unit reserve: probability drops to one day in 192 years. But designers decide to defer installing the fourth unit until the actual plant has gathered some operating experience.

Table 2 computes total annual fuel costs for each type of plant. The lower basic fuel cost of the steam turbines offsets their higher heat rate compared to the oil-engine plants. Note that 1-unit reserve policy loads the generating units pretty much below their level of top efficiency.

Table 3 lists factors making up the capital-charge rate. The steam-turbine units are expected to turn in a 30-year operating life, the oil engines 20 years.

Interest charged for this plant is modest compared to many industrial organizations. Many industries use a high return to offset rapid obsolescence. They may compensate for this by assigning a short life to a project and demanding a high depreciation. But we assume that our plant will be functioning for its "natural" life and compute the depreciation rate on a straight-line basis: 1/(number of years of life).

Insurance is a typical 0.25% and taxes of all forms related to investment run 3% of capital. Summing up for both plants, we have a 12.55% capital-charge rate for the steam plant and 14.25% for the shorter-lived oil-engine plant.

A detailed study of all land, improvements, buildings, accessories as well as main equipment shows an investment of $310 per kw capacity for the steam plant and $220 for the oil-engine plant. We are now ready to make our economic comparison of the two generating plants.

1—Steam-turbine and oil-engine plants

1 Three 1250-kw units = 3750-kw plant capacity
2 1-unit reserve capacity needed at all loads
3 Protected peak to be carried = 2500 kw
4 Forced-outage rate for both steam and engine plants, Q = 0.015
5 Outage probability check: $(P+Q)^3 = (0.985 + 0.015)^3 = 1.0$
Probability of all units out, $Q^3 = 0.15^3 =$ 0.000,003
Probability of two units out, $3PQ^2 =$
$3 \times 0.985 \times 0.015^2 =$ 0.000,665
0.000,668
Outage in excess of reserve =
or 1/0.000,668 = 1 in 1500 days, or one day in 4.1 years
6 For a 4-unit plant with 2-unit reserve: $(P + Q)^4 = (0.985 + 0.015)^4$
Probability of all units out, $Q^4 = 0.15^4 =$ 0.000,000,05
Probability of three units out, $4PQ^3 =$
$4 \times 0.985 \times 0.015^3 =$ 0.000,013,30
0.000,013,35
Outage in excess of reserve =
or 1/0.000,013,35 = 1 in 70,000 days or one day in 192 years

2—Load and performance

Load, kw	Hours	Energy, mwhr	No. units on	Unit load, kw	Oil engines Ht rt Btu/kwhr	Oil engines Input, 10^9 Btu	Steam turbines Ht rt Btu/kwhr	Steam turbines Input, 10^9 Btu
2500	100	250	3	833	11,300	2.83	10,100	4.53
2000	2000	4000	3	667	12,250	48.90	10,600	74.40
1500	4000	6000	3	500	13,500	81.00	19,200	115.20
1000	2000	2000	2	500	13,500	27.00	19,200	38.40
500	660	330	2	250	19,300	6.37	22,800	7.52
	8760	12,580				166.00		240.05

Oil-engine fuel cost at 65¢/10^9 Btu = $166.0 \times 10^9 \times 0.65/10^9$
= $108,000 per yr
Steam-turbine fuel cost at 40¢/10^9 Btu = $240.05 \times 10^9 \times 0.40/10^9$
= $96,000 per yr

3—Capital charge factors

Item	Steam turbines	Oil engines
Life	30 years	20 years
Interest	0.06	0.06
Depreciation	0.033	0.05
Taxes	0.030	0.030
Insurance	0.0025	0.0025
Capital charge rate	0.1255	0.1425
Investment per kw	$310	$220

4—Economic comparison of steam and engine plant

Plant	Steam turbine		Oil engine	
1 Capital charges	$310 \times 3750 \times 0.1255 = \$145,800$		$220 \times 3750 \times 0.1425 = \$117,300$	
2 Fuel costs	At 40¢/10^9 Btu	96,000	At 65¢/10^9 Btu	108,000
3 Operating and maintenance labor	10 men × $5200 =	52,000	8 men × $5200 =	41,600
4 Maintenance material	At 0.05¢/kwhr	6300	At 0.06¢/kwhr	7600
5 Supervision	2 × $8000 =	16,000	2 × $8000 =	16,000
6 Supplies		4000		4000
7 Total annual costs		$320,100		$294,700
		2.54¢/kwhr		2.34¢/kwhr

5—Basics of economic evaluation

1 Rising capital-charge rates favor lower investment plans
2 Rising fuel costs favor higher-cost more-efficient plants
3 All consistent methods of economic evaluation lead to choosing the same plan, though the answers vary in form
4 Fuel costs should be estimated from loads likely to be carried on units and not on full-load heat rate alone

In table 4, item 1, we figure the annual capital charges for each plant by multiplying unit investment, capacity and capital-charge rate. Here the oil-engine plant shows its principal advantage. Item 2 records the fuel costs figured in table 2; the steam plant is lower. In item 3 the steam plant is estimated to need ten men for operation and maintenance at an annual average wage of $5200. The oil-engine plant needs only eight men, earning the same wage. Future inflation possibility should be considered.

Item 4 figures maintenance material at 0.05c per kwhr for the steam plant and 0.06c for the oil engine. Both plants need the same supervision—a superintendent and chief engineer at an average salary of $8000, item 5. Finally, supplies are figured at $4000 a year for each type of plant.

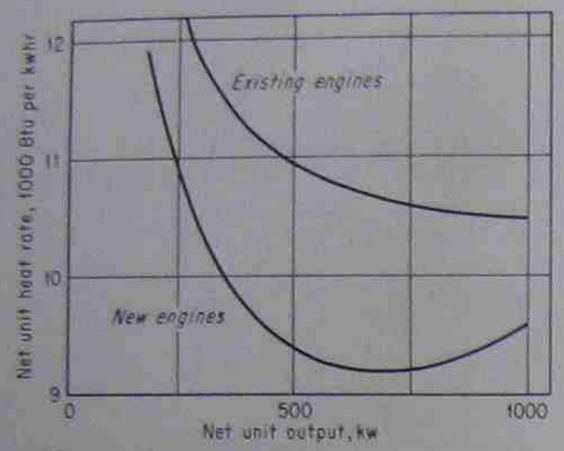
Summing the costs we find the oil-engine plant lower at $294,700 compared to the $320,100 for the steam plant. Dividing these by the 12,580 mwhr generated each year we get 2.34c per kwhr for the oil-engine energy and 2.54c per kwhr for the steam-plant energy. All other factors being equal, we would choose the oil-engine plant.

Balancing costs. Let's find the coal cost Y at which the two plants would be equal in annual total costs. This would be a value that reduces steam-plant cost by $20,100 $-294,700 = \$25,400$. Then $240 \times 10^9 \times Y/10^9 = 96,000 - 25,400$; solving, Y = 29.4c per million Btu.

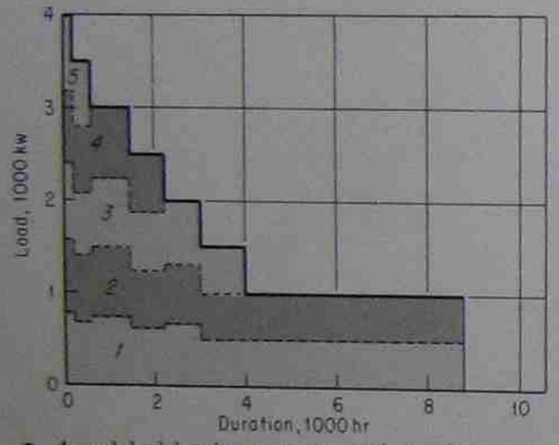
As an alternative, what would the steam-unit investment have to be for economic equality? We figure this by equating $Z \times 3750 \times 0.1255 = 145,800 - 25,400$; solving, we get Z = $263 per kw of capacity. Of course, there are other factors to be carefully considered together with this economic comparison before the final choice is made.

These balancing costs show us how much change is needed in the important operating and investment factors to make the alternate schemes equal. If actual and balancing investments are close, this may spur a critical review of plant design to cut costs.

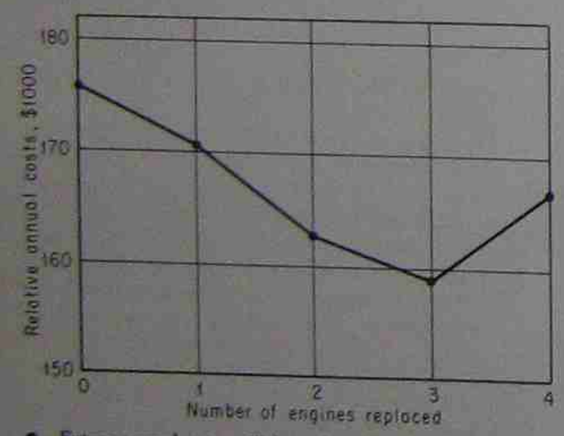
When fuel costs for alternate schemes using different fuels are close, a painstaking forecast of future fuel-cost trends should be undertaken. Available supplies and probable future demands may inflate prices sharply.



1 These are heat rates of existing engines and new ones proposed to replace some or all of them. Curves include auxiliaries



2 Annual load-duration curve, expected to stay constant into the future, shows division of load—always with a 1-unit reserve



3 Future annual costs will be reduced by replacing as many as three engines with new units. Fourth replacement causes a loss

When should old equipment be replaced?

Advances in the art of energy handling often raise this question: has existing equipment outlived its economic usefulness? Just how to make the comparison often causes confusion, and the stumbling block is what to do about capital charges on the existing equipment which may be replaced. But the answer's simple.

Replacing or keeping the old equipment does not affect commitments for amortizing or financing its investment. In any event capital charges run for the life of the bonds or loan. So the question boils down to whether the *total of capital charges and operating costs* of the new equipment will be less than *operating costs plus taxes and insurance* on the old equipment. When total annual cost of the new equipment comes to less than these specific costs of the old, it's time to make the replacement.

Installing new engines. As an example let's study a power plant with a load-duration curve that stays the same year-to-year, Fig. 2. A unit reserve is always needed on the line, so the plant has five 1-mw units to serve its 4-mw peak demand. Fig. 1 shows the existing units' heat rate. They burn oil costing 80c per million Btu.

New engines burning gas at 45c per million Btu are now available; Fig. 1 also shows their heat rate. Installed, they will cost $205 per kw. The old units, which originally cost $180 per kw, can be sold at a net return of $50,000 each. Table 1 summarizes these facts in brief fashion.

How many of the old units should be replaced? First we must figure output and input for the old and new units as they fit into the load-duration curve—all units are alike, which simplifies our problem. Table 2 summarizes load and energy division among the five units—we neglect starting and stopping losses and assume load is always equally divided among the units on the line.

In table 3, with the aid of table 2, we figure inputs and outputs on the old and new engines for various combinations, adding one new unit at a time. We start with the present plant and work up to keeping one old unit and replacing four with new units. Each arrangement must be studied to get a complete answer.

Calculations for each case are shown in table 4. Case A figures pre-

1—Obsolescence study factors

1 Five existing units	1000-kw each
2 One-unit installed and spinning reserve	at all loads
3 Investment in old units	$180 per kw
4 Investment in new units	$205 per kw
5 Oil fuel cost for new units	80¢ per million Btu
6 Gas fuel cost for new units	45¢ per million Btu
7 Salvage value of old units if retired now:	$50,000 per unit

2—Load duration and input data

Load, kw	Hours	Energy, mwhr	No. eng.	Eng load, kw	Engine heat rates, Btu per kwhr Old	New	Output per eng., mwhr	Input per engine, million Btu Old	New
4000	200	800	5	800	10,580	9250	160	1693	1480
3500	400	1400	5	700	10,630	9220	280	2976	2582
3000	800	2400	4	750	10,600	9230	600	6360	5538
2500	800	2000	4	625	10,730	9230	500	5365	4615
2000	800	1600	3	667	10,660	9220	534	5692	4923
1500	1000	1500	3	500	10,920	9400	500	5460	4700
1000	4760	4760	2	500	10,920	9400	2380	25,990	22,372
	14,460						4954	53,536	46,210

Annual average heat rate = 10,804 9328

4—Calculation of comparative annual costs

A—Costs with existing (old) engines

1 Fuel: 155,681 × 0.80 = $124,580

2 Maintenance
14,460 × 0.0012 = 17,360

3 Taxes and insurance @ 4%
$180 × 5000 × 0.04 = 36,000

4 Total excluding amortization and interest: $175,940

B—Costs with one engine replaced

1 Correction to 90% availability of new unit: 4953 × 0.9 = 4458 mwhr

New-unit input = $\frac{4458}{4953} \times 46{,}210$ = 41,580 million Btu

Corrected output of old units
9507 + 4953 − 4458 = 10,002

Corrected input of old units =
$\frac{10{,}002}{9507} \times 102{,}145$ = 107,600 million Btu

2 Fuel: 107,600 × 0.80 = $86,080
41,580 × 0.45 = 18,720

3 Maintenance:
10,000 × 0.0012 = 12,000
4458 × 0.0008 = 3570

4 Taxes and insurance @ 4%
$180 × 4000 × 0.04 = 28,800
$205 × 1000 × 0.04 = 8200

5 Amortization of new money
$\frac{205{,}000 - 50{,}000}{20}$ = 7750

6 Interest on new money @ 3.5%
(205,000 − 50,000)0.035 = 5420

7 Total $170,540

8 Saving from replacing one engine
= 175,940 − 170,540 = $5400 yearly

C—Costs with two engines replaced

1 Correction to 90% availability of two new units: 9907 × 0.9 = 8916 mwhr

Input of new units = $\frac{92{,}420}{9907} \times 8916$ = 83,150 million Btu

Corrected output of old units
4554 + 9907 − 8916 = 5545 mwhr

Corrected input of old units
$\frac{5545}{4554} \times 48{,}619$ = 59,100 million Btu

2 Fuel: 59,100 × 0.80 = $47,280
83,150 × 0.45 = 37,420

3 Maintenance: 5545 × 0.0012 = 6650
8916 × 0.0008 = 7130

4 Taxes and insurance @ 4%
$180 × 3000 × 0.04 = 21,600
$205 × 2000 × 0.04 = 16,400

5 Amortization of new money
$\frac{410{,}000 - 100{,}000}{20}$ = 15,500

6 Interest on new money @ 3.5%
(410,000 − 100,000)0.035 = 10,900

7 Total $162,880

8 Saving from replacing two engines
175,940 − 162,880 = 13,060 yearly

D—Costs with three engines replaced

1 No availability correction needed because third new engine can help fill base of load curve when two other new engines are out for overhaul

2 Fuel: 21,063 × 0.80 = $16,850
116,258 × 0.45 = 52,300

3 Maintenance: 1980 × 0.0012 = 2380
12,680 × 0.0008 = 9980

4 Taxes and insurance @ 4%
$180 × 2000 × 0.04 = 14,400
$205 × 3000 × 0.04 = 24,600

5 Amortization of new money
$\frac{605{,}000 - 150{,}000}{20}$ = 22,750

6 Interest on new money @ 3.5%
(605,000 − 150,000)0.035 = 15,900

7 Total $159,160

8 Saving from replacing three engines
= 175,940 − 159,160 = $16,780 yearly

E—Costs with four engines replaced

1 No availability correction needed

2 Fuel: 4669 × 0.80 = $3740
130,473 × 0.45 = 58,700

3 Maintenance: 440 × 0.0012 = 530
14,020 × 0.0008 = 11,220

4 Taxes and insurance @ 4%
$180 × 1000 × 0.04 = 7200
$205 × 4000 × 0.04 = 32,800

5 Amortization of new money
$\frac{820{,}000 - 200{,}000}{20}$ = 31,000

6 Interest on new money @ 3.5%
(820,000 − 200,000)0.035 = 21,700

7 Total $156,890

8 Saving from replacing four engines
= 175,940 − 156,890 = $9050 yearly

9 Loss from replacing four engines compared to replacing three engines
= 166,890 − 159,160 = $7730 yearly

3—Combined outputs and inputs for the engines

Total engine inputs in million Btu and outputs in mwhr

Load, kw	Energy, mwhr	5 old units		4 old units and 1 new				3 old and 2 new units				2 old and 3 new units			
				4 old units		1 new unit		3 old units		2 new units		2 old units		3 new units	
		Input	Output	Input	Output	Input	Output	Input	Output	Input	Output	Input	Output	Input	Output
4000	800	8465	800	6772	640	1480	160	5079	480	2960	320	3386	320	4440	480
3500	1400	14,880	1400	11,904	1120	2582	280	8928	840	5164	560	5952	560	7746	840
3000	2400	25,440	2400	19,080	1800	5538	600	12,720	1200	11,076	1200	6360	600	16,614	1800
2500	2000	21,460	2000	16,095	1500	4615	500	10,740	1000	9230	1000	5365	500	13,845	1500
2000	1600	17,076	1600	11,384	1067	4923	533	5692	534	9846	1067	0	0	14,769	1600
1500	1500	16,380	1500	10,920	1000	4700	500	5460	500	9400	1000	0	0	14,100	1500
1000	4760	51,980	4760	25,990	2380	22,372	2380	0	0	44,744	4760	0	0	44,744	4760
	14,460	155,681	14,460	102,145	9507	46,210	4933	48,619	4554	92,420	9907	21,063	1980	116,258	12,680

1 old and 4 new units			
1 old unit		4 new units	
Input	Output	Input	Output
1693	160	5920	640
2976	280	10,328	1120
0	0	22,152	2400
0	0	18,460	2000
0	0	14,769	1600
0	0	14,100	1500
0	0	44,744	4760
4669	440	130,473	14,020

sent plant costs. Maintenance comes to 1.2 mills per kwhr on the present units. Taxes and insurance are ordinarily classed as capital charges, but they should be figured here because they change when the old units are replaced by new. The financing items of amortization and interest won't be affected; they go on for the duration of the bonds and stocks issued to cover them—in other words, they are a constant in all cases and so can be ignored in this comparison of relative annual costs.

In Case B we replace one old engine with a new one. Here we have to adjust for the running of the new engine which we place on base load. Calculation from load duration, Fig. 2 and table 3, assumes that the new unit would run for 8760 hr a year. But experience in this plant shows that units are only 90% available; they are out for overhauls 10% of the time on the average. So we reduce the output and input of the new engine by 10%. The old engines take over when the new unit is unavailable, so their output and input is higher than first calculated.

Now we're ready to figure fuel and maintenance costs for both old and new engines. Maintenance on the new engine is expected to be only 0.8 mills per kwhr. Taxes and insurance change because of the difference in investment. We need less new money by the amount of salvage on the old engine. Amortization is on the straight-line basis. Relative annual cost of Case B is $5400 under Case A, so it would pay to replace one engine.

In Case C we replace two old engines. Here again we need to adjust for 90% availability on both new engines, since both could run for 8760 hr yearly. When one is out for overhaul, an old engine will have to run in its place, Fig. 2, producing kwhr at a higher cost.

Replacing two old engines saves 170,540 − 162,880 = $7660 over the 1-engine case, so installing at least two new engines saves money for the long run.

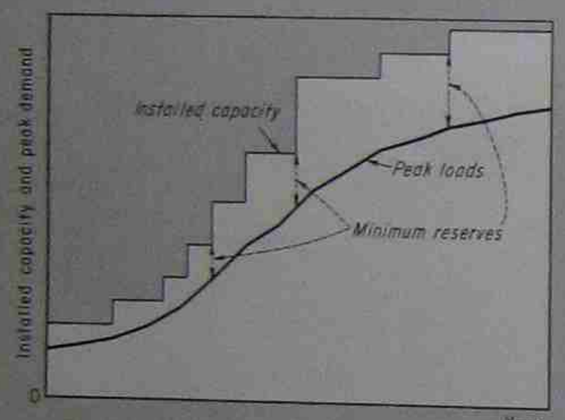
In Case D we replace three old engines. Now, a study of the load-duration curve shows that the third new engine can substitute for the two on base when they are out for overhaul, besides being on the line for 4000 hr to carry its part of the load. In addition, there will be enough time to take out the third new engine for overhaul.

We find that replacing three engines saves 162,880 − 159,160 = $3720 a year over replacing only two engines. So it pays to replace three engines.

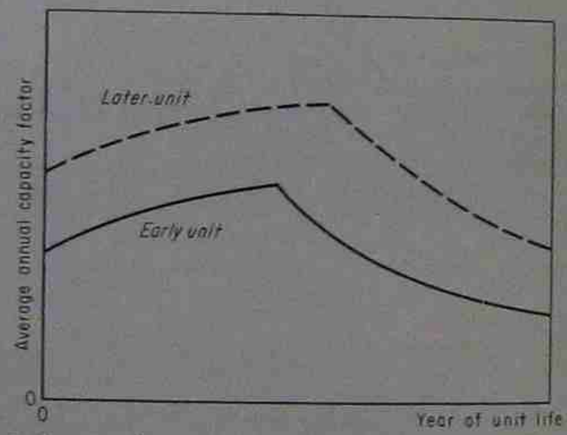
In Case E we replace four old engines. Again no availability correction is needed, but we find that replacing the fourth engine loses 166,890 − 159,160 = $7730 yearly.

This study suggests that we can reduce overall operating costs of the plant by replacing three of the old engines. Note that these savings are above the amortization and interest cost of the old units. These might be (3 × 1000 × 180)(0.05 + 0.035) = $45,900 yearly. They would be paid off from the normal proceeds of the overall business, which would be boosted by savings shown in this study. The key here is to recognize the costs that will be unaffected by the change.

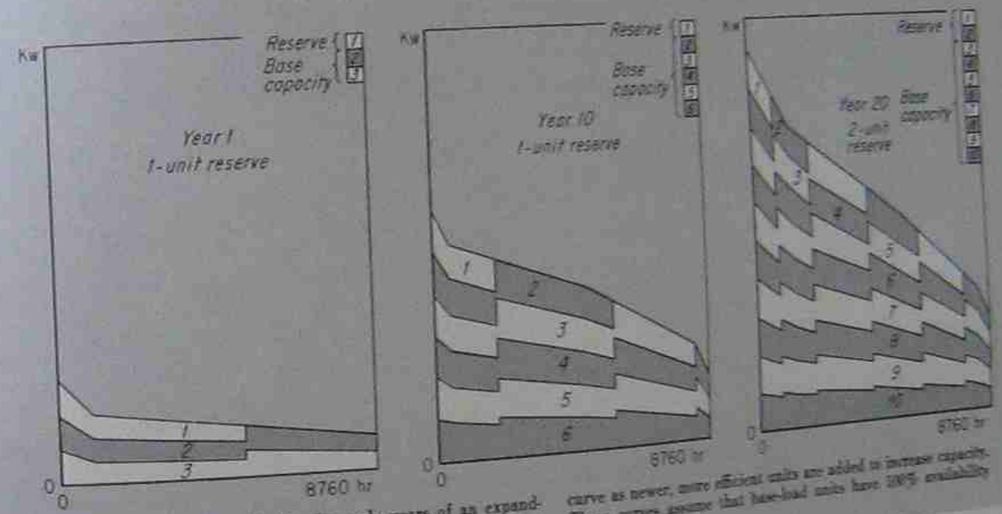
Growing energy systems need constant study and special analysis



1 Climbing annual peak loads require periodic expansion of installed capacity. Minimum reserves, too, will probably grow



2 On a growing system, average annual capacity factor of an individual unit rises during early years, then drops off later



3 Units that were base loaded in the early years of an expanding system gradually work their way to the top of the load curve as newer, more efficient units are added to increase capacity. These curves assume that base-load units have 100% availability

How to evaluate growing systems

Up to this point we have studied methods of evaluating loads that stay essentially constant with the years. But the most prevalent condition is growth—the energy system expands yearly at a persistent rate, Fig. 1. To keep the system peak demand protected, blocks of capacity must be added well in advance of the minimum reserve needed.

In choosing among alternative units of capacity we follow essentially the same method we did for the constant load; we look for the unit with the lowest overall annual cost. But we must also take account of future variation in annual output and so annual cost of units working on a growing system. Fig. 3 shows annual load-duration curves for a system starting with three units in the Year 1, with a 1-unit reserve. In the Year 10 peak demand has grown by a factor of 2.5 and in the Year 20 by 4.0, with corresponding growth in kwhr.

Note what happens to the first three units: they finally serve only during peak hours with greatly reduced output. In the Year 20, base-load Unit 6 of the Year 10 is going to be forced off the base when the 11th unit is installed.

These load-duration curves assume the base-load units are available 100% of the time. This is not so—there will be some mitigation of the variation in annual output. The base-load units will produce less than shown, and peaking and intermediate units will produce more when they substitute for the efficient units on the base.

Fig. 2 shows the variation in annual output of two typical units in terms of annual capacity factor. When units serve on the base their outputs grow from year to year along with system load. But once off the base their annual output drops quickly as they climb to the peak.

As the system matures, later units stay in the base area for more years and don't drop to as low a level as they approach the peak of load-duration curve.

We must account for this diminishing output over the lives of the alternatives we're evaluating. An estimate of the type in Fig. 3 should be made to find the annual capacity factor curve as in Fig. 2.

Next we evaluate annual total cost of the new units being added for the first year of their operation. Then the operating costs (exclusive of capital charges) should be diminished to their average over the expected life of the new units. We assume operating costs vary directly with annual capacity factors.

At this point it's customary to recognize that the *present worth* of future savings or costs is considerably less than their face value. So variations in costs are weighted according to how far they are from the present. We figure the present worth of a sum by dividing it by the present worth factor; for example:

$$W = \frac{C}{(1+i)^n}$$

where W = present worth of future sum C, i = interest rate and n = number of years hence that sum C will be realized or in hand.

Since costs vary directly as the capacity factor CF for the year, we can find the ratio of average weighted CF's to the first year's CF to find the age factor r by which to diminish the first year's cost. Table, opposite next page, shows how weighted CF's are figured. Then we convert total present worths into an equivalent constant annuity by:

$$A = W \frac{i}{1-(1+i)^{-n}}$$

continued

where A represents the equivalent average annual cost over the life of the unit in terms of CF. Then the age factor is:

$$r = A/CF_1$$

where CF_1 is the annual capacity factor for the first year of operation of the new unit. Table 1 uses a hypothetical capacity-factor variation and an 8% interest rate. For these conditions:

$$A = 569.2\,\frac{0.08}{1 - 1.08^{-20}}$$

$$= 569.2 \times 0.1019 = 58.0$$

From which we can figure:

$$r = \frac{58.0}{70.0} = 0.83$$

How would we use this factor? Suppose we were comparing two units, A and B, for addition to this growing system. We find that for unit A:

Annual capital charges =	$400,000
First year's operating costs =	380,000
Total first year's generating costs =	$780,000

Applying the age factor to the operating cost:

Annual capital charges =	$400,000
Average annual operating cost, 0.83 × 380,000 =	316,000
Average annual generating cost =	$716,000

Now for unit B we find:

Annual capital charges =	$380,000
First year's operating costs =	400,000
Total first year's generating cost =	$780,000

Applying the age factor:

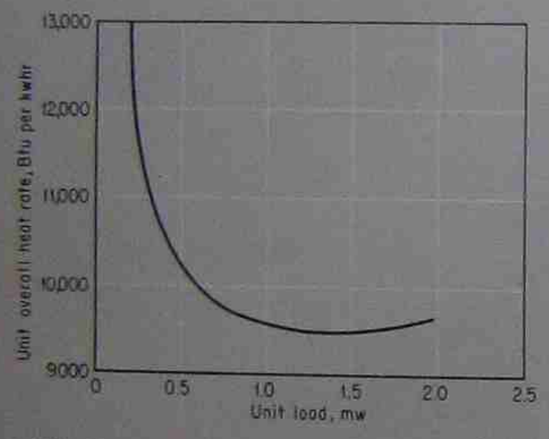
Annual capital charges =	$380,000
Average annual operating cost, 0.83 × 400,000 =	332,000
Average annual generating cost =	$712,000

If we didn't recognize the variation in annual operating costs, Units A and B would appear equal on an economic basis. But with the corrected operating costs we see that Unit B is cheaper by $4000 yearly.

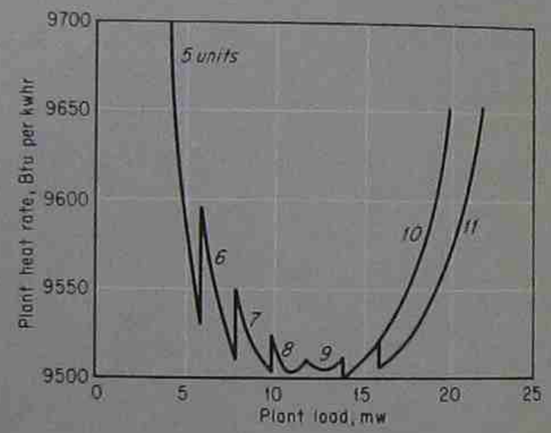
Age factor has a small effect here because annual capacity factor of the unit to be installed changes rather slowly. Where load grows faster on a system the age factor may drop to 0.6 and the growth must be accounted for to arrive at a rational choice. It is best to study this factor of system development—don't just assume that it has small importance. The faster the energy system grows the lower will be the age factor with greater final effect.

Present worth of annual capacity factors

Yr	CF	$\frac{1}{(1+i)^n}$	W	Yr	CF	$\frac{1}{(1+i)^n}$	W
1	70	0.926	64.8	11	48	0.429	20.6
2	72	0.857	61.6	12	44	0.397	17.4
3	73	0.794	57.9	13	41	0.368	15.1
4	74	0.735	54.4	14	38	0.341	13.0
5	75	0.681	51.0	15	35	0.315	11.0
6	70	0.632	44.3	16	32	0.292	9.4
7	65	0.584	37.9	17	30	0.270	8.1
8	60	0.540	32.4	18	28	0.250	7.0
9	56	0.500	28.0	19	26	0.232	6.0
10	52	0.463	24.1	20	24	0.215	5.2
							569.2



1 High-efficiency generating unit has flat heat-rate variation over much of its load range, which reduces station fuel cost



2 Plant heat-rate curve shows units in Fig. 1 running on 2-unit reserve. Units are added when needed to maintain the reserve

Base-load or peaking unit next?

Growing energy systems developing sharp peak demands as in Year 20, Fig. 3 on previous page, can use additional capacity in form of (1) high-efficiency base-load unit or (2) peaking unit. Choice depends on an economic study such as the following:

Power plant with ten 2-mw units has unit heat rates of Fig. 1 and plant heat rate of Fig 2. The plant is designed for a 2-unit reserve and so carries a protected peak demand of 20 − 4 = 16 mw. Another unit must be added to carry an expected peak of 17 mw.

Management decides to study two alternatives: (1) install another similar unit at $190 per kw or (2) a peaking unit costing $130 per kw and having a full-load heat rate of 18,000 Btu per kwhr.

New peak of 17 mw has a duration of 200 hr a year. Next step on the load-duration curve is 15 mw which will last 400 hr per year. Fig. 2 shows the plant heat rate with the 11th base-load unit added. Peak load at 17 mw can be carried at a better heat rate than with the existing ten units; all lower loads will be carried on ten units or fewer as dictated by the 2-unit reserve.

In comparison, if we installed a 2-mw peaking unit it would run only for the 200 hours; with ten high-efficiency units and the load-duration curve we're considering, it would seldom have to run at other times. So to compare the new high-efficiency unit with the peaking unit we only need to study operation at peak times.

No additional operating labor is needed for either unit, and maintenance costs are assumed equal. Capital-charge rate for the system is 15%, fuel costs 60¢ per million Btu.

High-efficiency unit will make an overall fuel saving at 17-mw system load of:

$$17{,}000(9537 - 9513)200 = 81.5 \text{ million Btu annually}$$

This is an overall operating-cost saving of:

$$81.5 \times 10^6 \times 0.60/10^6 = \$48 \text{ annually}$$

Then the relative generating cost for the new high-efficiency unit figures out to:

Capital charges = 190 × 2000 × 0.15 =	$57,000
Relative operating cost =	−48
Relative generating cost =	$56,952

Peaking unit will carry about 1/11th of the 17-mw peak or 1.5 mw for 200 hr. At this level its heat rate is 20,000 Btu per kwhr. The existing ten units would carry 17 − 1.5 = 15.5 mw at a heat rate of 9640 Btu per kwhr according to Fig. 2. This gives a plant heat rate of:

$$\frac{1.5 \times 20{,}000 + 15.5 \times 9640}{17.0} = 10{,}540 \text{ Btu per kwhr}$$

The existing ten units could carry the 17-mw load at 9537 Btu per kwhr, Fig. 2. Peaking unit then causes an annual fuel loss of:

$$17{,}000(10{,}540 - 9{,}537)200 = 3410 \times 10^6 \text{ Btu or } 3410 \times 10^6 \times 0.60/10^6 = \$2046$$

Relative generating cost for the peaking unit:

Capital charges = 130 × 2000 × 0.15 =	$39,000
Relative operating cost =	2046
Relative generating cost =	$41,046

So the peaking unit is the economic choice by:

$$56{,}952 - 41{,}046 = \$15{,}906 \text{ per year saving.}$$

The saving in capital charges far outweighs the higher fuel cost of the peaking unit.

We can estimate the number of hours we can be forced to run the peaking unit for standby emergency and still have it economically equal. Average heat rate of the existing units for a year's operation will be about 9530 Btu per kwhr, from Fig. 2. The peaking unit we can assume at an average of 20,000 Btu per kwhr running at an average load of 1.5 mw.

First let's find the fuel equivalent of the $15,906 annual saving:

$$\frac{15{,}906}{0.60/10^6} = 26{,}555 \times 10^6 \text{ Btu yearly}$$

Running in place of a high-efficiency unit the peaking unit causes a loss of:

$$1500(20{,}000 - 9530) = 15{,}705{,}000 \text{ Btu per hr}$$

Number of hours running, equivalent to annual generating-cost saving, is then:

$$\frac{26{,}555}{15.7} = 1690 \text{ hr}$$

With ten high-efficiency units in the plant it's unlikely that this many hours of emergency service will be required of the peaking unit beyond its normal peak hours of running.

To see the other side of the coin, let us find what the average heat rate of the existing system would need to be to make a new high-efficiency unit at least equal economically to the peaking unit.

Difference of high-efficiency-unit capital charges and relative generating cost of the peaking unit gives us the saving in operating costs that the former must make:

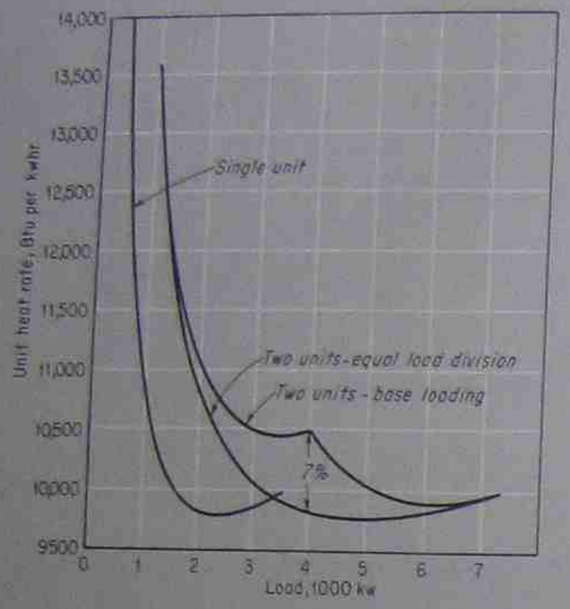
$$\$57{,}000 - 41{,}046 = \$15{,}954 \text{ annually}$$

This saving is $15{,}954/0.60/10^6 = 27.0 \times 10^6$ Btu a year. With a load factor of 50%, total kwhr is $17{,}000 \times 0.5 \times 8760 = 74.5 \times 10^6$ kwhr. New base-load unit at 80% capacity factor will generate $2.0 \times 0.8 \times 8760 = 14{,}020$ mwhr annually at an average heat rate of about 9550 Btu per kwhr. Average heat rate of the existing units will be about the same whether they're carrying the total energy or total less the new-unit generation. Letting HR be the average heat rate of the existing units, the annual saving equals:

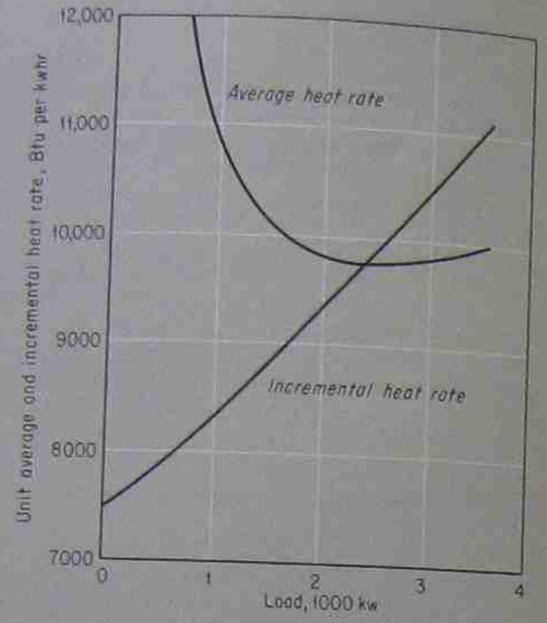
$$27.0 \times 10^6 = 74{,}500{,}000\,HR - (74{,}500{,}000 - 14{,}020{,}000) \times 9550$$

Solving, $HR = 11{,}480$ Btu per kwhr. A heat rate higher than this for the existing units makes a new base-load unit the preferred choice.

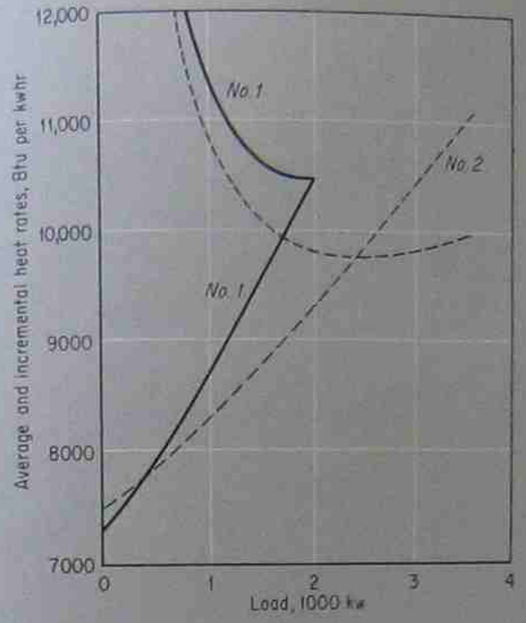
The lesson here is that a low-efficiency low-cost peaking unit can only be justified on a system that runs at high efficiency with its present load.



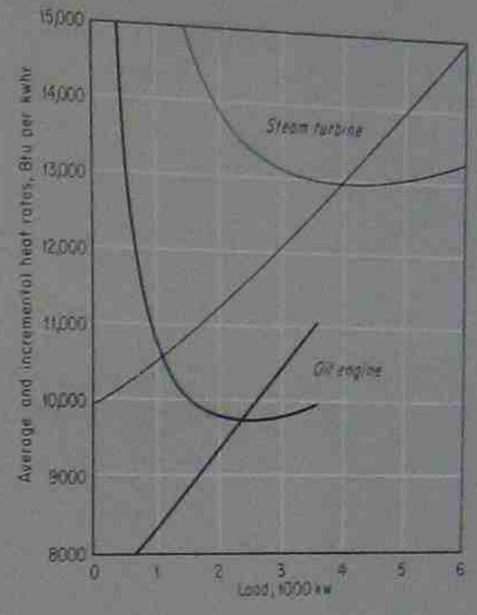
1 Depending on shape of unit heat-rate curve, improper load division can raise total fuel input above the minimum needed



2 Every generating unit, regardless of its type, has an average-heat-rate curve and a corresponding incremental-heat-rate curve



3 Comparative heat- and incremental-heat-rate curves for two units; curves always cross at the minimum average heat rate



4 Comparative heat- and incremental-heat-rate curves for steam-turbine unit and an oil engine depend on operating conditions

Incremental rates—key to load division

How should we divide load between units working in parallel to feed a common demand? Despite extensive literature on the proper technique, many operators hold to the base-loading fallacy. First they load their most efficient unit to its full rating, then bring the next one to full rating and so on.

To see the error in this method of *base loading* let's study Fig. 1. Here the heat-rate curve of a single generating unit comes down from infinity at zero load to a best heat rate of 9780 Btu per kwhr at 2400 kw. It rises slightly to 10,000 Btu per kwhr at full rating of 3600 kw on the unit.

When we put two of these units on the line in parallel to carry a common load we get best efficiency by loading them equally; that is, each unit carries half the total load at all levels. They will then have the combined heat-rate curve labeled *Two units–equal load division*. This is a simple reproduction of the single-unit curve with the same heat rate at twice the load.

What happens when we decide to hold one unit at a minimum load of 400 kw while we bring the other up to 3600 kw and then bring the second one up to 3600 kw while the first stays at 3600? We get the heat-rate curve labeled *Two units–base loading*. Across the entire load range the combined heat rate is higher than for equal loading; where one unit reaches full rating we have a combined heat rate 7% higher than for equal loading. Each unit does not run to get the most kwhr for the least Btu. Let's study incremental rates to see why.

Every generating unit has two heat rates. The one we all know is properly called *average heat rate*, Fig. 2. It's the *total* Btu-per-hr input divided by the *total* kwhr output at any given load. But there's another one, called the *incremental heat rate*, which measures *added* Btu input needed to produce the *added* kwhr of output at any given load.

For instance, at zero load it takes a minimum Btu input to just turn over the prime mover without producing any kw. This minimum supplies all types of losses and radiation. To produce the first kw takes the Btu shown at zero load by the incremental heat-rate curve in Fig. 2—7540 Btu per kwhr. The average heat rate, though, is 7540 + total no-load input Btu, which gives us a very high *average* heat rate.

To get the second kwhr we have to put in slightly more than another 7540 Btu, because the incremental-heat-rate curve is rising. At any total load the incremental curve shows Btu that must be added to produce the *next* additional kwhr.

We find the incremental-rate curve for a prime mover from the average heat-rate curve, which should be determined by an accurate performance test run in accordance with the ASME Power Test Code for the type of prime mover. The average heat-rate curve should be plotted to a large scale, so you can read it to at least four figures—preferably five.

To demonstrate the method of figuring incremental heat rate we'll take a sample of the load range from 2000 to 2600 kw in 200-kw steps:

Load, kw	*Average heat rate, Btu per kwhr*	*Total input, Btu per hr*	*Increment input, Btu per hr*	*Incremental heat rate, Btu per kwhr*
2000	9826	19,651		
			1889	9445
2200	9791	21,540		
			1932	9660
2400	9780	23,472		
			1974	9870
2600	9785	25,446		

The load and average heat rates are multiplied to get total input in Btu per hr. They are listed above in thousands of Btu. Taking the differences in input corresponding to the 200-kw steps in output we have the increment inputs for 200 kw. Then, dividing each increment input by 200 kw, we get the incremental heat rate in Btu per kwhr. We can assume these apply to the midpoint of each step; for example, at 2100-kw load the incremental heat rate is 9445 Btu per kwhr, at 2300 kw it's 9660 Btu, etc. By so plotting we get the incremental-rate curve in Fig. 2. This curve is important to load division because it tells us what we have to pay for each added kwhr from a given unit.

Let's see how we use these curves in scheduling load division between units. Fig. 3 shows the average and incremental curves for two units in a plant, No. 1 with 2-mw and No. 2 with 3.6-mw capacity.

When we need only one of these units to carry load, we would take No. 2 because its average heat rate is lowest at all load levels. The average heat-rate curve helps our choice in this situation.

But when both units must operate, how shall we divide the load? The basic rule is simple: for each added kw of load produced we want to pay the minimum input in Btu. The incremental-rate curves tell us just what we pay for each additional kw from each unit. Since we don't want to pay more from one unit than from the other, we conclude that the units should be loaded *so their incremental heat rates are equal.*

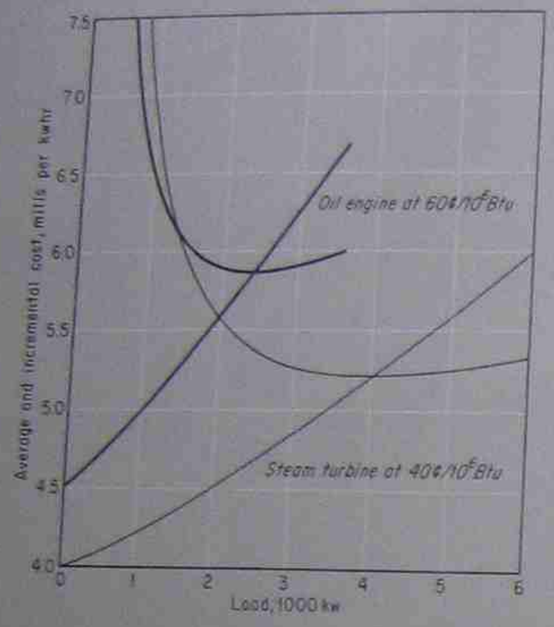
With this principle in mind let's work up a loading schedule for Units 1 and 2 in Fig. 3:

Incremental heat rate, Btu per kwhr	*Unit loading, kw*		
	No. 1	*No. 2*	*Total*
7900	540	460	1000
8500	850	1150	2000
9110	1220	1780	3000
9770	1600	2400	4000
10,500	2000	3000	5000
11,120	2000	3600	5600

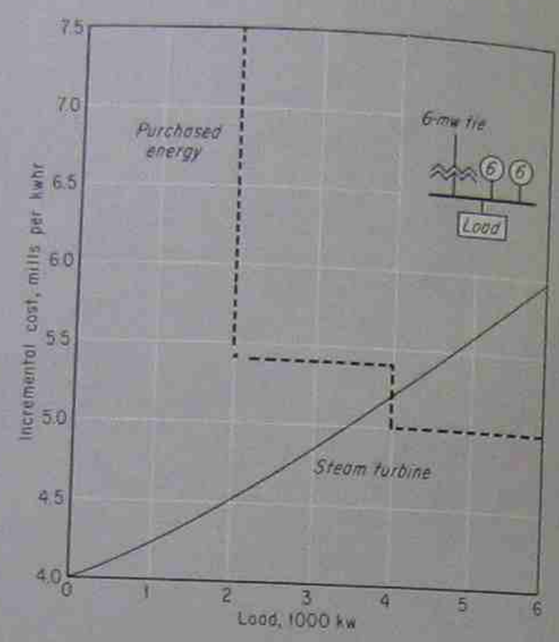
With this load schedule figured for maximum operating economy, note that less efficient Unit 1 reaches its full load before more efficient Unit 2.

Notice that in Fig. 1 the two similar units when equally loaded are running at equal incremental heat rates (IR). Now we can see why base loading is inefficient. Look at the loading table above and assume we are base-loading two units like No. 2. Following

Relative incremental cost of energy fixes proper load

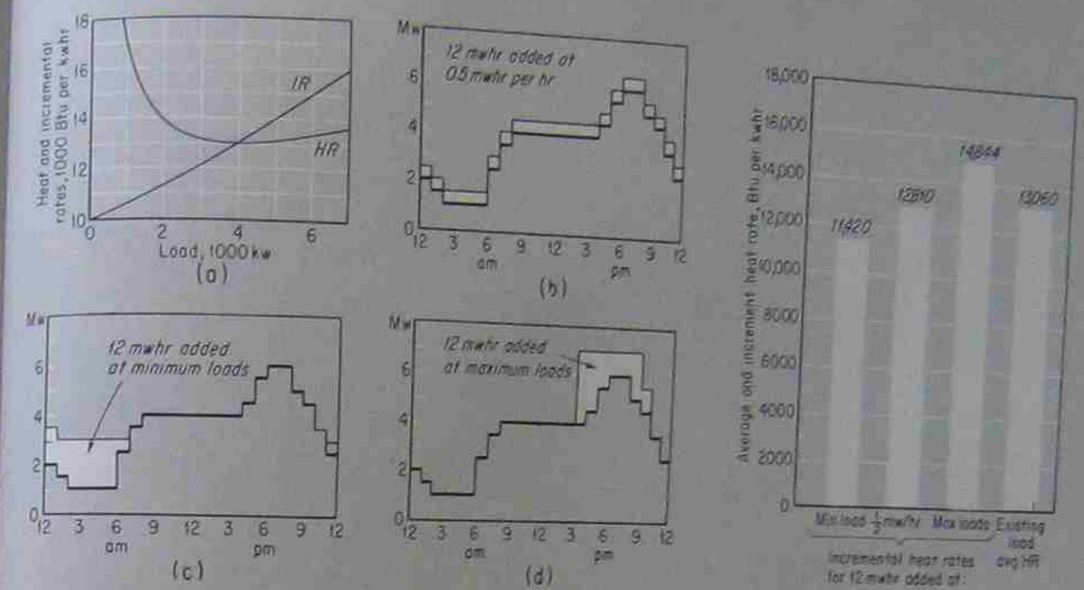


5 When fuel costs differ, performance curves should be converted to mills per kwhr to place them on proper basis for comparison



6 To load units economically in parallel with a tieline, you need to chart kwhr purchase cost and increment cost for the units

division for economy—in one plant or between plant and tieline



7 (a) Average and incremental heat rates of plant feeding daily load curve. (b) Generating 12 mwhr more daily by raising hourly load by 0.5 mw. (c) Generating 12 mwhr more by filling the valley. (d) Generating 12 mwhr more by broadening peak

this method, while we hold one unit at minimum load of 460 kw and at an IR of 7900, we are loading the other at IR way above 7900—up to 11,120 Btu per kwhr. We pay much more for added load this way than by equally loading the two units and always paying the same in each for added input to carry added load.

No matter how many units we have in a plant we divide load simply be keeping all incremental rates equal. Plot all the IR on a common graph, read off the loads on each unit for the same IR, and we have our load schedule.

Fuel cost. Heat expended is not the last word in load division—it's what the heat costs that's vital. We must aim for minimum dollar costs in running our energy systems. For example, suppose an oil engine and a steam-turbine unit run in parallel. Heat rate and IR curves are shown in Fig. 4. On a straight heat-expended basis, this would be the load-division schedule:

IR	Unit loading, kw		
	Steam turbine	Oil engine	Total
8300	1000*	1000	2000
9350	1000*	2000	3000
10,430	1000*	3000	4000
10,750	1250	3250	4500
10,950	1550	3450	5000
11,580	2400	3600	6000
15,000	6000	3600	9600

*Turbine minimum load

The oil engine, because of its superior efficiency, would take most of the load at lower plant levels, except for the minimum that must be put on the turbine for mechanical safety.

But in a plant setup of this type it's more than likely that the two units would be using different types of fuel. Suppose that while the turbine burns coal at 40c per million Btu, the oil engine uses diesel oil at 60c per million Btu.

Then, multiplying the average and incremental rates by their respective costs, we convert turbine and engine curves into average and incremental costs expressed in mills per kwhr, Fig. 5. This makes a big difference in load division, producing a schedule like this:

IR	Unit loading, kw		
	Steam turbine	Oil engine	Total
4.22	1000	0	1000
4.50	2000	0	2000
4.70	2600	400	3000
4.90	3200	800	4000
5.12	3800	1200	5000
5.35	4400	1600	6000
5.59	5000	2000	7000
5.84	5700	2300	8000
6.25	6000	3000	9000
6.58	6000	3600	9600

Comparing with the former table, we see that the fuel cost makes a radical change in economical load division. Now the steam turbine is favored since it's the lower cost producer of the two units. As fuel costs change with time, the load-division schedule must be updated to conform.

It's also evident that should the efficiency curves of any of the units change due to wear or equipment alterations, load-division schedule will need to be refigured.

A cost concurrent with the running of any unit is maintenance needed because of wear and tear. This factor is tough to evaluate. Some engineers raise the incremental-cost curves by the average cost of maintenance in mills per kwhr to account for it. At least this favors units that perform better maintenance-wise.

Where we buy energy from another system to supplement our own capacity to supply our load, incremental rates come in handy. Fig. 6 shows the system setup with two 6-mw steam-turbine units paralleled with a 6-mw tieline to supply a load. Graph shows the incremental-cost rate of the turbines as well as cost of purchased energy.

Contract for purchased energy includes a requirement that a steady flow of energy at 2000 kw shall be bought through the tieline at all times. For this condition an increment-cost step curve for the purchased energy is used. This states that energy bought at up to 2000-kw flow costs 1.0 c per kwhr. Energy bought at loads from 2000 to 4000 kw costs 5.4 mills per kwhr and energy at loads above 4000 kw costs 5.0 mills per kwhr. This gives us the step curve in Fig. 6; the solid point shows minimum load that's always carried by the tie.

Now we have the problem of scheduling load division between the tie and the two units. As far as possible we want to carry a 6-mw reserve. For this condition we can't apply the rule of equal incremental rates, but must use the more basic rule of buying the next increment of

1—Loading schedule for tieline and two units

Load, mw				Increment cost, mills per kwhr			Total cost, $ per hr		
Total	Tie	1	2	Tie	1	2	Tie	1 & 2	Total
3	2	1.0	0				20.00	6.77	26.77
				—	4.36	—			
4	2	2.0	0				20.00	11.13	31.13
				—	4.66	—			
5	2	3.0	0				20.00	15.79	35.79
				—	5.01	—			
6	2	4.0	0				20.00	20.80	40.80
6	2	2.0	2.0				20.00	22.26	42.26
				—	4.59	4.59			
7	2	2.5	2.5				20.00	26.82	46.82
				—	4.75	4.75			
8	2	3.0	3.0				20.00	31.58	51.58
				—	4.92	4.92			
9	2	3.5	3.5				20.00	36.50	56.50
				—	5.10	5.10			
10	2	4.0	4.0				20.00	41.60	61.60
				—	5.29	5.29			
11	2	4.5	4.5				20.00	46.90	66.90
				5.40	—	—	25.40	46.90	72.30
12	3	4.5	4.5						
				5.40	—	—	25.40	46.90	72.30
13	4	4.5	4.5				25.80	46.90	77.70
13	6	3.5	3.5				40.80	36.50	77.30
				—	5.10	5.10			
14	6	4.0	4.0				40.80	41.60	82.40
				—	5.29	5.29			
15	6	4.5	4.5				40.80	46.90	87.70
				—	5.49	5.49			
16	6	5.0	5.0				40.80	52.38	93.18
				—	5.69	5.69			
17	6	5.5	5.5				40.80	58.08	98.88
				—	5.89	5.89			
18	6	6.0	6.0				40.80	63.97	104.77

2—Comparison of heat rates for 12 mwhr added to daily load curve

Hr end	Hr	Mw	Avg heat rate	Total input	0.5 mw added every hour: Inc heat rate	0.5 mw added every hour: Inc input	12 mwhr added at minimum loads: Inc mw	12 mwhr added at minimum loads: Inc heat rate	12 mwhr added at minimum loads: Inc input	12 mwhr added at maximum loads: Inc mw	12 mwhr added at maximum loads: Inc heat rate	12 mwhr added at maximum loads: Inc input
1	1	2.0	13,908	27.82	11,450	5.73	1.5	11,873	17.81	—	——	——
2	1	1.5	14,850	22.28	11,060	5.53	1.5	11,460	17.19	—	——	——
6	4	1.0	16,935	67.74	10,700	21.40	2.0	11,270	90.16	—	——	——
7	1	2.5	13,425	26.85	11,870	5.93	0.5	11,870	5.94	—	——	——
8	1	3.5	13,040	45.64	12,750	6.38	—	——	——	—	——	——
4	8	4.0	13,000	416.00	13,230	52.92	—	——	—— (1 hr)	3.0	14,487	43.46
5	1	4.5	13,030	58.64	13,730	6.87	—	——	——	2.5	14,738	36.85
6	1	5.5	13,200	55.76	14,730	7.36	—	——	——	1.5	15,243	22.86
8	2	6.0	13,327	159.92	15,300	15.30	—	——	——	1.0	15,500	31.00
9	1	5.0	13,096	65.48	14,230	7.11	—	——	——	2.0	14,990	29.98
10	1	4.5	13,030	58.64	13,730	6.87	—	——	——	1.0	13,980	13.98
11	1	3.5	13,040	45.64	12,750	6.37	—	——	——	—	——	——
12	1	2.5	13,425	33.56	11,870	5.94	0.5	11,870	59.35	—	——	——
Totals		53.0*		1083.97		153.71			137.05			178.13
Averages		3.46	13,060		12,810			11,420			14,840	

* Sum of (mw × hr of duration)

energy at the least cost from either tieline or turbines.

Table 1 shows load division and some additional data. We start with the minimum 2-mw load on the tie and a minimum 1-mw load on one turbine for a total load of 3 mw (using the turbine of Fig. 5). Incremental rate on the tie for this condition is 5.4 mills, but on the turbine it is 4.22 mills, so we start loading the turbine in 1-mw steps. To find the average IR of the blocks of generation added, use averages of IR at each end of the block.

At 6-mw total load we have to add the second turbine to maintain reserve. We continue adding 1-mw increments to the turbines' generation until the units are running at 4.5 mw with an IR of 5.4 mills, same as the tieline. This happens at a total load of 11 mw. The moment we reach this point it is cheaper to buy energy from the tieline rather than load the turbines further, which brings us to 4 mw on the tieline at a total load of 13 mw. But then at the next step we can buy much cheaper energy from the tieline at 5.0 mills.

At this total load level it pays us to shift load among the units and carry the total 13 mw by loading the tieline to 6 mw and unloading each of the turbines to 3.5 mw. By doing this we drop 2 mw on the turbines at an average IR of 5.2 mills and replace it with tieline energy at 5.0 mills. But notice that we can't reach this lowest step of purchased energy until the total load grows to this level. Resist the temptation to load the tieline first to reach that cheap last block without watching your other costs.

Table 1 includes data on the hourly costs from the two energy sources to give the total hourly costs. You can use these to check any other method of loading, satisfy yourself that lowest-incremental-cost loading is the economical way to do it.

Cost of adding load on an existing system depends on the way it's done. To find the added fuel costs there's a great temptation to take the easy way and assume it will be at the average overall heat rate of the system with the current load. This can lead to gross error, if we don't appreciate the significance of incremental cost or heat rate in figuring overall costs.

Fig. 7*a* shows average and incremental heat-rate curves of a plant serving the loads shown in *b* to *d*. In Fig. 7*b* we add 12 mwhr to the system load, by raising the load by 0.5 mw at every hour.

In table 2 we list the current load and figure the average heat rate for the 24 hr which equals 13,060 Btu per kwhr. For the increment inputs of 0.5 mw we use the increment heat rates of 7*a* at the different load levels. Average heat rate for this added load is 12,810 Btu per kwhr, about 2% lower than the system average heat rate.

In Fig. 7*c* we add the 12 mwhr by "filling" the valley of the load curve. Table 2 shows that the added kwhr are generated at an average increment heat rate of 11,420 Btu per kwhr, 12.5% less than the 13,060 level.

In Fig. 7*d* we add the 12 mwhr all at the peak of the load curve at an average increment heat rate of 14,840 Btu per kwhr, 13.6% higher than the average 13,060 Btu.

To sum up: While most of our discussion centered on power-plant generation, *all* of the principles we covered apply to *any* type of energy system—both design and operation. We've given a condensed review of basic energy-system economics and their relations to practical systems; for more complete treatment see *Power Station Engineering and Economy* by Skrotzki and Vopat, 750 pp, McGraw-Hill Book Company.

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Disruptive critical voltage

answer Day (6) Day (7)/(8)

(13) The break down Strength of air at 76 cm pressure at 25°C is 30kv per cm or 21.1kv (rms) / cm. This value is 95. At a barometric pressure of b cm of mercury and t°C.

The break down voltage is δ 95 where

$$\delta = \frac{3.92b}{273+T}$$

E_g = break down voltage to neutral = $\delta g_o r \log_h D/r$

$$E_g = \delta g_b r \operatorname{Ln} D/r$$

In practice, it is necessary to allow for condition of surface of wire

$$E_g = m \delta g_b r \operatorname{Ln} D/r$$

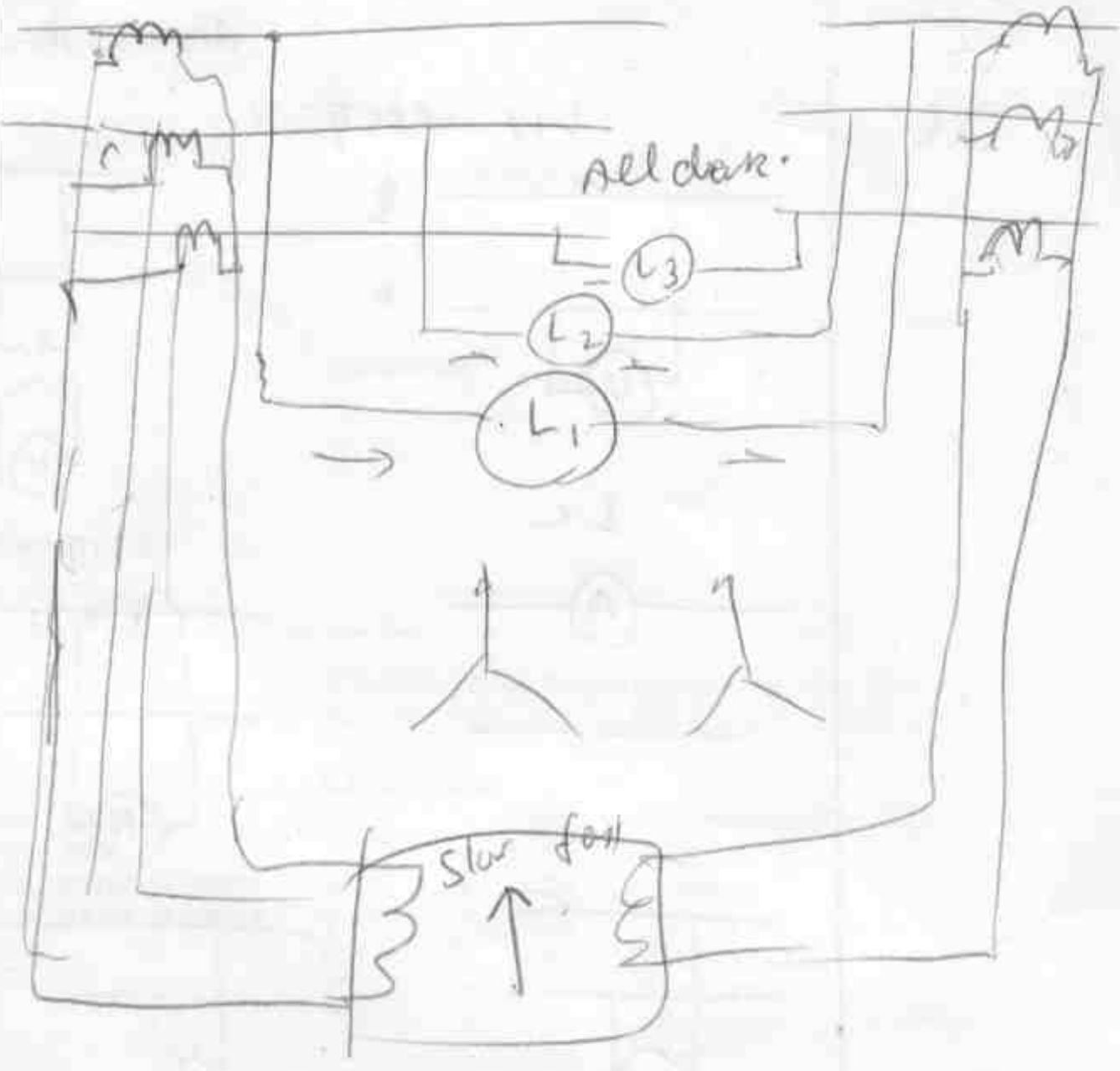
$$= 21.1 m \delta r \operatorname{Ln} D/r$$

where m = 1.0 for smooth wire
0.93 for roughened or weathered wire
0.87 for stranded wire

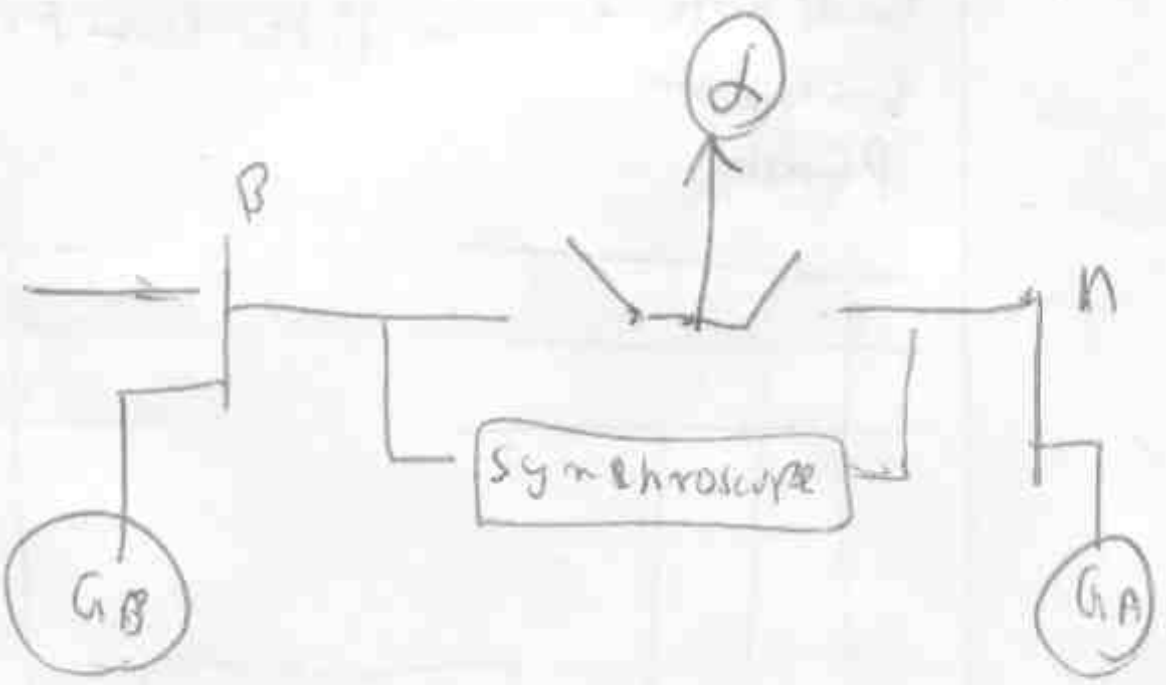
Visual Critical voltage

$$E_v = 21.1 m \delta r \left(1 + \frac{0.3}{\sqrt{\delta r}}\right) \operatorname{Ln} D/r$$ Kv rms to neutral

Date	Equipment	Borrower's Name Email & Phone



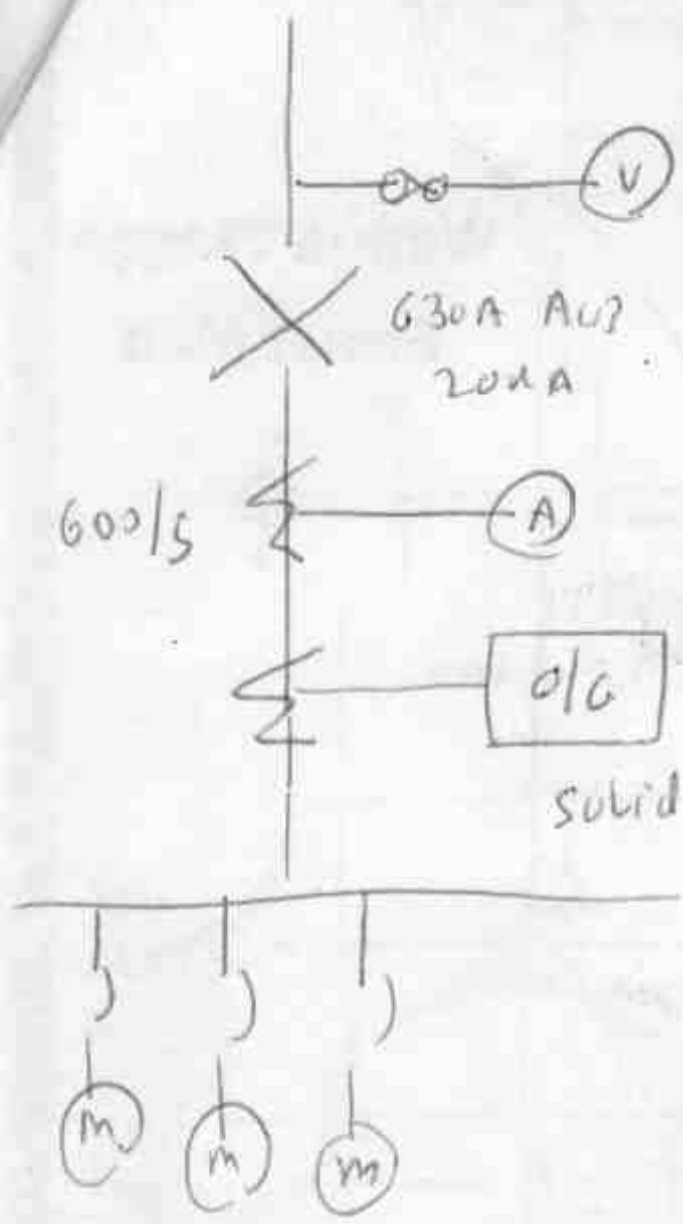
Very Important to determine synchronism.

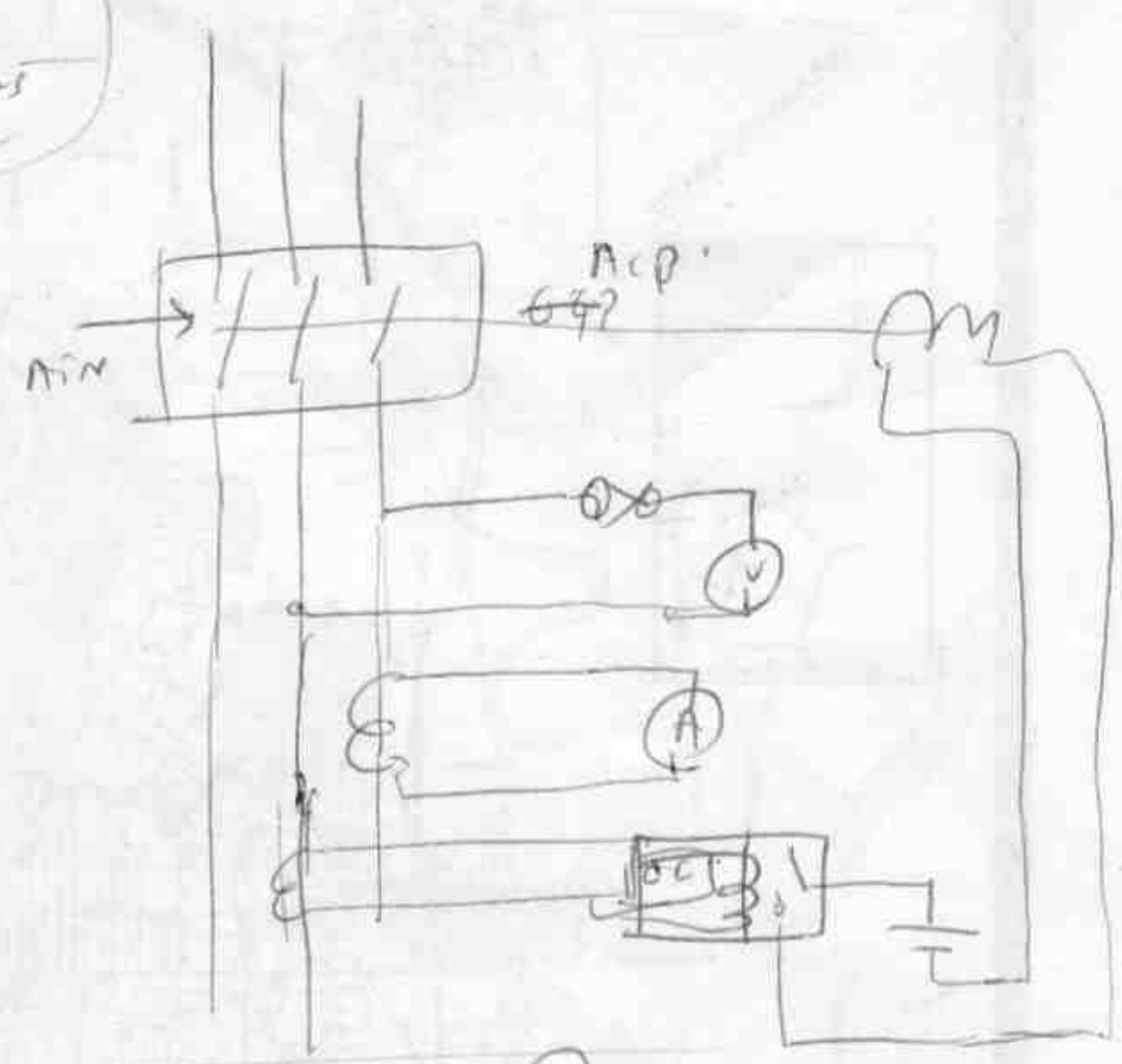


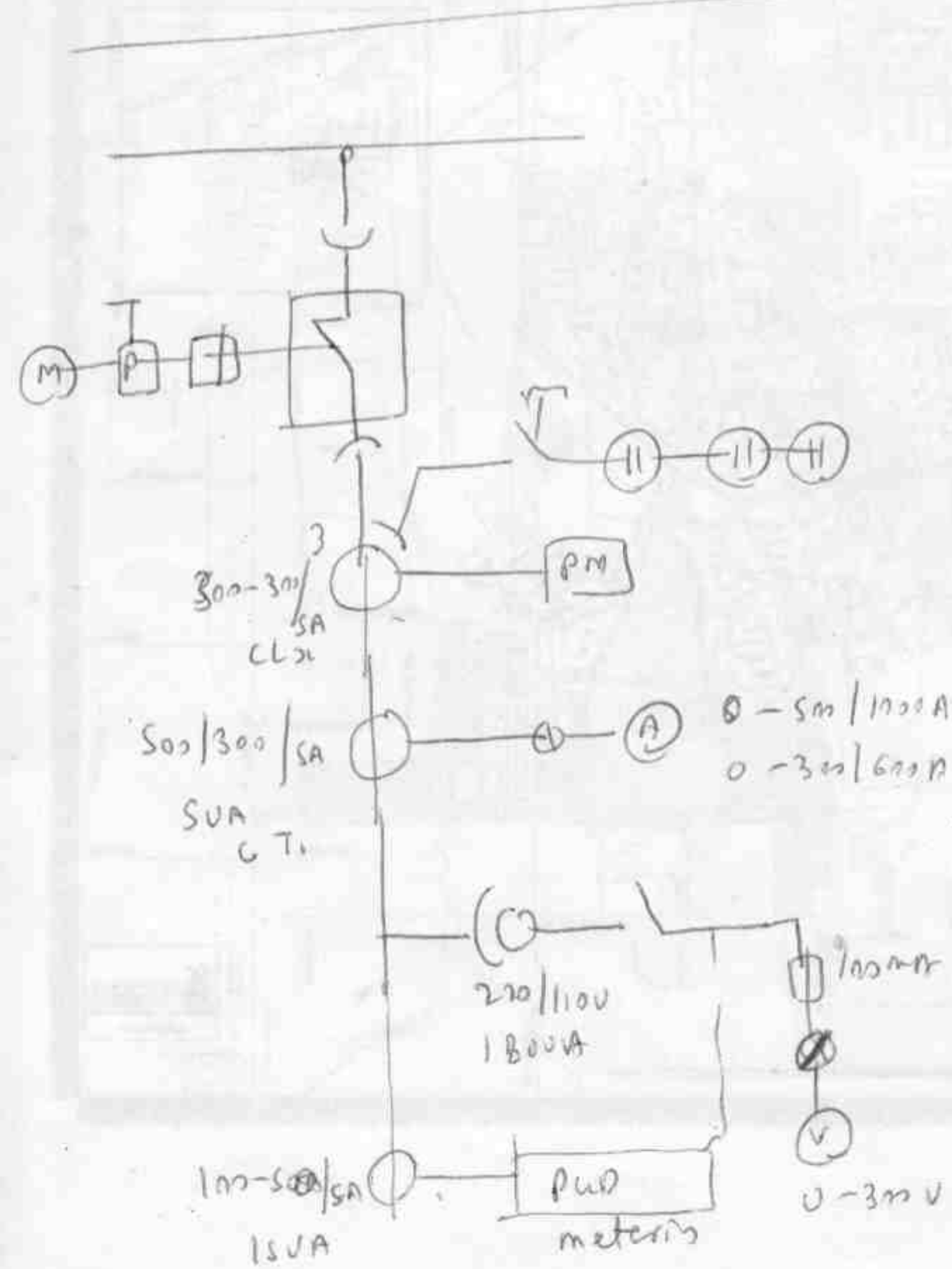
Power station Instrumentation

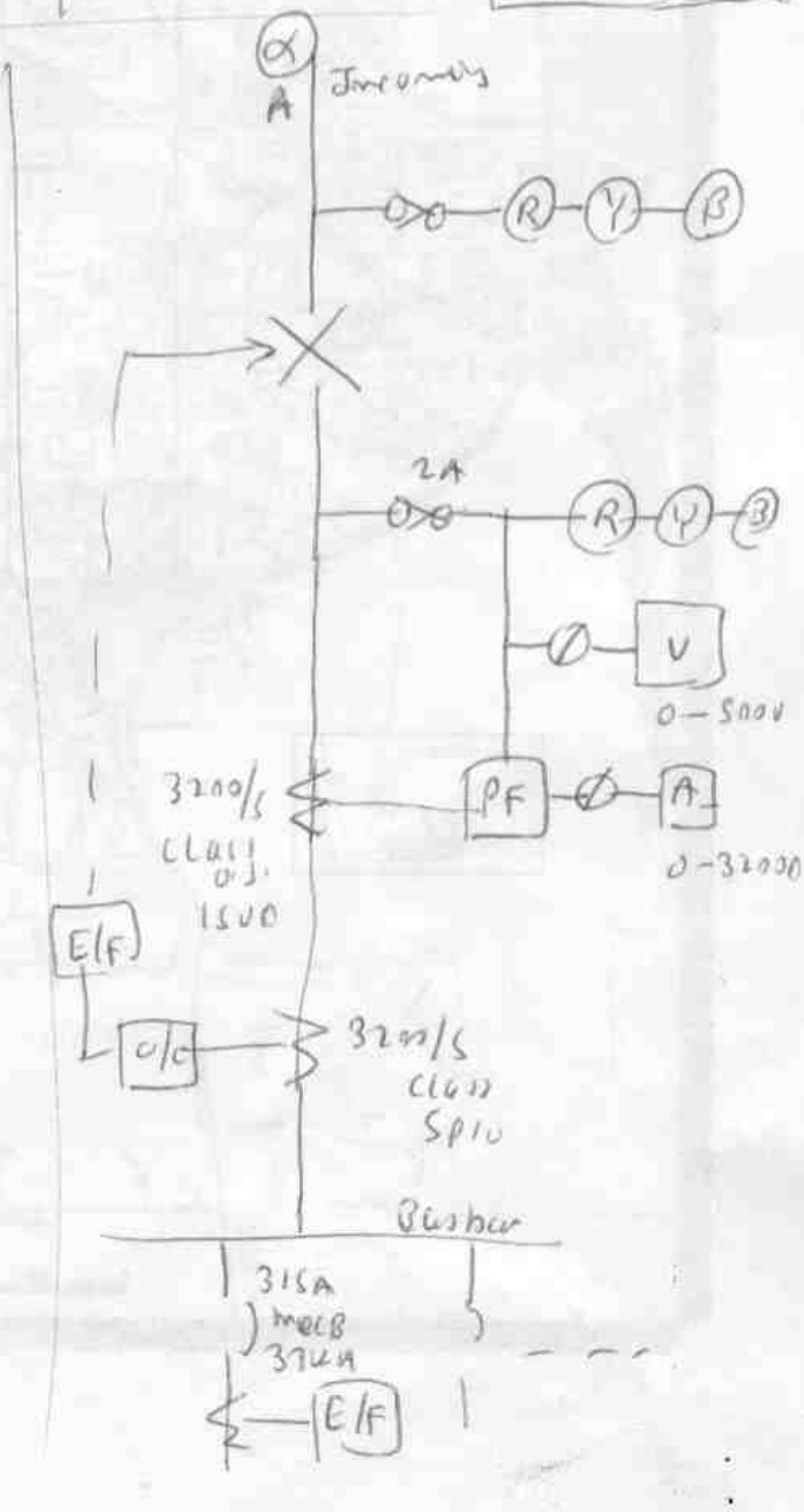
1 Line diagram

Examples of Meters Systems









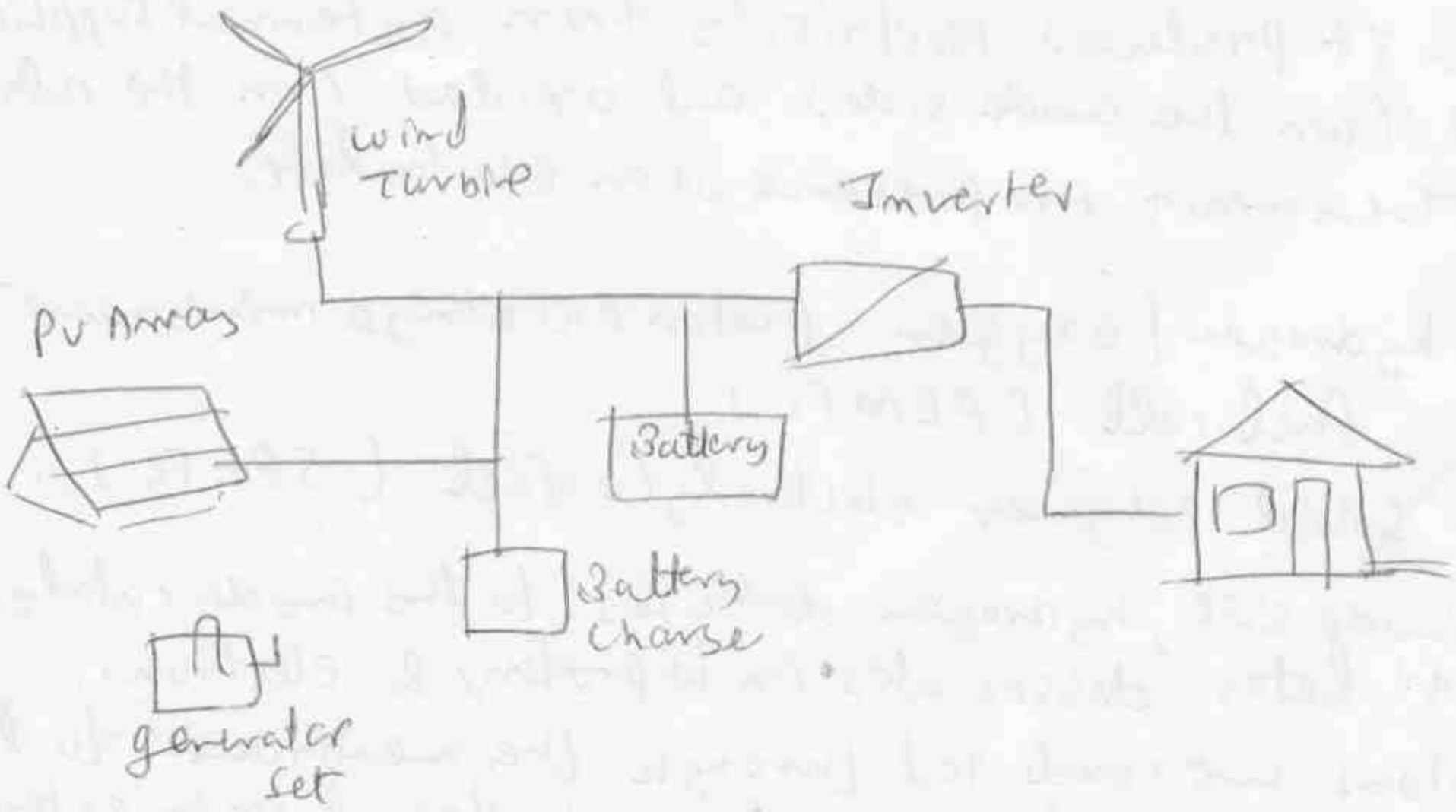
Combined Heat and Power

In combined Heat and power (CHP) systems, the fuel source can be natural gas, propane, fuel oil, coal, wood chips, biogas, other biomass material, or any combination. CHP uses this fuel to provide all or part of the electricity energy & thermal energy output to a facility.

CHP is the use of a heat engine or a power station to simultaneously generate both electricity & useful heat. conventional power plants emit the heat created as a by product of electricity generation into environment through cooling towers, as fuel gas or by other means.

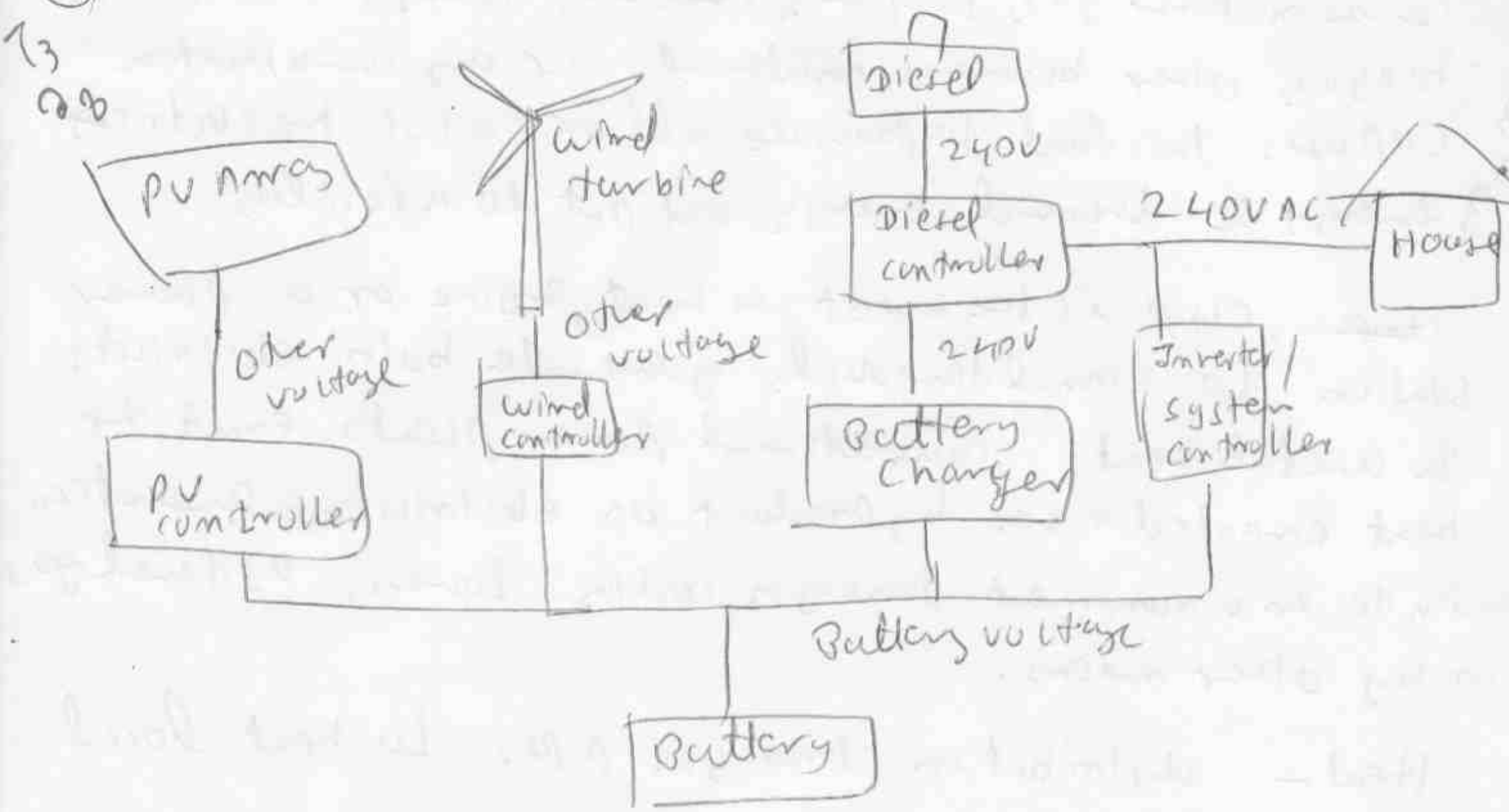
Heat — distribution through pipes, to heat local housing.

Remote Area Power Supply



Component page(63)

Solar power, wind turbines, microhydro,
(1) Regulators, inverters, batteries



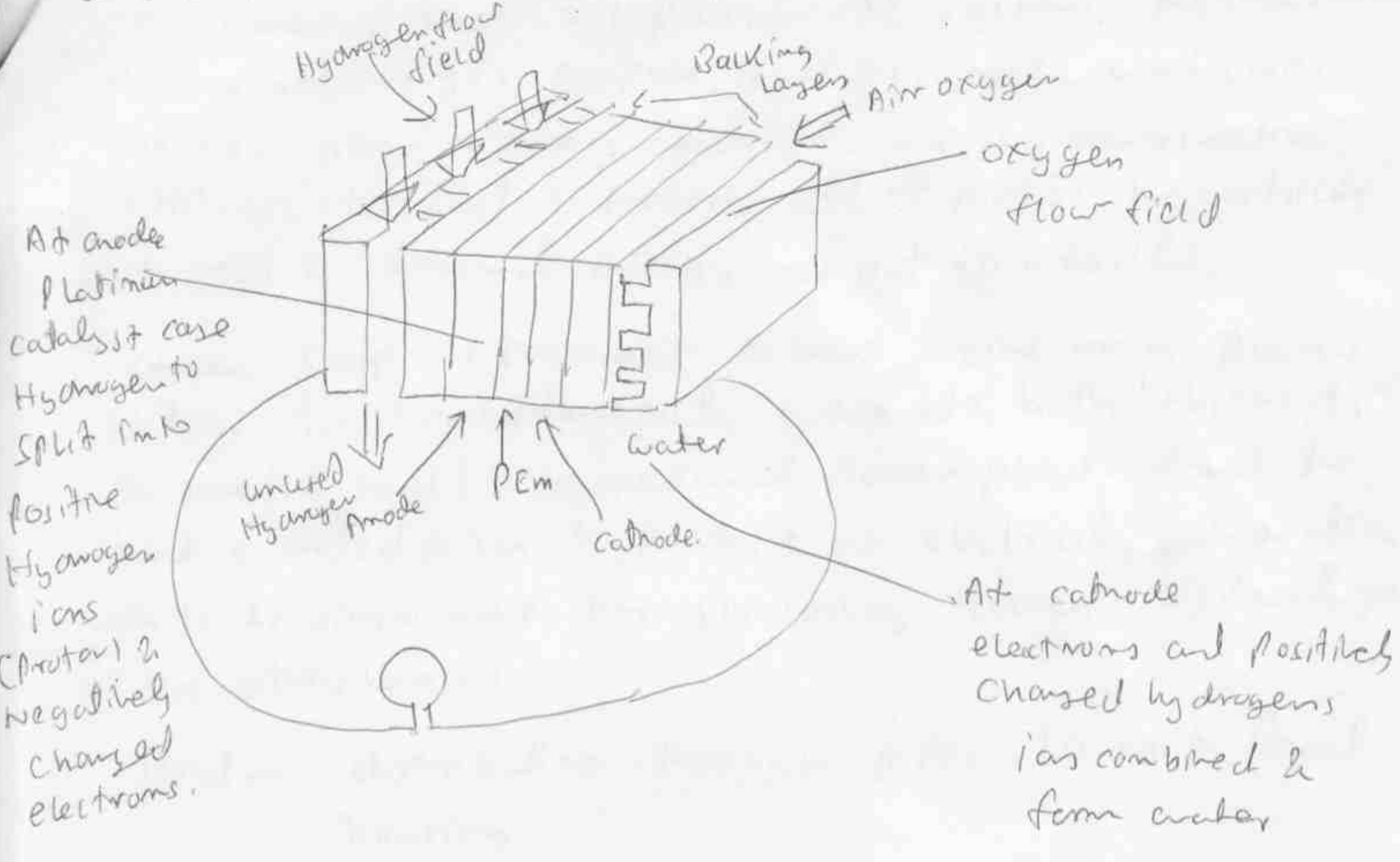
(13) (1) Fuel cell

(13) Qa A Fuel cell is an electrochemical energy conversion device. It produces electricity from external supplies of fuel (on the anode side) and oxidant (on the cathode side. These react in presence of an electrolyte.

Example hydrogen / oxygen proton exchange membrane fuel cell (PEMFC)
- solid polymer electrolyte fuel (SPEFC)

On the anode side, hydrogen diffuses to the anode catalyst where it later dissociates into protons & electrons. The protons are conducted through the membrane to the cathode but the electrons are forced to travel in an external circuit (supplying power) because the membrane is electrically insulating. On the cathode catalyst, oxygen

molecules react with the electrons (which have travelled through the external circuit) and protons to form water.



Corona 7302

corona forms when the voltage of a conductor passes the disruptive critical voltage. The ions on each conductor every half cycle and contributes a triple harmonic to the charging current, since the effective capacitance of the conductor increase, when the corona is present. The triple harmonic current passi through the neutral to earth in an earthed system.

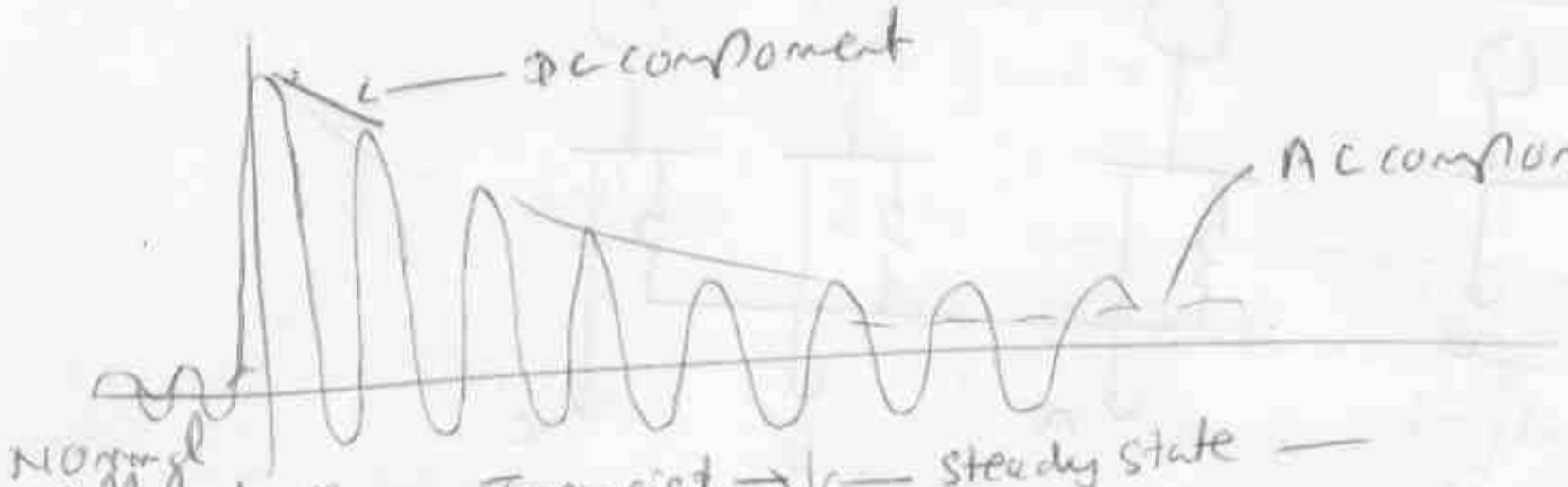
Avoidance of corona

The critical voltage can be raised either by increasing the spacing or the diameter of conductor. The spacing can not be increased greatly or the cost of the supports will be very high. The diameter of conductor can be increased by using hollow conductors which help core. steel core aluminium conductors have a large diameter for a given conductivity and weight are thus very good from point of view of corona.

Short circuit current of alternator

When an alternator is shorted across all 3 phases, the current rises rapidly to a high value about 18 times full load current in turbo generators. The value of peak current is only limited by transient leakage reactance of armature.

If the short circuit persists, sine wave become symmetrical then the armature reaction reduces the excitation and the current falls to a steady value which is 4 to 6 times the full load value.



$$i = A e^{-Rt/L} + B$$

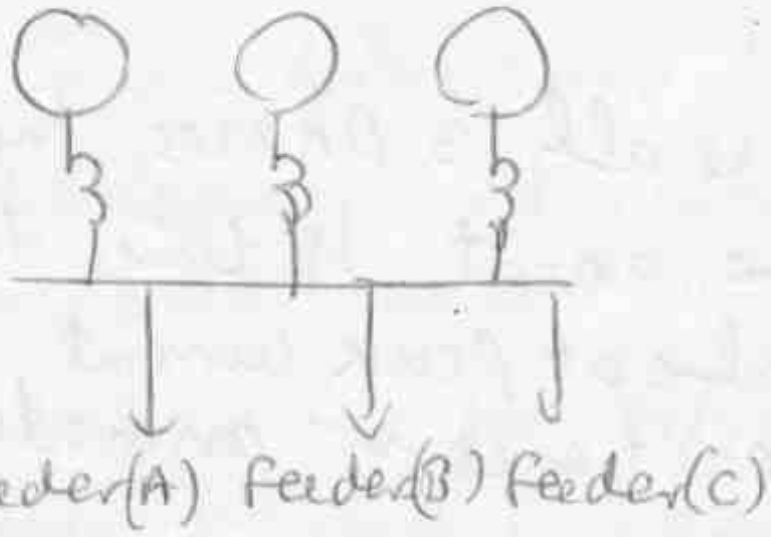
$$i = \frac{E}{\sqrt{R^2+(\omega L)^2}} \sin\left(\omega - \tan^{-1}\frac{\omega l}{R}\right) e^{-Rt/L}$$

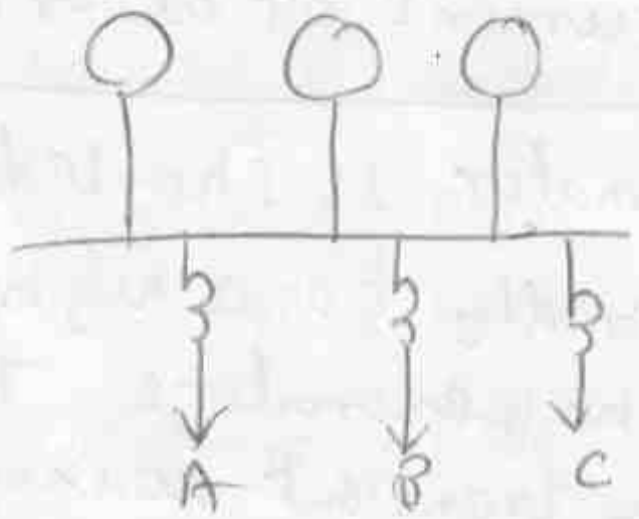
$$+ \frac{E}{\sqrt{R^2+(\omega L)^2}} \sin(\omega t + \omega - \tan^{-1}\frac{\omega L}{R})$$

where $A = \frac{E}{\sqrt{R^2+(\omega l)^2}} \sin\left(\omega - \tan^{-1}\frac{\omega l}{R}\right)$

$$B = \frac{E}{\sqrt{R^2+(\omega l)^2}} \sin\left(\omega t + \omega - \tan^{-1}\frac{\omega l}{R}\right)$$

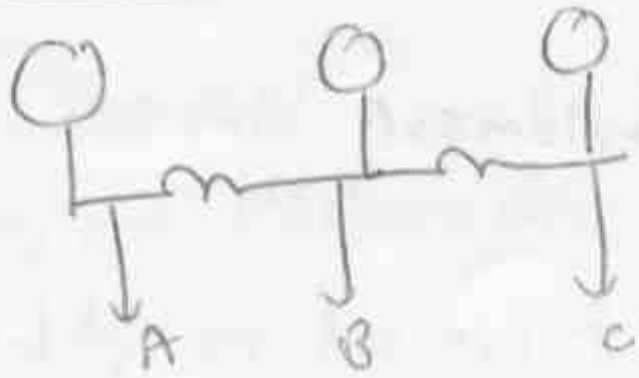
current limiting reactors

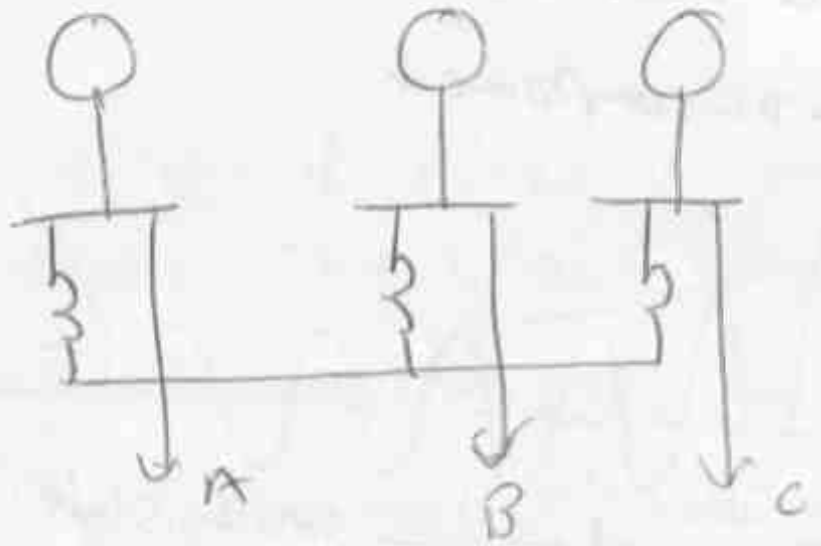




If is clear that the short circuit currents are decreased by an increase of the percentage reactance in the systems.

Location of reactor





$$X = \frac{(n-3)}{2n} G$$

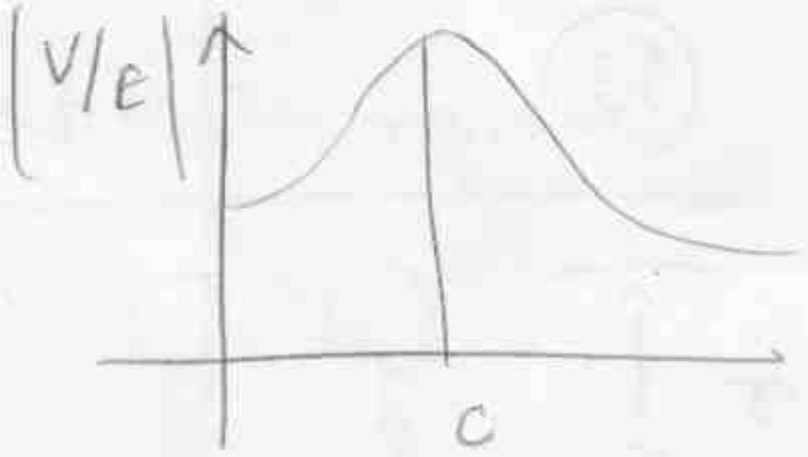
where X = % reactance of reactor (inductive reactance)

n = No. of sections

G = % Inductive reactance of generator.

Voltage Transients & Line Surges

There are various ways in which a transmission line may experience voltage greater than the working value. It is necessary to provide protective apparatus to prevent or minimize the destruction of the plant. Internal causes producing voltage rise are (1) resonance (2) switching operation (3) insulation failure (4) arcing earths, a very important external cause is lightning.

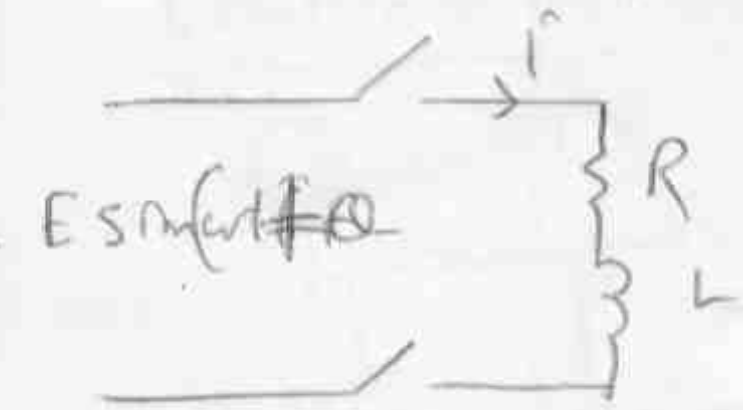


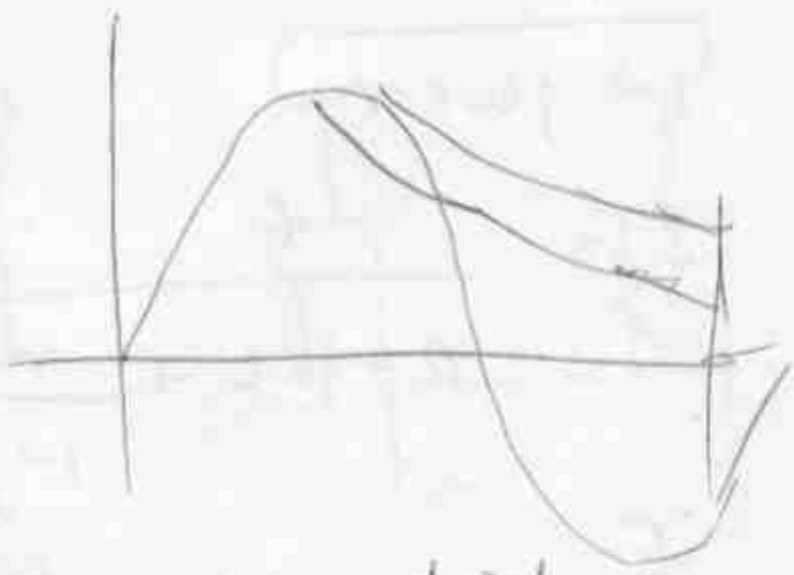
$$C = \frac{1}{\omega^2 L^2}$$

A reasonable value of L in 33kv system is 0.05H.
the resonating capacitance is then

$$C = \frac{1}{(2\pi 50)^2 \times 0.05} = 202\mu f$$

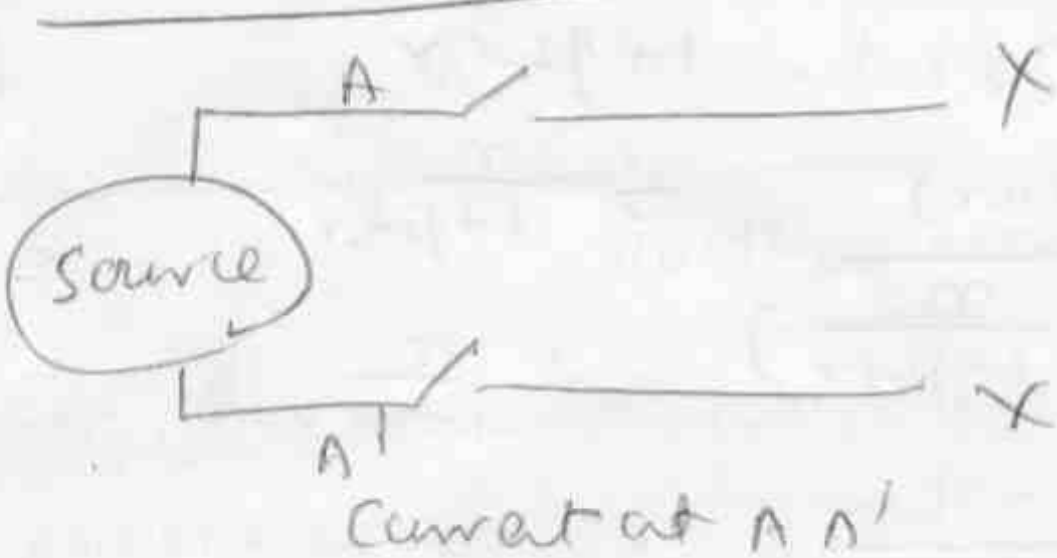
Switching operation





$$i = \frac{E}{\sqrt{R^2 + \omega^2 l^2}} \sin\left(\omega - \tan^{-1}\frac{\omega L}{R}\right) + \frac{E}{\sqrt{R^2 + \omega^2 l^2}} \sin\left(\omega t + \omega - \tan^{-1}\frac{\omega L}{R}\right)$$

Switching surge





Switching of Emf(E) to line results in a wave of current i with velocity v

$$v = \frac{1}{\sqrt{LC}} \qquad \therefore i = \frac{E}{\sqrt{C/L}} = \frac{E}{Z}$$

$$Z = \sqrt{L/C}$$

i = switching current Z = Switching Impedance (surge impedance) Ω

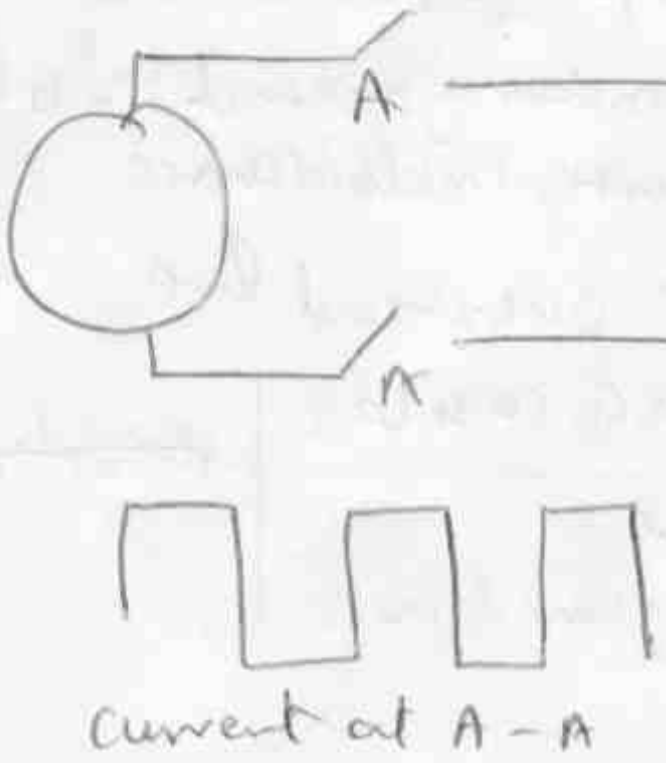
v = switching velocity

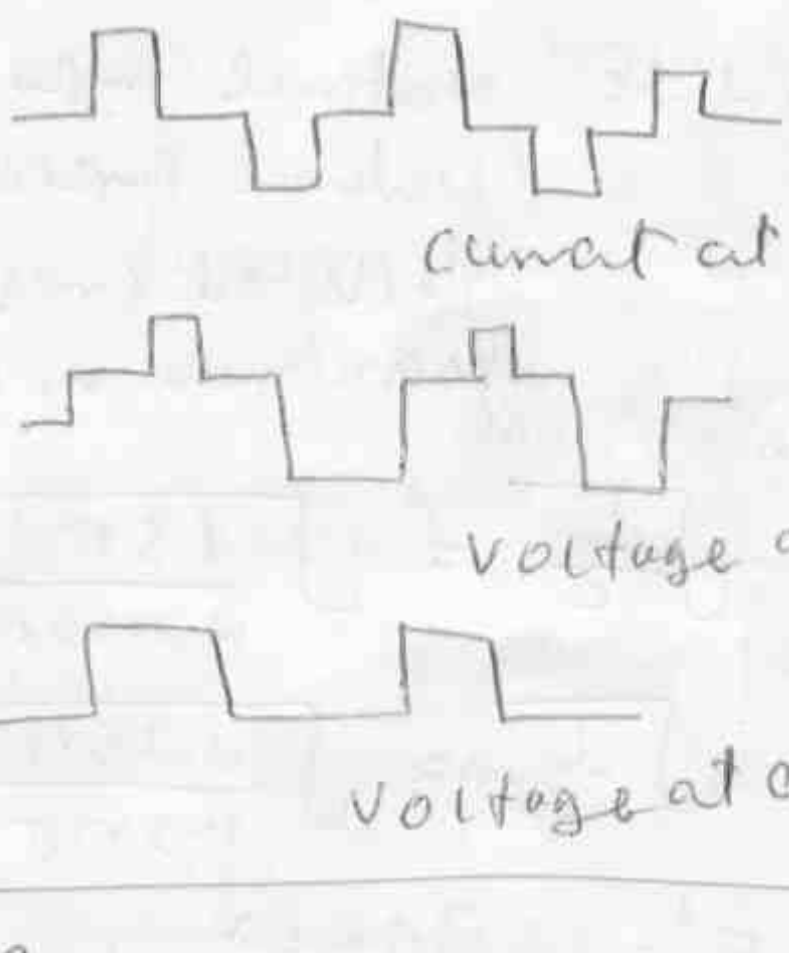
$L = 4 \ln D/r \times 10^{-6}$ H/cm

$C = \frac{1}{4 \ln D/r}$ pF/cm

$v = 3 \times 10^{10}$ cm/sec Light velocity

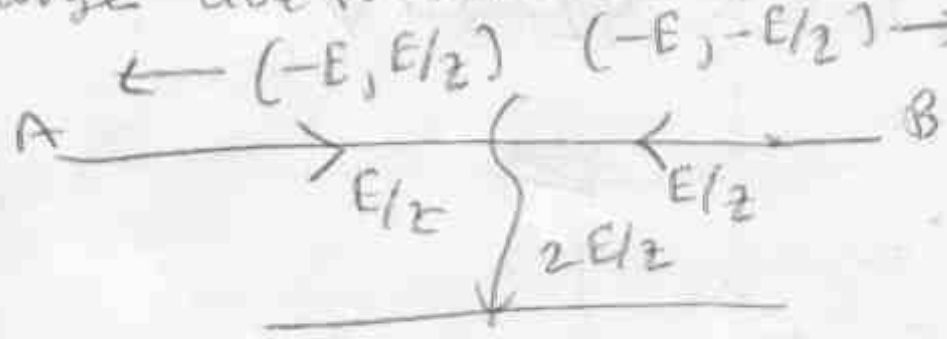
400 → 600Ω of OHLine
40-60Ω for cable





Sudden interuption of line

Surge due to failure of insulation

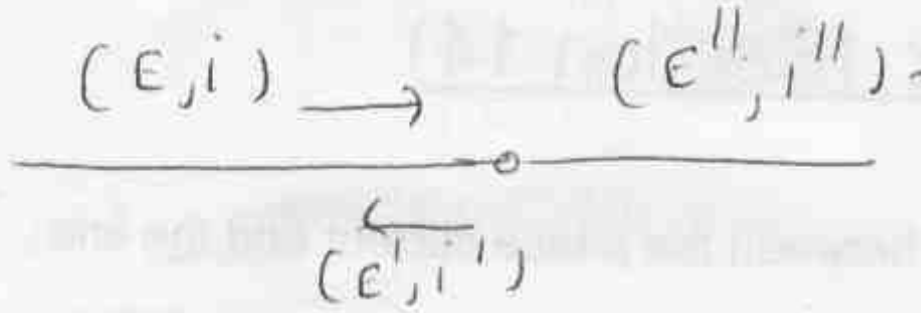




Total current & voltage = $i + \bar{i} = \left\{ \frac{2Z_1}{Z+R} \times i \right\}$

$$E + \bar{E} = \frac{2R}{Z+R} \times E$$

Junction of two lines



$$i'' = i + i' = \frac{2\,2_B}{2_A + 2_B}\, i$$

$$E'' = E + E' = \frac{2\,2_B}{2_A + 2_B}\, E$$

$$i' = \frac{2_B - 2_A}{2_A + 2_B} \times i$$

$$E' = \frac{2_B - 2_A}{2_A + 2_B} \times E$$

Z = Natural impedance $= \sqrt{L/C}$

E'' = maximum voltage at junction

E' = Reflected crest voltage

2_A = Natural impedance of cable A

2_B = Natural impedance of cable B

E = Normal system Line voltage

T3 03 Ph Transmission line 0.0125 μF capacitance & 1.5 mH inductance

It is joined with underground cable 0.3 μF capacitance & 0.25 mH inductance

calculate (A) Natural impedance of overhead line

(B) Natural impedance of UG cable

(C) Reflected crest voltage

(D) maximum voltage at junction

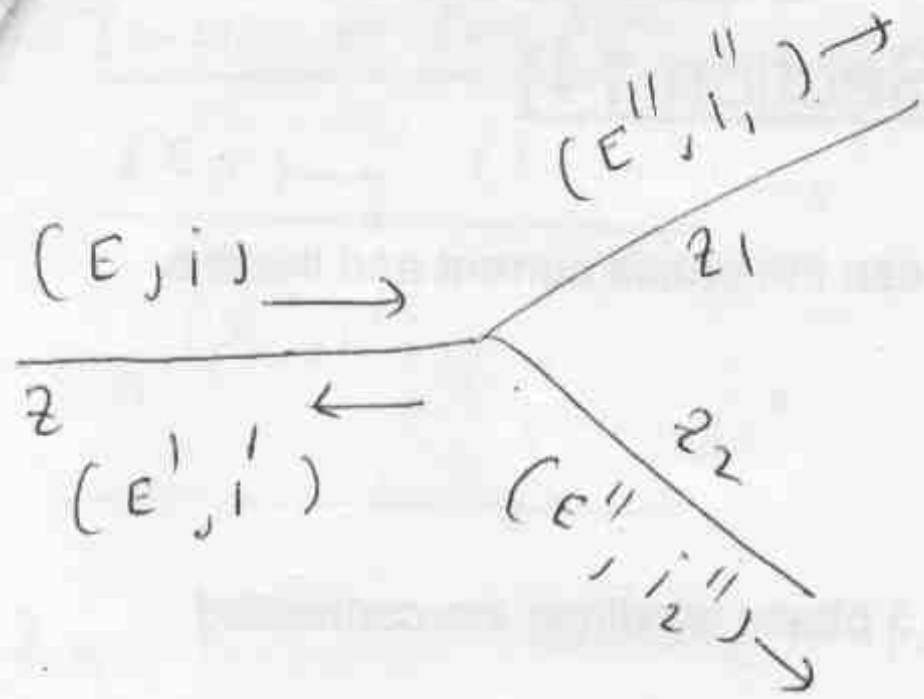
$$2_A = \sqrt{\frac{L}{C}} = \sqrt{\frac{1.5 \times 10^{-3}}{0.0125 \times 10^{-6}}} = 346.4\ \Omega$$

$$2_B = \sqrt{\frac{L}{C}} = \sqrt{\frac{0.25 \times 10^{-3}}{0.3 \times 10^{-6}}} = 28.9\ \Omega$$

$$E' = \frac{2_B - 2_A}{2_B + 2_A}\, E = \frac{28.9 - 346.4}{28.9 + 346.4} \times 50 = -42.3\ \text{kV}$$

$$E'' = E + E' = 50 + |-42.3| = 92.3\ \text{kV}$$

Reflection at junction



$$E' = E \frac{\left(\frac{1}{Z} - \frac{1}{Z_1} - \frac{1}{Z_2}\right)}{\frac{1}{Z} + \frac{1}{Z_1} + \frac{1}{Z_2}}$$

$$E'' = E + E'$$

$$i_1'' = \frac{E''}{Z_1}, \quad i_2'' = \frac{E''}{Z_2}$$

$$E'' = \frac{2E}{1 + \frac{Z}{Z_1} + \frac{Z}{Z_2}}$$

Q3

(10kV line with 700Ω) is connected to 100Ω and 200Ω line,

calculate (i) Reflected voltage (ii) maximum voltage (iii) maximum currents in line 2 branch line.

$$E' = E \frac{\left(\frac{1}{Z} - \frac{1}{Z_1} - \frac{1}{Z_2}\right)}{\frac{1}{Z} + \frac{1}{Z_1} + \frac{1}{Z_2}} = 10,000 \frac{\left(\frac{1}{700} - \frac{1}{100} - \frac{1}{200}\right)}{\frac{1}{700} + \frac{1}{100} + \frac{1}{200}}$$

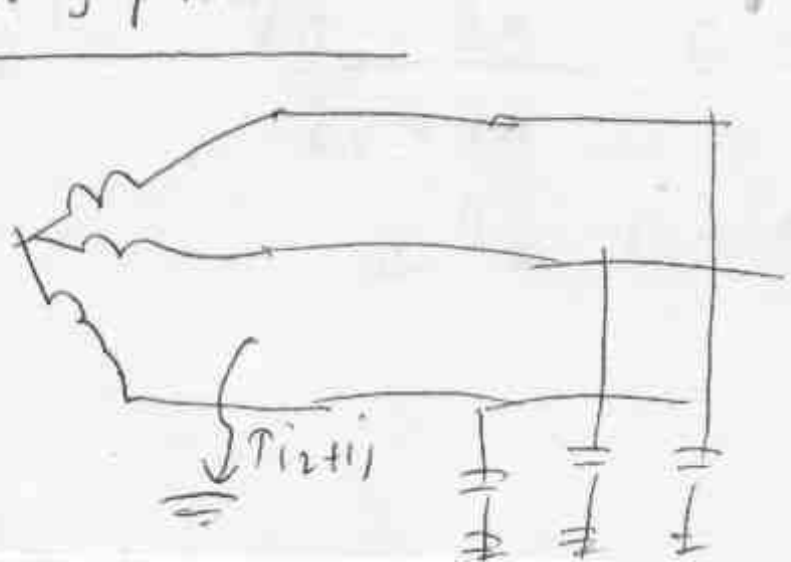
$$= -8260\ V$$

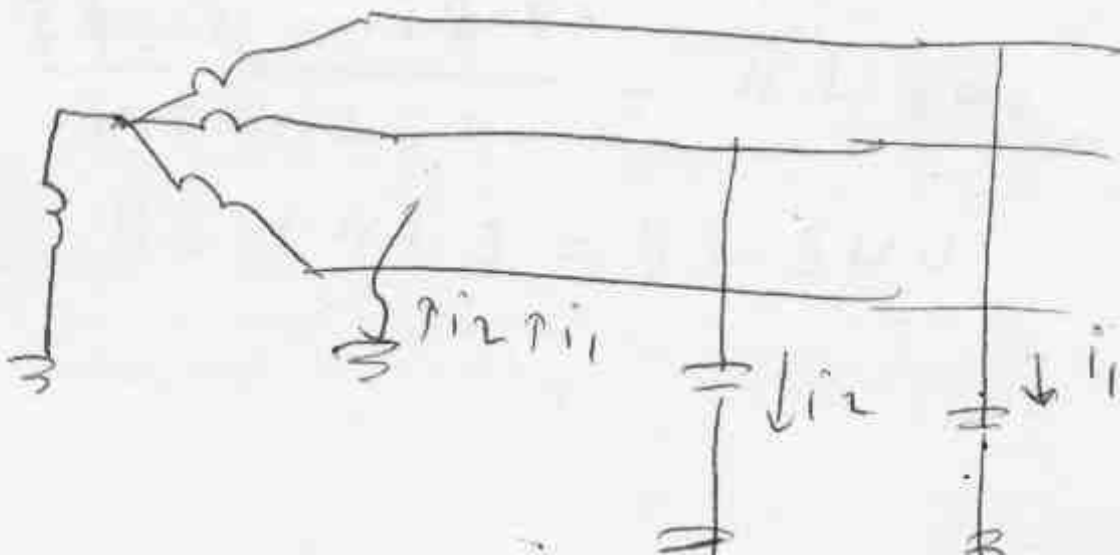
$$E'' = E + E' = 10,000 + |-8260| = 18260\ V$$

$$i_1'' = \frac{E''}{Z_1} = \frac{18260}{100} = 182.6\ Amp$$

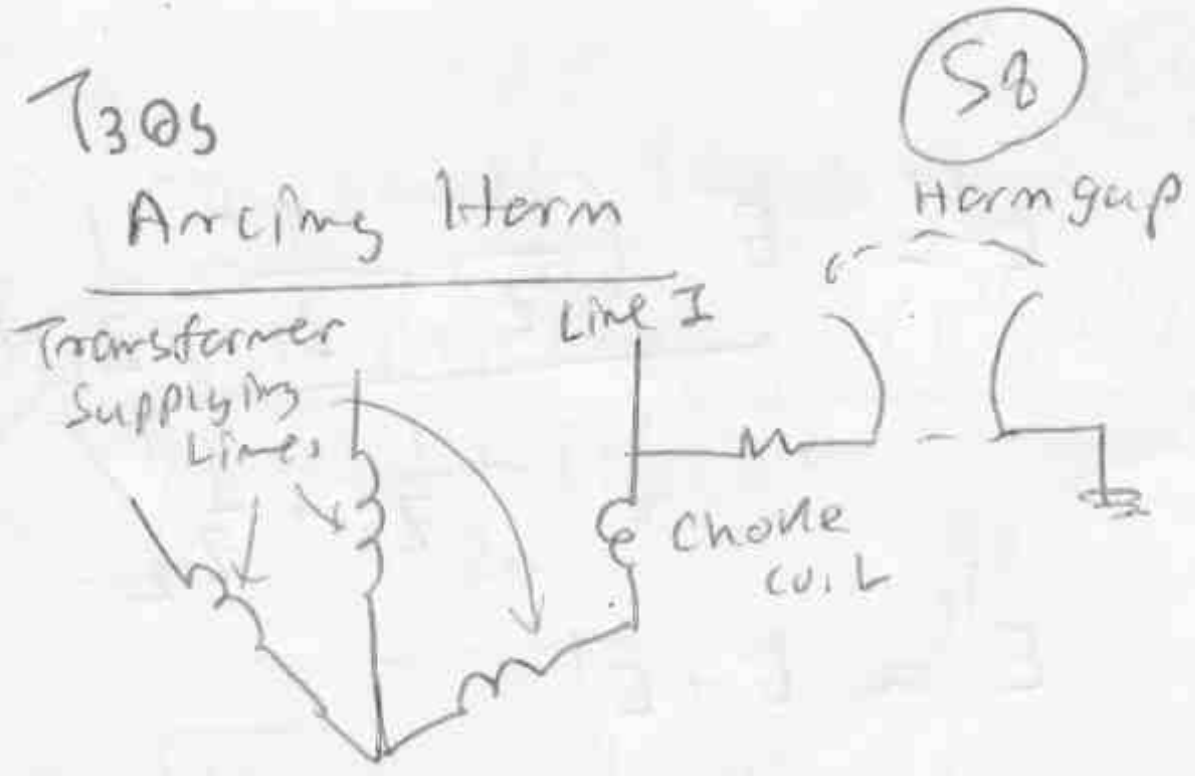
$$i_2'' = \frac{E''}{Z_2} = \frac{18260}{200} = 91.3\ Amp.$$

Lightning Protection

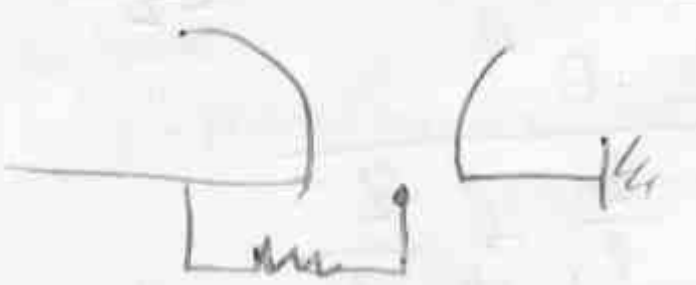


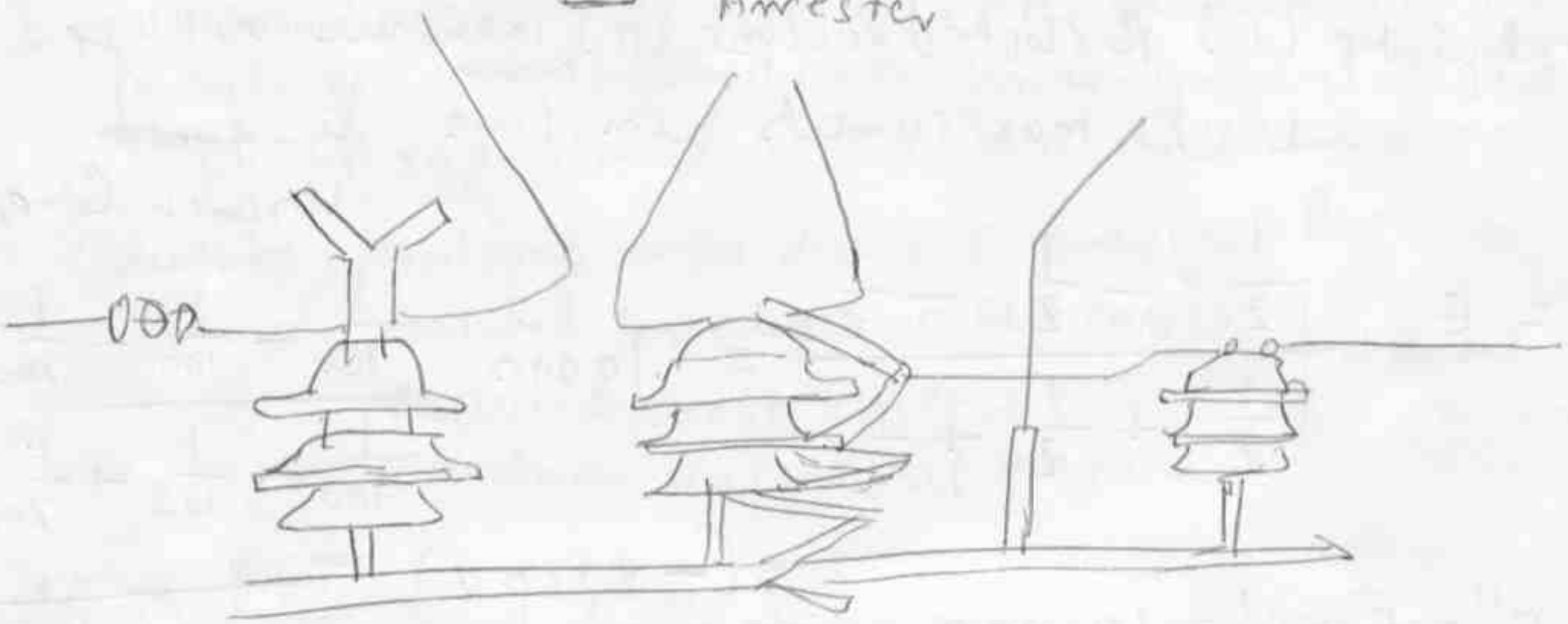


Arcing Horn

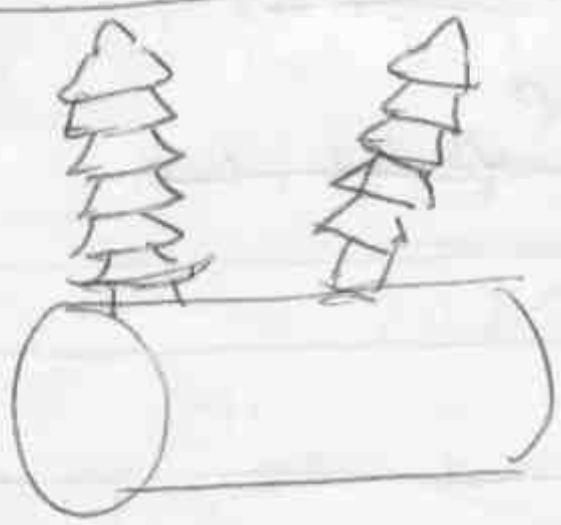


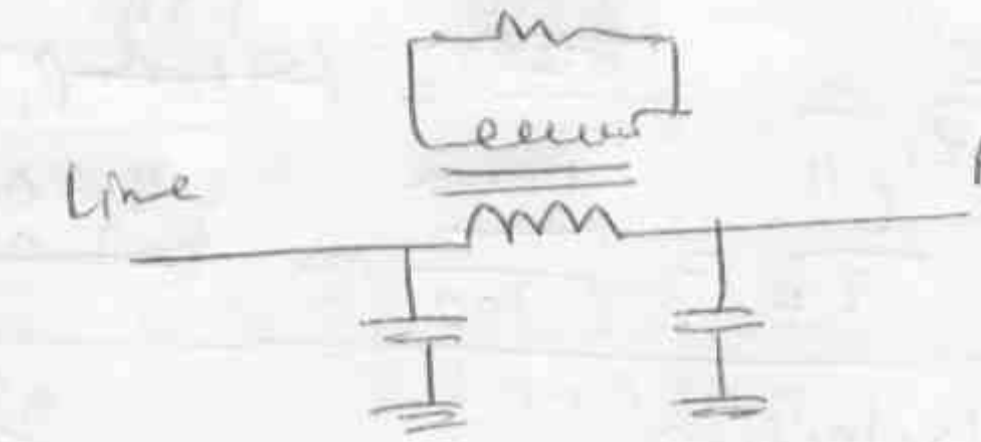
Lightning Arrester





Surge absorber





Equivalent circuit.