CIBO
ENERGY EFFICIENCY HANDBOOK

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Finally, and most importantly, we would like to thank the many CIBO members, too numerous to mention, who participated in the preparation of this handbook, and also their employers, for allowing these members to contribute freely of their time and expertise.

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Chapter 1: Introduction

The Energy Efficiency Handbook was prepared to help owner/operators get the best and most energy-efficient performance out of their boiler systems. This manual gives information and helpful operational tips on virtually every aspect of boiler operation, from Water Treatment, through Combustion and Heat Recovery, to Flue Gas Treatment and Cogeneration.

It is written in a style that is easy to understand and minimizes technical description. In some instances there is a necessity to explain why certain actions occur and why, to help the reader understand how to minimize energy consumption and increase boiler efficiency.

Since each boiler system is unique, much of the material is general in nature, written to represent the majority of operational components. Each chapter concludes with a checklist of suggested actions for maximizing efficiency where appropriate. In addition, Chapter 8, Energy Auditing, contains a summary checklist of energy-saving tips.

Chapters are supported by graphic diagrams and charts for a better understanding of what is being discussed.

The publication of this Handbook by the Council of Industrial Boiler Owners (CIBO) is believed to be the first of its kind and, as such, could benefit from comments by its readers. Please feel free to let us know what you think of this first-time effort, including additional material you feel should be included. We will consider your suggestions in future revisions.

Council of Industrial Boiler Owners (CIBO)
6035 Burke Center Parkway, #360
Burke, Virginia 22015
Phone: (703) 250-9042
Fax: (703) 239-9042
World Wide Web: http://www.cibo.org

Chapter 2: Water Treatment

Water is the essential medium for steam generation. Conditioning it properly can increase the efficiency of the boiler as well as extend the boiler's life. Treating boiler water also insures safe and reliable operation; without proper treatment, severe problems can develop, some so severe that the boiler itself can be destroyed.

This chapter will describe some of the more common and severe water-related problems that occur in industrial boilers and follows with a discussion on proper boiler water treatment.

Each boiler and its water supply represents a unique situation. The information given here is a generalized discussion; it is important to enlist the help of experts, such as water service companies or consultants, to select the proper water treatment equipment and chemicals or to modify an existing program to increase boiler efficiency and reduce corrosion.

Compound	ppm as $CaCO_3$	
Calcium	32°F (0°C)	212°F (100°C)
Bicarbonate	1,620	decomposes
Carbonate	15	13
Sulfate	1,290	1,250
Magnesium		
Bicarbonate	37.1	decomposes
Carbonate	101	75
Sulfate	170,000	356,000
Sodium		
Bicarbonate	38,700	decomposes
Carbonate	61,400	290,000
Chloride	225,000	243,000
Hydroxide	370,000	970,000
Sulfate	33,500	210,000

Table 2-1. Solubility of Chemical Compounds.

Boiler Water Problems

Boiler water problems generally fall into two classes: deposit-related and corrosion-related. Because the two often interact, it is very common to find a boiler experiencing both simultaneously. There are many instances where deposits cause corrosion and corrosion causes deposits. It is important to avoid both problems.

Deposit-Related Problems

Boiler Scale

One of the most common deposit problems is boiler scale. This happens when calcium, magnesium and silica, common in most water supplies, react with tube metal found in boilers to form a hard scale on the interior of the boiler tubes, reducing heat transfer and lowering the boiler's efficiency. If allowed to accumulate, boiler scale can eventually cause the tubes to overheat and rupture. Scaling is one of the leading causes of boiler tube failures. Scale is equivalent to having a thin film of insulation between the furnace gases and boiler water. It can drop a boiler's efficiency by as much as 10-12%.

Scale forms as the solubilities of the scale-forming salts in water decreases and the temperature and concentrations of the salts increases. When feedwater is elevated to boiler water temperature, the solubility of the scale-forming salts is decreased, and solid scale begins to form on the boiler systems. See Table 2-1.

Removing calcium and magnesium or other deposit-forming materials from the feedwater before they enter the boiler system is the best way to prevent scaling. Small amounts of hardness (calcium plus magnesium) can be effectively treated in the boiler and related system components by using boiler water treatment products such as chelates, polymers, and/or phosphates. Scale formation also occurs in economizers, feedwater pumps and related service lines. It also forms in low-pressure boilers where no pre-treatment or poorly maintained treatment chemicals, boiler water treatment products or pretreatment chemicals such as sodium zeolite are used. It is not normally found in boiler systems where demineralization is used or in high pressure, high purity systems.
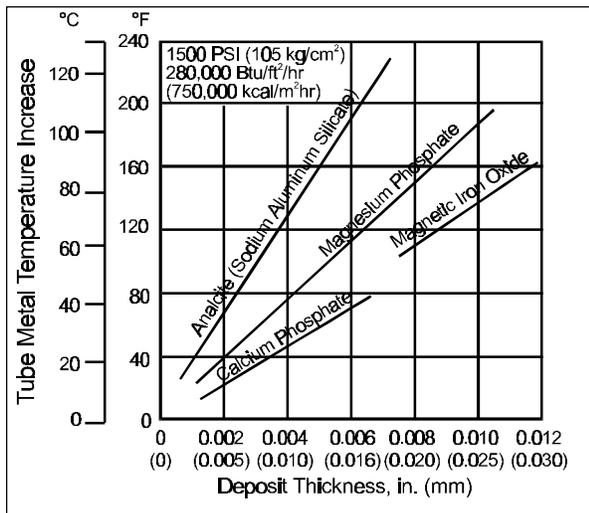
Figure 2-1. Effects of boiler scale on tube metal temperature.

Large amounts of hardness that cannot be successfully treated using boiler water treatment products must be treated by some other process.

Silica Scale

Silica scale is another kind of scale that affects boilers, much in the same manner as calcium and magnesium scale. Silica is found in most water supplies and it is not as easily removed as calcium and magnesium.

Silica can form several types of deposits, such as amorphous silica and magnesium silicate. Amorphous silica appears on boiler surfaces as a smooth, glass-like deposit that is very difficult to remove. A hydrofluoric acid-based cleaner is used to clean such affected surfaces. Magnesium silicate has a rough-textured tan to off-white appearance, and, while easier to remove than amorphous silica, is still difficult to remove.

Silica scale is found primarily in lower pressure systems where the pretreatment system uses sodium zeolite for softening and is not designed for silica removal. Silica-based deposits can also be found in high pressure systems where silica leakage through the anion unit(s) has occurred. Deposits form more readily as silica levels increase and hydrate alkalinities decrease. Silica deposits have high insulating properties which limit heat transfer and thus boiler efficiency and may also cause the failure. Silica can also distill from the boiler as silicic acid. Any silica carryover can promote deposits on steam turbine blades. Silica carryover at pressures about 600 psig (40 bar), becomes more serious as pressure increases.

Silica control can be done through pretreatment and proper boiler blowdown, and in low pressure boilers by maintaining at least a 3:1 ratio of hydrate alkalinity to silica in the boiler water.

Effects of Boiler Scale

The chemical structure of the scale, it's porosity and the design and operational method of the boiler all influence the amount of heat lost. For example, 1/8-inch (3mm) of scale can cause a 2.0-3.0% loss in fire-tube boilers and water tube boilers.

A second but more serious effect from scale is the overheating of boiler tube metal, causing eventual tube failure. In modern boilers with high heat-transfer rates, even extremely thin layers of scale will cause a serious elevation in the temperature of tube material. This is dramatically shown in Figure 2-1.

A third serious effect of scale formation is localized corrosion. Boilers with high heat transfer rates above 75,000 Btu/sqft/hr Effective Projected Radiant Surface (EPRS) are subject to localized corrosion, a situation where the deposits are actually causing the corrosion. This is a good example of the interaction between deposit-related and corrosion-related boiler water problems. Secondary corrosion is particularly present in systems with iron oxide deposits. The net effect is that the stack gas temperature may increase as the boiler absorbs less heat from the furnace gases, leading to increased pollution and more fuel consumption through inefficient operation.

Iron Deposits

Iron oxide is another compound which will accumulate on boiler surfaces. Iron enters the boiler in the feed-water or it can form in the boiler from corrosion. Iron oxides can be present in both soft and hard-scale deposits. Both types are frequently found at the same location, with the hard deposit existing as a layer next to the boiler tube and the soft layer on top of it.

Iron oxides are porous deposits, which will allow boiler water to seep through and "flash" to steam, leaving behind the dissolved solids. These dissolved solids in the boiler water, such as caustic and chelates, can concentrate in these localized areas to thousand of parts per million even though the water contains the normally recommended levels of these compounds. These excessive concentrations can result in rapid and severe

metal dissolution and tube failure. See Figure 2-2.

Minimizing Iron Deposit-Related Problems

The most obvious and effective way to minimize iron-related problems is to keep as much iron out of the boiler as possible. The supply water should be subject to pretreatment techniques such as filtration, clarification, etc. Likewise, if steam condensate is returned to the boiler, action should be taken to minimize the corrosivity of the condensate through proper chemical treatment. Water treatment chemicals such as chelates, polymers and phosphates (residual with and without polymer) can minimize iron deposits.

Other areas that should receive attention include hot and cold lime softeners, filters, sodium zeolite softeners, and water-cooled packing glands on feedwater pumps because they can contribute iron to the system. These system components must be operating properly before chemical treatment can be effectively applied.

Corrosion-Related Problems

Oxygen Attack

Dissolved oxygen interacts with boiler component surfaces, forming "pits" on the metal surface. These pits may eventually grow large enough to penetrate the metal, forcing a boiler shutdown.

Oxygen present in boiler feedwater becomes very aggressive when heated, causing corrosive damage to preheaters and economizers. Oxygen which enters the boiler itself can also cause further damage to steam drums, mud drums, boiler tubes and headers. Damage can also occur to condensers and condensate piping from oxygen still present in the steam.

Controlling the oxygen content in the feedwater is done through deaeration and chemical treatment. Deaerators in steam generating systems use steam to strip oxygen from the feedwater. A properly designed and maintained deaerator can effectively remove almost all the oxygen from the feedwater, typically to < 15ug/lppb (parts per billion) without the need to add an additional oxygen scavenger.

The final traces of oxygen can be removed from the feedwater with an oxygen scavenger.
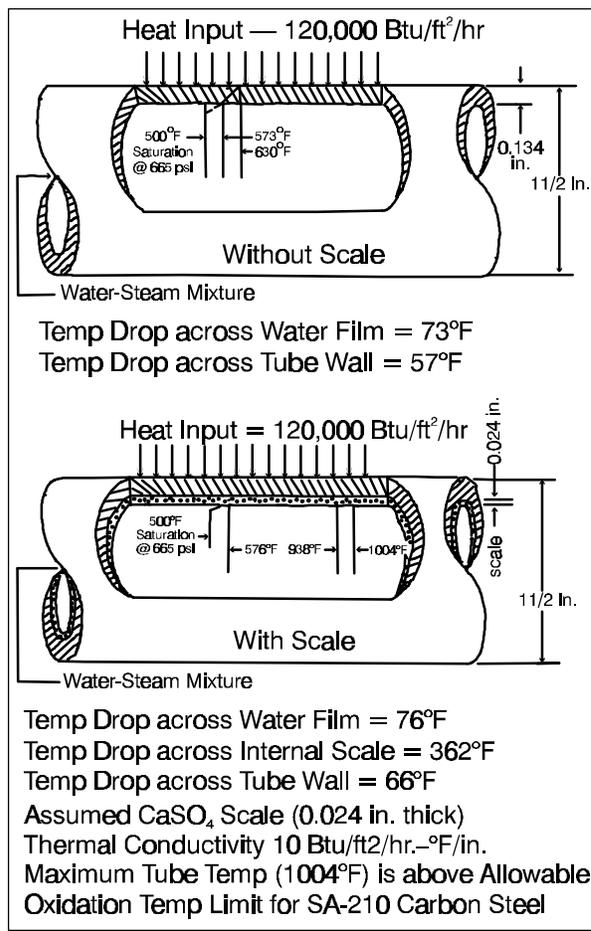
Figure 2-2. Effect of $CaSO_4$ scale on high heat flux boiler plate.

The most common scavenger is sodium sulfite, although other organic materials also work well. Some of these materials also form a protective oxide on large preheater and economizer surfaces. **Scavengers cannot effectively substitute for the function of the deaerator; if the oxygen content of the feedwater is greater than 50ug/1 (ppb) then oxygen corrosion can occur even when oxygen scavengers are used.**

Two of the most common causes of corrosion are the presence of carbon dioxide and oxygen in the condensate. Carbon dioxide will form carbolic acid and reduce the pH of the condensate and cause acid attack while oxygen can directly attack metal. The source of carbon dioxide in condensate is usually carbonate found in boiler water carried over in the steam. Boilers using softened water are more prone to this than those using demineralized water. The presence of oxygen in condensate can be caused by poorly operating deaerators, leakage of air into vacuum condensers, leakage of cooling water and other factors. Treatment of condensate is done with neutraliz-

Drum Operating Pressure	0.300 psig	301-450 psig	451-600 psig	601.750 psig	751.900 psig	901.1000 psig	1001-1500 psig	1501-2000 psig
Dissolved Oxygen (mg/l)	<0.007	<0.007	<0.007	<0.007	<0.007	<0.007	<0.007	<0.007
Total Iron (mg/l)	≤0.1	≤0.5	≤0.3	≤0.25	≤0.2	≤0.2	≤0.1	≤0.1
Total Copper (mg/l)	≤0.05	≤0.025	≤0.02	≤0.02	≤0.15	≤0.01	≤0.01	≤0.31
Total Hardness (mg/l)	≤0.3	≤0.3	≤0.2	≤0.2	≤0.1	≤0.05	ND	ND
pH @ 25°C	8.3-10.0	8.3-10.0	8.3-10.0	8.3-10.0	8.3-10.0	8.8-9.6	8.8-9.6	8.8-9.6
Chemicals for preboiler protection	NS	NS	NS	NS	NS	VAM	VAM	VAM
Nonvolatile TOC (mg/l)	<1	<1	<0.5	<0.5	<0.5	<0.2	<0.1	<0.2
Oily matter (mg/l)	<1	<1	<0.5	<0.5	<0.5	<0.2	<0.1	<0.2
Silica (mg/l as SiO_g)	150	≤90	≤40	≤30	≤20	≤8	≤2	≤1
Total Alkalinity*	<350	<300	<250	<200	<150	<100	NS	NS
Free OH Alkalinity* (mg/l)	NS	NS	NS	NS	NS	NS	ND	ND
Specific Con____ (__Cm) without neutralization	5400-1100	4600-900	3800-800	1500-300	1200-200	1000-200	5,150	580
TDS (max mg/l)	1.0-2.0	1.0-2.0	1.0-2.0	0.5-0.1	0.5-0.1	0.5-0.1	0.1	0.1

ND = Not Detected   NS = Not Specified   * = CaCO3   VAM = Use only alkaline

Table 2-2. Suggested Water Chemistry Limits, Industrial Watertube, High Duty Primary Fuel Fired, Drum Type Boilers, Materials Upstream of Attemperation Water Source.

ing amines. Carbon dioxide reacts with water to form carbonic acid, a highly corrosive material that can attack equipment.

It cannot be emphasized strongly enough that the deaerator is the one piece of equipment in the water treatment process that should receive careful maintenance attention.

Caustic Attack

Caustic attack on boilers can take two forms: caustic gouging or caustic cracking, also called caustic embrittlement.

Caustic gouging causes deep elliptical depressions in metal boiler surfaces, which occur in areas of high heat flux or under heavy porous deposits, such as iron oxide deposits. This is another clear case of an interrelated deposit and corrosion problem. Underneath these deposits, boiler water can concentrate to the point where high caustic concentration accumulates, causing a localized corrosion. This very rapid action can take place and even cause a failure within a few days or even a few hours. Careful control of boiler water chemistry can prevent caustic gouging; if the "free hydroxide alkalinity" is set too high or uncontrolled, then caustic gouging may result. Prevention of porous deposit formation (such as iron oxide) eliminates a place for caustic gouging to occur.

Caustic cracking is a form of stress corrosion cracking that happens when a high concentration of caustic is present at a heated and stressed steel surface. These cracks can occur quickly and cannot be readily seen, sometimes causing a violent failure. All parts of the boiler are subject to this type of corrosion, including boiler tubes, headers, steam drums, mud drums, bolts, etc. Avoiding heated, stressed surfaces in boilers is not feasible, so care should be taken to prevent high concentrations of caustic from forming. However, maintaining an excessive "free hydroxide alkalinity" while using caustic to regenerate anion exchange resins and control the pH of the boiler water can cause high caustic concentrations.

Acid Attack

A third corrosion-related problem is caused when the boiler water pH drops below about 8.5. Known
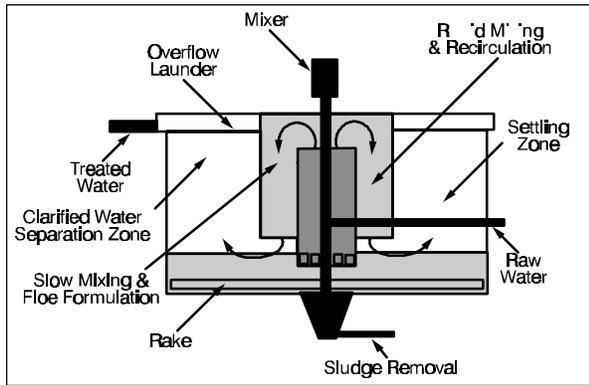
Figure 2-3. Clarifier.

as acid attack, the effect exhibits rough pitted surfaces, with some of the pits being quite deep. Again, the presence of iron oxide deposits on boiler surfaces can encourage this kind of corrosion. A low boilerwater pH is usually caused by contamination of the boiler feedwater, from sources such as hydrochloric or sulfuric acid from leaks in demineralizers and condenser leaks of cooling tower water. Contamination can also occur from process leaks of acid or acid-forming materials into the return condensate system.

Boiler feedwater pH should be continuously monitored.

Boiler Water Treatment

Boiler water treatment is grouped into three main areas:

- External treatment
- Internal treatment
- Condensate treatment

Quality requirements for boiler feed-water and boiler water vary from system to system. Generally speaking, the higher the steam pressure, the higher the quality of water that is required. The table below shows generally good parameters for boiler operations but should not be applied to all situations. As stated before, a specific water treatment should be recommended by someone who has knowledge of both boiler water treatment practice and the conditions of the boiler to be treated.

External Treatment

This type of treatment involves the removal of impurities which from the boiler feedwater. Treatment falls into three categories, depending on what needs to be removed:

- Removal of suspended solids
- Removal of hardness and other soluble impurities
- Oxygen removal

Removal of Suspended Solids

Untreated boiler feedwater frequently contains suspended matter such as mud, silt and bacteria. Left in the water, this material can cause problems, such as foaming or deposits in the boiler.

The process of clarification or filtration removes most suspended matter. One common method involves both processes; the water is first passed through a clarifier which removes most of the suspended matter, then a filter, which removes the rest.

To perform the clarification function, a flocculent aid is mixed with the raw water in either the raw water feed line or in the "rapid mix zone" of the clarifier. Primary clarification occurs in the "rapid mix zone", where small solids are formed. The solids grow in size in the "slow mixing zone" and settle in the "settling zone". The resulting sludge is removed from the bottom of the unit while the clarified water is drawn from the top by overflowing into a launder (a device that functions much like a pool skimmer). A rake at the bottom of the clarifier moves slowly through the settled sludge to keep it from "setting up", or solidifying.

Filtration can be done several different ways. The most common filters are granular media filters, made from sand, anthracite (hard coal) and garnet. Other types of filters, such as cartridge filters, sock filters and strainers are used in some installations. Filter media choice, filter bed depth and other design parameters are determined by the quality of the water and boiler requirements.

Removal of Hardness and Other Soluble Impurities

The second type of boiler water treatment involves the removal of impurities, such as calcium, magnesium and silica which, as discussed earlier, can cause scale. Common treatment methods to remove these impurities include lime softening, sodium cycle cation exchange (often called sodium zeolite softening), reverse osmosis, electrodialysis, and ion exchange demineralization. Which treatment is most appropriate again depends on the water supply quality and the purity requirements of the boiler.

Quick or slaked lime added to hard water, reacts with the calcium, magnesium and, to some extent, the silica in the water to form a solid pre-
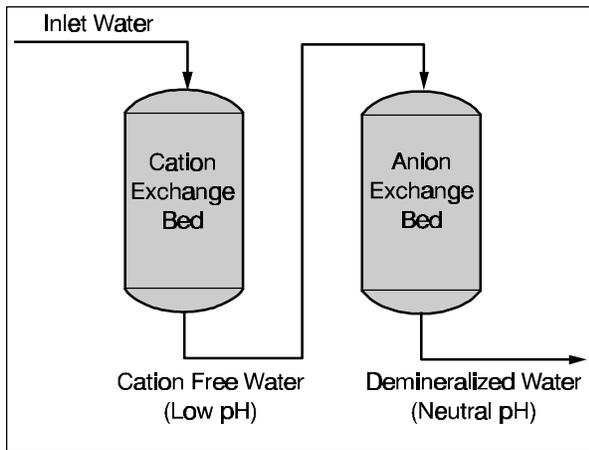
Figure 2-4. Two-bed demineralizer.

Figure 2-5. Deaerator.

cipitate. The process typically takes place in a clarifier, similar in function to the one shown in figure 2-3. The lime is added to the "rapid mix zone", where it reacts with some of the calcium, magnesium and silica. The combined precipitate is removed from the bottom of the clarifier and the treated water is now softer than the untreated inlet water but still unsuitable for the boiler.

Lime softening treatment is followed by either sodium cycle cation exchange or ion exchange demineralization. Cation exchange is usually picked for lower pressure boilers (450 psig) and demineralization for higher pressure boilers (above 600 psig).

Ion exchange is just what it implies: a process that exchanges one type of ion (charged particle) for another. Many troublesome impurities in supply water are ions, making this process extremely important in boiler water treatment. Ion exchange takes place in a closed vessel which is partially filled with an ion exchange resin. The resin is an insoluble, plastic-like material capable of exchanging one ion for another. There are two types: cation and anion resins. Each is capable of exchanging one or the other types of ions.

Another method of ion exchange involves a sodium exchange softener, where hard water enters the unit and the calcium and magnesium are exchanged for sodium. The treated water will normally have most of the hardness removed, but will still contain other impurities. This method is suitable only for low pressure boilers.

If very pure water is required, for high pressure boilers for example, then demineralization is required. A demineralizer contains one or more cation exchange beds, followed by one or more anion exchange beds. Such a system is shown in figure 2-4.
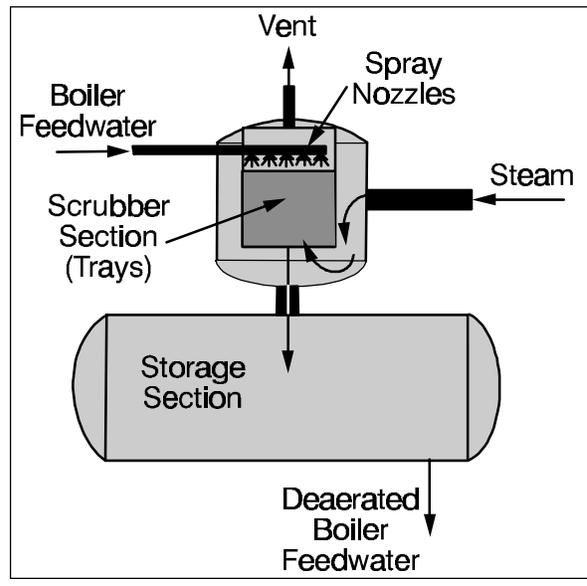
In the demineralizer, water is treated in two steps. First, it is passed through the cation exchange bed, where the cations (calcium, magnesium and sodium) are exchanged for hydrogen ions. The treated water is now free of cations but is too acidic and cannot yet be used in the boiler.

In the second step the water passes through the anion exchange bed where the anions (sulfate, chloride, carbonate and silica) are exchanged for hydroxide ions. The hydrogen and hydroxide ions react to form water, now suitable for use in the boiler.

For higher purity water, more elaborate systems are employed than the one shown here, but the basic principle remains the same.

Ion exchange resins have a limited capacity and will eventually become exhausted. They can be regenerated however; sodium cycle cation exchange beds are regenerated with brine, cation exchange beds are regenerated with hydrochloric or sulfuric acid and the anion exchange beds become regenerated with caustic soda.

Other technology is sometimes employed to remove undesirable impurities from the water supply, including reverse osmosis, electrodialysis, and electrodialysis with current reversal. These are all known as membrane processes. Reverse osmosis uses semipermeable membranes that let water through but block the passage of salts. In the case of electrodialysis, the salts dissolved in the water are forced to move through cation-selective and anion-selective membranes, removing the ion concentration.

Oxygen Removal with a Deaerator

The third type of boiler water treatment involves the removal of dissolved oxygen in the water.

A deaerator (sometimes called a dearating heater), as shown in figure 2-5, takes advantage of the fact that the solubility of oxygen in water decreases as the water gets hotter. The oxygen is removed by spraying the untreated boiler water onto trays in the deaerator, where it makes intimate contact with steam rising through the tray. The steam heats the water while stripping the oxygen. Proper functioning of the deaerator requires that the two non-condensable gases, oxygen and nitrogen be vented away from the water being treated. Deaerated water should have an oxygen concentration of less than 15ppb (ug/l).

Maintenance Suggestions with a Deaerator

Here are some things to remember to keep the deaerator operating properly:

1. Steam should be vented from the deaerator. The deaerator vent should always be open to remove scrubbed gases. Steam is carried along with the gases. The plume should form about six inches from the top of the vent and be visibly steam for only two feet. This is enough to remove gases; more than two feet is a waste of steam.
2. Check the oxygen concentration of the deaerated feedwater to be sure it is functioning properly. This can be done using simple calorimetric tests. Be sure to turn the oxygen scavenger off before taking any measurements.

Internal Treatment

Internal boiler water treatment continues the process of purifying the water begun using external treatment methods. All treatment additives discussed here are designed to assist with managing corrosion or deposits. A good internal treatment program can protect boilers which use a proper quality of feedwater but it cannot protect boilers with grossly contaminated boiler feedwater. It is essential to have both external and internal treatment procedures that are effective, well-maintained and closely monitored.

Boilers are typically protected from corrosive attack by a thin film of magnetite (a black magnetic iron oxide) which forms on the surface of the boiler metal. Water treatment programs should be designed that encourage and maintain this protective film by maintaining the proper pH, assuring the absence of oxygen through a deaerator, the use of an oxygen scavenger, and the employment of other chemical additives.

Oxygen Scavengers

Most of the oxygen in boiler feedwater is removed by the deaerator but trace amounts are still present which can, over time, cause boiler corrosion. To prevent this, oxygen scavengers are added to the boiler water, preferably in the storage tank of the deaerator so the scavenger will have the maximum time to react with the residual oxygen. Under certain conditions, such as when boiler feedwater is used for attemperation to lower steam temperature, other locations are preferable.

The most commonly used oxygen scavenger is sodium sulfite. It is inexpensive, very effective and rapidly reacts with the trace amounts of oxygen. It is also easily measured in boiler water.

In most cases it i the oxygen scavenger of choice. There are instances in some higher pressure boilers (generally above 900 psig), that some of the sulfite may decompose and enter the steam, causing problems in the condensate systems and condensing steam turbines. In these cases, substitute (usually organic-based) oxygen scavengers can be used.

New oxygen scavengers have been introduced in recent years. The decision to use them or rely on sodium sulfite should only be made by those qualified to make boiler water treatment decisions. In all cases the new product should be carefully added and its effectiveness evaluated in accordance with operating procedures.

Other Chemical Additives

Phosphate
Used almost as often as oxygen scavengers, phosphate plays several important roles in boiler water treatment:

- It buffers the boiler water pH to minimize the potential for boiler corrosion.
- It precipitates small amounts of calcium or magnesium into a soft deposit which can then accumulate in mud drums or steam drums rather than as hard scale.
- It helps to promote the protective oxide film on boiler metal surfaces.

Common phosphate compounds added to treat boiler water include sodium phosphate (monoso-

dium phosphate, disodium phosphate or trisodium phosphate) or sodium polyphosphate. They all function approximately the same; the choice of which to use depends on the quality of the boiler water and the handling requirements of the user.

As phosphate functions as a precipitating boiler water treatment, creating a sludge as it reacts with hardness, a procedure should be established to remove the sludge during a routine boiler shutdown. The rate of sludge accumulation varies according to the hardness of the water entering the boiler and the operating conditions of the boiler. Although boilers treated using phosphates (without chelates or polymers) tend to require more frequent cleaning, they also tend to show very low corrosion rates.

Chelates and Polymers

Rather than precipitate with hardness compounds, chelates and polymers "solubilize" or combine with hardness (calcium and magnesium and to some extent iron) to form a stable chemical compound. Sometimes they are used in conjunction with phosphate.

The resulting compounds can be eliminated by blowdown.

The two most commonly used chelates are nitrilotriacetic acid (NTA) and ethylenediamine tetraacetic acid (EDTA). Either product can be used in low pressure (up to 150psig), while EDTA is preferred for higher pressure boilers. They have been successfully used for many years; however, since many water treaters base the chelate dosage on the amount of hardness encountered in the boiler feedwater, other water treatment programs are often chosen when large swings in feedwater hardness occur on a frequent basis. A well-operating deaerator is important when using chelates.

Most polymers used in boiler water treatment are synthetic in composition. Some act like chelates but none are as strong as EDTA. Polymers disperse suspended solids; thus they are referred to as "dispersents". A wide variety of different polymers are available; some are effective in controlling hardness deposits, while others in controlling iron deposits.

In some cases the most effective treatment program uses a combination of chelates and polymers. Again, the decision to use one or the other or a combination of both should be made by those who understand the functions of various polymers and the needs of the boiler. The uses of steam might also be considered. Steam used in food processing has specific chemical addition restrictions. Lastly, these treatment measures are only effective when boiler feedwater pretreatment is effective.

Blowdown

Blowdown is a very important part of any water treatment program. Its purpose is to limit the concentration of impurities in the boiler water. The right amount of blowdown is critical: too much results in energy loss and excessive chemical treatment cost; too little and excessive concentrations of impurities build up. There are no hard and fast rules as to the amount of blowdown because of the variation in water quality varies from place to place. It can range from 1% (based on feedwater flow) to as much as 25%.

Location varies; it can be from beneath the water surface in the steam drum, from the mud drum or bottom header, or it can be from the bottom of the boiler. Blowdown can be continuous or intermittent. Here are some principles to help establish an effective blowdown program:

1. In drum-type boilers, the concentration of the water should be controlled by blowdown from the steam drum. Continuous blowdown is preferred.
2. Also in drum boilers, blowing from the mud drum or bottom headers removes suspended solids from the boiler. Trying to control the concentration of impurities by blowdown from this location can cause a severe disruption of circulation in the boiler, causing damage to the boiler. Bottom blowdown should be of short duration, on a regular basis. These are determined by boiler design, operating conditions and the accumulation rate of suspended solids.
3. Fire tube boiler blowdown can be either continuous or intermittent. It can be blown down from below the surface or from the bottom. Type, frequency and duration depend on boiler design, operating conditions and the type of water treatment program.

A way to reduce the energy loss is to install a continuous blowdown heat recovery device. These are now economical for blowdowns as low as 500 lb/hr.

Other Internal Treatment Materials

Caustic, in the form of sodium hydroxide or potassium hydroxide or a combination of the two, can be used to control the pH of boiler water. Sometimes caustic is used in conjunction with polyphosphate.

Other chemicals used in boiler water treatment are ammonia and hydrazine. Since both

materials are nonprecipitating and will volatize into the steam, they are commonly referred to as "all volatile treatment" (AVT). Used frequently in large electrical power generating plants, they are less common in other industries because hydrazine must be treated as an extremely hazardous substance and AVT treatment is ineffective for harder water.

Condensate Treatment

Corrosion of condensers, steam traps and condensate piping is common. Adding a basic material, such as amines to the steam will neutralize the acid as the steam condenses, keeping the pH of the condensate high. Neutralizing amines can only protect the system from acid attack from carbon dioxide.

The most commonly used amines are morpholine, cyclohexylamine and diethylaminoethanol (DEAE). A mixture of amines is usually required, since most steam/condensate systems are quite large and contain numerous condensers. Using a mixture assures protection throughout the system because some amines condense faster and the slower condensing ones will be able to protect equipment that is farther down the system. Someone who is very familiar with the steam/condensate system and knows the chemical and physical properties of amines should be employed to assist in the selection of the best mix of amines.

Protection from oxygen attack can be achieved using film amines. These compounds form a very thin film of organic material on metal surfaces which acts as a barrier to oxygen but has little effect on the pH of the condensate. There is minimal effect on heat transfer because the film is thin. Like neutralizing amines, they are added to the boiler water or they can be added directly to the steam. Two commonly used amines are dodecylamine and octadeccylamine.

Benefits From a Proper Water Treatment Program

Emphasis has been made in several instances of the importance of using knowledgeable people to ensure proper evaluation of water treatment needs. It is always best to use someone familiar with the boiler system operation as well.

As an example, an Arizona manufacturer saved almost $100,000 a year after contracting with an outside water treatment firm who had run a computerized analyses on the efficiency of the firm's six chillers. The company was spending over $50,000 on water treatment chemicals, an amount they considered excessive.

The consultants found one of the six units operating at only 56% of its maximum efficiency. The problems identified included scale, which was treated with an inhibited acid. A second analysis was performed and the efficiency of the unit rose dramatically to 99.5%. Based on this improvement, the manufacturer ordered a complete cleanup program on the entire system.

Another problem that was discovered was that the facility's five cooling towers had accumulated a significant amount of dirt an biological growth. This was removed by scraping and washing with pressure hoses.

As a result of this cleaning and new water treatment program, this manufacturer will save about $26,000 on water treatment chemicals and a projected $70,000 in energy costs because of cleaner heat transfer surfaces in the condenser tubes. Not included in the savings figure is the 2.5 million gallons of water that is also saved, resulting from increased cycles of concentration within the cooling towers.

Operator's Checklist for Water Treatment Systems Maintenance

As has been stressed, water treatment is a highly specialized, highly individual process and, as such, should only be undertaken with the advice and help of outside water service companies or consultants. Such organizations are in a position to analyze the water used in a boiler at several different stages, make recommendations for additives or treatment and, in many cases, provide a monitoring service to be sure the proper chemical balance is maintained.   ∎

Chapter 3: Combustion

Efficient fuel burning (combustion) requires attention to the entire combustion apparatus. Since some of the problem areas are common to all types of combustion systems, those areas will be discussed before reviewing specific system problems.

Air Infiltration

Excess air is defined as the air supplied to the burner beyond the air required to theoretically assure complete combustion. Excess air infiltration interferes with the efficiency of the fuel-burning process. Excess air can find its way into the furnace, the steam generating section, or through the burner or stoker. Any test to determine if there is excessive air leakage should be performed when there is a planned maintenance session.

An easy way to check for leakage is by starting the furnace draft and system and applying a small flame, such as a wooden match or fireplace butane lighter, to the suspected leakage areas. The flame will be drawn towards the furnace where there is leakage. A more thorough way is to pressurize the furnace with a smoke bomb. Any leakage will then be readily apparent. Leakage is more likely on older tube and tile-constructed furnaces, although welded wall furnaces can leak air at seal areas, such as corner seams. Sealing the furnace at these potential leak sites will allow operating at lower excess air conditions and improve efficiency.

Air infiltration in the steam generating section back to the induced draft fan is a less serious intrusion. It can reduce the usefulness of oxygen analyzers which are reading the infiltrated air and can affect draft fan capacity. This may restrict maximum steam production from the boiler. The best way to prevent air infiltration is to look for air leaks and seal them.

Air infiltration can also occur at the seals between the burner or stoker and the furnace. Here again, the lighted match, butane lighter or candle flame will be drawn towards the area of the leak. Any apparent leakages should be repaired.

Warped or cracked access doors which do not seal properly should be replaced. A view port

sight glass that is cracked or missing should also be replaced. Leaks located in ductwork should be patched, especially when upstream of an air heater or economizer.

As always, the combustion equipment manufacturer's instructions for proper maintenance should be followed. In general, leak checking should be done anytime O_2 levels or flue gas volumes increase, or exhaust temperatures decrease.

Combustion Air Temperature

Another common area that affects all types of combustion equipment is combustion air temperature. It can have a dramatic effect on boiler efficiency. Changes in combustion air temperature directly affect the amount of combustion air supplied to the boiler and may increase or decrease the excess level.

High excess air levels mean additional energy losses, increased stack temperatures and reduced boiler efficiency. Low excess air levels may result in incomplete combustion, sooting and wasted fuel.

To minimize this loss, well-designed burners are set up to operate efficiently at 15% excess air. This varies with boiler design and fuel. Unfortunately, this does not stay at a fixed level. Seasonal changes in temperature can cause the excess air levels to change, as can changes in the boiler setting, burners that are out of service and tramp air infiltration. The table below (Table 3-1) shows the effect changes in temperatures can have on excess air levels.

Air Temperature, °F	Resulting Excess Air, %	
40	25.5	
50	20.2	
80	15.0	Initial Setting
100	9.6	
120	1.1	

Table 3-1. Effects of Air Properties.

As can be seen, a decrease of 30° Fahrenheit in the combustion air temperature changes the

excess air level by 5% while a 40° Fahrenheit change will change the level by 10%.

Normal burner-monitoring procedures can often detect potential combustion-related problems. Changes in flame shape, color and sound are often early indicators. An outside air temperature increase or drop will most certainly affect combustion air temperatures. A combustion analyzer should be used to confirm actual combustion performance, although the use of an 02 analyzer can produce satisfactory measurements. An oxygen trim system, not generally found on older industrial boilers, can also help maintain the highest efficiency level.

Fuel and Air Linkages

Changes in the fuel and air linkage settings can also affect boiler efficiency by changing the fuel-to-air ratio. These changes can also act on excess air levels. As emphasized earlier, since the linkages are mechanical, the correct settings should be physically marked or pinned together and become a part of regular system monitoring, checking for position, tightness and operation.

Types of Combustion Systems and Their Particular Requirements

Gas Burner Systems

Gas burner systems consist of a gas metering device, burner nozzles, an air delivery and metering system and a flame ignition and management system. If nitrogen oxide (NOx) control is part of the system, there may be staged combustion, low NOx burner adjustments or flue gas recirculation.

As with everything in the combustion system, proper maintenance and operation of each of these systems is essential to an efficient and safe combustion process. Here are some specific items relative to gas burner systems that should receive routine attention:

- Boilers with multiple burners should have the burner use patterns set for maximum efficiency where load conditions do not require the use of all burners at all times. Again, consider seasonal outside temperatures in setting these patterns.
- The operation of the gas modulating control valve should be checked to make sure it is responding to signals from the controls.

- Nozzle gas pressure should be correct.
- The operation of the air control damper should be checked to make sure it's responding properly to signals from the controls.
- The fuel/air ratio should be adjusted for the most efficient operation for the type of load the boiler carries. Settings may be different for base-loaded (fixed setting) boilers as opposed to a boiler that follows load swings from a heating or process load. Boilers having swinging loads might not be able to operate at as low an excess air setting as a base-loaded boiler.
- The burner management system should be maintained for peak performance, in accordance with manufacturer recommendations. Flame detection devices should be adjusted to allow minimum excess air operation safely.
- Burners with NOx controls should have the dampers for staged combustion or flue gas recirculation free and adjusted to follow the signals from the controls. The rest of the NOx and burner controls should be adjusted for maximum NOx control at maximum efficiency and minimum carbon dioxide or volatile organic compound production.
- Gas pressure is critical to proper burner operation and efficient combustion. Irregular pressure may cause fuel-rich combustion, high carbon dioxide (CO) levels and soot buildup that might reduce boiler efficiency. Gas pressure problems can originate from fluctuations in gas supply pressure, the boiler regulator or a dirty or defective gas pressure regulator.

Oil Burner Systems

Oil burner systems consist of an oil metering valve system, burner nozzles, an air delivery and metering system and a flame ignition and management system. As in gas burner systems, if nitrogen oxide (NOx) control is part of the combustion system, there may be staged combustion or low NOx burner adjustments. Proper maintenance and operation in accordance with manufacturer recommendations is essential to an efficient and safe combustion process. Here are some specific items relative to oil-burning systems that should receive routine attention:

- As with a gas burner system, boilers with multiple burners should have the burner use patterns set for maximum efficiency where load conditions do not require the use of all burners at all times. Consider seasonal outside temperatures in setting these patterns.
- Clean burner nozzles are essential to an efficient flame. Soot buildup is more likely with

Formation
$N_2 + O \rightarrow NO + N$ Propagation T > 2800°F
$O_2 + N \rightleftarrows NO + O$ Propagation T > 2800°F
$NO + (C \text{ or } H) \rightarrow N2 + O (C \text{ or } H)$
All are time-temperature dependent

Control	
Fuel Selection	Nitrogen Content
Furnace Sizing	Furnace Temperature
Burner Selection	Combustion Temperature
Low Excess Air Firing	Oxygen Availability
Two-Stage Firing	Furnace Temperature
Off Stoichiometric Firing	Furnace Temperature
Flue Gas Recirculation	Reverse Reactions

Table 3-2. NOx Formation & Control

an oil burner. Any deterioration in flame characteristics is an indication that the nozzles should be cleaned.

–   Units firing heavy oil must be monitored for flame variation and the correct oil temperature maintained. Changes in oil temperature are usually a result of a dirty heat exchanger or a misadjusted or defective temperature control. Consult with pump and heater manufacturers for correct recommendations.
–   Oil recirculation systems should operate freely. Any decrease in outside air temperature or the oil temperature itself should call for a system inspection.
–   Oil pumps and pressure control valves should be monitored and deliver the oil to the burner nozzles at the correct pressures. A pressure check should be performed at least daily.

Changes in pressure directly affect the ability of the oil to properly atomize and burn completely. The consequences include fuel-rich combustion, sooting and oil buildup in the furnace, factors that could reduce boiler efficiency and increase operating costs. Oil pressure irregularities can be caused by a worn pump, faulty relief valve, dirty strainer, or a change in movement in mechanical linkage or pressure-regulating valve set point.

Oil combustion requires an atomizing medium, which is usually air or steam. Changes in the pressure of this medium can also cause sooting, which will eventually lead to a loss in boiler efficiency. The cause of this pressure loss can usually be traced to a regulator or air compressor problem or a dirty oil nozzle.

Coal Combustion Systems

Conventional coal combustion systems are pulverized coal (PC) and are one of three stoker types:

–   Overfeed spreader stokers.
–   Overfeed mass burn stokers.
–   Underfeed stokers.

Bubbling bed fluidized combustion and circulating bed fluidized combustion systems have unique and specialized maintenance procedures and for that reason will not be discussed in this manual.

Pulverized Coal Systems

Similarities exist in PC combustion systems and gas or oil-fired systems components. PC systems contain a fuel delivery system, considerably more complicated than gas or oil-burning systems, an air control system, an ignition system which might be gas or oil-fired and a flame management system. Many of the maintenance procedures recommended for gas and oil systems are the same for PC-fired systems. There are several differences, however:

PC systems have coal feeders which are generally gravimetric to measure the rate of coal fed to the pulverizers. The correct functioning of these coal feeders is absolutely essential to efficient and safe operation. Feeders are mechanical devices having a weighing system and a conveyor system. Some of the devices in the coal feeder system need to be maintained for most efficient combustion. For example:

–   The feeder system needs to be checked routinely to be sure it is accurately following the signals from the combustion control system.
–   Air seals need also to be periodically checked for leaks.
–   All mechanical linkages and bearing surfaces also need periodic checking.

A good pulverizer maintenance program is critical. Coal sizing as well as proper air temperatures to the pulverizer must be maintained to manufacturer's recommendations. Here, too, air seals need to be checked for leaks. The fineness generated by the pulverizing process is directly related to burner efficiency.

Boilers may have NOx controls, such as low NOx burners, overfire air-staged combustion, flue gas recirculation or burner out-of-service procedures. The control of these devices should
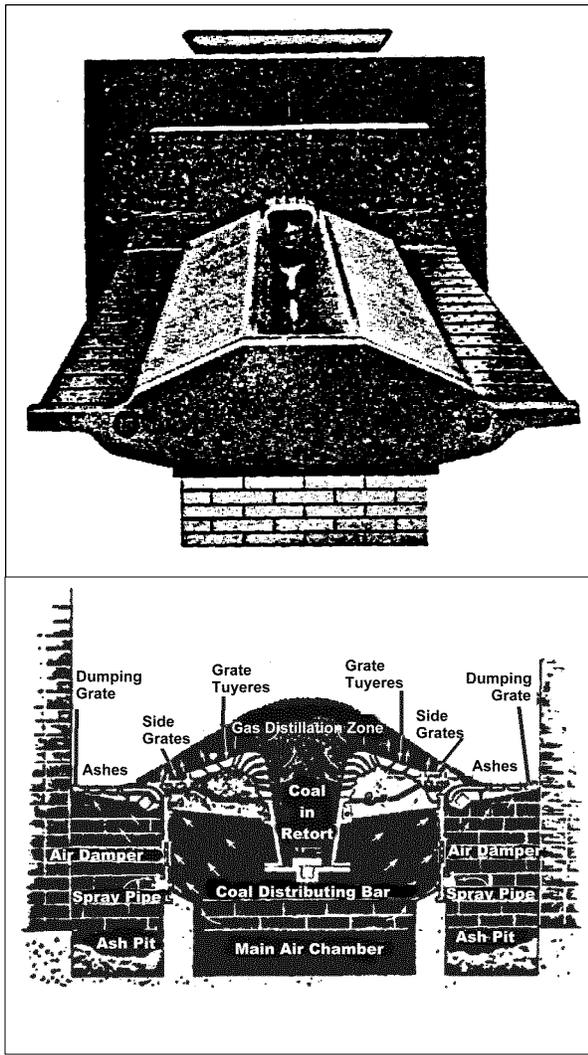
Figure 3-1. Underfeed stoker.

be maintained in relation to the burner combustion control for maximum efficiency in relation to the desired NOx control. Manufacturer's recommended procedures should be followed.

Stoker Systems

One of the principal differences in stoker types is the coal delivery system—overfeed spreader, overfeed mass burn, or underfeed. Each stoker type in turn has three elements which must be controlled. These are:

- Fuel feed.
- Forced draft air control.
- Overfire air control.

Overfeed Spreader Stokers
Spreader stokers might also have an overfire air system designed for staged combustion for NOx

control. They also have multiple feeders for delivering coal to the furnace. Each feeder needs to be adjusted and that adjustment monitored so that even fuel distribution is maintained over the entire grate surface. This makes combustion most effective and evenly distributed over the entire plan area of the furnace. Here are some items that need to be routinely checked:

- The metering devices of the coal feeders should be adjusted to assure that each feeder is delivering the same amount of coal. The fuel feed controller for all the feeders can be either mechanical or electric. The metering device should be checked periodically to be sure it is following the signal from the combustion controls.
- Grate speed controls the depth of ash coming off the end of the grate. The ash depth should be controlled to provide a protective ash cover for the grates without forming clinkers or slag on the grates.
- The forced draft air supply through the grates should be controlled so that the air supply flows evenly through the entire grate surface. To do this, the forced draft damper should be able to move freely and closely follow the signals from the combustion controls. Manual and automatic air dampers should be adjusted for the most efficient combustion while maintaining minimum flame opacity. All spreader stokers have overfire air systems for the control of opacity and efficient combustion. Systems with overfire air systems for the control of NOx are more complicated to control. Overfire air adjustments affect NOx, excess air and opacity. Combinations of settings will produce desired results. If necessary, the manufacturer can assist.

Overfeed Mass Burn Stokers
The overfeed mass-fired stoker burns coal progressively as it moves through the furnace on the grate. Coal is fed out of a hopper at one end of the furnace onto the grate and moves through the furnace, discharging ashes at the rear of the grate. Multiple air zones under the grate control the rate of combustion while the fuel feed gate controls the depth of coal as it passes into the furnace. Since these systems are usually manually operated, they should be adjusted for maximum performance and checked periodically for proper operation. Grate speed is controlled by the fuel feed control, which can be either a mechanical or electrical device. The speed should correctly follow the signal from the control.

The air flow to all the combustion air zones is controlled by the main forced draft fan damper, which is usually manually operated. Adjustment to
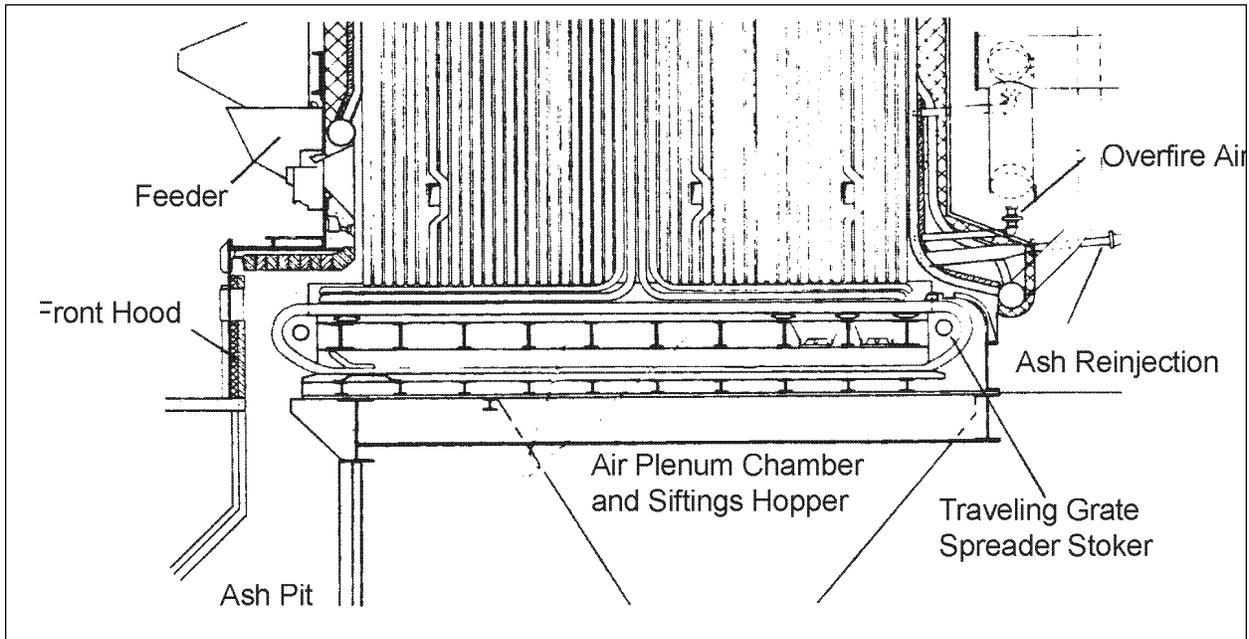
Figure 3-2. Spreader stoker.
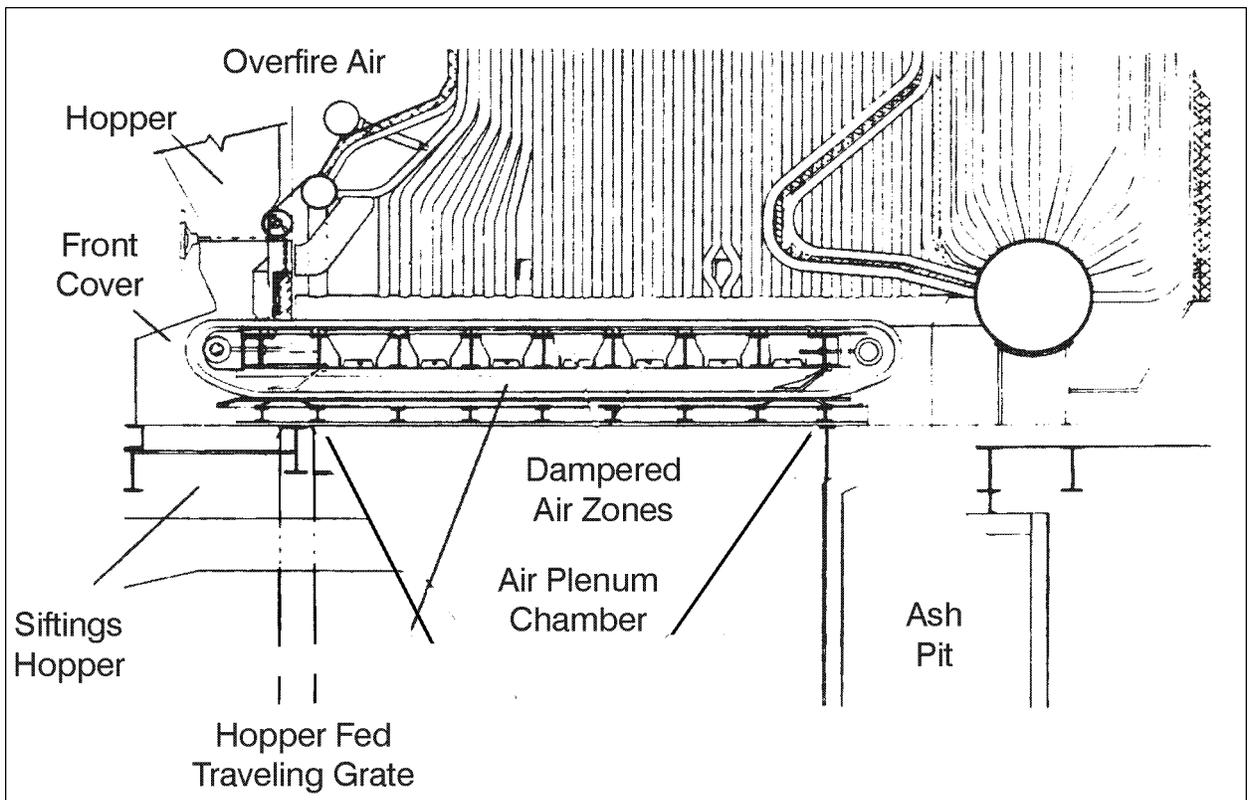
Figure 3-3. Mass-feed stoker.

the damper should be set for minimum opacity over the load range and monitored periodically. Overfire air systems are used to control opacity and efficient combustion. Overfire air systems are located in the front wall of the furnace over the fuel feed gate.

Underfeed Stokers

An underfeed stoker has rams or screw feeders which deliver the coal to the furnace. As in the overfeed stoker, air is sent through the grates by one or more zones, usually manually controlled. Both of

these functions need to be checked a minimum of once per shift under steady state conditions to make sure each is correctly following the signal from the combustion controls. If conditions are changing (wet fuel, for example), more frequent checking may be requires. Underfeed stokers may also have a small overfire air system to control opacity.

Unburned Carbon in Conventional Coal Burning Systems

Another potential problem is that of unburned carbon losses. This is solid fuel that is injected into the furnace but not burned. It is discharged from the furnace with the bottom ash and fly ash. To minimize carbon loss:

- Insure that the fuel preparation system, including crushers, pulverizers and hoggers, is working properly. This includes checking to be sure there is not an excessive amount of oversize pieces. It may also mean that fuel samples be taken and checked for particle size distribution. Manufacturer's specifications for correct particle size should be closely followed.
- On spreader stokers, check to make sure that fuel distribution in the furnace is even.
- Observe the burner for any unusual flame patterns.

- Take periodic ash samples and check for unburned carbon. Sudden changes in unburned carbon may be an indication of a problem starting in the fuel handling of firing equipment. If this is observed, control instrument calibration should be checked and verified. If necessary an authorized service representative may need to be called to investigate the problem.

Other Fuels Fired in Solid Fuel Systems

Some other fuels that are burned today include wood waste, bagasse (leftover plant material) from sugar cane processing or the waste from grape harvest processing, petroleum coke, biomass and municipal waste. Either stoker or fluidized bed combustion technologies may be used, depending on the fuel being burned, when full load is desired without auxiliary fuel firing. Or, these fuels might be burned as a partial load, with the main load being handled by gas, oil or coal.

Whatever combination of combustion processes is chosen depends on fuel properties. Wood waste is very high in volatile matter (indicating a fast burning time), compared to carbon and might be high in moisture. Petroleum coke is very high in carbon compared to the volatile matter.

Operator's Checklist for Combustion Systems Efficiency and Maintenance

General System Checkpoints

Air Infiltration
- Check for air leaks. Using a butane fireplace lighter is more convenient and safer than wooden matches. Be sure and check welded seams on the furnace.
- Also check for air infiltration at the stoker and the steam generator.
- The boiler's performance efficiency should be measured. Follow owner's procedures.
- Check combustion air temperature. Factor in seasonal outside air temperature.
- Check fuel and air mechanical linkages for wear and out-of-adjustment settings.

All of the above inspections should be performed periodically under steady state conditions. The equipment manufacturer can provide a suggested schedule. Changing conditions, such as wet fuel, might require more frequent checking.

Gas Burner System Checklist

- Multiple burner systems should be adjusted to maximum efficiency where load conditions don't require all of them. Seasonal changes, production shifts and time-of-day requirements should all be considered.
- Check the gas modulating control valve for sensitivity to signals from the burner controls.
- Check nozzle gas pressure. Monitor gas supply source for correct pressure range.
- Check the air control damper for sensitivity to signals from the burner controls.
- Check the fuel/air ratio.
- Monitor the burner management system for correct settings.
- Be sure systems with NOx controls have the dampers checked for proper operation.

All of the above inspections should be performed periodically under steady state conditions. The equipment manufacturer can provide a suggested schedule. Changing conditions might require more frequent checking. ∎

Chapter 4: Boilers

This chapter discusses the maximization of boiler efficiency regardless of the method of firing. Where applicable, specific techniques for particular types of combustion will be highlighted.

Boiler Efficiency

Since most stoker-fired boilers are between 65% and 85% efficient, ways should be sought to reduce the resulting 15%-35% waste energy. Some of this waste is unavoidable, but some of it can be recovered, if it is understood how the waste is generated.

"Heat Loss" is the terminology used to describe used to describe wasted energy. In Figure 4.1, one can see where heat losses occur in stoker-boilers. Other fossil fuel firing systems have similar losses.

It is helpful to understand how boiler efficiency is determined by the measurement of heat losses.

Conservation of Energy

One of the laws of physics is that energy is always conserved. In combustion, chemical energy is being converted to thermal energy, but nothing is lost. For instance, if one added up the energy in the steam, the energy in the flue gas, the energy radiated from the boiler and all the other forms of energy leaving the boiler, they will exactly equal the energy in the coal, oil or gas burned. In a simple formula it would look like this:

Energy in Coal, Oil or Gas=Energy in Steam+Energy in Heat Losses

Boiler efficiency is the percentage of the coal, oil or gas energy which is converted to steam energy. The heat-loss method is the most accurate way of determining boiler efficiency. To do this, one simply measures the individual heat losses (expressed as a percent of heat input) and subtract them from 100% (representing the fact that energy is never lost). Once again, a simple formula will show:

Boiler Efficiency=100% - Heat Losses
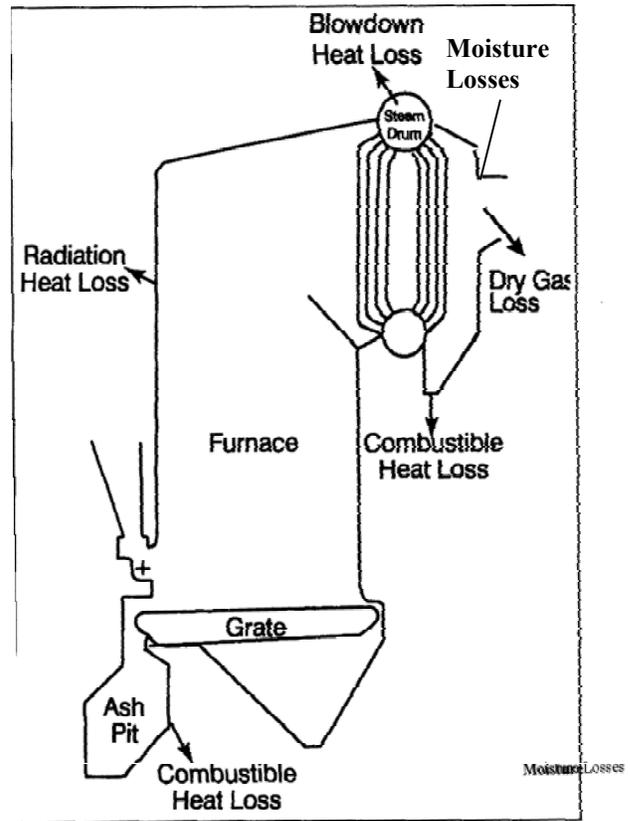
Figure 4-1. Heat loss sources in a stoker-boiler.

Heat Loss Sources

Stack Gas

The biggest energy loss in a conventional fossil fuel-fired boiler goes "up the chimney"; that is, out the stack. The loss could amount to as much as 30-35% of the fuel input in the worst cases. This stack gas heat loss consists of three different ways:

- Heat loss due to dry gas
- Heat loss due to moisture in the fuel
- Heat loss due to water from the combustion of hydrogen

The size of the heat loss depends on the temperature and the volume of gas leaving the boiler, therefore, reducing either one of these will reduce the heat loss.

Some stack gas heat loss is unavoidable, but to

eliminate this loss altogether, the stack gas temperature would have to be reduced to the air temperature around the boiler. Practically speaking, this is impossible.

The practical gas flue temperature limit is about 300 degrees Fahrenheit. This can vary, depending on the fuel used. Lower temperatures makes the small amount of sulphuric acid vapor in the gas condense on cold metal surfaces and cause severe corrosion.

The three basic strategies for minimizing stack gas heat loss are:

- Minimizing excess air
- Keeping heat transfer surfaces clean
- Adding flue gas heat recovery equipment where justified;
- Controlling air infiltration

With reduced excess air, stack gas volume is also reduced. Stack gas temperature is also reduced because gas velocities are reduced, allowing the gas to spend more time inside the boiler where the heat can be absorbed. The economics are attractive. As a rule of thumb, boiler efficiency can be increased one percent for each 15 percent reduction in excess air; 1.3 percent reduction in oxygen content or 40 degree Fahrenheit reduction of stack gas temperature. See Chapter 3, *Combustion*, for tips on how to reduce furnace excess air.

Keeping heat transfer surfaces clean on the water side is largely a matter of water treatment management. Ash deposits on water walls, (slagging), and on boiler tubes (fouling) and scale deposits on the waterside tube surfaces act as insulation, reducing heat absorbtion by the boiler water from the flue gas. Predictably, flue gas temperature is higher than it should be and boiler efficiency is lowered. Fouling and slagging are controlled by proper use of soot blowers, overfire air and excess air. Scale deposits are controlled by feedwater treatment and proper use of blowdown. See Chapter 2, *Water Treatment* for more information on water treatment and the proper use of blowdown.

Combustible Heat Losses
This is the second largest source of heat loss in coal stokers and is caused by unburned fuel.

Sometimes it can exceed 5 percent of the coal's energy. It comes from three sources:

- Carbon in the bottom ash
- Carbon in the flyash
- Combustible gases in the flue gas (this can happen in oil and gas-fired units as well)

Carbon in the bottom ash comes from unburned coal being dumped in the ash pit. This can be controlled by proper adjustment of the stoker. On traveling and chain grate stokers this is done by properly adjusting the coal gate position, grate speed and the undergrate air flow. On spreader stokers the grate speed, undergrate air flow and coal feeders must be adjusted properly.

Unburned fuel in the bottom ash can be a significant loss of heat. The table below shows the results of tests on 18 stokers that had unburned carbon in their bottom ash:

Type	Lowest	Highest	Average
Spreader Stokers	0.0%	3.4%	0.9%
Overfeed Stokers	0.4%	8.1%	2.4%
Underfeed Stokers	1.2%	3.9%	3.2%

Carbon in the flyash comes from small coal particles that have not been burned. They could be blown off the grate or, in the case of spreader stokers, small particles caught up in the gas flow before they land on the grate. This as also called flycarbon, carbon carryover or combustibles in the flyash. The primary remedy is assure that there is adequate combustion air. One way is to increase the overfire air. Reducing the excess air may also work. Coal with fewer fines or less ash may also help. Flyash reinjection from a mechanical dust collector will reduce this heat loss as long as there is a high efficiency particulate removal system before the stack.

Here are test results of 18 stokers with heat losses due to carbon in the flyash:

Type	Lowest	Highest	Average
Spreader Stokers	0.5%	9.2%	4.4%
Overfeed Stokers	0.3%	1.1%	0.5%
Underfeed Stokers	0.1%	0.2%	0.1%

Proper control of coal finenessss and excess air in pulverized coal-fired systems will minimize losses.

The most common combustible gas that often enters the flue gas unburned is carbon monoxide. It forms when excess air is too low in some area of the grate, or when the flame strikes a cold water wall. If the coal is evenly distributed on the grate, and if the undergrate air and overfire air are properly adjusted, this heat loss can be minimized. A carbon monoxide concentration of below 400ppm (0.04%) should be the goal. This represents about a .0.5% heat loss. Modern spreader stoker and pulverized coal fired boilers operate at lower carbon monoxide levels. See Chapter 3, *Combustion*, for more information.

Radiation Heat

A portion of the heat from combustion escapes from the walls of the furnace without being absorbed by the boiler water. Some of this is unavoidable. Heat loss from this occurrence is controlled through proper insulation techniques and the maintenance of insulation layers. See Chapter 10, *Steam Systems*, for more information on what to look for in maintenance of insulation.

A properly insulated boiler has radiation heat losses at full load, as shown in the table below. Use these numbers as guidelines. Note that larger boilers lose a smaller fraction of their heat through radiation.

Boiler Size	Radiation Heat Loss
200,000 lbs. Steam/hr	.5%
100,000 lbs. Steam/hr	.7%
50,000 lbs. Steam/hr	.9%
20,000 lbs. Steam/hr	1.0%

Blowdown

Other heat losses occur but they are usually quite small. One exception is blowdown. Some blowdown is necessary to get rid of dissolved solids in the boiler water. Because those solids have absorbed heat, blowdown is a heat loss. As referenced earlier, a continuous blowdown heat recovery device, available for boilers that generate as low as 500lbs steam/hour, can reduce this heat loss. See Appendix B, *Savings Possible Through Heat Recovery on Continuous Blowdown* and Appendix C, *Savings Possible with Improved Blowdown Control,* for typical savings from continuous blowdown. Also, see Chapter 2, *Water Treatment*, for more information on blowdown and water treatment.

Turbulators and Firetube Boilers

Turbulators can increase the heat treatment of the flue gas heat as it travels through the firetube. This is due to the additional movement through the tubes.

In the combustion process, the mixture of combustion air and fuel is designed to develop clean and stable combustion, using a tightly controlled turbulence. In the firing chamber, this is adequate to assure high heat transfer rates. As combustion ends and the flue gas products journey into the first pass of convection tubes, some additional turbulence is developed. By this time, however, the outer portion of the gas envelope has begun to cool, as it comes in contact with the cooler convection tube. This causes the gas envelope to lose its turbulence and develop a straight or parallel flow.

This phenomena is quite common in older, coal-fired boilers that were designed to only have the flue gases heat the water in two stages (known as two pass boilers). The addition of turbulators extracted more heat from the gases, allowing less of it to escape up the stack.

Turbulators are simply corkscrew-shaped pieces of metal that are inserted into the convection tubes. They can be made of flat steel, twisted into a spiral.

With the development of three and four-pass boilers, the need for turbulators has decreased. There are still a number of older two and three-pass boilers that could benefit from the installation of turbulators.

As mentioned at the beginning of this chapter, all of these heat losses taken together can add up to as much as 35 percent of the coal's, or for that matter, any fuel's energy. Significant savings are available for implementing a heat loss control program and properly operating the stoker-boiler at peak efficiency.

Operator's Checklist for Efficient Boiler Operation and Maintenance

General System Checkpoints

Undergrate Air Distribution
Undergrate air distribution must be properly distributed for peak burning efficiency. Be sure to replace worn, broken or warped grate sections. Also replace worn air seals which might allow undergrate air to short circuit the grate. Maintain seals around PC, gas or oil burner systems and maintain seals around PC coal feeders. Repair or replace undergrate air zone dampers which prevent proper control of the air distribution. Adjust or repair the coal feed mechanism if it does not distribute an even bed of coal to the grate. Be sure that PC coal feeders are accurately measuring coal delivery and that pulverizers are grinding the coal to proper fineness.

Air Infiltration
Air infiltration to the furnace must be minimized. Boiler economizer and air heater casings should be tight, with no air leaks. Leaks can be detected using the open flame technique described in Chapter 3, Combustion. Seals between the stoker and the boiler must also be tight. Replace missing sight glass in view ports. Patch leaks in ductwork, especially when upstream of an air heater or economizer.

Insulation
Much has been discussed about the importance of properly maintained insulation. Heat losses can be expensive without insulation. For instance, the heat loss from 100 feet of bare 2-inch pipe carrying saturated steam at 150 psig is equivalent to a fuel loss of one ton of coal every 12 days. An uninsulated 12 inch pipe at 250 psig would waste one ton of coal, 143 gallons of fuel oil, or 15,000 cubic feet of natural gas every 2 days.

Steam Leaks
Leaks are also expensive. Check pipe joints, flanges, valves and unions. And don't forget steam traps. See Chapter 10, Steam Systems, for a complete discussion of leaks and steam traps.

Soot Blowers
Check for proper operation. If ash deposits are allowed to accumulate on boiler tubes, some of the coal's heat will not be making steam and will lost in the stack gas. Just 1/8 inch of soot is equivalent to one inch of insulation.

Instrumentation and Controls
Pressure and draft gauges and temperature and flow indicators are the eyes of the operator into the stoker-boiler system. These should be regularly calibrated and serviced.

Properly functioning boiler system components and controls are required to maintain optimum firing operations. Check for proper movement of valves, excessive play in linkages, adequate instrument air pressure, regulators, unnecessary cycling of firing rate, and proper operation of all safety interlocks and boiler trip circuits.

These inspections should be performed a minimum of once per shift under steady state conditions; more often if conditions change during a given shift.

The Operator's Log
Maintaining a complete log of panel readouts and significant events gives the plant engineer or supervisor a complete picture of system efficiency as well as the ability to detect deterioration in stoker-boiler performance.

For example, if the stack gas temperature creeps upward with time, it may indicate a slagging or fouling problem, or a problem with excess air. Other trends may indicate other problem areas requiring attention.

Whatever the boiler size, the most important efficiency-related items to record are the steam flow or pressure, flue gas temperature and excess

Figure 4-2. Operator's log for twice-daily readings.

Figure 4-3. Operator's log for hourly readings.

air. Flue gas temperature can be measured by a stem thermometer or thermocouple. Excess air can be determined by an oxygen or carbon dioxide monitor. Both devices are highly recommended and will pay for themselves in energy savings very quickly. The stem thermometer or thermocouple should be installed after the last heat recovery device.

See Figures 4.2 and 4.3 for full-sized examples of an operator's log sheet; one for twice-daily entries, the other for hourly readings. They may be freely reproduced for operator usage.

Chapter 5: Controls

Since the 1950s, great strides have been made in boiler control technology, giving significant improvements to boiler operations and efficiency. Owners and managers have largely replaced the older pneumatic and analog electronic control systems with digital, computer-based distributed control systems (DCS) and, in the process, have also learned that the life of their boilers can be extended. This is because control strategies are now based on computer software changes, as opposed to the difficulties in making operation changes in the hardware-sensitive older systems.

Another advantage of software-controlled systems is their reliability. Computers of any type are inherently self-diagnostic, and the distribution of control modules which are computer-driven allows each module to check itself out on a predetermined frequency. Faults are easily isolated and corrective action is often automatic. In essence, the control system practically inspects itself.

Since their introduction in the late 1970s, computer-based control systems with ever-greater functionality have replaced the older systems on a continuous basis. One reason for this integration is the growing scarcity of parts and service people familiar with pneumatic and analog control systems. But there are a number of other reasons. Here's a comparison chart that shows why:

Centralized control pnuematic/analog	Computer-based distributed control (DCS)
– Constant recalibration required	– "Set and forget" software commands
– Changes require rewiring	– Changes made in software
– Hard to expand beyond initial configuration	– Easy, incremental expansion
– Difficult troubleshooting and repair	– Self-diagnostic, on-line, module swap-out
– Separate data acquisition required	– Integrated data acquisition functions
– Vulnerable, single point	– Failure tolerance through function partitioning or redundancy or both

Table 5.1. Comparison of centralized vs. distributed control systems.

Burner Controls

Gas/Oil Multiple Burner Systems

Boilers with multiple burners can benefit significantly from modern, microprocessor technology. Older systems measured fuel and air flow to the boiler, controlled fuel flow to satisfy the demand for boiler steam production, and controlled the combustion air dampers to maintain overall fuel/air ratio at its predetermined level. When one or more burners were idle, this ratio had to be maintained on a per/burner basis. Air leakage through the idle burners destroyed the maximum efficiency of the fuel/air ratio, making effective control impossible unless all burners were operating.

In a computer-based system, additional control logic can be added for a fraction of what it would cost to add the same control on an older system. Modern, multiple burner control, coupled with excess air trim control also using control logic can result in fuel savings of 3%-%.

A typical metered combustion control system monitored by computer and its input/output signals is shown in Figure 5-1. The metered combustion control system accepts a boiler demand signal from the Plant Master, the highest level controller in the automatic control system. The boiler demand signal can be altered by the operator through the Boiler Master Station, a regulating device located on the operator's control panel, by biasing the demand. The output of the Boiler Master is the firing rate, which is sent to the fuel and air controls and changed into a setpoint for fuel and air flow. The fuel setpoint is high-limited by the measured air flow limiting the fuel demand to the air available for combustion. The fuel demand is also low-limited for flame stability. The air flow setpoint is low-limited by fuel flow. The fuel limit prevents the demand for air from decreasing below the required level for safe combustion. The air flow setpoint is also low-limited to prevent the air from decreasing below the continuous purge requirement. This cross-limiting of the fuel and air controls is the approach recommended in National Fire Protection Association (NFPA) 85B and 85D.
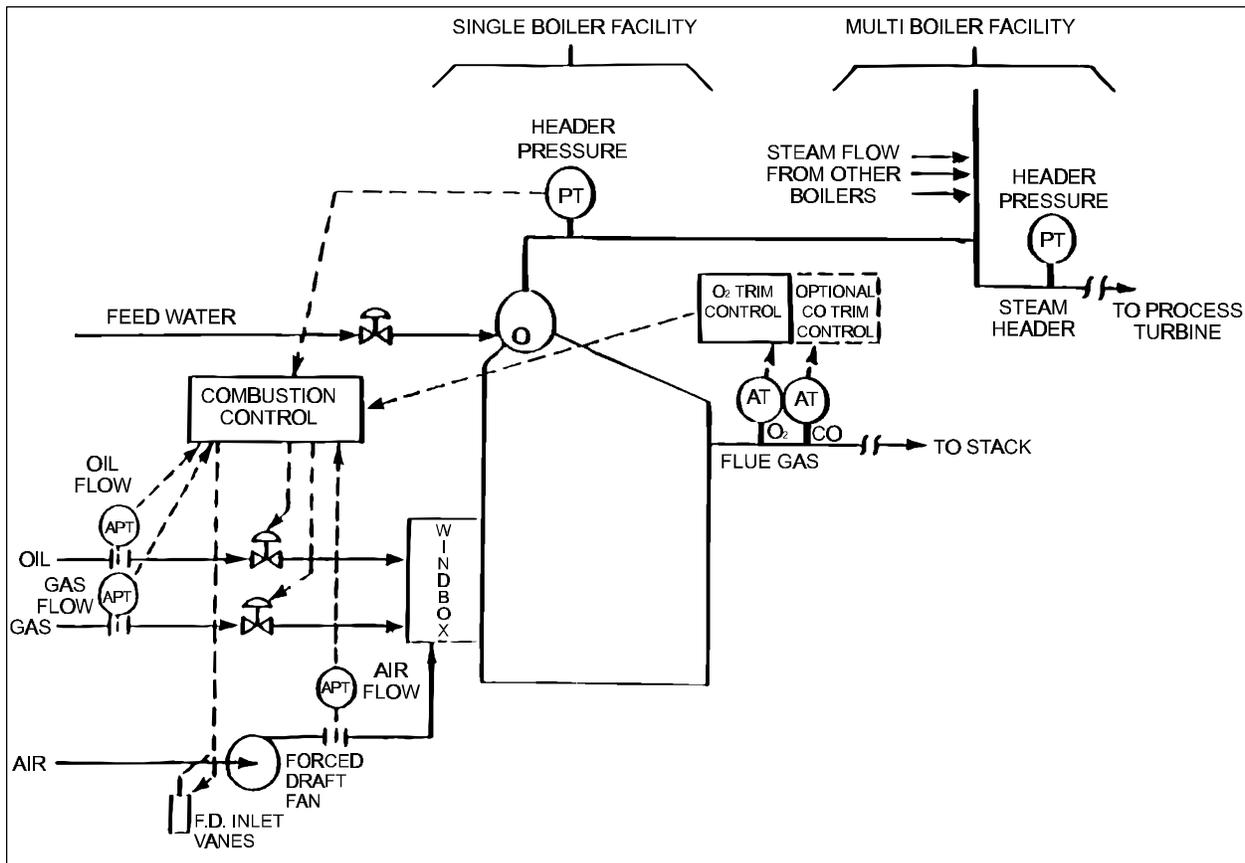
Figure 5-1. Typical computer-monitored metered combustion control system.

Cross-limiting permits a preset mismatch to exist (typically 5%) between the combustion air demand and the actual air flow. The technique improves boiler response to load changes over classical cross-limiting techniques which use a gain of 1.0 on the cross-limiting signals.

If the cross-limiting constraint for available air is satisfied, the fuel demand is sent directly to the fuel valve through the fuel minimum limit. A function generator, which equates input signal to the characteristic of the device being controlled, permits linearization of the fuel demand with the fuel flow. The fuel demand is compared to the measured fuel flow to correct the demand to the fuel control valve. This combination of feed-forward and feedback control gives stable, fast and accurate control of fuel flow.

Oxygen Control Loop

Boiler efficiency improves by incorporating an excess air trim control loop. Limiting excess air reduces heat loss up the stack and ensures complete combustion. The excess air trim signal adjusts the fuel-to-air ratio continuously. Most burners require more excess air at low loads than

at high loads because at low loads there are lower flame temperatures and less effective fuel-to-air mixing. With a DCS, the excess air controller can adjust the oxygen setpoint continuously as a function of boiler load. The measured oxygen in the flue gas is compared to this setpoint and the air flow is adjusted accordingly.

At times it may be necessary to operate with a different excess air level than the one programmed into the DCS. For example, the introduction of wet, solid fuel may change the excess air level.

This is done by biasing the setpoint program in the controller. The trim station can also allow manual adjustment of the air flow during calibration checks and routine maintenance on the oxygen analyzer. For safety, the trim station cannot override the air flow minimum nor the fuel-to-air cross-limits built into the metered combustion control logic, either in the automatic or manual modes.

Carbon Monoxide Trim Control Loop

If the combustion air is reduced too far, inefficient boiler operation occurs because of incom-
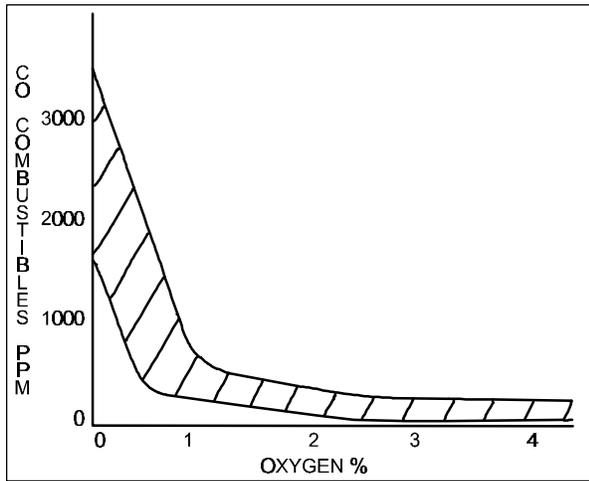
Figure 5-2. Carbon monoxide content compared to a preset point.

plete combustion. Steam is produced at lowest cost when the combustion air is just enough to burn all the fuel. A carbon monoxide trim loop, in conjunction with the oxygen trim loop, performs this task. The carbon monoxide (combustibles) controller compares the carbon monoxide content in the flue gas to a preset fixed setpoint. This is shown graphically as a point just above the dog-leg in Figure 5-2.

This is the most efficient operating point for the boiler. The carbon monoxide controller will bias the oxygen setpoint to control the carbon monoxide to this value. Normally, this controller should only have to make minor adjustments to the oxygen setpoint program. Should the burner, boiler or oxygen deteriorate, the controller will have to make larger adjustments. Under these circumstances, the controller activates an alarm.

Interlocks

Another advantage that a DCS has over older systems is the ability to configure interlocks into the control program to make sure the integrity of the overall combustion is not violated. For example, interlocks can insure the combustion controls are placed in the automatic mode in the proper sequence. This will prevent operator error and maximize automatic operation when a sensor failure is detected.

Burner Management Interface (BMS)

In a DCS, an interface to an automatic burner management system is installed, as defined in National Fire Protection Association (NFPA) Standard 8501. Flame safety sequencing can be

incorporated in the DCS, using the same type of hardware, eliminating the need for separate systems. The BMS oversees safe start-up and shutdown of the boiler and eliminates nuisance boiler trips.

BMS sends these commands to the combustion control system:

1. **Set to Purge Position:** This command forces the combustion air station to the purge position. Upon completion of the purge, the station will go to a minimum if in automatic, or hold if in manual.
2. **Set to Light-Off Position:** This command, sent to the combustion control system, forces the fuel and air control stations to their light-off positions. When the command is removed, the stations can be released to automatic.
3. **Number of Oil/Gas Burners On:** These commands allow the combustion control to select which oxygen setpoint to use. They are also used to trim the demand to the oil or gas flow control valves.

The BMS also receives a "trip burner" command from the combustion control system if any of the following conditions exist:

- Controller power is lost
- Fuel at a minimum and fuel cross-limited
- Burner management commands are inconsistent

Spreader Stoker Applications

In coal-fed furnaces, particularly those with spreader stoker feeders, special design problems need consideration. Air flow control strategy is directed towards efficient operation of the boiler but requires attention to three particular areas:

- Variations in overfire to underfire air ratios
- Variations in excess air to control clinkering
- Effects on opacity from dusting (too much air) and smoking (too little air)

In the minimal control strategy, fuel and air are controlled in parallel. The operator observes the fire, the stack and the ash falling off the grate to adjust the fuel-to-air ratio for maximum efficiency and minimum pollution by stack emissions. In a basic control strategy, the boiler demand is sent in parallel to the stoker feed, overfire air and the forced draft (FD) fan. However, unlike the minimal control strategy, measured fuel flow, overfire air flow and

combustion or total air flow are used to trim the parallel demands. Because actual fuel flow cannot be measured, it is derived from pressure-compensated steam flow that is a steady-state inferential measurement of heat released from the fuel. The result is a fast, responsive system that is the characteristic of a parallel system but with the accuracy of a metered fuel system.

Overfire air damper, FD fan and induced draft (ID) fan demands all use two element control strategies. With overfire air damper, boiler demand positions the damper directly and is trimmed by he duct pressure controller. The operator can bias demand to account for changes in coal quality and sizing. Air flow, as measured by an orifice, venturi or anubar in the air flow duct, is used by the feedback controller to adjust the FD damper demand set by boiler demand.

The operator reduces clinker formation by applying biases provided to adjust air flow. By using FD fan demand as a feedforward to initially set ID fan demand, continuous operation of the ID and FD fans during process upsets and load changes is possible. It is then trimmed by the furnace draft controller to position ID fan motor or inlet dampers. Ideally, the controls should be operated as close to atmospheric pressure as possible to reduce air infiltration and improve efficiency.

Oxygen or opacity measurements can be implemented in the control strategies to further improve boiler efficiency. Using oxygen measurement lets the fuel-to-air ratio to be maintained within practical high and low oxygen limits. As noted earlier, the operator-adjustable oxygen set point helps reduce clinkers.

Opacity monitoring can warn of impending operational problems; a high reading could indicate inadequate air for combustion, too much air, rapid air increases or sootblowing. As discussed earlier, the advanced control strategies will gracefully degrade to basic automatic control levels when the gas analyzers are out of service.

Target Steam Flow Plant Master

The Plant Master generates a steam flow demand for each boiler that feeds a common steam header. The total demand to the boilers must match the plant demand for steam in order to maintain steam header pressure. The predominate plant master algorithm used in DCS is the target steam flow plant master. It gives a faster response to load changes than either a single or two element plant master and is best suited for use where loads move rapidly and/or tight pressure control is critical.

Disadvantages of Single and Double Element Plant Masters

A single element Plant Master controls demand to the boilers based on the error between steam header pressure and set point. As a result, this type of Plant Master:

- Overcompensates to changes in process steam demand
- May require different tuning parameters over the operating range of the system
- Could create operational inefficiencies and thermal stress to the boiler due to steam pressure oscillations.

The two element Plant Master uses steam flow as a feedforward signal to the header pressure error. The biggest problem associated with this type of Plant Master is the tendency for over-correction in changes in both steam flow and header pressure, giving conflicting responses to changes in header pressure and steam flow. For example, header pressure will drop due to a decrease in BTU content of the fuel. The pressure controller reacts to increase boiler demand. However, the decreased header pressure results in decreased steam flow. The feedforward index acts to decrease boiler demand. Oscillations in boiler demand then occur until the system can stabilize.

By contrast, the target steam flow Plant Master gives stable steam header pressure by adjusting the firing rate of all operating boilers and adapts to varying boiler availability without operator adjustment. The control action is adapted, depending on which of the boilers are available to respond to changes in steam demand and automatically compensates for transient energy effects. This combination of functions provides stable and precise control of steam header pressure with minimal operator intervention.

Furnace Pressure (Induced Draft Damper) Control

Effective furnace pressure control improves boiler efficiency and inhibits boiler deterioration. Boiler load changes and combustion stability both affect furnace pressure. The furnace pressure control uses a feed-forward index and non-linear control response, giving fast and smooth furnace pressure control.

In a DCS, the furnace pressure control is part of the air flow control. The FD fan demand is characterized to program the ID inlet damper to a position approximating the desired furnace

draft as the boiler changes load. Such variables as exit temperature, boiler leakage and others are compensated by the furnace pressure control system, trimming the feed-forward demand with a furnace pressure feedback loop for accurate control of the furnace pressure.

Boiler Steam Temperature Control

Boiler outlet steam temperature impacts both steam users and the boiler itself. Poor steam temperature control can cause equipment degradation from thermal stress caused by temperature variations. The thermal efficiency of steam turbines depends on maintaining steam temperature at the design setpoint.

The response of steam temperature to changes in spray water flow is normally quite slow because of the time lag through the secondary superheater. However, air flow can be used as a feedforward index to program the control valve position as a function of load. Compensation for changes i heat absorption characteristics is done by comparing steam temperature to its setpoint. A controller then trims the valve program to control steam to its setpoint. Since most boilers do not make rated temperatures at low loads, the control logic has an algorithm to keep the control system properly aligned until the boiler increases the level where control is possible.

Supervisory Monitoring and Control Strategies

Another feature with the DCS is its ability to provide supervisory functions. Using it for control and monitoring purposes has many advantages over the typical distributed/central computer control scheme. For example, communication in a DCS does not "bog down" with information overload. In addition, network failure does not shut down the system. Only data logging, archival storage and operator display is sent on the shared data highway. All process variable information is used only down at the distributed levels. If the shared highway fails, supervisory control is still available to local controls because, as previously noted, efficiency and steam cost calculations are done at the distributed level. Distributed/central computer systems must send all process variable information on the shared data highway, making it vulnerable to supervisory control failure if the network fails.

Another advantage of a DCS is that no one failure can bring down the system. Each supervisory control function resides in a dedicated microprocessor module. A single module failure means loss of that module's supervisory function only. By contrast, failure of the CPU in distributed/central computer systems causes failure of all supervisory functions. Thus, this allowance for distribution of risk is perhaps the most important advantage of the DCS.

Performance Assessment

A system to measure boiler performance should be included in the implementation of an industrial power plant control system. Besides monitoring equipment performance, plant operations personnel can measure the effects of the integrated plant control approach. An effective performance assessment system will show accurate equipment performance which, when delivered as needed, gives safe, reliable and economical operation of the facility. Employing preventive maintenance systems that detect poor performance maximizes plant efficiency and extends boiler life. Real-time monitoring and assessment of vital operating data lets operations personnel make timely and informed decisions.

On-line performance assessment (actual performance) is superior to deterministic performance (calculated performance) packages because the calculated performance of each piece of equipment can be compared directly with the expected performance under similar operating conditions. Thus, true changes in plant equipment performance are easily noted. Calculations are performed in accordance with American Society of Mechanical Engineers (ASME) Power Test Code for each device. Typical performance equations include:

- Gas Turbine Performance Calculations (ASME PTC 22)
    - Thermal efficiency
    - Power output
    - Gas turbine specific fuel consumption
    - Gas turbine heat rate

- Heat Recovery Steam Generator (HRSG) Performance Calculations (ASME PTC 4.4-1981)
    - Duct burner fuel consumption
    - HRSG efficiency, input-output method
    - HRSG efficiency, thermal loss method
    - HRSG overall effectiveness
    - HRSG pinch point

- Steam Turbine Performance Calculations (ASME PTC 6)
    - Steam flow and enthalpy to condenser
    - Steam turbine heat rate
    - High Pressure isentropic efficiency
    - Intermediate Pressure isentropic efficiency
    - Low Pressure isentropic efficiency

- Turbine Cycle Equations (ASME 6.1)

- Boiler Efficiency Calculations (ASME 4.1)

- Feedwater Heater Performance Equations

- Condenser Performance Calculations (ASME PTC 12.1-1983)
    - Condenser pressure (vacuum)
    - Overall thermal transmittance
    - Condensate subcooling
    - Cleanliness factor with respect to design overall transmittance
    - Condenser cooling duty
    - Fouling resistance

- Cooling Tower Performance Calculations
    - Cold water temperature
    - Approach
    - Range

- Overall Plant Performance Calculations
    - Plant power factor
    - Gross plant power output
    - Net plant power output
    - Plant total fuel consumption
    - Gross/net plant heat rate
    - Gross/net plant efficiency
    - Thermal use

As noted earlier, output displays give both actual and expected performance information. Expected values are derived from equipment manufacturer design curves. These are displayed with actual performance curves, allowing for comparison and analysis of equipment performance. Similarly, equivalent loss in heat rate; the difference between actual and expected values is also computed and displayed. This loss can be further converted into an equivalent fuel cost to assist in the performance interpretation, allowing plant operations personnel to figure the overall cost of substandard equipment performance.

In summary, then, key features of a performance assessment package are:

- On-line performance computations

- Determination of expected plant performance
- Displaying results at operator's console

Three basic performance assessment displays help plant personnel interpret the data:

- Overall plant performance display
- Controllable parameters display
- Deterioration of plant components display.

Each group of displays is designed for a specific group of personnel. For example, plant management is interested in overall current plant performance relative to past plant performance whereas plant operators are concerned with monitoring controllable parameters, allowing the most efficient plant operation. Displays for plant engineers allow them to schedule plant maintenance when component deterioration shows a need.

Statistics are employed in performance assessment calculations, giving a confidence interval for each performance indicator. Not knowing the accuracy of a given computation can lead to inaccurate conclusions and subsequent faulty decisions on equipment maintenance and upgrades. It is therefore critical to provide quantitative indication of the accuracy of the result. Using the statistical approach gives more information to users in their decision as to whether the change in performance is from measurement error or actual equipment deterioration.

Boiler Load Allocation

Although boiler efficiency obtained from the performance assessment package is an index of boiler performance, it alone cannot improve overall plant performance. Plant configuration, operating techniques and the structure of the objective function all contribute to overall plant efficiency, in addition to combustion costs.

A plant consists of many subsystems, each using some resource that costs money. For example, pump drives consume steam energy and water treatment uses chemicals. Steam cost is the complete system's economic index but plant expenses are not necessarily minimized if load is allocated to maximize boiler efficiencies. Therefore, steam cost must be calculated to allocate for overall plant operations optimization. Boiler steam cost functions are developed on-line and updated continuously. Temporary abnormal events are filtered out to prevent distortion of results. In general, steam cost can be written as shown in Equation 5-1 on the next page.

$$\text{Steam Energy Cost (\$/hr)} = \frac{\text{Fuel Cost x (Enthalpy of Steam Enthalpy of FW)} + \text{Cost of Auxiliaries}}{\text{(Fuel High Heating Value x Efficiency)}}$$

Equation 5-1. Computation of steam energy cost.

The four allocation methods used in industry today are:

- Equal Loading
- Base Loading
- Biased Equal Loading
- Optimal Allocation

Optimal Allocation is the preferred method because it minimizes total cost of energy generation. It is based on the Biased Equal Loading method that allows all plant units to participate in load swings, making it most responsive to load changes. The allocator operates as a supervisory control system to the basic, biased system.

Figure 5-3 describes the process of how the Optimal Allocation method directs the load demand. Here's how that's done: When considering optimal allocation between multiple boilers, they should be operated at incremental steam cost. If the boilers are operating with unequal incremental steam costs, the loads will be allocated through the boiler masters. The relationship among boiler efficiency, steam cost and incremental steam cost is shown in figure 5-3. The slope of the tangent to the steam cost v. load curve is the incremental steam cost. If the steam cost curve is modeled as a second order polynomial, then the incremental steam cost, that is the derivative of the steam cost v. load curve, is linear with respect to load, as is shown in figure 5-3.

As discussed earlier, the Optimal Allocator allows all boilers to swing with a load change. However, unlike the bias loading method that has preset biases, the optimal allocator adjusts biases to distribute load most efficiently as demand changes. For example, at a given demand, biases selected in bias equal loading may be economically desirable, but as demand changes, all boilers are permanently shifted. This may result in poor performance. Base loading of the most effi-
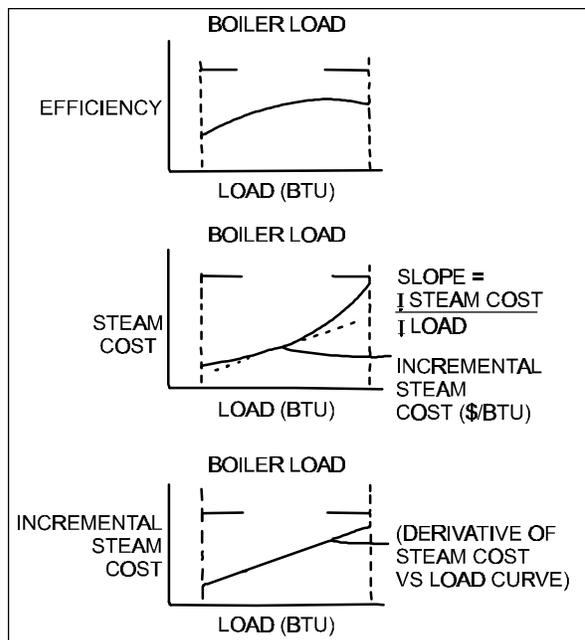
Figure 5-3. Relationship between boiler efficiency, steam cost, and incremental steam cost.

cient boilers may be economical at high loads, but at lower loads the same base loading might be quite costly.

The boiler load allocation problem is solved through nonlinear optimization techniques. From the nonlinear optimization results, it is determined the allocator must balance the incremental costs (change in steam cost/change in load) unless a limit is encountered, a boiler is on hand or a boiler is not selected for optimization. This is done when the allocator reduces load in the boiler with the greatest incremental cost and increases load in the boiler with the smallest incremental cost. By exchanging the load from a boiler where production is expensive to a boiler where it is less expensive, efficiency is maximized and costs reduced. ∎

Chapter 6: Heat Recovery

Heat recovery equipment includes various types of heat exchangers located where they can absorb heat from the combustion gases after the gases have passed through the superheater and steam generating sections of the boiler.

Economizers

Economizers help to improve boiler efficiency by extracting heat from the flue gases discharged from the final superheater section of a radiant/reheat unit or the evaporative bank of a non-reheat boiler. Heat is transferred to the feedwater, which enters at a much lower temperature than saturated steam.

Economizers are a series of horizontal tubular elements and can be characterized as bare tube and extended surface types. The bare tube usually includes varying sizes which can be arranged to form hairpin or multi-loop elements. Tubing forming the heating surface is generally made from low-carbon steel. Because steel is subject to corrosion in the presence of even low concentrations of oxygen, water must be practically 100 percent oxygen free. In central stations and other large plants it is common to use deaerators for oxygen removal. (See Chapter 2, *Water Treatment,* for further discussion on oxygen control and deaerators.)

Small, low-pressure boilers may have economizers made of cast iron, not as prone to corrosion. Applications of this kind are generally limited to pressures of 250 psig.

Economizer Erosion and Leaks

In coal-fired boilers, an accumulation of flyash particles will result in a certain amount of metal erosion on economizer tubes. Unit operation much above maximum continuous rating and design excess air also encourages the process of flyash erosion. Any reduction of flow area, such as localized flyash plugging will increase gas velocity and erosion potential by concentrating flyash in an area adjacent to the plugged area. A regular program of washing during out-of-service periods should be part of normal maintenance procedures.

Economizer tube ruptures require immediate attention. Delayed repairs can result in steam damaging adjacent tubes, turning a minor repair job into a major one. Economizer ruptures, left unattended, can also lead to plugging of the economizer and air heater from the water mixing with the flyash, a mixture that can set as hard as concrete.

Another precaution associated with economizer operation is the accumulation of steam in the economizer during the period when pressure is rising. During this period there is no feedwater flow through the economizer; nevertheless, even with the economizer's location in relatively low pressure zones, steam is generated and becomes trapped and remains so until feedwater flows through the economizer. This makes the control of steam-drum water level difficult and causes water hammer. This can be overcome by supplying feedwater constantly, venting the steam out of the economizer or by recirculating boiler water through the economizer. If a recirculating line is used, the valve in this line must be left open until feedwater is being fed continuously through the economizer to the boiler.

Air Heaters

Air heaters cool flue gases before they pass into the atmosphere, increasing fuel-firing efficiency and raising the temperature of the incoming air of combustion. In low pressure gas or oil-fired industrial boilers, air heaters function as gas coolers as there is no need to preheat the oil or gas in order for it to burn. Pulverized coal fired furnaces, however, require the use of air heaters or preheaters to evaporate the moisture in the coal before ignition can take place. This heated air also serves to transport the pulverized fuel to the furnace. Stoker fired boilers do not require preheated air until the moisture content of the coal exceeds 25 percent.

Corrosion is the biggest problem associated with keeping an air heater operating efficiently. Sulfur content of the fuel, moisture content of

the gases and type of firing all have a bearing on corrosion formation. While proper design can often deter or even prevent corrosion, certain maintenance techniques are often employed to keep air heaters operating efficiently. These include sootblowing and water washing.

Sootblowing

Some types of air heaters are furnished with sootblowing equipment. They use superheated steam or dry compressed air as the cleaning medium. Compressed air is favored over steam because of the lack of moisture, although care should be taken to install a proper line of traps and separators to remove any moisture from the air.

See Chapter 11, *Compressed Air Systems and Diesel Engine Power Cogeneration,* for a discussion on drying compressed air. Similar precautionary measures should be taken when using steam to ensure a medium that is as free of moisture as possible.

Water Washing

The use of water in removing residual deposits is effective in instances where sootblowing can't easily remove residual deposits that inhibit air flow through the air heater. Most deposits that form are water soluble and are easily removed, using high-penetration, stationary multi-nozzle devices. Adequate drainage should be provided.

Washing can be done on an out-of-service basis. On an in-service basis, isolated washing can be done where boiler load is reduced and the air heater to be washed is isolated from the boiler on line. It can also be performed as on-stream washing, only feasible where drains are located, to eliminate moisture from entering the dust collectors, precipitators, windboxes and the boiler itself.

Other Sources of Heat Recovery

See Chapter 11, *Compressed Air Systems and Diesel Engine Power Cogeneration,* for further sources of heat recovery. ∎

Chapter 7: Auxiliaries

In this chapter, we will cover a broad range of auxiliary equipment, including fans, boiler feedwater pumps, motors and turbines, electronic motor drives, materials handling equipment, and boiler sootblowers. We will also discuss cogeneration and the sale of excess electricity.

Fans

There are three types of induced draft (ID) and forced draft (FD) fans most commonly used in power plants; the backward-curved, also known as the airfoil; the straight blade and the radial tip. The most efficient is the airfoil; it has a 90% efficiency. Other advantages of the airfoil include: very stable operation, low noise level and the suitability for high-speed service.

Straight blade and radial tip fans are more subject to erosive conditions. As an example, straight blade fans are used mainly for pulverizer exhaust and radial tip fans for applications downstream from a low efficiency particulate removal system.

The desired air or gas flow and its pressure in a fan are determined by the employment of one of the following:

- Inlet damper control
- Inlet vane control
- Variable speed control

Dampers or vanes are used when the fan is coupled to a single or two-speed motor. Fan manufacturers usually favor vanes over dampers as they feel they are slightly more efficient due to the pre-swirl effect that vanes impart to the air or gas flow. A variable-speed drive, however, is the most efficient control. It provides only the power necessary to overcome system resistance at a given condition. It is particularly effective when operating conditions call for frequent low load periods. The diagram below illustrates the amount of power necessary at various speeds for a hypothetical centrifugal fan and system resistance.

Fan Maintenance Checkpoints

1. Fans and their housings need to be checked periodically for dirt and dust buildup. An ac-cumulation of dirt or dust can decrease the efficiency of the fan by slowly changing its configuration and adding weight to the fan. This inspection should be done at least twice yearly, more frequently if the fans are located in a high-dust environment (pulverizers, conveyor belts, etc.)

2. Fan bearings should be checked for wear and adequate lubrication. Clearance between the fan and its housing should also be checked.

Boiler Feedwater Pumps

Boiler feedwater pumps function as the delivery system to the boiler, providing water under pressure to the boiler. They do this by taking suction from a deaerating feedwater heater and pumping the feedwater into the boilers through high pressure feedwater heaters. There are numerous methods available to control feedwater volume and provide sufficient suction head to the pumps.

One way to control volume is to use a variable speed drive motor with the boiler feed pump. Another way is to use an electric motor running at a constant speed, coupled to a variable speed hydraulic drive. Where the expense of a variable speed drive is not justified or desirable, volume can be controlled by a throttling valve installed between the pump and the boiler. A decision depends on whether the capital expense of a variable speed drive is offset by a savings in electrical power. A feedwater control valve requires a large drop in pressure for proper operation; therefore the pump must have added head capacity.

In this type of operation, the condensate in the deaerator will be saturated, requiring the deaerator to be elevated as far as possible above the boiler feedwater pump to provide sufficient net positive suction head (NPSH) for the pump. This elevation may require additional structural and piping costs which can be offset by the installation of booster pumps that provide the additional suction head for the boiler feedwater pumps.

A minimum of two feedwater pumps are usually installed, depending on the need to maintain ca-

pacity in the event of pump failure. This also allows pump deactivation to perform normal maintenance, such as replacing the bearing seals, packing or repairing the electric motor driving the pump.

Recirculation of the feedwater back to the deaerator is necessary when a single speed motor is used and flow is at or below the pump's minimum flow. Steam turbines are often used to drive feedwater pumps because the speed of the turbine and pump can be varied like a variable speed motor. An automatic recirculation control valve or a modulated control valve controlled by the operation's distributed control system can perform this function. Pumps should be in a recirculation mode as little as possible to maximize energy savings.

Motors and Turbines

Electric induction motors or steam-driven turbines can be used to drive fans, pumps or other industrial process machinery. Picking one or the other depends on the availability of steam versus the cost of electricity. If high pressure steam is available and there is a need for low pressure steam, a turbine can serve as a pressure reduction station while driving the fan or pump. If there is no need for low pressure steam, a condensing steam turbine could be used, although turbines of this size are not efficient. If electricity is being generated on-site, it is usually more efficient to use electric motors.

Motors are available today that are known as "premium efficiency." They are more expensive, but the efficiency is more than offset by the cost. With electricity costs typically at $0.065/kwh and higher, the payback analysis justifies the extra expense. Here are some typical motor efficiencies available today from "premium efficiency" motor manufacturers:

HP Size	Efficiency
5-10	85%
15-40	90%
50-150	94%
200 or greater	95%

Motors should be checked on a regular basis for excessive vibration, bearing wear and adequate lubrication in accordance with manufacturer's recommendation.

It is common to find motors installed that are oversized for the task they are required to perform. These motors represent another excessive energy consumption area. Some surveys have shown as many as 60% of all motors in industrial facilities to be oversized.

Electronic Motor Drives

A promising area for saving energy and reducing maintenance is the marrying of energy-efficient electric motors to the latest generation of electronic motor drives. These drives can make motors more productive by controlling starting, stopping, speed regulation, reversing and even positioning.

The new drives offer protective features for the motor. They can control high inrush current and its subsequent voltage sag on the power distribution grid. Other features can limit current and shut down overloads that can allow a motor to self-destruct. Electronic motor drives can also minimize motor burnout, a potential fire hazard.

Most importantly, these new drives save energy. For example, varying a pump's speed rather than throttling the output flow can save 25-40 percent of the electricity consumed. Putting a motor on standby rather than allowing it to continue running when it's not needed can also save energy. A typical motor can consume 10-20 times its cost per year; the payback period for installing drives is often under two years.

It is estimated that less than 3 percent of all installed AC motors have electronic drives. Other estimates indicate that at least a quarter of all AC motors could benefit from the use of drives. Other factors that make the use of electronic drives attractive include declining prices, better accuracy and reliability, the discovery of new applications and increased user acceptance.

Another advantage of electronic drives is their easy setup and adjustment. These functions are done through an operator keypad or interface device. Since the settings are entered digitally, they are very accurate and not subject to drifting. Older analog drives were set by electromechanical potentiometers, similar to older radio controls. These were subject to dust and dirt contamination and often requiring frequent calibration and readjustment.

Today's electronic drives have a much larger tolerance of line voltage fluctuation, thanks to the integration of an electronic technique known as pulse width modulation. The older power-switching devices, silicone-controlled rectifiers, had tolerances as low as 5-10 percent; with the newer systems, tolerances start at 10 percent and can go up to as high as 30 percent.

Materials Handling Equipment

Solid fuel-fired power plants need systems to receive, store and deliver fuel and to collect, store and remove ash. This can include furnaces designed to burn coal, wood, food processing wastes and municipal and industrial processed refuse. The size and complexity of these systems vary widely but all of them require energy to operate.

Fuel Handling Systems

Pneumatic systems are available for certain requirements but most fuel-handing systems are mechanical, using belt or drag conveyors. They are very efficient on the basis of tons per kW. Energy-saving options for conveyors are few; however, some of the equipment installed as part of the conveyor system might deserve a second look.

For example, a major power consumer in a coal handling system can be a crusher, used to size coal. Power can be saved, in some cases, by changing to a different crusher or installing a bypass which separates properly sized particles from the crusher. Some installations require that the crusher need only be used intermittently. A change in the coal supply could cause a crusher to be taken out of service. Dusty areas of the system containing electrical equipment need to be monitored and kept clean to minimize power draw.

Fugitive dust collection systems on coal conveyors should be maintained in the same way as other dust collectors. These usually have bag filters and the cleaning cycles should be adjusted to minimize draft loss and reduce fan power consumption.

Pneumatic fuel-handling systems of both the lean and dense phase kinds are used by a number of plants. They usually consume more power than mechanical types on a kW per ton basis. Good maintenance procedures can conserve power in these systems. In some cases the system can be redesigned to eliminate changes in direction, significantly reducing line loss. Longer term solutions might include replacing the pneumatic system altogether.

Ash Handling Systems

Although ash handling systems move lower tonnage of material than fuel handling systems, they often consume far more power than necessary because of their design and mode of operation. The most common types move ash by inducing a vacuum on the piping system, using a steam exhauster or motor-driven blower. Water exhausters have been used for flyash conveying from large pulverized coal fired units.

Systems with capacities in excess of 15 or so tons- per-hour tend to use vacuum blowers where smaller systems have historically used steam exhausters. Water pollution and efficiency problems with steam exhausters have caused many of these systems to be converted to motor-driven blowers, a move that almost always reduces power consumption.

If the decision is made to retain the vacuum system, the maintenance of the piping is essential for efficient operation. An active leak detection program is essential as leaks will cause loss of conveying capacity, increase running time and maintenance of the pipe, fittings and air cleaning equipment as well as consuming more energy. See Chapter 11, *Compressed Air Systems and Diesel Engine Power Cogeneration,* for more discussion on leak detection. If steam exhausters are used, it is important to maintain the steam nozzles and venturi sections to maintain efficiency.

Pneumatic ash systems are most often run intermittently, pulling ash on a batch basis. Power consumption can be reduced by maximizing the conveying rate of the system. If the system is manually operated, the operator should feed the intakes at the highest obtainable rate. System controls should be optimized to minimize the non-conveying cycle times.

In the case of continuous pull systems, often found on dust hoppers in the gas cleaning train, controls should be set to avoid pulling on empty hoppers.

Larger industrial coal-burning installations may find a conversion to a mechanical system practical. Power consumption is far less but this would have to be weighed against the capital cost of a new system.

Ash systems serving biomass-fired boilers generally use mechanical systems. Finally, hydraulic ash systems are rarely used because of high power consumption and water usage. These systems can be converted to mechanical or pneumatic to solve probable water cleanup problems and potentially reduce power use depending on the type of replacement system selected.

Boiler Sootblowers

Efficient heat transfer is one of the major contributors to an energy-efficient boiler system. One of the most important boiler auxiliary op-
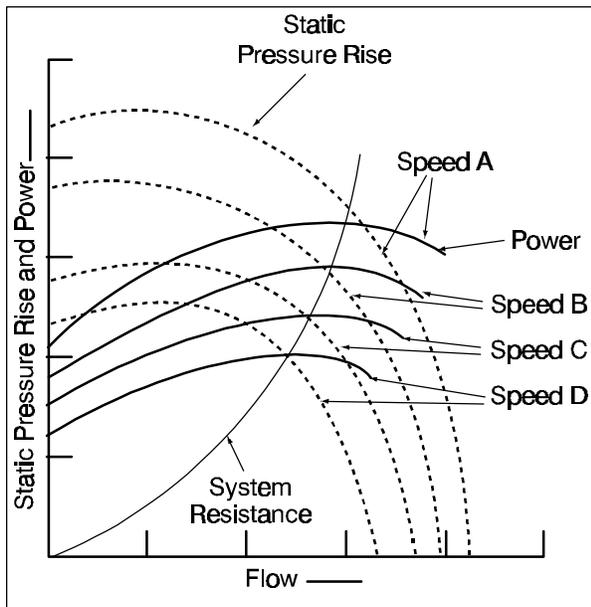
Figure 7-1. Static pressure rise and power versus air flow.

Generation and cogeneration operation and benefits comparison

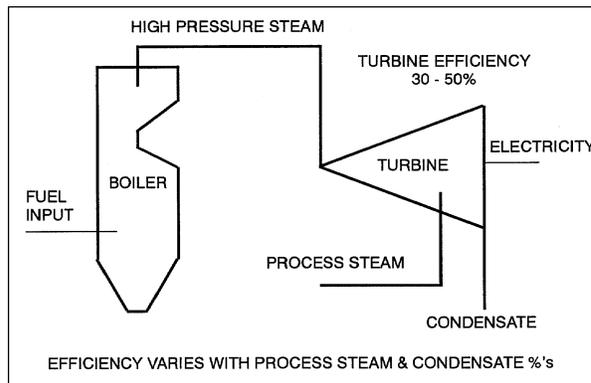**Figure 7-2.** Industrial steam-electric cogeneration, system thermal efficiency 80 to 90%.

erations is the on-line, in-service fireside cleaning of heat absorbing surfaces. This operation performs two important functions; it assures proper heat transfer and also prevents sections of the boiler from becoming plugged. Plugged sections can restrict gas flow and cause load limitations.

Sootblowing systems are required on coal and oil-fired furnaces. Because oil has a low ash content and the residue is a thin, water-soluble substance, it's removal is done by water-washing the furnace walls during the annual shutdown. For this reason, furnace-wall sootblowers are not required on oil-fired units.

In the superheater and reheater sections of oil-fired units, there is ash buildup on the tubing surfaces. High-vanadium content oils, containing additives to combat high-temperature corrosion, are especially prone to this. But when solid-powder additives are employed, ash deposits in the high-gas-temperature areas increase markedly. Fortunately, these deposits crumble and pulverize easily and are readily removed with sootblowers.

Coal-fired units require large numbers of permanently installed sootblowing equipment. Factors such as ash-fusion temperatures and the percentage of ash in the coal determine just what sootblowing coverage is required.

Superheated steam or compressed air is the medium used to remove deposits, employing a short, single-nozzle retractable blower and cleaning a surface with a five-foot radius. The effective

blowing frequency depends on slag buildup, but a normal range would be 4-8 hours.

Superheater, reheater and economizer sections of the boiler are cleaned with long, retractable lances which are most effective at cleaning radiant and convective heat surfaces. Effective cleaning radius, using a helical blowing pattern from two nozzles, is 4 to 9 feet.

Sootblower Operation

Since deposits in the radiant and convection sections of the boiler can vary from hard slag to a dry powdery coating, the blowing sequence is not set by a hard and fast rule. Sequence and frequency, instead, must be adjusted during initial operation by starting with an assumed sequence and frequency of perhaps one complete cycle per 8-hour shift. The operator should observe fouling patterns either through observation doors (during operation) or by gas-side inspection during shutdowns. Necessary adjustments can then be made. Once the pattern is established it can be implemented and run automatically.

Cogeneration

Cogeneration combines the production of electrical and thermal energy for eating and process use from a single act of combustion. It uses less total fuel than needed to produce the two forms separately. Cogeneration represents a major step towards maximum energy efficiency and also contributes to reduced pollution.

For example, in most cases, a company generates its own steam and purchases electric power
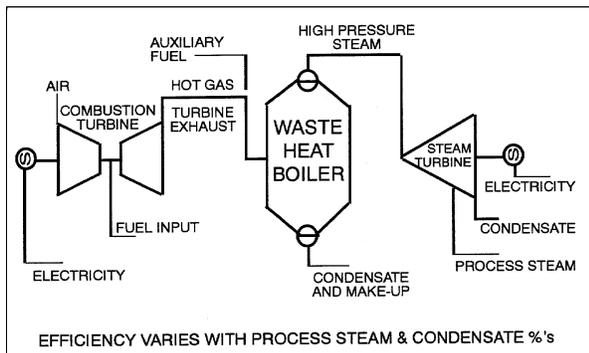
Generation and cogeneration operation and benefit comparison

EFFICIENCY VARIES WITH PROCESS STEAM & CONDENSATE %'s

Figure 7-3. Industrial combination turbine combined cycle cogeneration, system thermal efficiency 80 to 90%.

Separate Steam & Electric Cogeneration
Overall Thermal Efficiency of Both Systems 60 to 70%

EFFICIENCY VARIES WITH PROCESS STEAM & CONDENSATE %'s

Industrial Steam-Electric Cogeneration
System Thermal Efficiency 80 to 90%

EFFICIENCY VARIES WITH PROCESS STEAM & CONDENSATE %'s

Figure 7-4. Generation and cogeneration operation and benefits comparisons. Above: Separate steam and electric cogeneration. Below: Combined industrial steam and electric cogeneration.

from the local utility. The typical industrial steam generation steam-electric cycle has a thermal efficiency of 75-85 percent, whereas the utility cycle has a thermal efficiency of only about 35 percent. The net thermal efficiency of this system, depending on the relative amount of steam and electricity required could be in the range of 66 to 80 percent.

In a typical industrial steam turbine cogeneration cycle, however, high pressure steam first produces electric power and then is used for process needs. Because such a facility can attain an overall efficiency of up to 88 percent the savings in fuel use can be as high as 15-20 percent. Fuel used can be gas, oil, coal, wood, municipal solid waste or industrial wastes.

In a gas turbine combined-cycle cogeneration facility, after generating electricity, the hot exhaust from the gas combustion turbine-generator is used to make steam. The steam can be used for electric power, process needs or space heating. Overall thermal efficiencies could be as high as 90 percent. This compares to a maximum fuel efficiency to produce the steam and power separately of 58 percent when a combustion turbine is used. Fuel is usually limited to natural gas or oil.

Cogeneration plants are either topping or bottoming systems. A topping system has the steam producing electric power first and all or a part of the exhausted thermal energy is then used in industrial processes or for space heating or cooling. Bottoming systems use the waste heat from industrial processes or other high-

temperature processes to generate electricity by generating steam in a waste heat (heat recovery) boiler.

Sale of Excess Electricity

A further economic consideration for Cogeneration is the ability to sell excess power generated to the local utility. Federal regulations, intended to encourage cogeneration, compel the utility to purchase a cogenerator's excess power at a price determined by the utilities (called "avoided cost") or cost of power displaced by the cogenerator's output.   ■

Chapter 8: Energy Auditing

Here is a summary of many of the energy-saving tips that are discussed in depth in one or more of the other chapters. Where appropriate, those chapters are referenced.

Steam Systems (Chapter 10)

- Maintain excess oxygen below 5%; below 8% for stokers.
- Reduce stack temperature to 330 degrees for sulfur-bearing fuels.
- Minimize combustibles in stack gas and ash.
- Control oil tank temperature at minimum.
- Use fuel flow/air flow control with oxygen trim.
- Reduce deaerator vent to < .1% water flow or < .5% steam flow.
- Keep steam pressure and temperature at maximum if system has turbines.
- Lower steam header pressure if there are no turbines.
- Burn non-hazardous wastes in boilers or vaporizers.
- Automate boiler blowdown.
- Minimize use of stabilizing fuel if it is expensive.
- Split range control of fans if they are variable speed.
- Install blowdown heat exchanger.
- Optimize load-sharing between boilers or vaporizers.
- Check the flue gas ductwork for air in leakage.
- Check boiler/vaporizer efficiency regularly.
- Check turbine and condenser performance regularly.
- Keep tube surfaces free from scale.
- Install smaller turbine nozzles.
- Optimize the sootblowing schedule.
- Use the utilized cost method of determining the cost of coal.
- Set discharge pressure at minimum on turbine boiler feed pumps.
- Check feedwater heaters for efficient heat transfer.
- Use clean effluent water for ash sluicing

Steam Utilization (Chapter 10)

- Eliminate or find a use for vented steam.
- If turbine exhaust must be vented, vent it to the atmosphere.
- Drive turbines with let-down steam to minimize the use of PRVs.
- Ensure bypass valves around PRVs are not leaking.
- Return all condensate to feedwater system.
- Stop steam leaks.
- Isolate unused steam lines.
- Establish an effective steam trap maintenance program.
- Reduce failed traps to < 5% of total.
- Keep all steam and condensate lines properly insulated.
- Adjust steam header pressures to maximize turbine work.
- Install jet compressor to make low steam useful.
- Shift users to lowest pressure header to maximize turbine work.
- Close turbine hand valves or install pneumatic operators.
- Recover waste heat wherever possible.
- Optimize steam balance with the right combination of motors and turbines.
- Install condensate flash tanks to recover low pressure steam.
- Replace steam vacuum jets with mechanical vacuum pumps.
- Be sure vacuum jets have the correct nozzle size.
- Operate the minimum number of vacuum jets.
- Be sure vacuum jets have the correct steam supply and exhaust.
- Reduce pressure of heating steam during warmer weather.

Cooling Towers (Chapter 13)

- Correct defects to achieve design approach to wetbulbs.
- Run minimum number of pumps.

- Throttle flow in plant to get >10 degree Fahrenheit delta T across the tower.
- Select fan speed for ambient conditions.
- Install adjustable pitch fan blades.
- Maintain correct cycle of concentration.
- Maintain tower equipment to run at design conditions.

Compressed Air (Chapter 11)

- KW/100 SCFM (Kilowatts per 100 Standard Cubic Feet per Minute) should be <19 for 100PSI and <24 for 160 PSI.
- Operate minimum number of compressors for the load.
- Keep antisurge valves closed.
- Control antisurge valves with flow rather than pressure.
- Base load centrifugals and carry swings (types of air compressors) on reciprocal compressors.
- Reduce the system pressure to the minimum necessary.
- Use IGV (governor valve) for control of centrifugal compressor discharge pressure.
- Monitor stage temperatures and pressures to detect problems.
- Eliminate air trap leakage.
- Replace "heatless" air dryers with heated ones.
- Use booster compressor for small high pressure loads.
- Do not use compressed air for cleaning or agitation.
- Check compressor discharge temperature to detect valve or piston leaks.
- Keep air intake filters clean.
- Cool air intake where possible.
- Recover heat from aftercoolers.

- Repair air leaks.
- Eliminate discharge throttle valves.
- Use low pressure blowers instead of compressed air.
- Shut off compressed air to equipment that is down.
- Monitor compressed air use to detect abnormal changes.

Fans (Chapter 7)

- Use variable speed drives.
- Reduce speed with sheave change to minimum damper throttling.
- Control output with IGV to reduce throttling loss.
- Install ductwork to give minimum static pressure loss.
- Minimize duct leakage.
- Keep fan belts from slipping

Pumps

- Reduce system pressure to minimum needed by the users.
- Trim impellers to avoid throttling loss.
- Connect plant HXs (heat exchangers) in series to reduce cooling water flow.
- Use booster pumps for small high pressure flow.
- Operate the minimum number of pumps for the load.
- Maintain pumps to produce design deadhead discharge pressure.
- Substitute gravity flow where possible.
- Change impellers when seasonal pressure requirements vary widely.
- Maintain packing at proper leadage rate.   ∎

Chapter 9: Flue Gas Treatment

Treating flue gas minimizes or eliminates both the environmentally unacceptable nitrogen oxide (NOx) and sulfur dioxide (SO2) emissions as well as the collecting of un-burned solid particles before they escape into the atmosphere. Both techniques involve a number of steps.

NOx Reduction Techniques

Fuel Selection

Control of NOx pollutants begins with the proper fuel selection. A coal with a sufficiently low fuel nitrogen (less than 1.5%) as shown in a routine fuel analysis may eliminate the need for any NOx reduction techniques. Natural gas has no nitrogen in the fuel; fuel oil typically has a lower nitrogen content than coal. Coal reactivity may also be decreased to slow down combustion and decrease temperatures to minimize NOx production. Lower flame temperatures will result in a lower level of NOx production in oil and gas-fired systems. Boiler systems that have highly turbulent flames and high temperature furnaces usually need lower fuel nitrogen than is normally available in the required quantities. Reduction techniques would then be needed.

Furnace Sizing

This step is only practical if a new facility is planned. By increasing the furnace cooling sur-face, the high temperature and time aspects of NOx production can be reduced. Another benefit is the increased flexibility in coal purchasing es-pecially in specifications and price.

Burner Selection

Selecting a burner relative to furnace size limits the oxygen availability to form NOx while simul-taneously shaping the flame to minimize the 2800 degree residency time. This permits the use of moderate and low-nitrogen coal and meeting NOx emission regulations. This method gener-ally produces good results.

Low Excess Air Combustion

This technique also limits the availability of oxy-gen and increases the efficiency of a high-turbulence burner. There is little change in the 2800-degree residency time and only fair results can be expected. Also, when this technique is used, a fairly complex series of controls must be installed to maintain the best combustion. Coal ash problems may also arise due to the reduced oxygen levels.

Two-Stage Firing

This technique also limits oxygen availability by adding excess oxygen, needed for complete com-bustion, through overfire air ports. The rate of combustion is lessened and the 2800 degree resi-dency time is decreased. It produces good results with moderate-to-high fuel nitrogen coals. There is the possibility of decreased carbon burnout and furnace heat absorption and an increase in fireside deposits and potential corrosion.

Off-Stoichiometric Firing

This method also limits oxygen availability and flame temperature but for different levels of burners on large units. It is fairly successful and easily applied to existing units. As in the two-stage firing technique, there can be carbon loss and increased slagging.

Flue Gas Recirculation

This method takes advantage of the reaction that tends to drive fuel nitrogen towards N2 in the presence of NO. With NO present, there is a ten-dency to minimize the formation of thermal NOx by driving the reaction toward the more stable N2. This is a "last resort" technique when regulations must be met with high-nitrogen coal. It is the most effective method but it is the most expensive and difficult to install. Combustion control equipment and operating requirements with fans, ductwork and air balancing increase the complexity and can create problems.

Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR)

There are two types of SNCR control technologies for retrofit to industrial boilers; one uses ammonia as the reducing agent; the other urea.

They reduce NOx in the flue gas to molecular hydrogen at high temperatures between 1600 and 2000 degrees Fahrenheit without a catalyst. With a catalyst the conversion takes place at a much lower temperature range, roughly 575-800 degrees Fahrenheit. This is called SCR. Typically these agents are injected in the post-combustion region.

Because of the significant load variations in industrial boilers which cause the optimum temperature zone to shift location in the boiler, the application and effectiveness of this type of flue gas treatment is limited.

Solid Particle Removal

The removal of solid particles from the flue gas (also called particulate emissions) is an important part of the combustion process, as proper system selection and the maintenance of that system can significantly affect plant operating costs, as well as legislative compliance. These solid particles are basically the nonburnable elements in coal that leave the furnace and boiler after combustion.

There are a number of control techniques that can be applied, varying with the type of coal and combustion equipment installed (stoker, fluidized-bed or pulverized-coal firing):

Mechanical Collection

This is the oldest form of particulate collection. It extracts ash particles from the flue gas circular air current, which forces the particles to the outer portion of the current and downward into a storage hopper. It is typically found in stoker-fired boilers. Some spreader stoker fired boilers use mechanical collectors ahead of precipitators or baghouses for reinjection of the flycarbon and for an increase in overall collection efficiency.

Sidestream Separation

This is an additional technique applied to mechanical collection to improve collection efficiency. In operation, some 10-20% of the flue gas is removed from the bottom hopper of the collector and cleaned in a small baghouse. This can increase ash collection efficiency by up to 35-50%.

Electrostatic Precipitators

These devises operate on the principle that the ash particles can accept an electrical charge. Particles pass through an electrical field and are attracted to a vertical metal plate, where, periodically, they are shaken loose and collected in the collection hopper.

Baghouse Collectors

These systems, quite simply, work on the same principle as a household or industrial bag-type vacuum cleaner. The ash is removed in one of two ways; a reverse stream of air is blown through the bag during collection shutdown, which removes the ash coating and channels it into a collection hopper. The other method involves collection of the ash on the outside of the bag. A high-pressure pulse of air is periodically forced down through the bag, shaking the ash from the bag and into the ash hopper.

Wet Scrubbers

These devises cause the ash to be mixed with water droplets in a high-velocity air stream. The ash-laden droplets are then collected in a downstream scrubber demister section. Care must be taken in the disposal of the contaminated water, which will contain sulfuric and hydrochloric acid from the chemical combination of water and flyash. Also, additional care must be taken to assure the water is properly and completely removed from the flue gas. A wet scrubber has an advantage since additional heat is removed from the flue gas and can be recovered by exchangers for heating makeup water For comparison purposes, here are the cost differentiation factors between the various solid particulate collection systems, starting with the assumption that the mechanical collector is a factor of one:

Method Collector	Differentiation Factor
Mechanical Collector	1x
Sidestream Separator	2x (the cost of a mechanical one)
Baghouse	4x
Cold Electrostatic Precipitator	4x
Hot Electrostatic Precipitator	6x
Wet Scrubbers	3.5x

Sulfur Dioxide Removal and Control

All coal and oil contain some sulfur. As a result, there is bound to be some amount of sulfur dioxide generated in the combustion process. Just how its emission is minimized depends on a number of available techniques.

Coal Benefication

Using washed coal is considered the best alternative for meeting sulfur regulations. Factors such as transportation, availability and price need to be considered. This practice is not as common as it used to be, given the availability of lower-sulfur coal.

Wet Nonregenerative Scrubbers

These systems can operate in a "throwaway" mode, where the sulfur dioxide gas reacts with a chemical, such as limestone, and the combined compound is disposed of or sold for gypsum. With additional processing, the elemental sulfur can be separated and made available for sale. Solids and pH levels are continuously monitored from a slipstream takeoff.

Wet Regenerative System

These scrubbers substantially speed up the collection process. However, their effectiveness requires the use of expensive sodium hydroxide or sodium carbonate, which require recovery systems. A major benefit, however, is the lack of solids buildup, scaling, or critical pH control.

Dry Scrubbers

Here the flue gas is combined with chemicals in a water-based spray. The heat in the flue gas dries up the moisture, leaving a solid product, collectable in the baghouse. Critical elements in these systems include residence time in the chamber, flue gas temperature, which must be high enough to assure 100% moisture evaporation and adequate mixing of the chemical with the flue gas.　　　　■

Chapter 10: Steam Systems

Generating steam is the primary function of most boiler systems. In some industries, where 40-60 percent of all energy is consumed in the generation of steam in fired or wasteheat boilers, efficient operation and regular maintenance can represent a great potential in energy savings.

For instance, in the absence of an effective maintenance program, it's common to find 15 to 20 percent of steam traps not working properly. Another energy-waster is to allow steam leaks to persist, reducing steam production by as much as three to five percent. Insulation deterioration can cause another 5 to 10 percent steam loss during rain storms, as the insulation gets wet and loses its effectiveness. Fouled turbines and exchangers can cause as high as a 25 percent efficiency loss.

In a discussion on steam systems, many overlaps may occur when addressing maintenance and operation procedures. For example, Chapter 2, *Water Treatment,* discusses the addition of amines to keep the pH of the condensate high, avoiding acid attack. In this chapter, that subject is related to corrosion in steam traps, a specific problem area in steam systems.

Besides its use and subsequent availability in numerous industrial processes and also in generating electricity, steam is also employed to drive pumps and compressors as well as providing freeze protection for winter operations. Steam system operation is complex because of its generation, distribution, recovery and use at several different pressure levels.

There are five general "rules" that should be followed for maximum efficiency in steam generation. They are:

1. Always produce steam at the highest possible temperature and pressure. This is a basic thermodynamic and economic principle.
2. Always apply steam to process use at the lowest possible pressure and temperature levels.
3. In fired boilers, only produce steam for valid end uses, such as process steam and reboilers.
4. Always expand steam from a higher pressure level to a lower pressure level through the most efficient means possible.
5. Always produce maximum steam from process wasteheat recovery systems.

Proper steam system design will greatly increase operational efficiency. Poorly designed steam traps are the ones mot likely to function improperly or fail completely. Steam Tracing systems (a system designed to monitor steam temperature on a process pipe, for example), frequently evolve in a haphazard manner, often to solve a short-term problem, such as a steam trap that doesn't work. Leaks, freezing, steam system dead-ends and equipment damage can all be consequences of improper design. Heat loss can be avoided by proper insulation design and maintenance.

Because there are so many different potential problem areas to address, it is helpful segregate as many of them as possible in common groups.

General Operational Procedures

1. Process analyzers and advanced control techniques should be employed to minimize energy consumption of plants. Many plants use feed preheaters to supply heat for operation. Significant energy savings can be associated with system optimization. Specific operating control targets should be employed with energy conservation in mind.
2. Improperly operated vacuum systems can significantly increase steam usage. Any leaks that develop should be repaired.
3. Every operating area should have checklists and Standard Operating Instructions (SOIs) to ensure that unneeded steam traps and tracing systems are turned off as they can be a significant source of steam usage. Tracing systems are routinely left on year-round but are only needed during the colder months.
4. Steam consumption targets and guidelines should be established at all facilities and for all major pieces of equipment. Targets should be routinely adjusted for process feed-rate changes. Target consumption should be plotted relative to load (load curves). The goals should be to operate the plant on these load curves.

5. Each steam generator should be rated according to its performance characteristics or efficiency. That way, during a period of increasing steam demand, the most efficient generators can be loaded first, keeping energy consumption to a minimum while getting the most steam out of the most efficient systems. Also, where options exist and there is flexibility, the most efficient systems should be used first.

6. Steam systems should be surveyed routinely to identify seldom-used steam lines which could be removed from service. Adjustments to systems should be made as dictated by plant steam requirements. If not automated, these adjustments should be described in a set of clearly stated, written instructions to the operator.

7. Steam tracing systems should be held to an absolute minimum, as their use can downgrade overall steam distribution efficiency. Alternatives to steam tracing should be investigated, such as electrical heating tapes for remote locations where the monitoring of a steam tracing system would be impractical.

8. Steam distribution and condensate systems should be designed so that effective corrosion treatment systems can be employed. See Chapter 2, *Water Treatment,* for information on these treatment systems.

9. Steam systems should also be designed with adequate metering to be able to keep track of where the steam is going and to routinely get facility-wide and individual process-unit steam balances.

Steam Traps

1. Every operating area should have a program to routinely check steam traps for proper operation. Testing frequency depends on local experiences but should at least occur yearly.

2. All traps should be numbered and locations mapped for easier testing and record-keeping. Trap supply and return lines should be noted to simplify isolation and repair.

3. Maintenance and operational personnel should be adequately trained in trap testing techniques. Where ultrasonic testing is needed, specially trained personnel should be used.

4. High maintenance priority should be given to the repair or maintenance of failed traps. Attention to such a timely maintenance procedure can reduce failures to three to five

percent or less. A failed open trap can mean steam losses of 50-100 lb/hr.

5. All traps in closed systems should have atmospheric vents so that trap operation can be visually checked. If trap headers are not equipped with these, they should be modified.

6. Proper trap design should be selected for each specific application. Inverted bucket traps may be preferred over thermostatic and thermodynamic-type traps for certain applications.

7. It is important to be able to observe the discharge from traps through the header. Although several different techniques can be used, the most foolproof method for testing traps is observation. Ultrasonic, acoustical and pyrometric test methods often suggest erroneous conclusions.

8. Traps should be properly sized for the expected condensate load. Improper sizing can cause steam losses, freezing and mechanical failures.

9. Condensate collection systems should be properly designed to minimize frozen and/or premature trap failures. Condensate piping should be sized to accommodate 10 percent of the traps failing to open.

Insulation

1. Systems should be regularly surveyed to replace or repair missing and deteriorated insulation. This is especially important after insulation has been removed to repair steam leaks.

2. An overall survey of steam lines should be conducted every five years (or one fifth of the facility per year) to identify areas where insulation or weatherproofing has deteriorated. Typical culprits include prolonged exposure to moisture, chemicals or hydrocarbons. Instruments to measure the effectiveness of insulation include thermographic (heat image) devices. This instrument gives an indication of surface temperatures by displaying various colors. It is ideal for large areas. Others include portable infrared pyrometers, or heat guns, that measure surface heat by infrared wave emitted from the surface and contact-type pyrometers and surface crayons, which must be in contact with the surface to measure heat.

3. Following any maintenance work, areas where work has been performed should be

Steam pressure	Hole size	Steam loss–lb/hr	*Loss | $/yr
115 psi	1/16"	15	400
115 psi	1/8"	60	1,600
115 psi	1/4"	240	6,400
115 psi	1/2"	1,010	27,000
115 psi	1"	3,900	104,000
415 psi	1/16"	55	1,450
415 psi	1/8"	220	5,800
415 psi	1/4"	880	23,200
415 psi	1/2"	3,520	92,800
415 psi	1"	14,080	372,000

2. Plume Length Method

Plume Length	Steam Loss–lb/hr		
	45° F. Ambient	70° F Ambient	90° F Ambient
115 psi			
3 ft.	10	30	50
6 ft.	30	170	280
9 ft.	70	420	700
12 ft.	110	650	1,100
415 psi			
3 ft.	20	35	50
6 ft.	50	170	290
9 ft.	130	500	800
12 ft.	220	870	1,400
	*Loss–$/year		
115 psi			
3 ft.	260	790	1,300
6 ft.	790	4,420	7,280
9 ft.	1,820	10,920	18,200
12 ft.	2,860	16,900	28,600
415 psi			
3 ft.	520	910	1,300
6 ft.	1,300	4,420	7,540
9 ft.	3,380	13,000	20,800
12 ft.	5,720	22,620	36,400

*Annual loss is based on a steam value of $3.00/thousand lbs.

Table 10-1. Estimate of steam losses.

inspected to see where insulation should be repaired or replaced. Removable insulation blankets should have been reinstalled on all equip- ment. The last step in any maintenance work should be the repair, replace- ment or reinstallation of insulation. System components often overlooked and left uninsulated include valves, turbines, pumps and flanges.

4. Optimal insulation thickness should be applied to any new piping systems.
5. During steam line surveys, insulation should be visually inspected for the following defects:

   – Physical damage
   – Cracks in vapor barriers
   – Broken bands or wires
   – Broken or damaged weather-tight joint seals
   – Damaged covers and weatherproofing

Leaks

1. All steam leaks should be repaired as quickly as possible. Leaks are one of the most visible forms of energy waste. The table in Figure 27 shows steam loss at pounds per hour, for a given sized hole, at a given pressure. Steam leaks can also suggest management indifference to efficient operation and pose significant safety hazards. Steam leaks don't get smaller, neither does the cost of fixing them.
2. Standard procedures should dictate that proper gaskets and packing are used in steam system flanges and valves.
3. An on-stream, leak-repair specialist should be employed to repair leaks when the steam system cannot be taken down.
4. All steam systems should be designed for minimum leakage. For example, flanges and threaded piping should be minimized.

Pressure

1. There are large incentives to use steam at its lowest possible pressure for heating, primarily to reduce energy consumption. Process or equipment changes will often allow the use of lower steam pressure. These considerations are part of the plant initial design phase and any changes recommended should undergo an economic analysis to justify process or equipment changes.
2. The utilization of steam at all pressure levels should be maximized. High pressure steam should not be reduced in pressure through control valves and low pressure steam should not be vented. Typically, there are large in-

centives to eliminate steam venting and pressure letdown. A significant reduction in fuel cost is perhaps the largest incentive. Instrumentation should be designed to continuously monitor steam pressure letdown and venting. In short, all steam systems should be balanced.

3. Reboilers and steam preheaters should use only the lowest steam pressure possible. This can often be done by using extended tube surfaces, nucleate boiling tubes and lower tower pressures.

Special Notes on Turbines

1. Steam turbines should always be operated at the lowest back pressure possible. In topping turbines, high back pressure can be caused by inadequate piping or high steam consumption from declining turbine efficiency. A high pressure drop between the turbine exhaust and the steam header could mean the piping is restrictive. In condensing turbines, high back pressure can be caused by vacuum system problems.

2. Condensing turbines are not very efficient as they tend to lose energy and utilize only 15 to 20 percent of the available steam thermal energy. At some point, consideration should be given to replacing these turbines with topping turbines, electric motors or direct-drive gas turbines.

3. Low turbine efficiency is often the result of blade fouling. Fouling is usually a result of water that has not been treated properly. See Chapter 2, *Water Treatment,* for further recommendations. Water-washing turbines onstream will often restore their efficiency. Improperly treated feedwater can also cause permanent long-term damage to boiler waterwall surfaces and superheater tubes. ■

Chapter 11: Compressed Air Systems and Diesel Engine Power Cogeneration

Compressed air systems can be an area for signifi-cant energy losses. Some consultants estimate that 20 percent of all power used in American industry to generate compressed air is wasted. Most people are unaware that it takes 7 horsepower of electrical energy to produce 1 horsepower of compressed air. Knowing this, operators and plant managers may want to review what tasks could be accomplished more economically by using electricity or steam rather than compressed air. Another misunderstanding is the belief that because compressed air is a necessity in some applications, its availability for other uses is "free."

Locating Compressed Air System Leaks

An effective compressed air management program starts with the location and repair of leaks. The economic penalty for air leaks can be easily calculated. For example, if electricity is purchased for $0.065/kwh, the full burdened cost of compressed air can reach $2.65/100 cfm/hr. A good analogy to the cost of wasting compressed air can be made by comparing it to hiring several employees and allowing them to stay home sick. Many operators and managers consider leaks as just another cost of doing business. The identification and repair of those leaks, however, could represent important "hard" dollar savings for an organization. In most cases, the largest electric motors are used to drive air compressors and a good leak management program could probably reduce electrical costs to power those motors by 15-20 percent. Another benefit is reduced noise in the manufacturing environment.

A good way to start is to identify the more obvious audible leaks. An audible leak is normally at least 2cfm/hr. Once identified, they should be marked by tags, surveyor's tape or fluorescent paint. A list should be made identifying each leak, assigning a cost to its existence, and totaling the overall waste cost of all the leaks. The net savings will be the total, less the cost of repairing each leak.

The next step in a comprehensive air leak control program might involve the purchase or lease of more sophisticated leak detection equipment, such as microsonic or ultrasonic leak detectors. These instruments are capable of locating leaks in noisy production areas as well as in overhead and other limited access areas. The cost of these instruments is most often more than offset by the money they will save by stopping the leaks.

Much of the waste of compressed air, besides leaks, rests with the end user. Compressed air is routinely used for tasks better (and more economically) suited to other methods.

A good example is the use of compressed air to clean up a dusty production area. In one particular organization, an electric leaf blower was purchased for the individual responsible for clean-up to use in lieu of the compressed air. The blower functioned well and the employee was informed after the clean-up was complete that the cost of the compressed air used in the clean-up would purchase the electric blower after only 3 days usage. This made an impression on the employee and focused attention on the true cost of compressed air.

Compressed air management involves leak detection and repair, employee education, and a review and revision of current practices to see if there are other economical alternatives to using compressed air. Here are some suggestions for better control of compressed air systems:

Pressure Drop

A major source of energy waste is a loss of pressure in the compressed air system. If system pressure drops below the minimum operating pressure of tools and equipment, efficiency declines rapidly.

For example, many air tools are designed to operate at an inlet pressure of 90 to 100 PSIG. A ten percent drop in pressure means nearly a 40 percent loss in work output of the tool. Some reasons for pressure drop include:

- Undersized air compressor
- Excess number of tools or pieces of equipment on the system
- Excessive leakage
- Air friction in the piping system

This last category can be managed knowing a few basic rules:

- For a given pipe or hose size and length, the pressure loss increases as the volume of air increases.

- Under the same conditions, the pressure loss increases with a lower initial pressure and decreases with a higher initial pressure.
- A smooth inner lining of the pipe or hose will cause less pressure drop. Conversely, a rough inner lining of the pipe or hose will cause more pressure drop.
- Couplings, fittings and valves increase the pressure drop.

Drying Compressed Air

Moisture can cause problems in any compressed air system. Moisture reduces the efficiency of air-operated equipment and creates excessive maintenance costs and downtime through equipment corrosion and breakdowns. While compression of air reduces its volume, it does not eliminate moisture.

For example, a 25 horsepower compressor delivering 100 CFM at a pressure of 100 PSIG can produce 18 gallons of water per day at fairly standard conditions of 90 degree ambient temperature and 50 percent relative humidity. An after-cooler will remove approximately 66 percent of this moisture, still leaving 6.2 gallons of water per day to flow through the system. This will find its way downstream where it can ruin air-operated tools, equipment and instrumentation, foul spray processes and sand blast operations and contaminate food packaging and processing and create air line freeze-ups.

Separators can remove up to 98 percent of free water flowing through the system but do nothing to remove moisture present in saturated air. Complete moisture removal is done by reducing the dewpoint temperature of the compressed air. Dewpoints (temperatures where moisture condenses) are reduced physically by refrigeration or chemical means.

Refrigerated dryers cool the air by mechanical refrigeration to condense water vapor in the air; a moisture separator removes the condensate. The initial cost of these units is relatively low. Ongoing operating and maintenance costs are also low, due to the sealed nature of the unit. These units can operate in an ambient temperature down to 35° Fahrenheit.

Regenerative or Desiccant compressed air dryers use porous, nonconsumable materials (known as desiccants) to absorb water molecules from the air stream onto the surface of the desiccant. Periodically, the desiccant is removed from the air stream to be regenerated for reuse. This process involves removing the entrapped water from the material. Typically, two desiccant towers are employed; one absorbing moisture from the air stream while the other is drying out.

In lubricated compressor installations, oil removal filters are required at the dryer inlet to prevent slugs of water from reaching the dryer and damaging the desiccant. After-filters are recommended at the dryer outlet to keep fine desiccant particles from entering the compressed airstream. These dryers can be used in any application that requires a pressure dewpoint below 35° Fahrenheit.

Operator's Checklist for Compressed Air Systems

- Get control of compressed air needs through the generation of usage standard, system controls, operating pressure, increased storage (compressed air is one of the few energy sources that is easily handled and stored), and a program to reduce air-operated systems for clean-up, pumping, etc.
- Another way to reduce compressed air need is through a leakage control program. Also, reexamine clean-up and production start-up schedules to more efficiently distribute the demand.
- Reduce electrical consumption by reducing system pressure where possible and disconnecting unneeded equipment.
- Formalize maintenance procedures and monitoring using non-invasive predictive maintenance techniques and automatic controls where economically feasible.
- On larger systems or the existence of multiple compressed air networks, the employment of an Air Optimization Consultant may identify additional ways to cut down compressed air waste.

Diesel Engine Power Cogeneration

Diesel engines are frequent choices for power cogeneration and standby use. They are compact sources of power and can be started and brought into service quickly with a minimum of operator intervention. They are available in a wide variety of sizes from a wide variety of manufacturers.

An energy-saving by-product of diesel engine power cogeneration is additional heat. During operation, the energy input in the fuel is distributed among four end points. Some of the energy is converted into mechanical shaft power. The re-
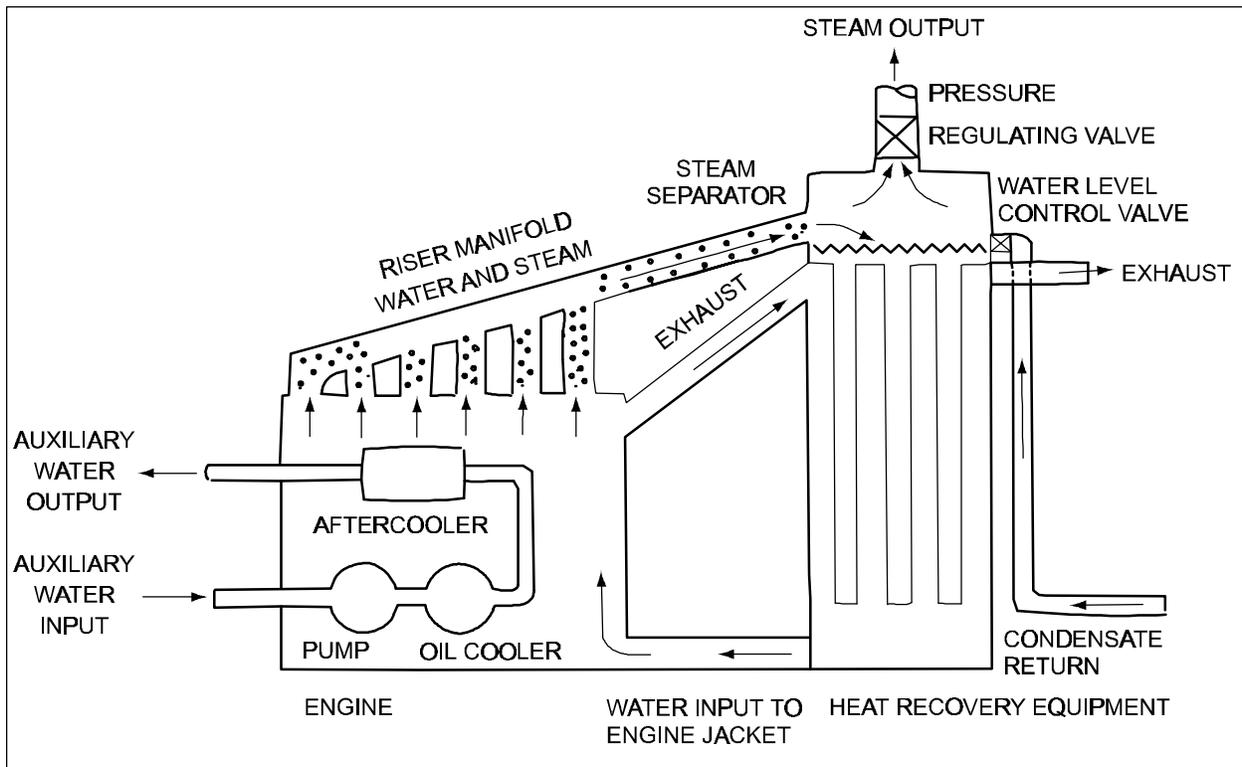
Figure 11-1. An ebullient system.

mainder is either absorbed by the water used to cool the cylinders, by the engine lubricating or exits with hot exhaust gases. A small portion is lost to radiation.

The energy and work capability of the exhaust can be recovered to produce steam. In addition, the jacket cooling water can be used to produce hot water or, in some cases, low-temperature steam.

The net thermal efficiency of the diesel engine remains fairly constant down to approximately 50 percent load. After that, it begins to drop rapidly. Also, as loading drops, the majority of additional relative heat production is absorbed in the cooling water. The exhaust heat content, however, as a percent of fuel input remains fairly constant over the load range, within about 5 percent. Exhaust temperature remains fairly constant as well, within plus or minus 5 percent.

Using a diesel engine in a cogeneration application is somewhat restricted by the capability to recover heat in a useful form. Process applications are limited to temperature and heat rate characteristics of the jacket cooling water and exhaust gases.

Process heat can be recovered in the form of hot air, hot water or steam. A requirement for hot air is satisfied by capturing it through the jacket water radiator and/or from exhaust gases

flowing through a heat exchanger. Where contamination is not a concern, the exhaust can be used directly. A requirement for hot water can be satisfied from these sources as well. Heat exchangers must be used when capturing heat from the cooling jacket to prevent coolant contamination.

A requirement for steam at a pressure above 205 kPa can be satisfied by an exhaust recovery boiler. Below 205 kPa, the heat energy absorbed by the jacket cooling water can be recovered as an additional steam supply, through the use of a flash boiler or ebullient cooling. With the flash boiler mounted above the engine, jacket water approaches the boiler, the static pressure drops and the water flashes to steam. In an ebullient system, vapor formation is allowed in the engine cooling jacket with natural circulation being used to continually remove the steam bubbles from the cooling surfaces. See Figure 11-1.

A steam separator is required at some point above the engine. Jacket water steam production is limited to approximately 205 kPa because of the high-speed engine jacket operating temperature limit of approximately 90k. However, conventional absorption air-conditioning chillers are designed to use low-pressure steam at approximately 184 kPa and represent an extensive energy-reuse potential. ∎

Chapter 12: Electrical Distribution Systems

Electrical power distribution systems perform the task of making the right amount of electrical power available at the right place for the appropriate electrical apparatus.

An electrical power distribution system diagram for a typical building or industrial plant appears below.

This type of diagram is known as a "single line diagram" (SLD) because one single line is shown to represent the three phase conductors, neutral conductor and/or grounding conductor. The various symbols used represent transformers, reactors, resistors, fuses and circuit breakers, motors, etc.

Note that this distribution system represents a facility that is buying its power from a utility. A facility that has a cogeneration process will have a different distribution system. Such systems are described and shown in Chapter 11, *Compressed Air Systems and Diesel Engine Power Cogeneration.*

In Figure 12-1, the incoming supply power from the utility is at the left, feeding the primary substation transformer **T1.** If the primary substation is owned by the utility, the primary feed may be one of several high voltage levels, such as 35kV, 69kV, or perhaps 100kV or higher. The secondary tap of **T1** is commonly one of several medium voltages, such as 6.9kV, 12.47kV, or 15kV. This is usually the feed voltage to the various secondary substations in the facility. Individual large (200 hp and larger) synchronous or induction motors may be fed by a special substation, such as **T2**, at one of several medium voltages, such as 2.3kV or 4.16kV.

Further along in the system, the remaining motor loads are typically fed by one or more sec-
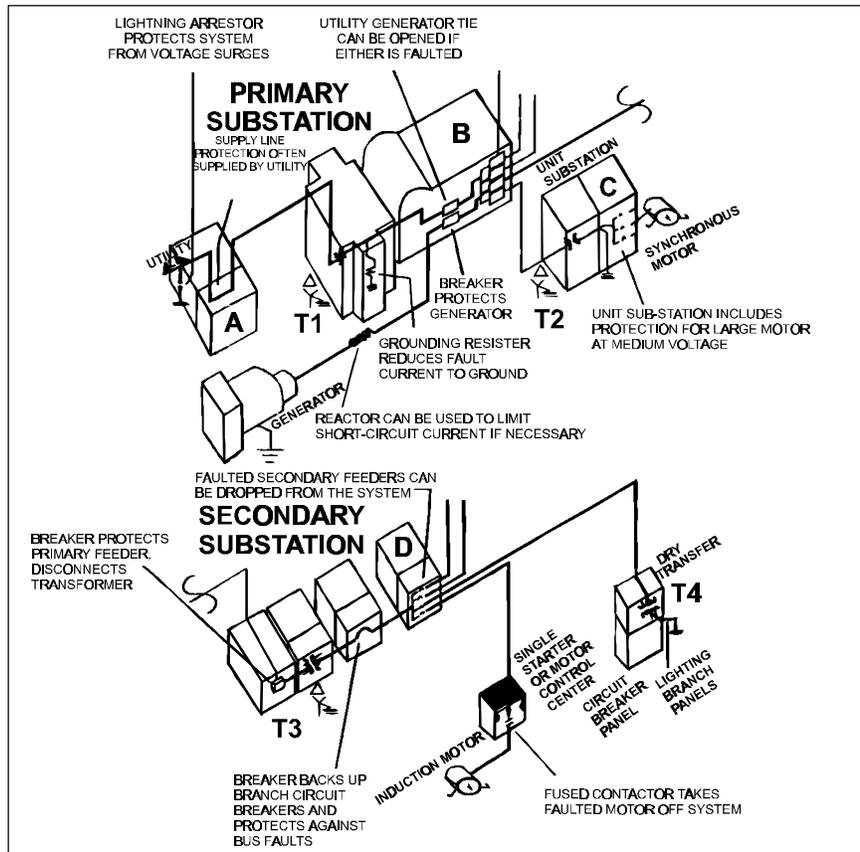
Figure 12-1. Electrical Power Distribution System.

ondary substations such as **T3**. Here the most common secondary voltage is 480 volts, with a grounded wye transformer connection.

Lighting circuits are usually powered from a lighting panel supplied by a small (10-45kVA) dry-type transformer **T4**, with a primary tap of 480 volts and a secondary tap of 208/120 volts, also with a grounded wye transformer connection. Occasionally, lighting circuits will be operated at 277 volts phase-to-neutral, supplied through a three-phase, 480 volt circuit breaker on the secondary side of transformer **T3**.

Permanent metering of voltage, current, kW and kWh can be installed at locations **A** through **E**. Potential and current transformers are always used at locations **A**, **B** and **C**, and may also be used at **D** and **E.** Portable survey meters should be connected to the secondary terminals of these

instrument transformers at locations **A**, **B** and **C**, and may be direct connected at **D** and **E**.

Note that when portable survey metering is connected to the secondary terminals of potential and current transformers at locations **A**, **B** and **C**, the appropriate multiplier must be included to reflect the ratio factors of the transformer(s).

Monitoring and Metering Techniques

The employment of an energy analyzer can provide important data regarding the consumption of electrical power. A good analyzer can measure, record, display electric power demand and help to analyze electrical power usage as well as conduct energy surveys.

In the meter mode, the analyzer can display the present values for monitored and calculated parameters. In the scope mode, it displays volt-age and current waveforms and their phase angles to detect loads that are out of balance.

The analyzer can also provide programmable reports that aid in analysis and can be generated automatically when conditions are met, such as a threshold crossing of a pre-programmed parameter limit.

Analyzers can be permanently or temporarily installed to allow use at several locations. Permanent installation is usually made at the electrical service entrance to the facility or at major substations within the facility. It is at these other locations where it is important to make sure demand, energy consumption and power factor do not become excessive.

When used as a portable test instrument to survey the facility electrical system at several different locations, the analyzer is normally connected at each location for a full operating cycle only (a day, week or month), or for short periods, like checking the power factor of an individual motor, for example. ∎

The Case for Individual Metering

The isolation and identification of individual departments as energy consumers can go a long way in reducing electrical power consumption. Here are six reasons for individual metering:

1. **Charge Out Energy to Individual Departments**. This is the most basic reason to meter. Each month the total energy bill is proportioned to the various departments. This data is used to compare costs against the department's budget and thus develop a variance-dollar value. Also included is the use of meters for revenue-building when energy is sold to a third party, as in a cogeneration arrangement.

2. **Accountability for Energy Used**. Trending of energy consumption per unit of production or service performed is the basis for initial analysis and resulting corrective actions.

3. **Efficiency of Utility Equipment and Systems**. The experience one company gained from their utility test process provides the following guideline values:

A. Centrifugal air compressors at 125 psig:
3.2-4.0kWh/1000 standard cubic feet (scf).

B. Centrifugal chiller drives producing 45 degree F. water:
0.6-1.0 kW/ton refrigeration or
0.6-1.0 kWh/ton-hour refrigeration

C. Refrigeration delivered to the conditioned space:
1.0-2.0 kW/ton refrigeration or
1.0-2.0 kWh/ton refrigeration

D. Steam boilers at 250 psig:
Number 6 fuel oil = 7.1-9.0 gal/1,000 lbs. steam
Natural gas = 1,000-1,300 scf/1,000 lbs. steam
Pulverized coal = 100/120lbs./1,000 lbs. steam
(Fuel consumption values will be 25 percent higher at 600 psig.)

4. **Provide Information for Audits of Energy Projects**. With funding getting harder to secure, audits of cost reduction energy management projects have been required more frequently over the past five years.

5. **Maintenance Work, Identify Performance Problems, Feedback to Managers**. The collection of energy consumption data in support of maintenance work is a viable tool, helping in the identification of equipment performance problems. As a side issue, performance problems associated with personnel operating the equipment are also readily identified, allowing managers to take any necessary corrective action.

6. **Identify Potential Future Additional Energy Savings**. ∎

Chapter 13: Cooling Towers

The cooling tower portion of the industrial facility deserves special attention for a number of reasons. First, it is located outdoors and, as such, subject to weather and atmospheric damage. Second, the neglect of necessary and routine maintenance can have a big impact on the cost of operation. Third, this same neglect can cause early component failure through corrosion.

Cooling towers transfer heat from circulating water to the atmosphere through evaporation. The two main areas that need to be addressed are the outside structure itself and the maintenance of a proper water treatment program to minimize scale and corrosion. See Chapter 2, *Water Treatment,* for further information.

A regular inspection program is key to early problem detection. At the end of this chapter is a reproducible form (Table 13-1, Cooling Tower Check List) which can be adapted to a particular facility installation.

Cooling Tower Inspection Process

Generally, the cooling tower structure and system should be inspected every six months in temperate climates. In more tropical and desert climates the interval should be more frequent, in accordance with equipment manufacturer and engineering recommendations. A list of items that need to be inspected is shown below:

1. Wooden structural members. Look for rotten and broken boards, loose hardware and excessive fungal growth. The plenum area after the drift eliminators is the most likely to suffer wood rot, since biocides added to the water do not reach this area. Pay particular attention to structural members in this area.
2. Other structural members. Check concrete supports and members for excessive weathering and cracking. Look for metal corrosion. On fiberglass ductwork and piping, check for cracking and splitting.
3. Water distribution throughout the tower should be uniform. Check piping for leaks.
4. Fans should be free of excessive vibration. Check mounts for deterioration and looseness. Examine blade leading edges for fouling, corrosion and dirt

buildup. Check the fan stack for integrity, shape and stack-to-blade clearance. See Chapter 7, *Auxiliaries,* for further suggestions.
5. Inspect for broken fill, debris in the fill, scale on fill water outlet.
6. Look for debris and plant growth in the drift eliminator. Make sure the eliminator is not broken or missing altogether.
7. Check for algae growth, scale and plugged nozzles in the hot water bays (crossflow towers). Nozzles should be checked monthly during the cooling season.
8. Record all observations on the Operator Checklist. This should include gearbox oil levels, oil additions (frequent refills could be a sign of bearing wear or leaks), water data, chemical inventories and hot water bay observations.

Cooling Water Monitoring

1. Be sure to keep the water log sheet records up to date. Maintain a record of necessary components, control ranges, control capabilities (especially for calcium, pH, alkalinity, biocide, chemical feeds, conductivity, possible phosphate content.) Follow water treatment procedures closely.
2. Periodically check the water appearance for turbidity and foam.
3. Inspect wet surfaces for evidence of slime, algae or scale. Do the same for submerged surfaces. Use a corrosion coupon to monitor system corrosion rates where potential corrosion problems are indicated.
4. Monitor chemical additions for visible and uniform flow and proper rate.

Measuring Cooling Tower Efficiency
A good way to determine if the cooling tower is doing its job is to measure its efficiency. This is done using a thermal test as described in Cooling Tower Institute (CTI) Code ATC-105. The calculations are commercially available for programmable calculators and PCs. Another method that has a tolerance of plus or minus 10 percent can be made using circulating water flow rate, hot and cold water temperature and the air wet bulb temperature. This same test can be performed by knowledgeable plant personnel or outside contractors.

Heat exchangers can also be monitored for heat transfer performance to give an early warning of water treatment deficiencies. Small sidestream test heat exchangers are available commercially for monitoring cooling water site fouling.

Biological growth can rapidly cause systems to get fouled. Slime appearing on a submerged coupon is a good indicator that there is a problem. Submerged coupons, which are found in the cooling tower reservoir, indicate growth in less accessible areas of the cooling tower. When this happens:

1. Recheck biocide levels (chlorine or other proprietary brands). If low, reestablish to the correct level.
2. If the biocide level is correct, an increase may be advisable to "shock" the system. Maximum biocide levels must not be exceeded to prevent possible toxicity problems.
3. Alternate biocides are to be used for persistent problems so that biological growth does not become immune to a single type of biocide.

Energy Efficiency in Cooling Tower Operation

Most costs in operating a cooling tower stems from electricity consumption for the fans, assuming the tower has induced draft. Fans are generally multi-speed. Experience will tell an operator the best time to go from low-speed to high-speed and return, which will result in the lowest energy consumption, as will routing water to different cells. ■

DATE			OPERATOR →				
FANS MUST BE SHUT DOWN TO CHECK GEAR BOX OIL LEVELS							
	FANS-1	MECHANICAL CK	CK. VIB. & NOISE				
	FANS-2	MECHANICAL CK	CK. VIB. & NOISE				
	FANS-3	MECHANICAL CK	CK. VIB. & NOISE				
		CHEMICAL ADDITION					
	Treat Chem.-1 TANK LEVEL		GALLONS	—		—	—
	Treat Chem.-2 TANK LEVEL		GALLONS	—		—	—
	Treat Chem.-? TANK LEVEL		GALLONS	—		—	—
	Foam Control TANK LEVEL		GALLONS	—		—	—
	Slim Control TANK LEVEL		GALLONS	—		—	—
	Chem.-1 Feed Pump FLOW		mL/min	—		—	—
	Chem.-2 Feed Pump FLOW		mL/min	—		—	—
	Chem.-? Feed Pump FLOW		mL/min	—		—	—
	SUMP Visual INSPECTION		OK? or LOW?				
	CHLORINE FEED RATE		LBS/DAY	—		—	
	HCl CONTROL VALVE POSITION		% OPEN				
	Return Water RISER PRESSURES		EQUALIZED?	—		—	—
	Return Header pH SAMPLE FLOW		YES or NO				
	Recirc. Pump Disc. pH SAMPLE FLOW		YES or NO				
	Recirculation Pumps						
	Pump-1 DISCHARGE PRES.		RECORD				
		OIL LEVELS	FULL	—		—	
	Pump-1 PACKING GLAND CK.		COOL or WARM				
	Pump-2 DISCHARGE PRES.		RECORD				
		OIL LEVELS	FULL	—		—	
	Pump-2 PACKING GLAND CK.		COOL or WARM				
	Pump-? DISCHARGE PRES.		RECORD				
	MP/P	OIL LEVELS	FULL	—		—	
	P PACKING GLAND CK.		COOL or WARM				

Table 13-1. Cooling Tower Check List

Appendix A: Excess Air Levels

For a given steam load, a boiler operating at optimum excess air levels will be at its peak efficiency. Optimum excess air, or its equivalent excess oxygen, is that percentage which gives the best compromise between unburned fuel and flue gas heat losses. Boilers usually operate at excess air levels higher than optimum rather than lower. Some reasons for this include:

– The boiler is controlled by a positioning system where fuel/air ratio is determined by mechanical linkages. These need to be checked on a regular basis and adjusted to allow for wear. The linkages are typically calibrated for conservatively high excess air operation to allow for variations in fuel supply pressure (fuel feed rate), heating value, etc.
– The boiler's oxygen analyzer is nonfunctional (or nonexistent).
– Plant operations management desires to maintain the boiler fuel/air ratio comfortably above potential fuel-rich conditions.

A general rule is that a 1% reduction in excess oxygen will reduce fuel usage by 1%. This happens because less air or oxygen means that less flue gas is generated, gas velocities are lower, combustion time residence time is increased and heat transfer is improved. Here are some other variables:

– 5% coal moisture equals about 1% boiler efficiency
– 1% ash over 10% equals about 0.3% boiler efficiency
– 1% hydrogen equals about 1% boiler efficiency
– 40 degrees boiler exit temperature equals about 1% boiler efficiency

A good method for evaluating boiler performance improvements from implementing excess air reduction measures involves figuring boiler efficiency at conditions before corrections are applied and then again after corrective measures have been taken. Efficiency an be calculated using the American Society of Mechanical Engineers (ASME) "Test Form for Abbreviated Efficiency Test," as provided in the ASME Power Test Code PTC 4.1 for Steam Generating Units.

To figure the performance efficiency of the boiler, boiler data is taken with the unit baseloaded at a given load. No attempt should be made to improve the excess air level from that dictated by the control system. Excess air is now adjusted to a level just above visible smoke (as seen at the fire) or significant carbon monoxide/ combustibles conditions. At this point the improved efficiency is measured. For solid fuels, the excess air level should be somewhat higher, to minimize the carbon losses that occur in ash.

The procedure for gathering valid efficiency data begins with transmitter/analyzer calibrations being checked and verified and a current fuel analysis requested. The boiler should then be stabilized at a given load. Data should be recorded over a period of time, with boiler conditions being held constant. Pressure and temperature are averaged, while rate quantities, such as steam and fuel flow are totalized. For acceptance test purposes, the ASME recommends the duration of these "stabilization" and "run" periods be one hour and four hours, respectively, for gas, oil and pulverized coal (PC).

The table below presents typical efficiency data for boilers at various excess oxygen levels, while firing natural gas, #2 or #6 fuel oil or bituminous coal. This efficiency data is representative of boilers equipped with economizers and air heaters.

Excess Air %	Natural Gas	#2 Oil	#6 Oil	Bituminous Coal
2.0	83.08%	—	—	—
2.5	82.37%	85.35%	88.91%	
3.0	81.68%	84.63%	86.11%	87.58%
3.5	80.71%	83.61%	85.22%	86.74%
4.0	79.72%	82.57%	84.22%	85.79%
4.5	78.60%	81.40%	83.08%	84.72%
5.0	77.31%	80.05%	81.78%	83.48%
5.5	75.32%	78.51%	80.27%	82.07%
6.0	74.03%	76.68%	78.51%	80.40%
6.5	72.01%	74.52%	78.43%	78.42%

Table A-1. Typical Boiler Efficiencies (%) For Common Fuels as a Function of Excess Air.

With efficiency values for "before" and "after" excess air conditions available, fuel savings can be directly determined. The ratio of "before" and "after" efficiency represents the fraction of fuel required to produce the same amount of steam at the new efficiency. Fuel savings is one minus this ratio. For example, if the "before" efficiency is 82% and the "after" efficiency is 85% then:

$$\text{Fuel Fraction} = \frac{\text{Efficiency (baseline)}}{\text{Efficiency (improved)}} \qquad \text{Fuel Savings} = 1 - \frac{\text{Efficiency}}{\text{Efficiency}}$$
$$= \frac{82\%}{85\%} \qquad\qquad\qquad = 1 - \frac{82\%}{85\%}$$
$$= 0.9647 \text{ or } 96.47\% \qquad = 0.0353 \text{ or } 3.53\%$$

These formulae, when used in conjunction with the above table of efficiency data, provide a method of estimating fuel savings from reductions in excess oxygen levels. These savings are obtainable with a calibrated, tuned excess air trim control strategy.

As mentioned previously, since this is composed of mechanical linkages, the system should be inspected periodically for out-of-adjustment positions and corrected accordingly. ■

Appendix B: Savings Possible through Heat Recovery on Continuous Blowdown and Improved Blowdown Control

Heat Recovery on Continuous Blowdown

Conditions:

Steam rate = 1,000,000 lb. steam/hr
Boiler pressure = 200 psig
Makeup water temperature = 60° F.
Rate of blowdown = 5.0%
Boiler efficiency = 80%
Fuel = Oil at 150,000 Btu/gal, $1.00/gal delivered and fired (substitute current fuel values)
Using equations 1 and 7 from Section 2.1.2:
    blowdown = 0.05 feedwater, or feedwater
             = (20)(blowdown)
    feedwater = steam + blowdown
Substituting and solving for blowdown:
    blowdown = 52,631 lb/hr

Using a flash tank at 5 psig, the quantity of 5 psig steam available can be determined in two ways:

I. $\% \text{ flashed steam} = \dfrac{(hf)s\ (hf)F}{hfg} \times 100$

Where:

(hf)s = enthalpy of liquid at boiler pressure, Btu/lb
(hf)F = enthalpy of liquid at flash tank pressure, Btu/lb
hfg = latent heat of vaporization at flash tank pressure, btu/lb

II. An alternative method for approximating % flashed steam from boiler blowdown is to use the data from Figure A. By method I:

$\% \text{ flashed steam} = \dfrac{362 - 196}{960} = 17.3\%$
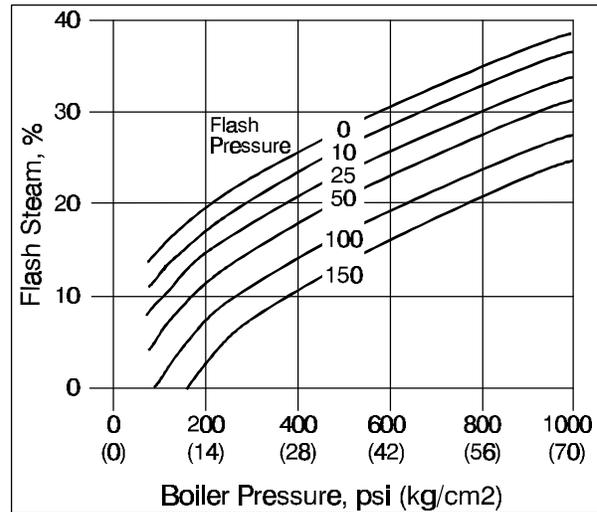
Flashed steam =
    52,631 lb/hr x 0.173 = 9,105 lb/hr

Figure B-1: The production of flash steam from boiler breakdown.

Blowdown from the flash tank =
    52,631 - 9,105 = 43,526 l/hr
Total heat of flashed steam at 5 psig =
    1156 Btu/lb
Heat saved in flashed steam =
    1156 Btu/lb x 9,105 lb/hr = 10.525 mm Btu/hr
    The drain water from the flash tank is passed through the heat exchanger and then to the sewer. The temperature of the water leaving the exchanger is 20° F. higher than the incoming makeup water temperature, or 80° F.

Heat of liquid leaving heat exchanger at 80° F.
    = 48 Btu/lb
Heat of liquid entering heat exchanger at 5 psig
    = 196 Btu/lb
Heat recovery
    = 196 – 48
    = 148 Btu/lb
Heat savings from heat exchanger
    = 43,526 lb/hr x 148 Btu/lb
    = 6,441,848 Btu/hr
Total savings
    = 10.525 mm Btu + 6.442 mm Btu/hr
    = 16.967 mm Btu/hr

At a boiler efficiency of 80%, 20% of heat input is lost, while only 80% is effective in producing steam.

Effective BTUs
    = 150,000 Btu/gal x 0.80
    = 120,000 Btu/gal oil

Fuel savings =
$\frac{16.967 \text{ mm Btu/hr}}{120,000 \text{ Btu/gal oil}}$ x 24 hr/day x $1.00/gal oil
= $3393/day

Heat Recovery on Improved Blowdown Control

Substantial savings can be achieved through improved blowdown control. Additional savings could be achieved through decreased chemical usage, less blowdown to treat at the waste treatment plant, and reduced makeup water demand.

Given:
    Boiler pressure = 600 psig
    Steam rate = 1,000,000 lb/hr
    Makeup water temperature = 60° F.
    Boiler efficiency = 80%
    Fuel = Fuel oil @ $1.00/gal, 150,000 Btu/lb
    Present blowdown rate = 8%
    Blowdown reduction =
        20% with change in blowdown practices

Calculation:
    Reduced Blowdown Rate
        = 8% – 8% (0.2)
        = 6.4%
From equations in Sec. 2.1.2.
    Feedwater @ 8% Blowdown
        = 1,086,956 lb/hr
    Feedwater @ 6.4% Blowdown
        = 1,068,376 lb/hr
    Feedwater saved
        = 18,580 lb/hr
    Heat of boiler water at 600 psig
        = 475 Btu/lb (from Table 1)
    Heat of makeup at 60° F.
        = 28 Btu/lb
    Heat savings
        = 475 – 28
        = 447 Btu/lb
    Total heat savings
        = 18,580 lb/hr x 447 Btu/lb
        = 8,305,260 Btu/hr
    At 80% boiler efficiency
        150,000 Btu/gal x 80%
        = 120,000 Btu/gal
    Fuel saved
        = 8,305,260 / 120,000
        = 69.21 gal/hr
    Savings @ $1.00/gal
        = 69.21 x 24 hr/day
        = $1660/day
        = $606,280/hr   ∎

Appendix C: References

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