# BOILERS & THERMIC FLUID HEATERS

## 1. INTRODUCTION

This section briefly describes the Boiler and various auxiliaries in the Boiler Room.

A boiler is an enclosed vessel that provides a means for combustion heat to be transferred to water until it becomes heated water or steam. The hot water or steam under pressure is then usable for transferring the heat to a process. Water is a useful and inexpensive medium for transferring heat to a process. When water at atmospheric pressure is boiled into steam its volume increases about 1,600 times, producing a force that is almost as explosive as gunpowder. This causes the boiler to be an equipment that must be treated with utmost care.

The boiler system comprises of: a feed water system, steam system and fuel system. The **feed water system** provides water to the boiler and regulates it automatically to meet the steam demand. Various valves provide access for maintenance and repair. The **steam system** collects and controls the steam produced in the boiler. Steam is directed through a piping system to the point of use. Throughout the system, steam pressure is regulated using valves and checked with steam pressure gauges. The **fuel system** includes all equipment used to provide fuel to generate the necessary heat. The equipment required in the fuel system depends on the type of fuel used in the system.

The water supplied to the boiler that is converted into steam is called **feed water**. The two sources of feed water are: (1) **Condensate** or condensed steam returned from the processes and (2) **Makeup water** (treated raw water) which must come from outside the boiler room and plant processes. For higher boiler efficiencies, an economizer preheats the feed water using the waste heat in the flue gas.
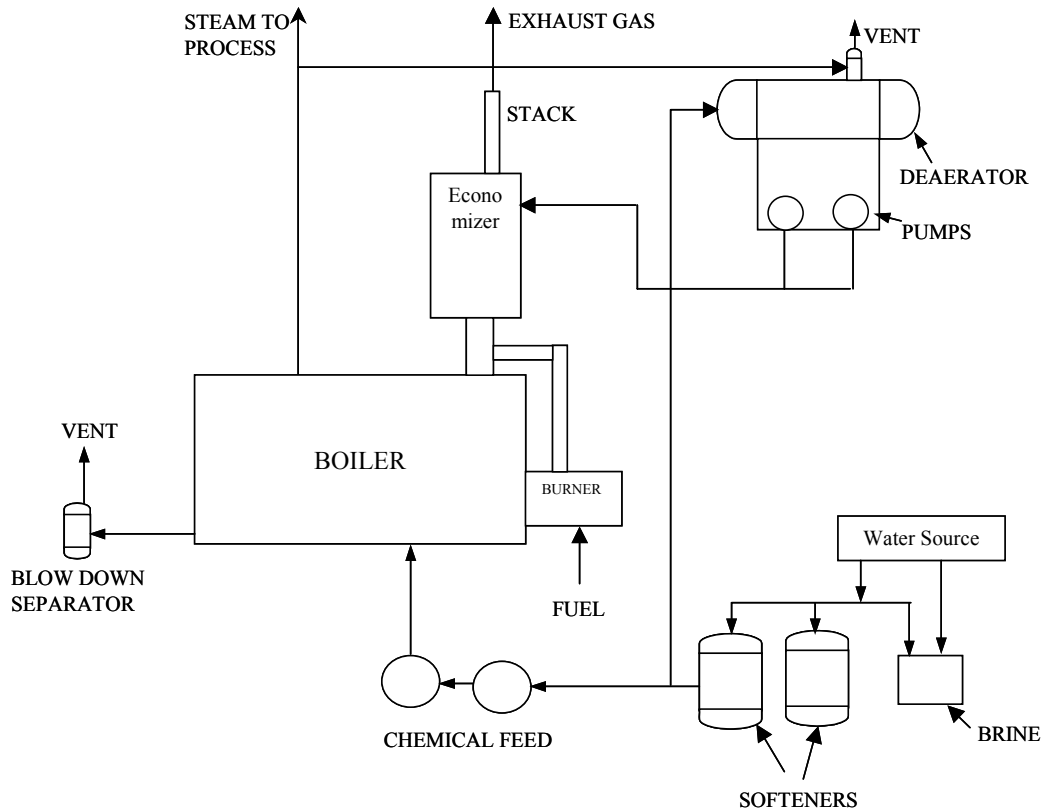
**Figure 1. Schematic diagram of a Boiler Room**

## 2. TYPE OF BOILERS

This section describes the various types of boilers: Fire tube boiler, Water tube boiler, Packaged boiler, Fluidized bed combustion boiler, Stoker fired boiler, Pulverized fuel boiler, Waste heat boiler and Thermic fluid heater.

### 2.1 Fire Tube Boiler

In a fire tube boiler, hot gases pass through the tubes and boiler feed water in the shell side is converted into steam. Fire tube boilers are generally used for relatively small steam capacities and low to medium steam pressures. As a guideline, fire tube boilers are competitive for steam rates up to 12,000 kg/hour and pressures up to 18 kg/cm$^2$. Fire tube boilers are available for operation with oil, gas or solid fuels. For economic reasons, most fire tube boilers are of "packaged" construction (i.e. manufacturer erected) for all fuels.
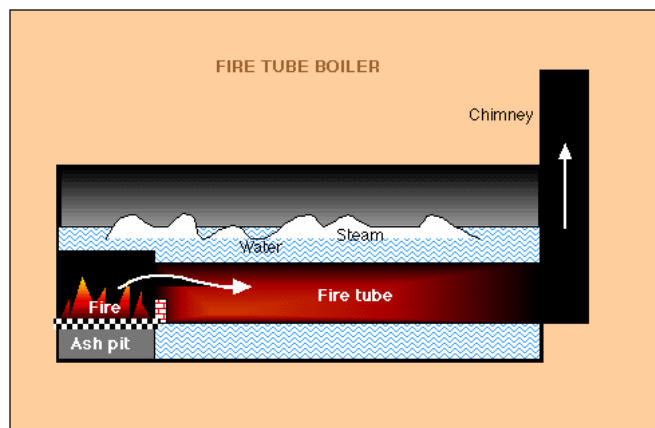


**Figure 2. Sectional view of a Fire Tube Boiler**
(Light Rail Transit Association)

## 2.2 Water Tube Boiler

In a water tube boiler, boiler feed water flows through the tubes and enters the boiler drum. The circulated water is heated by the combustion gases and converted into steam at the vapour space in the drum. These boilers are selected when the steam demand as well as steam pressure requirements are high as in the case of process cum power boiler / power boilers.

Most modern water boiler tube designs are within the capacity range 4,500 – 120,000 kg/hour of steam, at very high pressures. Many water tube boilers are of "packaged" construction if oil and /or gas are to be used as fuel. Solid fuel fired water tube designs are available but packaged designs are less common.

**Figure 3. Simple Diagram of Water Tube Boiler** (YourDictionary.com)

The features of water tube boilers are:
- Forced, induced and balanced draft provisions help to improve combustion efficiency.
- Less tolerance for water quality calls for water treatment plant.
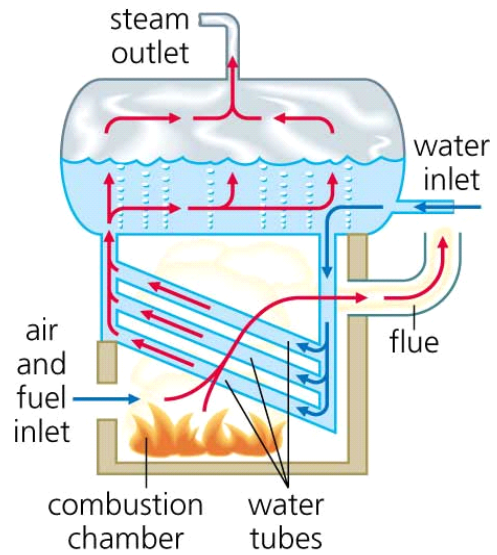- Higher thermal efficiency levels are possible

## 2.3 Packaged Boiler

The packaged boiler is so called because it comes as a complete package. Once delivered to a site, it requires only the steam, water pipe work, fuel supply and electrical connections to be made to become operational. Package boilers are generally of a shell type with a fire tube design so as to achieve high heat transfer rates by both radiation and convection.
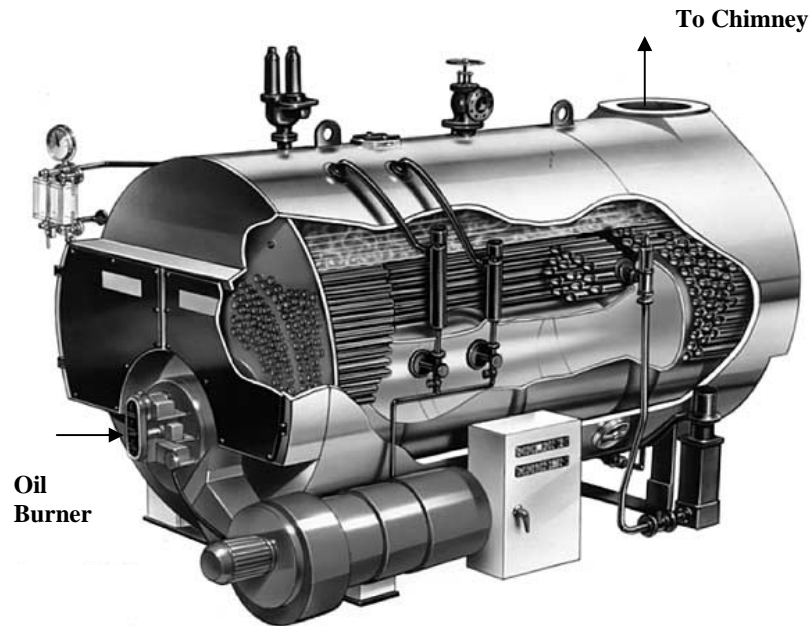
**Figure 4. A typical 3 Pass, Oil fired packaged boiler** (BIB Cochran, 2003)

The features of packaged boilers are:
- Small combustion space and high heat release rate resulting in faster evaporation.
- Large number of small diameter tubes leading to good convective heat transfer.
- Forced or induced draft systems resulting in good combustion efficiency.
- Number of passes resulting in better overall heat transfer.
- Higher thermal efficiency levels compared with other boilers.

These boilers are classified based on the number of passes - the number of times the hot combustion gases pass through the boiler. The combustion chamber is taken, as the first pass after which there may be one, two or three sets of fire-tubes. The most common boiler of this class is a three-pass unit with two sets of fire-tubes and with the exhaust gases exiting through the rear of the boiler.

## 2.4 Fluidized Bed Combustion (FBC) Boiler

Fluidized bed combustion (FBC) has emerged as a viable alternative and has significant advantages over a conventional firing system and offers multiple benefits – compact boiler design, fuel flexibility, higher combustion efficiency and reduced emission of noxious pollutants such as SOx and NOx. The fuels burnt in these boilers include coal, washery rejects, rice husk, bagasse & other agricultural wastes. The fluidized bed boilers have a wide capacity range- 0.5 T/hr to over 100 T/hr.

When an evenly distributed air or gas is passed upward through a finely divided bed of solid particles such as sand supported on a fine mesh, the particles are undisturbed at low velocity. As air velocity is gradually increased, a stage is reached when the individual particles are suspended in the air stream – the bed is called "fluidized".

With further increase in air velocity, there is bubble formation, vigorous turbulence, rapid mixing and formation of dense defined bed surface. The bed of solid particles exhibits the properties of a boiling liquid and assumes the appearance of a fluid – "bubbling fluidized bed".

If sand particles in a fluidized state are heated to the ignition temperatures of coal, and coal is injected continuously into the bed, the coal will burn rapidly and the bed attains a uniform temperature. The fluidized bed combustion (FBC) takes place at about $840^O$C to $950^O$C. Since this temperature is much below the ash fusion temperature, melting of ash and associated problems are avoided.

The lower combustion temperature is achieved because of high coefficient of heat transfer due to rapid mixing in the fluidized bed and effective extraction of heat from the bed through in-bed heat transfer tubes and walls of the bed. The gas velocity is maintained between minimum fluidization velocity and particle entrainment velocity. This ensures stable operation of the bed and avoids particle entrainment in the gas stream.

### 2.4.1 Atmospheric Fluidized Bed Combustion (AFBC) Boiler

Most operational boiler of this type is of the Atmospheric Fluidized Bed Combustion. (AFBC). This involves little more than adding a fluidized bed combustor to a conventional shell boiler. Such systems have similarly being installed in conjunction with conventional water tube boiler.

Coal is crushed to a size of 1 – 10 mm depending on the rank of coal, type of fuel fed to the combustion chamber. The atmospheric air, which acts as both the fluidization and combustion air, is delivered at a pressure, after being preheated by the exhaust fuel gases. The in-bed tubes carrying water generally act as the evaporator. The gaseous products of combustion pass over the super heater sections of the boiler flowing past the economizer, the dust collectors and the air pre-heater before being exhausted to atmosphere.

### 2.4.2 Pressurized Fluidized Bed Combustion (PFBC) Boiler

In Pressurized Fluidized Bed Combustion (PFBC) type, a compressor supplies the Forced Draft (FD) air and the combustor is a pressure vessel. The heat release rate in the bed is proportional to the bed pressure and hence a deep bed is used to extract large amounts of heat. This will improve the combustion efficiency and sulphur dioxide absorption in the bed. The steam is generated in the two tube bundles, one in the bed and one above it. Hot flue gases drive a power generating gas turbine. The PFBC system can be used for cogeneration (steam and electricity) or combined cycle power generation. The combined cycle operation (gas turbine & steam turbine) improves the overall conversion efficiency by 5 to 8 percent.

### 2.4.3 Atmospheric Circulating Fluidized Bed Combustion Boilers (CFBC)

In a circulating system the bed parameters are maintained to promote solids elutriation from the bed. They are lifted in a relatively dilute phase in a solids riser, and a down-comer with a cyclone provides a return path for the solids. There are no steam generation tubes immersed in the bed. Generation and super heating of steam takes place in the convection section, water walls, at the exit of the riser.

CFBC boilers are generally more economical than AFBC boilers for industrial application requiring more than 75 – 100 T/hr of steam. For large units, the taller furnace characteristics of CFBC boilers offers better space utilization, greater fuel particle and sorbent residence time for efficient combustion and $SO_2$ capture, and easier application of staged combustion techniques for $NO_x$ control than AFBC steam generators.
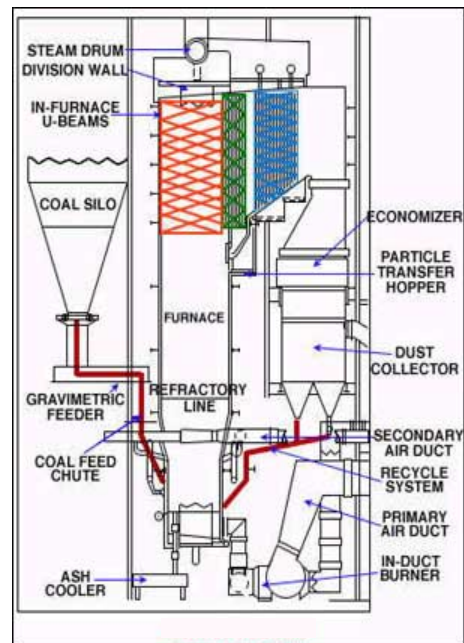


**Figure 5. CFBC Boiler**
(Thermax Babcock & Wilcox Ltd, 2001)

## 2.5 Stoker Fired Boilers

Stokers are classified according to the method of feeding fuel to the furnace and by the type of grate. The main classifications are spreader stoker and chain-gate or traveling-gate stoker.

### 2.5.1 Spreader stokers

Spreader stokers utilize a combination of suspension burning and grate burning. The coal is continually fed into the furnace above a burning bed of coal. The coal fines are burned in suspension; the larger particles fall to the grate, where they are burned in a thin, fast-burning coal bed. This method of firing provides good flexibility to meet load fluctuations, since ignition is almost instantaneous when the firing rate is increased. Due to this, the spreader stoker is favored over other types of stokers in many industrial applications.
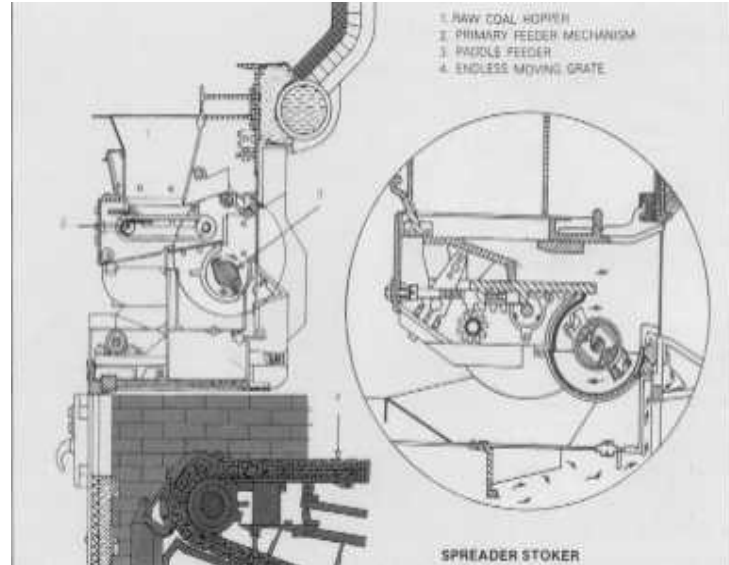


**Figure 6. Spreader Stoker Boiler**
(Department of Coal, 1985)

### 2.5.2 Chain-grate or traveling-grate stoker

Coal is fed onto one end of a moving steel grate. As the grate moves along the length of the furnace, the coal burns before dropping off at the end as ash. Some degree of skill is required, particularly when setting up the grate, air dampers and baffles, to ensure clean combustion leaving the minimum of unburnt carbon in the ash.

The coal-feed hopper runs along the entire coal-feed end of the furnace. A coal gate is used to control the rate at which coal is fed into the furnace by controlling the thickness of the fuel bed. Coal must be uniform in size as large lumps will not burn out completely by the time they reach the end of the grate.
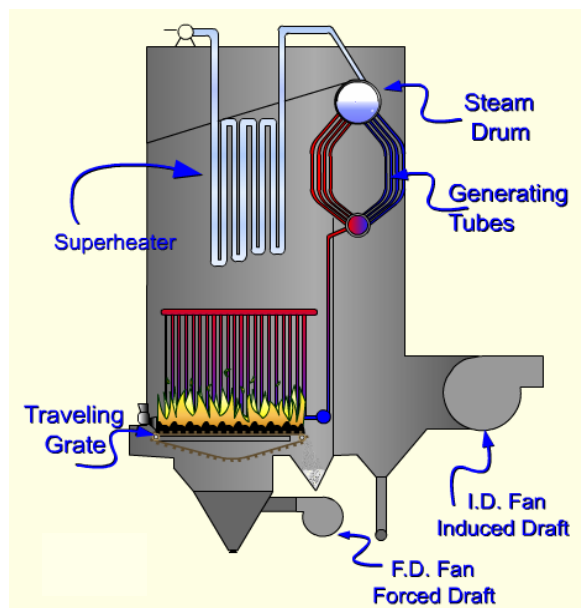


**Figure 7. View of Traveling Grate Boiler**
(University of Missouri, 2004)

## 2.6 Pulverized Fuel Boiler

Most coal-fired power station boilers use pulverized coal, and many of the larger industrial water-tube boilers also use this pulverized fuel. This technology is well developed, and there are thousands of units around the world, accounting for well over 90 percent of coal-fired capacity.

The coal is ground (pulverized) to a fine powder, so that less than 2 percent is +300 micrometer (μm) and 70-75 percent is below 75 microns, for a bituminous coal. It should be noted that too fine a powder is wasteful of grinding mill

**Figure 8: Tangential firing for pulverized fuel** (Reference unknown)

power. On the other hand, too coarse a powder does not burn completely in the combustion chamber and results in higher unburnt losses.

The pulverized coal is blown with part of the combustion air into the boiler plant through a series of burner nozzles. Secondary and tertiary air may also be added. Combustion takes place at temperatures from 1300-1700 °C, depending largely on coal grade. Particle residence time in the boiler is typically 2 to 5 seconds, and the particles must be small enough for complete combustion to have taken place during this time.

This system has many advantages such as ability to fire varying quality of coal, quick responses to changes in load, use of high pre-heat air temperatures etc.

One of the most popular systems for firing pulverized coal is the tangential firing using four burners corner to corner to create a fireball at the center of the furnace.

## 2.7 Waste Heat Boiler

Wherever the waste heat is available at medium or high temperatures, a waste heat boiler can be installed economically. Wherever the steam demand is more than the steam generated during waste heat, auxiliary fuel burners are also used. If there is no direct use of steam, the steam may be let down in a steam turbine-generator set and power produced from it. It is widely used in the heat recovery from exhaust gases from gas turbines and diesel engines.

**Figure 9: A simple schematic of Waste Heat Boiler** (Agriculture and Agri-Food Canada, 2001)

## 2.8 Thermic Fluid Heater

In recent times, thermic fluid heaters have found wide application for indirect process heating. Employing petroleum - based fluids as the heat transfer medium, these heaters provide constantly maintainable temperatures for the user equipment. The combustion system comprises of a fixed grate with mechanical draft arrangements.

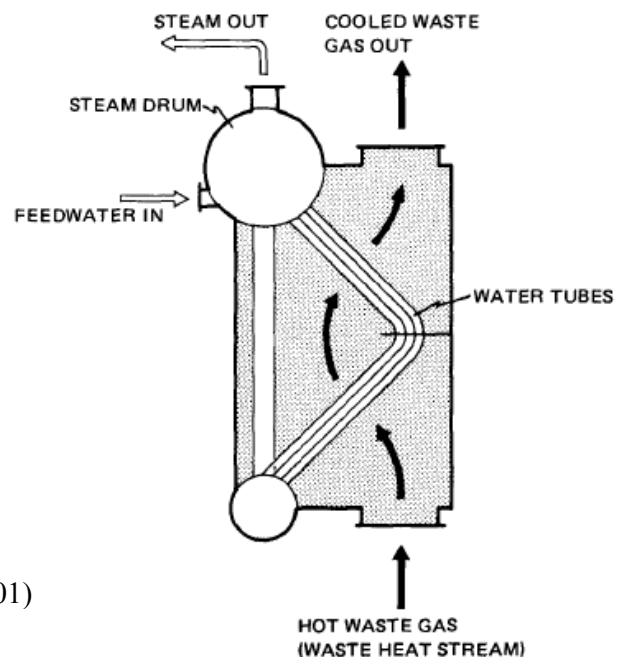The modern oil fired thermic fluid heater consists of a double coil, three pass construction and fitted a with modulated pressure jet system. The thermic fluid, which acts as a heat carrier, is heated up in the heater and circulated through the user equipment. There it transfers heat for the process through a heat exchanger and the fluid is then returned to the heater. The flow of thermic fluid at the user end is controlled by a pneumatically operated control valve, based on the operating temperature. The heater operates on low or high fire depending on the return oil temperature, which varies with the system load.
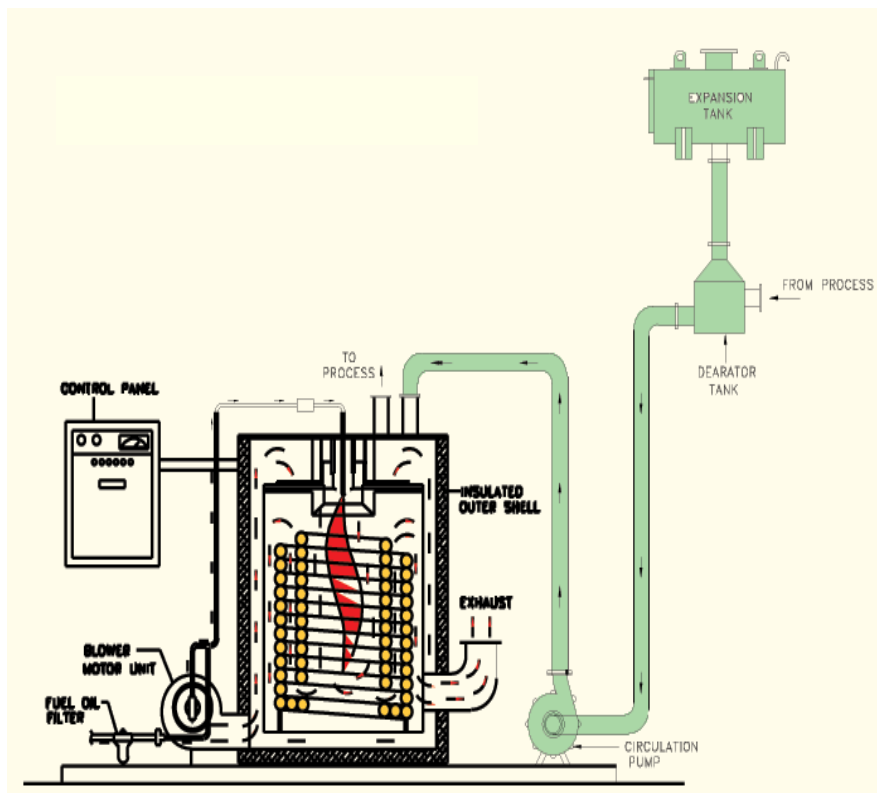


**Figure 10. A typical configuration of Thermic Fluid Heater**
(Energy Machine India)

The advantages of these heaters are:
- Closed cycle operation with minimum losses as compared to steam boilers.
- Non-Pressurized system operation even for temperatures around 250 $^0$C as against 40 kg/cm$^2$ steam pressure requirement in a similar steam system.
- Automatic control settings, which offer operational flexibility.
- Good thermal efficiencies as losses due to blow down, condensate drain and flash steam do not exist in a thermic fluid heater system.

The overall economics of the thermic fluid heater will depend upon the specific application and reference basis. Coal fired thermic fluid heaters with a thermal efficiency range of 55-65 percent may compare favorably with most boilers. Incorporation of heat recovery devices in the flue gas path enhances the thermal efficiency levels further.

# 3. ASSESSMENT OF A BOILER

This section describes the Performance evaluation of boilers (through the direct and indirect method including examples for efficiency calculations), boiler blow down, and boiler water treatment.

## 3.1 Performance Evaluation of a Boiler

The performance parameters of a boiler, like efficiency and evaporation ratio, reduces with time due to poor combustion, heat transfer surface fouling and poor operation and maintenance. Even for a new boiler, reasons such as deteriorating fuel quality and water quality can result in poor boiler performance. A heat balance helps us to identify avoidable and unavoidable heat losses. Boiler efficiency tests help us to find out the deviation of boiler efficiency from the best efficiency and target problem area for corrective action.

### 3.1.1 Heat balance

The combustion process in a boiler can be described in the form of an energy flow diagram. This shows graphically how the input energy from the fuel is transformed into the various useful energy flows and into heat and energy loss flows. The thickness of the arrows indicates the amount of energy contained in the respective flows.
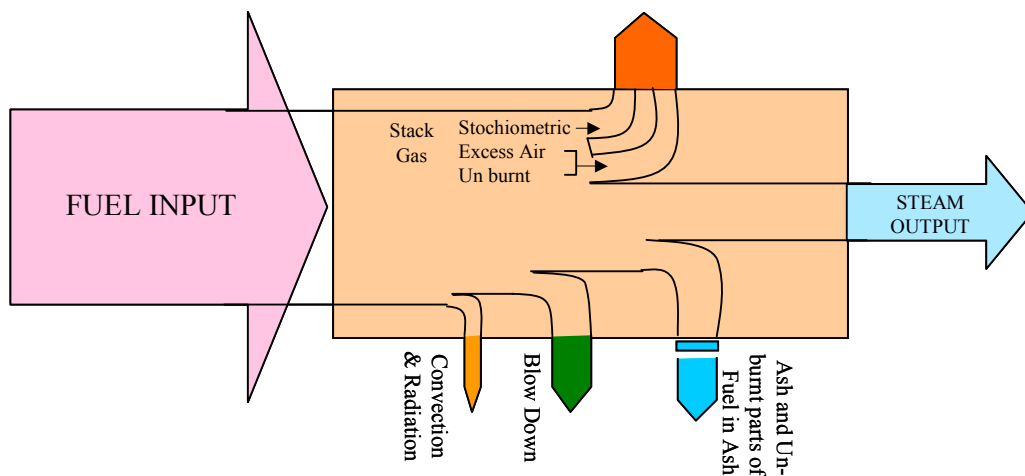


**Figure 11. Energy balance diagram of a boiler**

A heat balance is an attempt to balance the total energy entering a boiler against that leaving the boiler in different forms. The following figure illustrates the different losses occurring for generating steam.
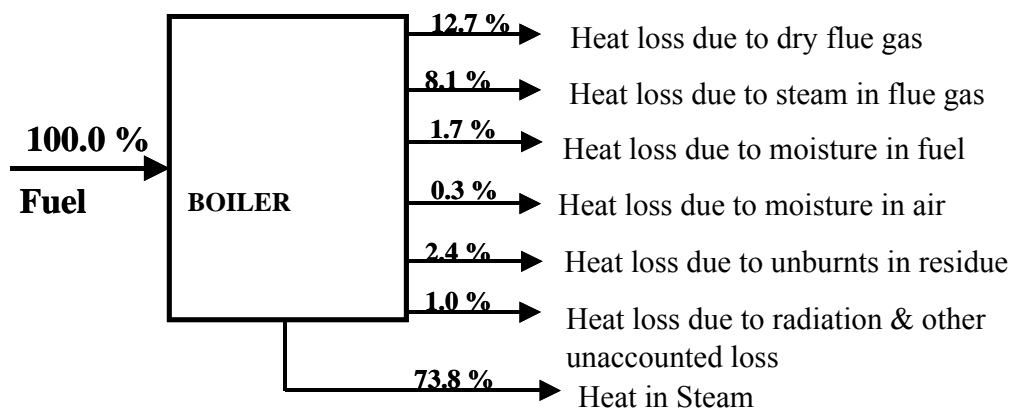


**Figure 12. Typical Losses from Coal Fired Boiler**

The energy losses can be divided in unavoidable and avoidable losses. The goal of a Cleaner Production and/or energy assessment must be to reduce the avoidable losses, i.e. to improve energy efficiency. The following losses can be avoided or reduced:
- Stack gas losses:
  - Excess air (reduce to the necessary minimum which depends from burner technology, operation, operation (i.e. control) and maintenance).
  - Stack gas temperature (reduce by optimizing maintenance (cleaning), load; better burner and boiler technology).
- Losses by unburnt fuel in stack and ash (optimize operation and maintenance; better technology of burner).
- Blow down losses (treat fresh feed water, recycle condensate)
- Condensate losses (recover the largest possible amount of condensate)
- Convection and radiation losses (reduced by better insulation of the boiler).

**3.1.2 Boiler efficiency**

Thermal efficiency of a boiler is defined as "the percentage of (heat) energy input that is effectively useful in the generated steam."

There are two methods of assessing boiler efficiency:
- The Direct Method: the energy gain of the working fluid (water and steam) is compared with the energy content of the boiler fuel
- The Indirect Method: the efficiency is the difference between the losses and the energy input

### 3.1.3 Direct method of determining boiler efficiency

*Methodology*

This is also known as 'input-output method' due to the fact that it needs only the useful output (steam) and the heat input (i.e. fuel) for evaluating the efficiency. This efficiency can be evaluated using the formula:

$$\text{Boiler Efficiency } (\eta) = \frac{\text{Heat Output}}{\text{Heat Input}} \times 100$$

$$\text{Boiler Efficiency } (\eta) = \frac{Q \times (h_g - h_f)}{q \times GCV} \times 100$$

Parameters to be monitored for the calculation of boiler efficiency by direct method are:
- Quantity of steam generated per hour (Q) in kg/hr.
- Quantity of fuel used per hour (q) in kg/hr.
- The working pressure (in kg/cm2(g)) and superheat temperature (oC), if any
- The temperature of feed water (oC)
- Type of fuel and gross calorific value of the fuel (GCV) in kcal/kg of fuel

And where
- $h_g$ – Enthalpy of saturated steam in kcal/kg of steam
- $h_f$ – Enthalpy of feed water in kcal/kg of water

*Example*

Find out the efficiency of the boiler by direct method with the data given below:
- Type of boiler:                             Coal fired
- Quantity of steam (dry) generated:          10 TPH
- Steam pressure (gauge) / temp:              10 kg/cm$^2$ (g)/ 180 $^0$C
- Quantity of coal consumed:                  2.25 TPH
- Feed water temperature:                     85 $^0$C
- GCV of coal:                                3200 kcal/kg
- Enthalpy of steam at 10 kg/cm$^2$ pressure:  665 kcal/kg (saturated)
- Enthalpy of feed water:                     85 kcal/kg

$$\text{Boiler Efficiency } (\eta) = \frac{10 \times (665 - 85) \times 1000}{2.25 \times 3200 \times 1000} \times 100 = 80.56 \text{ percent}$$

*Advantages of direct method*

- Plant workers can evaluate quickly the efficiency of boilers
- Requires few parameters for computation

- Needs few instruments for monitoring
- Easy to compare evaporation ratios with benchmark figures

***Disadvantages of direct method***

- Does not give clues to the operator as to why efficiency of the system is lower
- Does not calculate various losses accountable for various efficiency levels

## 3.1.4 Indirect method of determining boiler efficiency

*Methodology*

The reference standards for Boiler Testing at Site using the indirect method are the *British Standard, BS 845:1987* and the *USA Standard ASME PTC-4-1 Power Test Code Steam Generating Units*.

The indirect method is also called the heat loss method. The efficiency can be calculated by subtracting the heat loss fractions from 100 as follows:

Efficiency of boiler (n) = 100 - (i + ii + iii + iv + v + vi + vii)

Whereby the principle losses that occur in a boiler are loss of heat due to:

i.     Dry flue gas
ii.    Evaporation of water formed due to H2 in fuel
iii.   Evaporation of moisture in fuel
iv.    Moisture present in combustion air
v.     Unburnt fuel in fly ash
vi.    Unburnt fuel in bottom ash
vii.   Radiation and other unaccounted losses

Losses due to moisture in fuel and due to combustion of hydrogen are dependent on the fuel, and cannot be controlled by design.

The data required for calculation of boiler efficiency using the indirect method are:

- Ultimate analysis of fuel (H2, O2, S, C, moisture content, ash content)
- Percentage of oxygen or CO2 in the flue gas
- Flue gas temperature in $^{\circ}$C (Tf)
- Ambient temperature in $^{\circ}$C (Ta) and humidity of air in kg/kg of dry air
- GCV of fuel in kcal/kg
- Percentage combustible in ash (in case of solid fuels)
- GCV of ash in kcal/kg (in case of solid fuels)

A detailed procedure for calculating boiler efficiency using the indirect method is given below. However, practicing energy managers in industry usually prefer simpler calculation procedures.

Step 1: Calculate the theoretical air requirement

$$= [(11.43 \times C) + \{34.5 \times (H2 - O2/8)\} + (4.32 \times S)]/100 \text{ kg/kg of fuel}$$

Step 2: Calculate the percent excess air supplied (EA)

$$= \frac{O_2 \text{ percent} \times 100}{(21 - O_2 \text{ percent})}$$

Step 3: Calculate actual mass of air supplied/ kg of fuel (AAS)

$$= \{1 + EA/100\} \times \text{theoretical air}$$

Step 4: Estimate all heat losses

    i.      Percentage heat loss due to dry flue gas

$$= \frac{m \times C_p \times (T_f - T_a) \times 100}{\text{GCV of fuel}}$$

Where, m = mass of dry flue gas in kg/kg of fuel
m = (mass of dry products of combustion / kg of fuel) + (mass of N2 in fuel on 1 kg basis ) + (mass of N2 in actual mass of air we are supplying).
$C_p$ = Specific heat of flue gas (0.23 kcal/kg )

    ii.     Percentage heat loss due to evaporation of water formed due to H2 in fuel

$$= \frac{9 \times H_2 \{584 + C_p (T_f - T_a)\} \times 100}{\text{GCV of fuel}}$$

Where, H2 = percentage of H2 in 1 kg of fuel
$C_p$ = specific heat of superheated steam (0.45 kcal/kg)

    iii.    Percentage heat loss due to evaporation of moisture present in fuel

$$= \frac{M\{584 + C_p (T_f - T_a)\} \times 100}{\text{GCV of fuel}}$$

Where, M – percent moisture in 1kg of fuel
$C_p$ – Specific heat of superheated steam (0.45 kcal/kg)

    iv.    Percentage heat loss due to moisture present in air

$$= \frac{AAS \times \text{humidity factor} \times C_p (T_f - T_a)\} \times 100}{\text{GCV of fuel}}$$

Where, Cp – Specific heat of superheated steam (0.45 kcal/kg)

v.     Percentage heat loss due to unburnt fuel in fly ash

= Total ash collected/kg of fuel burnt x GCV of fly ash x 100
-----------------------------------------------------------------------
GCV of fuel

vi.     Percentage heat loss due to unburnt fuel in bottom ash

= Total ash collected per Kg of fuel burnt x G.C.V of bottom ash x 100
--------------------------------------------------------------------------------
GCV of fuel

vii.     Percentage heat loss due to radiation and other unaccounted loss

The actual radiation and convection losses are difficult to assess because of particular emissivity of various surfaces, its inclination, airflow patterns etc. In a relatively small boiler, with a capacity of 10 MW, the radiation and unaccounted losses could amount to between 1 percent and 2 percent of the gross calorific value of the fuel, while in a 500 MW boiler, values between 0.2 percent to 1 percent are typical. The loss may be assumed appropriately depending on the surface condition.

Step 5: Calculate boiler efficiency and boiler evaporation ratio

Efficiency of boiler (n) = 100 - (i + ii + iii + iv + v + vi + vii)

Evaporation Ratio = Heat utilized for steam generation/Heat addition to the steam

Evaporation ratio means kilogram of steam generated per kilogram of fuel consumed. Typical Examples are:
- Coal fired boiler: 6 (i.e. 1 kg of coal can generate 6 kg of steam)
- Oil fired boiler: 13 (i.e. 1 kg of oil can generate 13 kg of steam)

However, the evaporation ratio will depend upon type of boiler, calorific value of the fuel and associated efficiencies.

*Example*

- Type of boiler:                    Oil fired
- Ultimate analysis of Oil

  C:      84 percent
  $H_2$:    12.0 percent
  S:       3.0 percent
  $O_2$:    1 percent

- GCV of Oil:                       10200 kcal/kg

- Percentage of Oxygen:             7 percent

- Percentage of $CO_2$:    11 percent
- Flue gas temperature ($T_f$):    220 $^0$C
- Ambient temperature ($T_a$):    27 $^0$C
- Humidity of air    :    0.018 kg/kg of dry air

Step-1: Calculate the theoretical air requirement

= [(11.43 x C) + [{34.5 x (H2 – O2/8)} + (4.32 x S)]/100 kg/kg of oil
= [(11.43 x 84) + [{34.5 x (12 – 1/8)} + (4.32 x 3)]/100 kg/kg of oil
= 13.82 kg of air/kg of oil

Step-2: Calculate the percent excess air supplied (EA)

Excess air supplied (EA)
= (O2 x 100)/(21-O2)
= (7 x 100)/(21-7)
= 50 percent

Step 3: Calculate actual mass of air supplied/ kg of fuel (AAS)

AAS/kg fuel        = [1 + EA/100] x Theo. Air (AAS)
= [1 + 50/100] x 13.82
= 1.5 x 13.82
= 20.74 kg of air/kg of oil

Step 4: Estimate all heat losses

i.    Percentage heat loss due to dry flue gas

$$= \frac{m \times Cp \times (Tf - Ta) \times 100}{GCV \text{ of fuel}}$$

m = mass of CO2 + mass of SO2 + mass of N2 + mass of O2

$$m = \frac{0.84 \times 44}{12} + \frac{0.03 \times 64}{32} + \frac{20.74 \times 77}{100} \quad (0.07 \times 32)$$

m = 21.35 kg / kg of oil

$$= \frac{21.35 \times 0.23 \times (220 - 27)}{10200} \times 100$$

=    9.29 percent

*A simpler method can also be used:* Percentage heat loss due to dry flue gas

$$= \frac{m \times C_p \times (T_f - T_a) \times 100}{GCV \text{ of fuel}}$$

m (total mass of flue gas)

= mass of actual air supplied + mass of fuel supplied

= 20.19 + 1 = 21.19

$$= \frac{21.19 \times 0.23 \times (220-27)}{10200} \times 100$$

= 9.22 percent

ii. Heat loss due to evaporation of water formed due to H2 in fuel

$$= \frac{9 \times H2 \{584+0.45 (T_f - T_a)\}}{GCV \text{ of fuel}} \qquad \text{where } H2 = \text{percentage of H2 in fuel}$$

$$= \frac{9 \times 12 \{584+0.45(220-27)\}}{10200}$$

= 7.10 percent

iii. Heat loss due to moisture present in air

$$= \frac{AAS \times humidity \times 0.45 \times ((T_f - T_a) \times 100}{GCV \text{ of fuel}}$$

= [20.74 x 0.018 x 0.45 x (220-27) x 100]/10200

= 0.317 percent

iv. Heat loss due to radiation and other unaccounted losses

For a small boiler it is estimated to be 2 percent

Step 5: Calculate boiler efficiency and boiler evaporation ratio

Efficiency of boiler (n) = 100 - (i + ii + iii + iv + v + vi + vii)

i. Heat loss due to dry flue gas : 9.29 percent
ii. Heat loss due to evaporation of water formed due to H2 in fuel : 7.10 percent

| | | | |
|---|---|---|---|
| iii. | Heat loss due to moisture present in air | : 0.317 percent |
| iv. | Heat loss due to radiation and other unaccounted losses | : 2 percent |

$$= 100 - [9.29+7.10+0.317+2]$$

$$= 100 - 17.024 = 83 \text{ percent (approximate)}$$

Evaporation Ratio = Heat utilized for steam generation/Heat addition to the steam

$$= 10200 \times 0.83 / (660-60)$$
$$= 14.11 \text{ (compared to 13 for a typical oil fired boiler)}$$

*Advantages of indirect method*

▪ A complete mass and energy balance can be obtained for each individual stream, making it easier to identify options to improve boiler efficiency

*Disadvantages of indirect method*

▪ Time consuming
▪ Requires lab facilities for analysis

## 3.2 Boiler Blow Down

When water is boiled and steam is generated, any dissolved solids contained in the water remain in the boiler. If more solids are put in with the feed water, they will concentrate and may eventually reach a level where their solubility in the water is exceeded and they deposit from the solution. Above a certain level of concentration, these solids encourage foaming and cause carryover of water into the steam. The deposits also lead to scale formation inside the boiler, resulting in localized overheating and finally causing boiler tube failure.

It is therefore necessary to control the level of concentration of the solids in suspension and dissolved in the boiled water. This is achieved by the process of 'blowing down', where a certain volume of water is blown off and is automatically replaced by feed water - thus maintaining the optimum level of total dissolved solids (TDS) in the boiler water and removing those solids that have fallen out of solution and which tend to settle on the internal surfaces of the boiler. Blow down is necessary to protect the surfaces of the heat exchanger in the boiler. However, blow down can be a significant source of heat loss, if improperly carried out.

Since it is tedious and time consuming to measure TDS in a boiler water system, conductivity measurement is used for monitoring the overall TDS present in the boiler. A rise in conductivity indicates a rise in the "contamination" of the boiler water.

**Boiler Water Sampling**

A boiler water sample is only useful if it is representative of the conditions inside the boiler. Therefore samples taken from the level gauge glass, externally mounted level control chambers, or close to the feed water inlet connection are likely to be very inaccurate.

A sample taken from the boiler shell is unsafe and inaccurate because the water is under pressure and a significant proportion will flash into steam. Therefore higher TDS concentrations are measured in the sample than inside the boiler. Based on these sample analysis results, it is very common that more boiler water is blown down than necessary.

The solution is to use a sample cooler to extract water from a boiler. A sample cooler is a small heat exchanger that uses cold water to cool the sample being withdrawn, thereby eliminating any flashing and improving operator safety and sample accuracy. In some automatic systems, a conductivity sensor is mounted directly into the boiler shell to monitor the TDS levels continuously. Another reason for an automatic TDS control system is to avoid the influence of variability in steam load, rate of condensate return, and make-up water quality on the sample results.

### 3.2.1 Two types of blow down

Conventional methods for blowing down the boiler depend on two kinds of blow down: intermittent and continuous.

#### a) Intermittent blow down

The intermittent blown down is given by manually operating a valve fitted to a discharge pipe at the lowest point of the boiler shell to reduce parameters (TDS or conductivity, pH, Silica and Phosphates concentration) within prescribed limits so that steam quality is not likely to be affected. This type of blow down is also an effective method to remove solids that have fallen out of solution and have settled upon the fire tubes and the internal surface of the boiler shell. In intermittent blow down, a large diameter line is opened for a short period of time, the time being based on a general rule such as "once in a shift for 2 minutes".

Intermittent blow down requires l*arge* short-term increases in the amount of feed water put into the boiler, and hence may necessitate larger feed water pumps than if continuous blow down is used. Also, TDS level will vary, thereby causing fluctuations of the water level in the boiler due to changes in steam bubble size and distribution which accompany changes in concentration of solids. Also, a substantial amount of heat energy is lost with intermittent blow down.

#### b) Continuous blow down

There is a steady and constant dispatch of a small stream of concentrated boiler water, and replacement by steady and constant inflow of feed water. This ensures constant TDS and steam purity at a given steam load. Once a blow down valve is set for a given conditions, there is no need for regular operator intervention.

Even though large quantities of heat are removed from the boiler, opportunities exist for recovering this heat by blowing into a flash tank and generating flash steam. This flash steam can be used for pre-heating boiler feed water. This type of blow down is common in high-pressure boilers.

The residual blowdown which leaves the flash vessel still contains a good deal of heat energy and a significant proportion of this can also be recovered by introducing a heat exchanger to heat up cold make-up water.  Complete blowdown heat recovery systems such as the one illustrated below which extract the flash steam and the energy content of the residual blowdown, can recover up to 80% of the energy contained in the blowdown.  They can be applied to any size of steam boiler and an investment in such a system is often recovered in a matter of months.
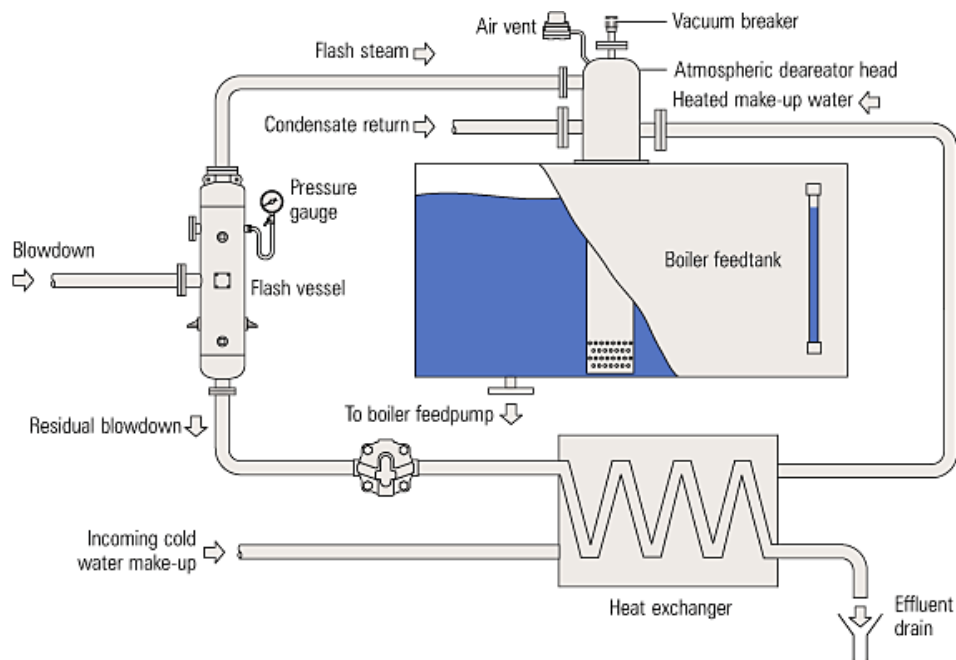


**Figure 13. Schematic of Recovery of Heat from Boiler Blowdown** (Spirax Sarco)

### 3.2.2 Blow down calculations

The quantity of blow down required to control boiler water solids concentration is calculated by using the following formula:

$$\text{Blow down (percent)} = \frac{\text{Make up water TDS x \% Make up water}}{\text{Maximum permissible TDS in boiler water}}$$

If the maximum permissible limit of TDS as in a package boiler is 3000 ppm, the percentage make up water is 10 percent and the TDS in make up water is 300 ppm, then the percentage blow down is given as:

$$= 300 \times 10 / 3000$$
$$= 1 \text{ percent}$$

If boiler evaporation rate is 3000 kg/hr then required blow down rate is:

$$= 3000 \times 1 / 100$$
$$= 30 \text{ kg/hr}$$

### 3.2.3 Benefits of blow down control

Good boiler blow down control can significantly reduce treatment and operational costs that include:
- Lower pretreatment costs
- Less make-up water consumption
- Reduced maintenance downtime
- Increased boiler life
- Lower consumption of treatment chemicals

## 3.3 Boiler Feed Water Treatment

Producing quality steam on demand depends on properly managed water treatment to control steam purity, deposits and corrosion. A boiler is the sump of the boiler system. It ultimately receives all of the pre-boiler contaminants. Boiler performance, efficiency, and service life are direct products of selecting and controlling feed water used in the boiler.

When feed water enters the boiler, the elevated temperatures and pressures cause the components of water to behave differently. Most of the components in the feed water are soluble. However, under heat and pressure most of the soluble components come out of solution as particulate solids, sometimes in crystallized forms and other times as amorphous particles. When solubility of a specific component in water is exceeded, scale or deposits develop. The boiler water must be sufficiently free of deposit forming solids to allow rapid and efficient heat transfer and it must not be corrosive to the boiler metal.

Deposit control is explain first, followed by the two major types of boiler water treatment: internal water treatment and external water treatment.

### 3.3.1 Deposit control

Deposits in boilers may result from hardness contamination of feed water and corrosion products from the condensate and feed water system. Hardness contamination of the feed water may arise due to a deficient softener system.

Deposits and corrosion result in efficiency losses and may result in boiler tube failures and inability to produce steam. Deposits act as insulators and slow heat transfer. Large amounts of deposits throughout the boiler could reduce the heat transfer enough to reduce the boiler efficiency significantly. Different types of deposits affect the boiler efficiency differently. Thus it may be useful to analyze the deposits for their characteristics. The insulating effect of deposits causes the boiler metal temperature to rise and may lead to tube-failure by overheating.

There are two main groups of impurities causing deposits.

*a) Hard salts of calcium and magnesium*
The most important chemicals in water that influence the formation of deposits in boilers are the salts of calcium and magnesium, which are known as hardness salts.

- Alkaline. Calcium and magnesium bicarbonate dissolve in water to form an alkaline solution and these salts are known as alkaline hardness. They decompose upon heating, releasing carbon dioxide and forming a soft sludge, which settles out. These are called temporary hardness-hardness that can be removed by boiling.
- Non-alkaline. Calcium and magnesium sulphates, chlorides and nitrates etc., when dissolved in water, are chemically neutral and are known as non-alkaline hardness. These are called permanent hardness chemicals and form hard scales on boiler surfaces, which are difficult to remove. Non-alkalinity hardness chemicals fall out of the solution due to reduction in solubility as the temperature rises, by concentration due to evaporation which takes place within the boiler, or by chemical change to a less soluble compound.

*b) Silica*
The presence of silica in boiler water can rise to formation of hard silicate scales. It can also interact with calcium and magnesium salts, forming calcium and magnesium silicates of very low thermal conductivity. Silica can give rise to deposits on steam turbine blades, after being carried over either in droplets of water in steam, or in a volatile form in steam at higher pressures.

### 3.3.2 Internal water treatment

Internal treatment involves adding chemicals to a boiler to prevent the formation of scale. Scale-forming compounds are converted to free-flowing sludge, which can be removed by blow down. This method is limited to boilers, where feed water is low in hardness salts, where low pressure, high TDS content in boiler water is tolerated, and when only a small quantity of water is required to be treated. If these conditions are not met, then high rates of blow down are required to dispose off the sludge. They become uneconomical considering heat and water loss.

Different types of water sources require different chemicals. Sodium carbonate, sodium aluminate, sodium phosphate, sodium sulphite and compounds of vegetable or inorganic origin are all used for this purpose. Proprietary chemicals are available to suit various water conditions. A specialist must be consulted to determine the most suitable chemicals to use in each case. Internal treatment alone is not recommended.

### 3.3.3 External Water Treatment

External treatment is used to remove suspended solids, dissolved solids (particularly the calcium and magnesium ions which are major a cause of scale formation) and dissolved gases (oxygen and carbon dioxide).

The external treatment processes available are:
- Ion exchange
- De-aeration (mechanical and chemical)
- Reverse osmosis
- Demineralization

Before any of these are used, it is necessary to remove suspended solids and colour from the raw water, because these may foul the resins used in the subsequent treatment sections.

Methods of pre-treatment include simple sedimentation in settling tanks or settling in clarifiers with aid of coagulants and flocculants. Pressure sand filters, with spray aeration to remove carbon dioxide and iron, may be used to remove metal salts from bore well water.

The first stage of treatment is to remove hardness salt and possibly non-hardness salts. Removal of only hardness salts is called softening, while total removal of salts from solution is called demineralization.

The external water treatment processes are described below.

### a) Ion-exchange process (Softener Plant)

In ion-exchange process, the hardness is removed as the water passes through a bed of natural zeolite or synthetic resin and without the formation of any precipitate. The simplest type is 'base

> **Softening reaction:**
> $Na2R + Ca(HCO_3)2 « CaR + 2 Na(HCO_3)$
> **Regeneration reaction**
> $CaR + 2 NaCl « Na_2R + CaCl_2$

exchange' in which calcium and magnesium ions are exchanged for sodium ions. After saturation regeneration is done with sodium chloride. The sodium salts being soluble, do not form scales in boilers. Since the base exchanger only replaces the calcium and magnesium with sodium, it does not reduce the TDS content, and blow down quantity. It also does not reduce the alkalinity.
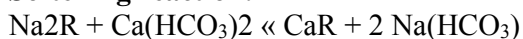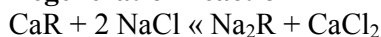
Demineralization is the complete removal of all salts. This is achieved by using a "cation" resin, which exchanges the cations in the raw water with hydrogen ions, producing hydrochloric, sulphuric and carbonic acid. Carbonic acid is removed in a degassing tower in which air is blown through the acid water. Following this, the water passes through an "anion" resin, which exchanges anions with the mineral acid (e.g. sulphuric acid) and forms water. Regeneration of cations and anions is necessary at intervals using, typically, mineral acid and caustic soda respectively. The complete removal of silica can be achieved by correct choice of anion resin.

Ion exchange processes can be used for almost total demineralization if required, as is the case in large electric power plant boilers

### b) De-aeration

In de-aeration, dissolved gases, such as oxygen and carbon dioxide, are expelled by preheating the feed water before it enters the boiler. All natural waters contain dissolved gases in solution. Certain gases, such as carbon dioxide and oxygen, greatly increase corrosion. When heated in boiler systems, carbon dioxide ($CO_2$) and oxygen ($O_2$) are released as gases and combine with water ($H_2O$) to form carbonic acid, ($H_2CO_3$).

Removal of oxygen, carbon dioxide and other non-condensable gases from boiler feed water is vital to boiler equipment longevity as well as safety of operation. Carbonic acid corrodes metal reducing the life of equipment and piping. It also dissolves iron (Fe) which when

returned to the boiler precipitates and causes scaling on the boiler and tubes. This scale not only contributes to reducing the life of the equipment but also increases the amount of energy needed to achieve heat transfer.

De-aeration can be done by mechanical de-aeration, chemical de-aeration, or both.

*Mechanical de-aeration*
Mechanical de-aeration for the removal of these dissolved gases is typically utilized prior to the addition of chemical oxygen scavengers. Mechanical de-aeration is based on Charles' and Henry's laws of physics. In summary, these laws state that removal of oxygen and carbon dioxide can be accomplished by heating the boiler feed water, which reduces the concentration of oxygen and carbon dioxide in the atmosphere surrounding the feed water. Mechanical de-aeration can be the most economical, operating at the boiling point of water at the pressure in the de-aerator. Mechanical de-aeration can be of vacuum or pressure type.
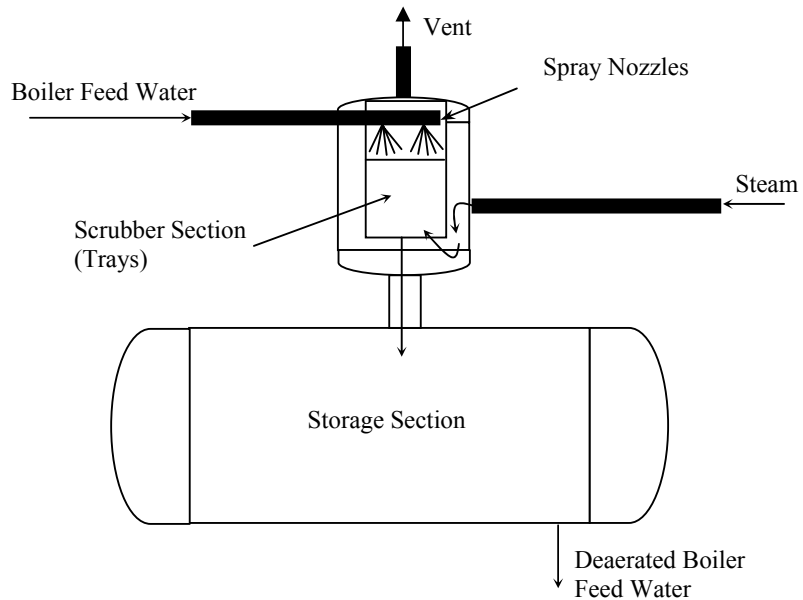


**Figure 14. Mechanical deaeration**
National Productivity Council

The vacuum type de-aerator operates below atmospheric pressure, at about $82^{o}$C, and can reduce the oxygen content in water to less than 0.02 mg/liter. Vacuum pumps or steam ejectors are required to maintain the vacuum.

Pressure-type de-aerators operate by allowing steam into the feed water through a pressure control valve to maintain the desired operating pressure, and hence temperature at a minimum of $105^{o}$C. The steam raises the water temperature causing the release of $O_2$ and $CO_2$ gases that are then vented from the system. This type can reduce the oxygen content to 0.005 mg/litre.

Where excess low-pressure steam is available, the operating pressure can be selected to make use of this steam and hence improve fuel economy. In boiler systems, steam is preferred for de-aeration because:
▪ Steam is essentially free from $O_2$ and $CO_2$
▪ Steam is readily available
▪ Steam adds the heat required to complete the reaction

*Chemical de-aeration*

While the most efficient mechanical deaerators reduce oxygen to very low levels (0.005 mg/liter), even trace amounts of oxygen may cause corrosion damage to a system. Consequently, good operating practice requires removal of that trace oxygen with a chemical oxygen scavenger such as sodium sulfite or hydrazine. Sodium sulphite reacts with oxygen to form sodium sulphate, which increases the TDS in the boiler water and hence increases the blow down requirements and make-up water quality. Hydrazine reacts with oxygen to form nitrogen and water. It is invariably used in high pressure boilers when low boiler water solids are necessary, as it does not increase the TDS of the boiler water.

## c) Reverse osmosis

Reverse osmosis uses the fact that when solutions of differing concentrations are separated by a semi-permeable membrane, water from a less concentrated solution passes through the membrane to dilute the liquid of high concentration. If the solution of high concentration is pressurized, the process is reversed and the water from the solution of high concentration flows to the weaker solution. This is known as reverse osmosis.
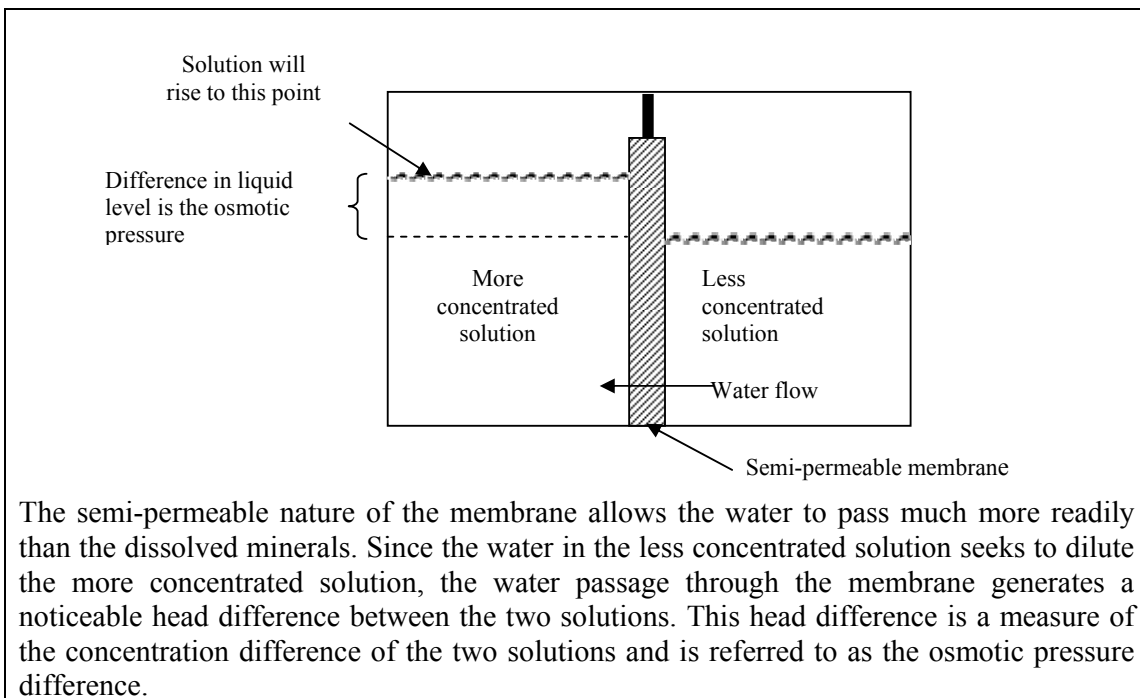


The semi-permeable nature of the membrane allows the water to pass much more readily than the dissolved minerals. Since the water in the less concentrated solution seeks to dilute the more concentrated solution, the water passage through the membrane generates a noticeable head difference between the two solutions. This head difference is a measure of the concentration difference of the two solutions and is referred to as the osmotic pressure difference.

When a pressure is applied to the concentrated solution, which is greater then that of the osmotic pressure difference, the direction of water passage through the membrane is reversed and the process that we refer to as reverse osmosis is established. That is, the membrane's ability to selectively pass water is unchanged, only the direction of the water flow is changed.



The feed water and concentrate (reject stream) ports illustrates a continuously operating RO system.

The quality of water produced depends upon the concentration of the solution on the high-pressure side and pressure differential across the membrane. This process is suitable for waters with very high TDS, such as seawater.

### 3.3.4 Recommended boiler and feed water quality

The impurities found in boiler water depend on the untreated feed water quality, the treatment process used and the boiler operating procedures. As a general rule, the higher the boiler operating pressure, the greater will be the sensitivity to impurities.

| RECOMMENDED FEED WATER LIMITS (IS 10392, 1982) | | | |
|---|---|---|---|
| **Factor** | **Up to 20 kg/cm$^2$** | **21 - 39 kg/cm$^2$** | **40- 59 kg/cm$^2$** |
| Total iron (max) ppm | 0.05 | 0.02 | 0.01 |
| Total copper (max) ppm | 0.01 | 0.01 | 0.01 |
| Total silica (max) ppm | 1.0 | 0.3 | 0.1 |
| Oxygen (max) ppm | 0.02 | 0.02 | 0.01 |
| Hydrazine residual ppm | - | - | -0.02-0.04 |
| pH at 25$^0$C | 8.8-9.2 | 8.8-9.2 | 8.2-9.2 |
| Hardness, ppm | 1.0 | 0.5 | - |

| RECOMMENDED BOILER WATER LIMITS (IS 10392, 1982) | | | |
|---|---|---|---|
| **Factor** | **Up to 20 kg/cm$^2$** | **21 - 39 kg/cm$^2$** | **40 - 59 kg/cm$^2$** |
| TDS, ppm | 3000-3500 | 1500-2500 | 500-1500 |
| Total iron dissolved solids ppm | 500 | 200 | 150 |
| Specific electrical conductivity at 25$^o$C (mho) | 1000 | 400 | 300 |
| Phosphate residual ppm | 20-40 | 20-40 | 15-25 |
| pH at 25$^0$C | 10-10.5 | 10-10.5 | 9.8-10.2 |
| Silica (max) ppm | 25 | 15 | 10 |

# 4. ENERGY EFFICIENCY OPPORTUNITIES

This section includes energy efficiency opportunities related to combustion, heat transfer, avoidable losses, auxiliary power consumption, water quality and blow down.

Energy losses and therefore energy efficiency opportunities in boilers can be related to combustion, heat transfer, avoidable losses, high auxiliary power consumption, water quality and blow down.

The various energy efficiency opportunities in a boiler system can be related to:

1.  Stack temperature control
2.  Feed water preheating using economizers
3.  Combustion air pre-heating
4.  Incomplete combustion minimization
5.  Excess air control
6.  Radiation and convection heat loss avoidance
7.  Automatic blow down control
8.  Reduction of scaling and soot losses
9.  Reduction of boiler steam pressure
10. Variable speed control for fans, blowers and pumps
11. Controlling boiler loading
12. Proper boiler scheduling
13. Boiler replacement

These are explained in the sections below.

## 4.1 Stack Temperature Control

The stack temperature should be as low as possible. However, it should not be so low that water vapor in the exhaust condenses on the stack walls. This is important in fuels containing significant sulphur as low temperature can lead to sulphur dew point corrosion. Stack temperatures greater than 200°C indicates potential for recovery of waste heat. It also indicates the scaling of heat transfer/recovery equipment and hence the urgency of taking an early shut down for water / flue side cleaning.

## 4.2 Feed Water Preheating using Economizers

Typically, the flue gases leaving a modern 3-pass shell boiler are at temperatures of 200 to 300 °C. Thus, there is a potential to recover heat from these gases. The flue gas exit temperature from a boiler is usually maintained at a minimum of 200°C, so that the sulphur oxides in the flue gas do not condense and cause corrosion in heat transfer surfaces. When a clean fuel such as natural gas, LPG or gas oil is used, the economy of heat recovery must be worked out, as the flue gas temperature may be well below 200 °C.

The potential for energy savings depends on the type of boiler installed and the fuel used. For a typically older model shell boiler, with a flue gas exit temperature of 260 °C, an economizer could be used to reduce it to 200 °C, increasing the feed water temperature by 15 °C. Increase in overall thermal efficiency would be in the order of 3 percent. For a modern 3-pass shell boiler firing natural gas with a flue gas exit temperature of 140 °C a condensing economizer would reduce the exit temperature to 65 °C increasing thermal efficiency by 5 percent.

## 4.3 Combustion Air Preheating

Combustion air preheating is an alternative to feed water heating. In order to improve thermal efficiency by 1 percent, the combustion air temperature must be raised by 20 °C. Most gas and oil burners used in a boiler plant are not designed for high air-preheat temperatures.

Modern burners can withstand much higher combustion air preheat, so it is possible to consider such units as heat exchangers in the exit flue as an alternative to an economizer, when either space or a high feed water return temperature make it viable.

## 4.4 Incomplete Combustion

Incomplete combustion can arise from a shortage of air or surplus of fuel or poor distribution of fuel. It is usually obvious from the colour or smoke, and must be corrected immediately.

In the case of oil and gas fired systems, CO or smoke (for oil fired systems only) with normal or high excess air indicates burner system problems. A more frequent cause of incomplete combustion is the poor mixing of fuel and air at the burner. Poor oil fires can result from improper viscosity, worn tips, carbonization on tips and deterioration of diffusers or spinner plates.

With coal firing, unburned carbon can comprise a big loss. It occurs as grit carry-over or carbon-in-ash and may amount to more than 2 percent of the heat supplied to the boiler. Non-

uniform fuel size could be one of the reasons for incomplete combustion. In chain grate stokers, large lumps will not burn out completely, while small pieces and fines may block the air passage, thus causing poor air distribution. In sprinkler stokers, stoker grate condition, fuel distributors, wind box air regulation and over-fire systems can affect carbon loss. Increase in the fines in pulverized coal also increases carbon loss.

## 4.5 Excess Air Control

The table below gives the theoretical amount of air required for combustion of various types of fuel.

Excess air is required in all practical cases to ensure complete combustion, to allow for the normal variations in combustion and to ensure satisfactory stack conditions for some fuels. The optimum excess air level for maximum boiler efficiency occurs when the sum of the losses due to incomplete combustion and loss due to heat in flue gases is minimized. This level varies with furnace design, type of burner, fuel and process variables. It can be determined by conducting tests with different air fuel ratios.

| THEORETICAL COMBUSTION DATA – COMMON BOILER FUELS (National Productivity Council, field experience) | | |
|---|---|---|
| **Fuel** | **kg of air req./kg of fuel** | **$CO_2$ percent in flue gas achieved in practice** |
| **Solid Fuels** | | |
| Bagasse | 3.3 | 10-12 |
| Coal (bituminous) | 10.7 | 10-13 |
| Lignite | 8.5 | 9 -13 |
| Paddy Husk | 4.5 | 14-15 |
| Wood | 5.7 | 11.13 |
| **Liquid Fuels** | | |
| Furnace Oil | 13.8 | 9-14 |
| LSHS | 14.1 | 9-14 |

| TYPICAL VALUES OF EXCESS AIR LEVELS FOR DIFFERENT FUELS (National Productivity Council, field experience) | | |
|---|---|---|
| Fuel | **Type of Furnace or Burners** | **Excess Air (percent by wt)** |
| Pulverized coal | Completely water-cooled furnace for slag-tap or dry-ash removal | 15-20 |
| | Partially water-cooled furnace for dry-ash removal | 15-40 |
| Coal | Spreader stoker | 30-60 |
| | Water-cooler vibrating-grate stokers | 30-60 |
| | Chain-grate and traveling-grate stokers | 15-50 |
| | Underfeed stoker | 20-50 |
| Fuel oil | Oil burners, register type | 15-20 |
| | Multi-fuel burners and flat-flame | 20-30 |
| Natural gas | High pressure burner | 5-7 |

| Wood | Dutch over (10-23 percent through grates) and Hofft type | 20-25 |
|---|---|---|
| Bagasse | All furnaces | 25-35 |
| Black liquor | Recovery furnaces for draft and soda-pulping processes | 30-40 |

Controlling excess air to an optimum level always results in reduction in flue gas losses; for every 1 percent reduction in excess air there is approximately 0.6 percent rise in efficiency.

Various methods are available to control the excess air:
- Portable oxygen analyzers and draft gauges can be used to make periodic readings to guide the operator to manually adjust the flow of air for optimum operation. Excess air reduction up to 20 percent is feasible.
- The most common method is the continuous oxygen analyzer with a local readout mounted draft gauge, by which the operator can adjust air flow. A further reduction of 10-15 percent can be achieved over the previous system.
- The same continuous oxygen analyzer can have a remote controlled pneumatic damper positioner, by which the readouts are available in a control room. This enables an operator to remotely control a number of firing systems simultaneously.

The most sophisticated system is the automatic stack damper control, whose cost is really justified only for large systems.

## 4.6 Radiation and Convection Heat Loss Minimization

The external surfaces of a shell boiler are hotter than the surroundings. The surfaces thus lose heat to the surroundings depending on the surface area and the difference in temperature between the surface and the surroundings.

The heat loss from the boiler shell is normally a fixed energy loss, irrespective of the boiler output. With modern boiler designs, this may represent only 1.5 percent on the gross calorific value at full rating, but will increase to around 6 percent, if the boiler operates at only 25 percent output.

Repairing or augmenting insulation can reduce heat loss through boiler walls and piping.

## 4.7 Automatic Blow down Control

Uncontrolled continuous blow down is very wasteful. Automatic blow down controls can be installed that sense and respond to boiler water conductivity and pH. A 10 percent blow down in a 15 kg/cm2 boiler results in 3 percent efficiency loss.

## 4.8 Reduction of Scaling and Soot Losses

In oil and coal-fired boilers, soot buildup on tubes acts as an insulator against heat transfer. Any such deposits should be removed on a regular basis. Elevated stack temperatures may indicate excessive soot buildup. Also same result will occur due to scaling on the water side. High exit gas temperatures at normal excess air indicate poor heat transfer performance. This condition can result from a gradual build-up of gas-side or waterside deposits. Waterside deposits require a review of water treatment procedures and tube cleaning to remove deposits. An estimated 1 percent efficiency loss occurs with every 22$^{\circ}$C increase in stack temperature.

Stack temperature should be checked and recorded regularly as an indicator of soot deposits. When the flue gas temperature rises to about 20 °C above the temperature for a newly cleaned boiler, it is time to remove the soot deposits. It is therefore recommended to install a dial type thermometer at the base of the stack to monitor the exhaust flue gas temperature.

It is estimated that 3 mm of soot can cause an increase in fuel consumption by 2.5 percent due to increased flue gas temperatures. Periodic off-line cleaning of radiant furnace surfaces, boiler tube banks, economizers and air heaters may be necessary to remove stubborn deposits.

## 4.9 Reduction of Boiler Steam Pressure

This is an effective means of reducing fuel consumption, if permissible, by as much as 1 to 2 percent. Lower steam pressure gives a lower saturated steam temperature and without stack heat recovery, a similar reduction in the temperature of the flue gas temperature results.

Steam is generated at pressures normally dictated by the highest pressure / temperature requirements for a particular process. In some cases, the process does not operate all the time, and there are periods when the boiler pressure could be reduced. But it must be remembered that any reduction of boiler pressure reduces the specific volume of the steam in the boiler, and effectively derates the boiler output. If the steam load exceeds the derated boiler output, carryover of water will occur. The energy manager should therefore consider the possible consequences of pressure reduction carefully, before recommending it. Pressure should be reduced in stages, and no more than a 20 percent reduction should be considered.

## 4.10 Variable Speed Control for Fans, Blowers and Pumps

Variable speed control is an important means of achieving energy savings. Generally, combustion air control is affected by throttling dampers fitted at forced and induced draft fans. Though dampers are simple means of control, they lack accuracy, giving poor control characteristics at the top and bottom of the operating range. In general, if the load characteristic of the boiler is variable, the possibility of replacing the dampers by a VSD should be evaluated.

## 4.11 Controlling Boiler Loading

The maximum efficiency of the boiler does not occur at full load, but at about two-thirds of the full load. If the load on the boiler decreases further, efficiency also tends to decrease. At zero output, the efficiency of the boiler is zero, and any fuel fired is used only to supply the losses. The factors affecting boiler efficiency are:
▪ As the load falls, so does the value of the mass flow rate of the flue gases through the tubes. This reduction in flow rate for the same heat transfer area reduces the exit flue gas temperatures by a small extent, reducing the sensible heat loss.
▪ Below half load, most combustion appliances need more excess air to burn the fuel completely. This increases the sensible heat loss.

In general, efficiency of the boiler reduces significantly below 25 percent of the rated load and operation of boilers below this level should be avoided as far as possible.

## 4.12 Proper Boiler Scheduling

Since, the optimum efficiency of boilers occurs at 65-85 percent of full load, it is usually more efficient, on the whole, to operate a fewer number of boilers at higher loads, than to operate a large number at low loads.

## 4.13 Boiler Replacement

The potential savings from replacing a boiler depend on the anticipated change in overall efficiency. A change in a boiler can be financially attractive if the existing boiler is:
- Old and inefficient
- Not capable of firing cheaper substitution fuel
- Over or under-sized for present requirements
- Not designed for ideal loading conditions

The feasibility study should examine all implications of long-term fuel availability and company growth plans. All financial and engineering factors should be considered. Since boiler plants traditionally have a useful life of well over 25 years, replacement must be carefully studied.

# 5. OPTION CHECKLIST

This section includes the most common options for improving a boiler's energy efficiency.

## 5.1 Periodic tasks and checks outside of the boiler

- All access doors and plate work should be maintained air tight with effective gaskets.
- Flue systems should have all joints sealed effectively and be insulated where appropriate.
- Boiler shells and sections should be effectively insulated. Is existing insulation adequate? If insulation was applied to boilers, pipes and hot water cylinders several years ago, it is almost certainly too thin even if it appears in good condition. Remember, it was installed when fuel costs were much lower. Increased thickness may well be justified.
- At the end of the heating season, boilers should be sealed thoroughly, internal surfaces either ventilated naturally during the summer or very thoroughly sealed with tray of desiccant inserted. (Only applicable to boilers that will stand idle between heating seasons)

## 5.2 Boilers: extra items for steam raising and hot water boilers

- Check regularly for build-up of scale or sludge in the boiler vessel or check TDS of boiler water each shift, but not less than once per day. Impurities in boiler water are concentrated in the boiler and the concentration has limits that depend on type of boiler and load. Boiler blow down should be minimized, but consistent with maintaining correct water density. Recover heat from blow down water.
- With steam boilers, is water treatment adequate to prevent foaming or priming and consequent excessive carry over of water and chemicals into the steam system?
- For steam boilers: are automatic water level controllers operational? The presence of inter-connecting pipes can be extremely dangerous.
- Have checks been made regularly on air leakages round boiler inspection doors, or between boiler and chimney? The former can reduce efficiency; the latter can reduce draught availability and may encourage condensation, corrosion and smutting.
- Combustion conditions should be checked using flue gas analyzers at least twice per season and the fuel/air ratio should be adjusted if required.
- Both detection and actual controls should be labeled effectively and checked regularly.
- Safety lockout features should have manual re-set and alarm features.
- Test points should be available, or permanent indicators should be fitted to oil burners to give operating pressure/temperature conditions.
- With oil-fired or gas-fired boilers, if cables of fusible link systems for shutdown due to fire or overheating run across any passageway accessible to personnel, they should be fitted above head level.
- The emergency shut down facility is to be situated at the exit door of the boiler house.
- In order to reduce corrosion, steps should be taken to minimize the periods when water return temperatures fall below dew point, particularly on oil and coal fired boilers.
- Very large fuel users may have their own weighbridge and so can operate a direct check on deliveries. If no weighbridge exists, occasionally ask your supplier to run via a public weighbridge (or a friendly neighbour with a weighbridge) just as a check? With liquid fuel deliveries check the vehicle's dipsticks?
- With boiler plant, ensure that the fuel used is correct for the job. With solid fuel, correct grading or size is important, and ash and moisture content should be as the plant designer

originally intended. With oil fuel, ensure that viscosity is correct at the burner, and check the fuel oil temperature.
- The monitoring of fuel usage should be as accurate as possible. Fuel stock measurements must be realistic.
- With oil burners, examine parts and repairs. Burner nozzles should be changed regularly and cleaned carefully to prevent damage to burner tip.
- Maintenance and repair procedures should be reviewed especially for burner equipment, controls and monitoring equipment.
- Regular cleaning of heat transfer surfaces maintains efficiency at the highest possible level.
- Ensure that the boiler operators are conversant with the operational procedures, especially any new control equipment.
- Have you investigated the possibility of heat recovery from boiler exit gases? Modern heat exchangers/recuperators are available for most types and sizes of boiler.
- Do you check feed and header tanks for leaking make up valves, correct insulation or loss of water to drain?
- The manufacturer may have originally provided the boiler plant with insulation. Is this still adequate with today's fuel costs? Check on optimum thickness.
- If the amount of steam produced is quite large, invest in a steam meter.
- Measure the output of steam and input of fuel. The ratio of steam to fuel is the main measure of efficiency at the boiler.
- Use the monitoring system provided: this will expose any signs of deterioration.
- Feed water should be checked regularly for both quantity and purity.
- Steam meters should be checked occasionally as they deteriorate with time due to erosion of the metering orifice or pilot head. It should be noted that steam meters only give correct readings at the calibrated steam pressure. Recalibration may be required.
- Check all pipe work, connectors and steam traps for leaks, even in inaccessible spaces.
- Pipes not in use should be isolated and redundant pipes disconnected.
- Is someone designated to operate and generally look after the installation? This work should be included in their job specification.
- Are basic records available to that person in the form of drawings, operational instructions and maintenance details?
- Is a log book kept to record details of maintenance carried out, actual combustion flue gas readings taken, fuel consumption at weekly or monthly intervals, and complaints made?
- Ensure that steam pressure is no higher than need be for the job. When night load is materially less than day load, consider a pressure switch to allow pressure to vary over a much wider band during night to reduce frequency of burner cut-out, or limit the maximum firing rate of the burner.
- Examine the need for maintaining boilers in standby conditions—this is often an unjustified loss of heat. Standing boilers should be isolated on the fluid and gas sides.
- Keep a proper log of boiler house activity so that performance can be measured against targets. When checking combustion, etc. with portable instruments, ensure that this is done regularly and that load conditions are reported in the log: percentage of $CO_2$ at full flame/half load, etc.
- Have the plant checked to ensure that severe load fluctuations are not caused by incorrect operation of auxiliaries in the boiler house, for example, ON/OFF feed control, defective modulating feed systems or incorrect header design.
- Have hot water heating systems been dosed with an anti-corrosion additive and is this checked annually to see that concentration is still adequate? Make sure that this additive

is NOT put into the domestic hot water heater tank, it will contaminate water going to taps at sinks and basins.
▪ Recover all condensate where practical and substantial savings are possible.

## 5.3 Boiler rooms and plant rooms

▪ Ventilation openings should be kept free and clear at all times and the opening area should be checked to ensure this is adequate.
▪ Plant rooms should not be used for storage, airing or drying purposes.
▪ Is maintenance of pumps and automatic valves carried out in accordance with the manufacturers' instructions?
▪ Are run and standby pump units changed over approximately once per month?
▪ Are pump isolating valves provided?
▪ Are pressure/heat test points and/or indicators provided on each side of the pump?
▪ Are pump casings provided with air release facilities?
▪ Are moving parts (e.g. couplings) guarded?
▪ Ensure that accuracy of the instruments is checked regularly.
▪ Visually inspect all pipe work and valves for any leaks.
▪ Check that all safety devices operate efficiently.
▪ Check all electrical contacts to see that they are clean and secure.
▪ Ensure that all instrument covers and safety shields are in place.
▪ Inspect all sensors, make sure they are clean, unobstructed and not exposed to unrepresentative conditions, for example temperature sensors must not be exposed to direct sunlight nor be placed near hot pipes or a process plant.
▪ Ensure that only authorized personnel have access to control equipment.
▪ Each section of the plant should operate when essential, and should preferably be controlled automatically.
▪ Time controls should be incorporated and operation of the whole plant should, preferably, be automatic.
▪ In multiple boiler installations, isolate boilers that are not required on the waterside and, if safe and possible, on the gas side. Make sure these boilers cannot be fired.
▪ Isolation of flue system (with protection) also reduces heat losses.
▪ In multiple boiler installations the lead/lag control should have a change round facility.
▪ Where possible, reduction of the system operating temperature should be made with devices external to the boiler and with the boiler operating under a normal constant temperature range.

## 5.4 Water and steam

▪ Water fed into the boilers must meet the specifications given by the manufacturers. The water must be clear, colorless and free from suspended impurities.
▪ Hardness nil. Max. 0.25 ppm CaCO3.
▪ pH of 8 to 10 retard forward action or corrosion. pH less than 7 speeds up corrosion due to acidic action.
▪ Dissolved O2 less than 0.02 mg/l. Its presence with SO2 causes corrosion problems.
▪ CO2 level should be kept very low. Its presence with O2 causes corrosion, especially in copper and copper bearing alloys.
▪ Water must be free from oil—it causes priming.

## 5.5 Boiler water

- Water must be alkaline—within 150 ppm of CaCO3 and above 50 ppm of CaCO3 at pH 8.3 - Alkalinity number should be less than 120.
- Total solids should be maintained below the value at which contamination of steam becomes excessive, in order to avoid cooling over and accompanying danger of deposition on super heater, steam mains and prime movers.
- Phosphate should be no more than 25 ppm P2 O5.
- Make up feed water should not contain more than traces of silica. There must be less than 40 ppm in boiler water and 0.02 ppm in steam, as SiO2. Greater amounts may be carried to turbine blades.

| Maximum Boiler Water Concentrations recommended by the American Boiler Manufacturers Association | |
| --- | --- |
| **Boiler Steam Pressure (ata)** | **Maximum Boiler Water Concentration (ppm)** |
| 0-20 | 3500 |
| 20-30 | 3000 |
| 30-40 | 2500 |
| 40-50 | 2000 |
| 50-60 | 1500 |
| 60-70 | 1250 |
| 70-100 | 1000 |

- Water treatment plants suitable for the application must be installed to ensure water purity, and a chemical dosing arrangement must be provided to further control boiler water quality. Blow downs should be resorted to when concentration increases beyond the permissible limits stipulated by the manufacturers.
- Alkalinity should not exceed 20 percent of total concentration. Boiler water level should be correctly maintained. Normally, 2 gauge glasses are provided to ensure this.
- Operators should blow these down regularly in every shift, or at least once per day where boilers are steamed less than 24 hours a day.

## 5.6 Blow down (BD) procedure

A conventional and accepted procedure for blowing down gauge is as follows:
1. Close water lock
2. Open drain cock (note that steam escapes freely)
3. Close drain cock
4. Close steam cock
5. Open water cock
6. Open drain cock (note that water escapes freely)
7. Close drain cock
8. Open steam cock
9. Open and then close drain cock for final blow through.

The water that first appears is generally representative of the boiler water. If it is discolored, the reason should be ascertained.

# 6. WORKSHEETS AND OTHER TOOLS

This section includes worksheets (Boiler Performance; Data Collection Sheet; Fuel Analysis Sheet) and other tools (Boiler Performance Checklist; Rules of Thumb; Do's and Don'ts)

## 6.1 Worksheets

### Worksheet Boiler 1. BOILER PERFORMANCE

| No. | Parameter reference | Units | Readings |
|---|---|---|---|
| 1 | **Ultimate Analysis** | | |
| | Carbon | percent | |
| | Hydrogen | percent | |
| | Oxygen | percent | |
| | Sulphur | percent | |
| | Nitrogen | percent | |
| | Moisture | percent | |
| | Ash | percent | |
| 2 | GCV of Fuel | KCal/kg | |
| 3 | Oxygen in Flue Gas | percent | |
| 4 | Flue Gas Temperature ($T_f$) | $^0C$ | |
| 5 | Ambient Temperature ($T_a$) | $^0C$ | |
| 6 | Humidity in Air | Kg/kg of dry air | |
| 7 | Combustible in Ash | percent | |
| 8 | GCV of Ash | KCal/kg | |
| 9 | Excess Air Supplied (EA) $(O_2 \times 100)/(21 - O_2)$ | percent | |
| 10 | Theoretical air requirement (TAR) $[11 \times C + \{34.5 \times (H_2 - O_2/8)\} + 4.32 \times S]/100$ | kg/kg of fuel | |
| 11 | Actual mass of air supplied $\{1 + EA/100\} \times$ theoretical air | kg/kg of fuel | |
| 12 | Percentage heat loss due to dry flue gas $\{k \times (T_f - T_a)\}$ / percent CO2      Where, k (Seigert const.)       =   0.65  for Coal       =   0.56  for Oil       =   0.40 for NG | percent | |

| No. | Parameter reference | Units | Readings |
|---|---|---|---|
| 13 | Percentage heat loss due to evaporation of water formed due to $H_2$ in fuel <br> [9 x H2 {584 + 0.45($T_f - T_a$)}]/ GCV of Fuel | percent | |
| 14 | Percentage heat loss due to evaporation of moisture present in fuel <br> [M x {584 + 0.45 x ($T_f - T_a$)}] / GCV of Fuel | percent | |
| 15 | Percentage heat loss due to moisture present in air <br> {AAS x Humidity x 0.45 ($T_f - T_a$) x 100} / GCV of Fuel | percent | |
| 16 | Percentage heat loss due to combustibles in ash <br> {Ash x (100 – Comb. In Ash) x GCV of Ash x 100} / GCV of Fuel | percent | |
| 17 | Total Losses | percent | |
| 18 | Efficiency | percent | |

## Worksheet Boiler 2: DATA COLLECTION SHEET

| S No. | Parameter reference | Units | Readings |
|---|---|---|---|
| 1 | Type of Boiler | | |
| 2 | Quantity of Steam Generated | TPH | |
| 3 | Steam Pressure | $Kg/cm^2$ (g) | |
| 4 | Steam Temperature | $^0C$ | |
| 5 | Fuel Used (Coal/Oil/Gas etc.) | | |
| 6 | Quantity of Fuel Consumed | TPH | |
| 7 | GCV of Fuel | kCal/kg | |
| 8 | Feed Water Temperature | $^0C$ | |
| 9 | Oxygen in Flue Gas | percent | |
| 10 | Flue Gas Temperature ($T_f$) | $^0C$ | |
| 11 | Ambient Temperature ($T_a$) | $^0C$ | |
| 12 | Humidity in Air | Kg/kg of dry air | |
| 13 | Combustible in Ash | percent | |
| 14 | GCV of Ash | KCal/kg | |

**Worksheet Boiler 3: FUEL ANALYSIS SHEET**

| No. | Parameter reference | Units | Readings |
|---|---|---|---|
| 1 | **Ultimate Analysis** | | |
| | Carbon | percent | |
| | Hydrogen | percent | |
| | Oxygen | percent | |
| | Sulphur | percent | |
| | Nitrogen | percent | |
| | Moisture | percent | |
| | Ash | percent | |
| 2 | GCV of Fuel | KCal/kg | |

## 6.2 Boiler Periodic Checklist

| Boiler Periodic Checklist | | | | |
|---|---|---|---|---|
| **System** | **Daily** | **Weekly** | **Monthly** | **Annual** |
| BD and Water Treatment | Check BD valves do not leak. BD is not excessive | - | Make sure solids do not build up. | - |
| Feed Water System | Check and correct unsteady water level. Ascertain cause of unsteady water level, contaminants over load, malfunction etc. | Check controls by stopping the feed water pump and allow control to stop fuel | Nil | Condensate receiver, deaerator system pumps. |
| Flue Gases | Check temp. at two different points | Measure temp. and compare composition at selected firings and adjust recommended valves. | Same as weekly. Compare with previous readings. | Same as weekly record references. |
| Combustion Air Supply | | | Check adequate openings exist in air inlet. Clean passages. | |
| Burners | Check controls are operating properly. May need cleaning several times a day | Clean burners, pilot assemblies, check condition of spark gap of electrode burners. | Same as weekly | Same as weekly, clean and recondition |
| Boiler operating characteristics | | Observe flame failure and characteristics of the flame | | |
| Relief Valve | | Check for leakages | | Remove and recondition |
| Steam Pressure | Check for excess | | | |

| Boiler Periodic Checklist | | | | |
|---|---|---|---|---|
| **System** | **Daily** | **Weekly** | **Monthly** | **Annual** |
| | loads which will cause excessive variation in pressure | | | |
| Fuel System | | | Check pumps, pressure gauges, transfer lines. Clean them | Clean and recondition system |
| Belt for gland packing | | | Check damages. Check gland packing for leakages and proper compression | |
| Air leaks in water side and fire side surfaces | | | | Clean surface as per manufacturer's recommendation annually |
| Air leaks | | | | Check for leaks around access openings and flame |
| Refractories on fuel side | | | | Repair |
| Elec. System | | Clean panels outside | Inspect panels inside | Clean, repair terminals and contacts etc. |
| Hydraulic and pneumatic valves | | | Clean equipment, oil spillages to be arrested and air leaks to be avoided | Repair all defects and check for proper operation |

## 6.3 General rules ("Rules of Thumb")

▪ 5 percent reduction in excess air increases boiler efficiency by 1 percent (or 1 percent reduction of residual oxygen in stack gas increases boiler efficiency by 1 percent).
▪ 22 °C reduction in flue gas temperature increases the boiler efficiency by 1 percent.
▪ 6 °C rise in feed water temperature brought about by economizer/condensate recovery corresponds to a 1 percent savings in boiler fuel consumption.
▪ 20 °C increase in combustion air temperature, pre-heated by waste heat recovery, results in a 1 percent fuel saving.
▪ A 3 mm diameter hole in a pipe carrying 7 kg/cm$^2$ steam would waste 32,650 litres of fuel oil per year.
▪ 100 m of bare steam pipe with a diameter of 150 mm carrying saturated steam at 8 kg/cm2 would waste 25 000 litres furnace oil in a year.
▪ 70 percent of heat losses can be reduced by floating a layer of 45 mm diameter polypropylene (plastic) balls on the surface of a 90 °C hot liquid/condensate.
▪ A 0.25 mm thick air film offers the same resistance to heat transfer as a 330 mm thick copper wall.
▪ A 3 mm thick soot deposit on a heat transfer surface can cause a 2.5 percent increase in fuel consumption.
▪ A 1 mm thick scale deposit on the waterside could increase fuel consumption by 5 to 8 percent.

## 6.4 Boiler Do's and Don'ts

| Boiler dos and don'ts | |
|---|---|
| **Do's** | **Don'ts** |
| 1. Soot blowing regularly<br>2. Clean blow down gauge glass once a shift<br>3. Check safety valves once a week<br>4. Blow down in each shift, to requirement<br>5. Keep all furnace doors closed<br>6. Control furnace draughts<br>7. Clear, discharge ash hoppers every shift<br>8. Watch chimney smoke and control fires<br>9. Check auto controls on fuel by stopping feed water for short periods occasionally<br>10. Attend to leakages periodically<br>11. Check all valves, dampers etc. for correct operation once a week<br>12. Lubricate all mechanisms for smooth functioning<br>13. Keep switchboards neat and clean and indication systems in working order<br>14. Keep area clean, dust free<br>15. Keep fire fighting arrangements at readiness always. Rehearsals to be carried out once a month.<br>16. All log sheets must be truly filled<br>17. Trip FD fan if ID fan trips<br>18. CO2 or O2 recorder must be checked/calibrated once in three months<br>19. Traps should be checked and attended to periodically<br>20. Quality of steam, water, should be checked once a day, or once a shift as applicable<br>21. Quality of fuel should be checked once a week<br>22. Keep sub heater drain open during start up<br>23. Keep air cocks open during start and close | 1. Don't light up torches immediately after a fire-out (purge)<br>2. Don't blow down unnecessarily<br>3. Don't keep furnace doors open unnecessarily<br>4. Don't blow safety valves frequently (control Operation)<br>5. Don't over flow ash hoppers<br>6. Don't increase firing rate beyond that permitted<br>7. Don't feed raw water<br>8. Don't operate boiler blind fold<br>9. Don't overload boiler as a practice<br>10. Don't keep water level too high or too low<br>11. Don't operate soot blowers at high loads<br>12. Don't trip the ID fan while in operation<br>13. Don't look at the fire in furnace directly, use tinted safety glasses<br>14. Avoid thick fuel bed<br>15. Don't leave boiler to untrained operators/technicians<br>16. Don't overlook unusual observation (sound change, change in performance, control difficulties), investigate<br>17. Don't skip annual maintenance<br>18. Don't prime boilers<br>19. Don't allow steam formation in economizer (watch temps.)<br>20. Don't expose grate (spread evenly)<br>21. Don't operate boiler with water tube leaking |

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