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Guide to Environmentally Sound Industrial Boilers

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Abbreviations

A

AAS Atomic Absorption Spectrometry; 153
AFBC Atmospheric Fluidized Bed Combustion; 37
APCD Air Pollution Control Devices; 115
ASTM American Society for Testing and Materials; 72

B

BAT/BEP Best Available Techniques/Best Environmental Practices; 17
BFBC Bubbling Fluidized Bed Combustion; 37

C

CANMET Canada Centre for Mineral and Energy Technology; 97
CCGT Combined Cycle Gas Turbines; 67
CE Control Efficiency; 115
CFBC Circulating Fluidized Bed Combustion; 37
CO_2 Carbon Dioxide; 17
CO Carbon Monoxide; 61

D

DME Di-Methyl Ethylene; 94
DOE Department of Energy; 18

E

EF Emission Factor; 144
EPA- Environmental Protection Agency; 18
ESEA East South East Asia countries: Cambodia, Indonesia, Lao PDR, Mongolia, Philippines and Thailand; 17
ESP Electrostatic Precipitator; 89

F

FBC Fluidized Bed Combustion; 35
FGD Flue Gas Desulphurization; 137
FGR Flue Gas Recirculation; 133

G

GEF Global Environmental Facility; 17
GHV Gross Heating Value; 20

H

HCB Hexa ChloroBenzene; 142
HCl Chloridic Acid; 153
HHV Higher Heating Value; 20
HRSG Heat Recovery Steam Generators; 68
HRT Horizontal Return Tubular; 27

I

I-TEQ Toxic Equivalent; 143

L

LHV Lower Heating Value; 20
LPG Liquefied Petroleum Gas; 62

M

MAWP Maximum Allowable Working Pressure; 42
MSW Municipal Solid Waste; 93

N

NO_x Nitrogen Oxides; 36

INTRODUCTION

This Guide is part of a United Nations Industrial Development Organization's (UNIDO) project on reducing dioxins from the heat and power sectors. In recognition of the importance of informed industrial boiler operation and proper fuel selection to reducing releases of pollutants from boilers, UNIDO has launched a project to simoultaneously reduce the emissions of carbon dioxide (CO_2) and dioxins/furans (also called polychlorinated dibenzodioxins/dibenzofurans; PCCD/PCDF) from power and industrial sources. The project, which is co-financed by the Global Environmental Facility (GEF), involves six East South East Asia (ESEA) countries: Cambodia, Indonesia, Lao PDR, Mongolia, Philippines and Thailand. Its aim is to create a positive attitude and environment for clean technologies that reduce persistent organic pollutants (POPs) releases from boilers through training, public awareness and pilot demonstration programs.

The Guide focuses on how to select and operate small and medium-sized boilers designed to produce steam for industrial processes, and minimize their effects on the environment through implementation of best environmental practices (BEP) and best available techniques (BAT). Specific issues related to boiler operation in the ESEA region are discussed. Combined production of steam and electricity, often used in large factories, is introduced. Boilers for power generation are not discussed, but some general concepts related to their operation are covered.

Air pollution control devices are extensively discussed in the Guide, including systems currently used on large boilers for power generation. Although their use in the industrial sector is currently limited to only a few plants, the growing public concern about air pollution and its effects on the environment and human health are likely to lead to more and stricter regulations for emissions in the years to come. This will ultimately result in the need to adopt more sophisticated air pollution control devices, even on smaller industrial boilers.

The Guide describes various types of boilers and, for each, highlights not only the main technical characteristics such as efficiency and steam production, but also the amount of pollutants released to the air, the quality of fuel the boiler can use, the most suitable air pollution control devices available, the achievable efficiency improvements, and the BAT/BEP that can be implemented to reduce the impact on the environment. Background information is provided on the various types of commercially available boilers, the fuels they burn, and the emissions they produce. Emission standards and compliance issues, technical details on emission control techniques, and other important pollutant control devices are also discussed.

Previously, very little information has been available, or provided, on the persistent organic pollutants (POPs) emitted from industrial boilers in small, but harmful, quantities. The Guide introduces and illustrates the effects on the environment and human health of releases of dioxins, furans and mercury (a fairly new type of POP normally not considered for industrial boilers), and how to reduce these effects.

The adoption of boilers equipped with BAT and the use of BEP for boiler operation are the most effective ways to reduce the releases of pollutants without affecting the industrial process requirements. Many studies and reports have demonstrated that it is possible to simultaneously reduce the releases of pollutants and improve the economics of the facility e.g., U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), UNIDO, United Nations Environment

Programme (UNEP), etc. The dissemination of this kind of information to developing countries is currently limited by language/cultural barriers, logistics problems and lack of business. The Guide focuses on BAT and BEP for developing and least developed countries.

While the content of the Guide mainly applies to operation of existing boilers, it is also useful for evaluating replacement of old boilers with new, less polluting ones, and for purchasing new boilers. It is mainly intended for operators of existing boilers, but may also prove helpful for boiler managers and factory decision-makers involved in boiler and steam operation or decisions on optimization of plant economics and emissions.

Other potential Guide users include boiler manufacturers, universities, training agencies, engineers involved in selection of boilers and combustion equipment that comply with emissions limits, and regulatory authorities dealing with emission issues and boiler permit applications.

Factory managers often look at boilers as a secondary part of the production process, whose only duty is to produce steam/heat to meet the needs of the manufacturing process, the core business. Industrial boiler operators are very often well-trained in how to operate a boiler safely and reliably, but not in how to reduce the pollutants emitted from the stack, or released to water and soil.

Since adoption and implementation of new technologies are expensive, factory owners in developing countries frequently prefer to purchase old, second-hand, less expensive boilers instead of investing money in a more expensive, modern boilers equipped with BAT. To promote better understanding of the advantages to production process economics, the Guide discusses the economics of BAT and BEP implementation on industrial boilers.

The Guide aims to be simple and clear, and limits the use of formulae. At the same time, it provides detailed information on boiler design and operation concepts and the characteristics of fuels used in boilers. It also gives numerous examples of how to use boiler performance calculations such as efficiency, steam properties, mass flow, emissions, operation, and controls.

REVIEW OF BASIC CONCEPTS

Units of measurement

Boiler documentation available from manufacturers and technical literature often use different units of measurement, depending on a document's origin. Knowing how to convert between measurement systems is therefore useful for understanding and managing technical documentation and reports on boilers. This Guide also uses different measurement units and systems (e.g., International System of Units, SI; Imperial System, U.S. System), depending on the sources consulted. To facilitate understanding, however, many of the examples in the Guide show two different units for the same quantity. ANNEX 1 provides definitions of units of measurement systems and conversion factor tables. Computer spreadsheet applications and free online conversion tools can also be used to convert units and measurements if the units are explicitly defined and the conversion is compatible (e.g., cmHg to kPa, kcal to MJ, kg to lb, etc.).

Steam properties

The temperature of the steam produced by a boiler is closely linked to its pressure. When water is heated, it starts the transformation into steam. At atmospheric temperature, water boils at 100 °C. At this temperature, bubbles of steam are produced within the bulk liquid phase and rise to the water surface, producing a furious turbulence (boiling). During this phase, water and steam are in equilibrium.

If the container of water is closed and continues to be heated, to above 100 °C, the steam pressure will start to rise, and, as the temperature continues to rise, the pressure will go on rising. What is happening is that steam is being evolved to match the temperature. The steam conditions are said to be saturated because, if the pressure is raised by external means at constant temperature, some of the steam will start to condense back to water.

If the steam pressure is held at a lower pressure level than that achieved at saturation, by taking steam off to feed a turbine or other steam usage, there is effectively an excess temperature for that pressure, and the steam is said to be superheated. It, in fact, becomes dry, and behaves as a gas. The amount of superheat can be quantified as so many degrees of superheat in °C (Celsius) or °F (Fahrenheit).

Saturated steam is normally used in small industrial boilers. For power boilers, superheated steam is preferred because it allows higher temperatures and efficiencies to be reached, and it is less harmful to the steam turbines used to drive the alternator, which produces electricity.

Steam turbine designers want steam to be superheated before reaching the turbine to avoid condensation, where small water droplets produced by the expansion of the superheated steam will cause blade erosion. Steam-producing boilers in power plants are therefore designed to produce superheated steam, working at high pressures and temperatures. Supercritical boilers, with high pressures and temperatures (more than 250 bar and 600 °C), are currently used for electricity production. In industrial plants where no steam turbines are used, only saturated steam at lower pressure and temperature levels (pressures between 2 bar and 10 bar) is normally generated.

The relationship between steam pressure and temperature is defined in the steam tables found in ANNEX 2 (SI) and ANNEX 3 (U.S. system). Before providing some examples of how to use the steam tables,(1) it is helpful to review the principle and definition of enthalpy.(2)

Enthalpy

Enthalpy is a measure of the total energy of a thermodynamic system. It includes the internal energy, which is the energy required to create a system, and the amount of energy required to make room for it by displacing its environment and establishing its volume and pressure. Enthalpy is a thermodynamic potential. It is a state function and an extensive quantity. The SI unit of measurement for enthalpy is the joule/kg, but other historical, conventional units are still in use, such as the British thermal unit (Btu)/lb and the calorie (kcal/kg).

The enthalpy is the preferred expression of system energy changes in many chemical, biological, and physical measurements as it simplifies certain descriptions of energy transfer. This is because a change in enthalpy takes account of energy transferred to the environment through the expansion of the system under study.

The total enthalpy, H, of a system cannot be measured directly. Thus, change in enthalpy, ΔH, is a more useful quantity than its absolute value. The change ΔH is positive in endothermic reactions, and negative in exothermic processes. ΔH of a system is equal to the sum of non-mechanical work done on it and the heat supplied to it.

For quasi-static processes under constant pressure, ΔH is equal to the change in the internal energy of the system, plus the work that the system has done on its surroundings. This means that the change in enthalpy under such conditions is the heat absorbed (or released) by a chemical reaction. More details on enthalpy are given in ANNEX 4. Water and steam tables can be used to calculate enthalpy changes. Online tools for calculating enthalpy and other quantities are available for different units of measure (e.g., SI, Imperial).

Examples (3)

Example #1: Boiling water at 100 °C (212 °F), 0 bar atmospheric pressure (absolute 1 bar =14.5 lb/inch^{2})

At atmospheric pressure (0 bar g, absolute 1 bar), water boils at 100 °C, and 417.51 kJ of energy are required to heat 1 kg of water from 0 °C to its evaporating temperature of 100 °C. Therefore, the specific enthalpy of water at 0 bar g (absolute 1 bar) and 100 °C is 417.51 kJ/kg (395.7 Btu).

Another 2257.92 kJ of energy are required to evaporate 1 kg of water at 100 °C into 1 kg of steam at 100 °C. Therefore, at 0 bar g (absolute 1 bar), the specific enthalpy of evaporation is 2257.19 kJ/kg.

Total specific enthalpy for 100 % steam at 100 °C is:

$$h_s = (417.51\ \mathrm{kJ/kg}) + (2257.92\ \mathrm{kJ/kg})$$

$$h_s = 2675.43\ \mathrm{kJ/kg}$$

Example #2: Boiling water at 170 °C, 7 bar atmospheric pressure

Steam at atmospheric pressure is of limited practical use because it cannot be conveyed under its own pressure along a steam pipe to the point of use. At 7 bar g (absolute 8 bar), the saturation temperature of water is 170.42 °C. More heat energy is required to raise its temperature to saturation point at 7 bar g than would be needed if the water were at atmospheric pressure. The steam tables give a value of 720.94 kJ to raise 1 kg of water from 0 °C to its saturation temperature of 170 °C.

The heat energy (enthalpy of evaporation) needed by the water at 7 bar g to change it into steam is actually less than the heat energy required at atmospheric pressure. This is because the specific enthalpy of evaporation decreases as the steam pressure increases. The evaporation heat is 2046.53 kJ/kg according to the steam tables.

Note! Because the specific volume also decreases with increasing pressure, the amount of heat energy transferred in the same volume actually increases with steam pressure.

In heating applications, saturated steam is preferable, because it has a better energy exchange capacity. Superheated steam must cool down, and become saturated steam, before condensing in a heat exchanger.

Fuels Heating values

The heating value (4), which gives the ability of the fuel to release heat, is an important parameter. The heating value or energy value of a substance, usually a fuel, is the amount of heat released during combustion of a specified amount of it. The energy value is a characteristic for each substance. It is measured in units of energy per unit of the substance, usually mass, such as kJ/kg, kJ/mol, kcal/kg, Btu/lb. The heating value is commonly determined by use of a bomb calorimeter.

The heat of combustion for fuels is expressed as follows:

- *Higher heating value:* The quantity known as higher heating value (HHV) (or gross energy or upper heating value or gross calorific value, GCV; or higher calorific value, HCV) is determined by bringing all the products of combustion back to the original pre-combustion temperature, and, in particular, condensing any vapour produced. Such measurements often use a reference temperature of 25 °C. The higher heating value takes into account the latent heat of vaporization of water in the combustion products, and is useful in calculating heating values for fuels where condensation of the reaction products is practical (e.g., in a gas-fired boiler used for space heat). In other words, HHV assumes all the water component is in liquid state at the end of combustion (in products of combustion).
- *Lower heating value*: The quantity known as lower heating value (LHV) (or net calorific value, NCV; or lower calorific value, LCV) is determined by subtracting the heat of vaporization of the water vapour from the HHV. This treats any water formed as a vapour. The energy required to vaporize the water therefore is not realized as heat. In this case the water produced by combustion is vapour. LHV calculations assume that the water component of a combustion process is in vapour state at the end of combustion, in contrast to HHV. In other words, the LHV assumes that the latent heat of vaporization of water in the fuel and reaction products is not recovered. It is useful when comparing fuels where condensation of the combustion products is impractical, or heat at a temperature below 150 °C cannot be put to use. This is the case of most steam producing industrial boilers.

Most industrial boilers that burn fuel produce water vapour during combustion, which is, and thus wastes, its heat content unused (water vapour leaves the boiler from the stack and is visible at low ambient temperatures because it condenses and forms a white plume). In such applications, the LHV is the applicable measure. This is particularly relevant for natural gas, whose high hydrogen content produces much water. The gross energy value is relevant for gas burned in condensing boilers and power plants with flue gas condensation that condense the water vapour produced by combustion before it leaves the stack, recovering heat that would otherwise be wasted to the external environment.

Boiler efficiency

Boiler efficiency is the ratio of heat absorbed in steam to the heat supplied in fuel, usually measured in percent. Boiler efficiency may be indicated by the following:

- *Combustion efficiency:* indicates a burner’s ability to burn fuel measured by unburned fuel and excess air in the exhaust
- *Thermal efficiency*: indicates the heat exchanger’s effectiveness in transferring heat from the combustion process to the water or steam in the boiler, exclusive of radiation and convection losses
- *Fuel to fluid efficiency*: indicates the overall efficiency of the boiler, inclusive of thermal efficiency of the heat exchanger, radiation and convection losses — output divided by input.

Boiler efficiency is usually indicated by either thermal or fuel to fluid efficiency depending on the context. Boiler efficiency related to the boiler's energy output to the boiler's energy input can be expressed as:

Boiler efficiency (%) = heat exported by the fluid (water, steam, etc.)/heat provided by the fuel x 100 (1)

If a fluid like water is used to export heat from the boiler, exported heat can be expressed as:

$$q = (m / t)\ c_p\, dT$$

where:

q = heat exported (kJ/s, kW)
m/t = mass flow (kg/s)
m = mass (kg)
t = time (s)
c_p = specific heat capacity (kJ/kg °C)
dT = temperature difference between inlet and outlet of the boiler (°C)

For a steam boiler, the heat exported as evaporated water at the saturation temperature can be expressed as:

$$q = (m/t)\ he$$

where:

m = mass flow of evaporated water (kg)
t = time (s)
he = evaporation energy in the steam at the saturation pressure the boiler is running (kJ/kg)

Heat exchange surfaces

According to the temperature difference between the hot gases generated from the combustion of the fuel and the water introduced into the boiler, the heat is transferred to the water. The heat transfer rate depends mainly on the temperature difference between the two fluids (hot gases and water), on the thermal conductivity of the tubes, which is the ability of the metal to transmit heat, and on the heat exchange surface area, based on the following (simplified) formula:

$$Q = k \times S \times (T_{\text{hot gas}} - T_{\text{water}})$$

Where:

Q = heat
k = Thermal conductivity (W/m^2 °C)
S = Contact area
$T_{\text{hot gas}}$ = Temperature at gas side
T_{water} = Temperature at water side

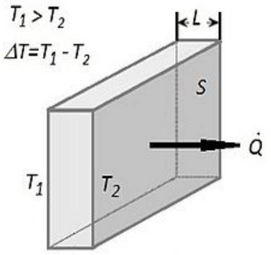


Figure 1 Heat transmission scheme (Wikipedia) (184)

This means that:

- the higher the T° difference, usually indicated as ΔT, the higher the heat exchange rate and the lower the heat exchange surface;
- the greater the exchange surface, the higher the heat exchange rate; and
- the higher the thermal conductivity, the higher the heat exchange rate.

The rule of thumb is that lower ΔT corresponds to low transferred heat and, consequently, the need for larger heat exchange surfaces (the boiler dimensions will therefore increase). ΔT affects the heat that is exchanged in the different heat exchange areas of the boiler. Figure Figure 1 shows a schematic of a heat transmission scheme.

Working temperatures are also important. The first section of the boiler works at the highest gas temperatures (1000 °C to 1300 °C), while the last section works at the lowest gas temperatures (300 °C to 400 °C). The exit gas temperatures are in the order of 200 °C to 250 °C. For example, in a watertube boiler, the first pass accounts for 60% to 70% of heat transfer, the second pass accounts for about 20% to 35%, while the third pass accounts for 10% to 25%. In contrast, the tube bank surfaces are greater for the third pass and lower for the first pass, as shown inTable 1.

Table 1 Heat exchange in tubes passes

	1st pass	***2nd pass***	***3rd pass***
Tubes' total surface	***10-15%***	***40-50%***	***40-50%***
Heat exchange rates for tube sections	***60-70%***	***20-35%***	***10-25%***

The heat transfer varies with feedwater temperatures and steam pressure. Table 2 shows the heat required to bring the water into steam for a boiler at different feedwater temperatures and pressures. The Table shows that:

- The higher the feedwater temperature, the less heat is needed to transform the water into steam.
- The higher the feedwater pressure, the more heat is needed to transform the water into steam, which means that the steam will have more intrinsic energy (enthalpy) for the process.

Table 2 Effect of feedwater temperature on heat required to produce steam

Feedwater Temperature (°F)	Boiler Pressure (psi)				
	50	**100**	**200**	**225**	**250**
100	*7.1*	*8.6*	*10.5*	*10.9*	*10.8*
200	*3.7*	*5.2*	*7.0*	*7.4*	*7.4*
250	*1.9*	*3.4*	*5.3*	*5.7*	*5.7*

CHAPTER 1 – BOILER TYPES AND CHARACTERISTICS

SUMMARY

This Chapter introduces the main concepts for boiler design, construction, and production of steam, and the types of industrial boilers available on the market (including a brief look at the history of boilers). Boilers are classified and discussed according to the main manufacturing characteristics (e.g., fire tubes, water tubes, fluidized beds); and the type of fuel they burn (e.g., solid, liquid, or gaseous fuel).

The Chapter also discusses boiler components and auxiliaries, preliminary concepts for emissions, the main issues to consider when selecting and buying a boiler, and combined production of electricity and steam (co-generation).

Definition of steam boiler

A "steam boiler" can be defined as a sealed vessel in which water is converted into steam. (5) Because this conversion needs energy, the vessel has to be heated until it reaches the temperature at which it will start boiling, accelerating its transformation into steam. This temperature, at atmospheric pressure and zero altitude, is equal to 100°C (212°F), but, if the boiler is designed for pressures higher than atmospheric pressure, the temperature of the steam can be much higher. In large, sophisticated power boilers, the steam temperature can reach 600°C (1112°F) and above. In small/medium industrial boilers, the steam temperature normally ranges between 140°C and 200°C (284°F – 392°F).

To heat the water, energy sources are usually needed. "Energy sources" can be defined as sources from which energy can be obtained to provide heat, light, and power. Sources of energy have evolved from human and animal power to fossil fuels, uranium, water power, wind, and the sun. (6) The energy sources most used for boilers are fossil fuels, such as coal and oil products; gaseous fuels (e.g., natural gas, liquefied petroleum gas (LPG), liquefied natural gas (LNG); and biomass (e.g., wood, rice husks, saw dust, etc.).

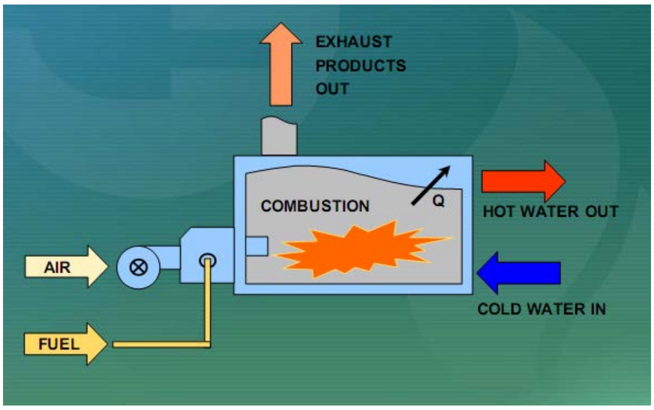


Figure 2 Schematic of a boiler (Landers-ASHRAE) (221)

The concept of heating value (heat of combustion) is explained in more detail in ANNEXES 5 and 6, and the heating values of the most used fuels are shown in different units. Heating values may vary by available fuel. In the examples, different heating values may appear for the same fuel (e.g., fuel oil). A fuel can have different names e.g., fuel oil, Bunker C, residual oil; also No. 6 fuel oil may refer to the same product. The heating value can also vary depending on the refining process used. A schematic of a boiler is shown in Figure 2.

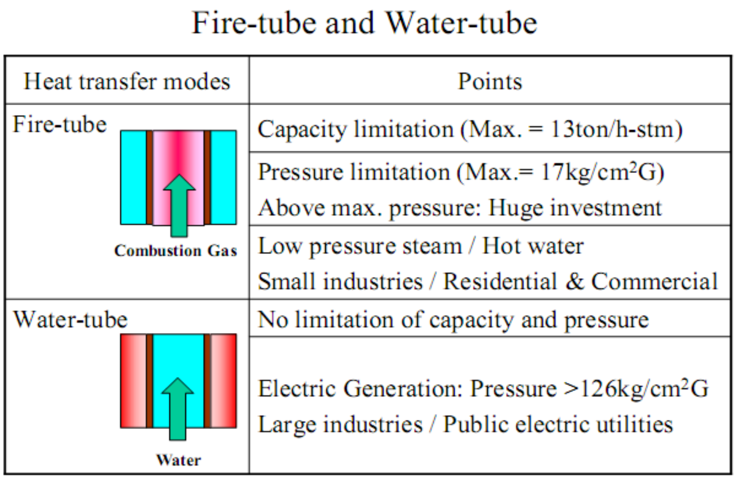
Classification of boilers by type

Boilers can have different dimensions and shapes, according to their design, the fuel they use, and the steam they are required to produce. It is challenging to classify the several hundred thousand boilers that are in operation all over the world. A boiler can be classified by the fuel it uses (e.g., coal boilers, biomass boilers, gas boilers, etc.); its main characteristics (e.g., fire tubes, water tubes, etc.); or its application (e.g., industrial boilers, power boilers, etc.).

This Guide focuses on industrial boilers, which can be classified by boiler type:

- cast iron boilers
- firetube (or shell) boilers
- watertube boilers
- fluidized bed boilers

Cast iron boilers, which have a basic design, are most suitable for hot water production because they can withstand moderate pressures. The capacity and pressure limitations of firetube boilers make them more suitable for small boilers at low working pressure (around 15 to 20 bar), while watertube boilers are more appropriate for larger capacities and higher-pressure boilers. Figure 3 shows the heat transfer modes and main characteristics of firetube and watertube boilers.



Fire-tube and Water-tube

Heat transfer modes	Points
Fire-tube Combustion Gas	Capacity limitation (Max. = 13ton/h-stm)
	Pressure limitation (Max.= 17kg/cm²G) Above max. pressure: Huge investment
	Low pressure steam / Hot water Small industries / Residential & Commercial
Water-tube Water	No limitation of capacity and pressure
	Electric Generation: Pressure >126kg/cm²G Large industries / Public electric utilities

Figure 3 Firetube and watertube heat transfer modes (Courtesy of APO-Japan) (34)

Cast iron boilers

Cast iron is mostly used as the heating vessel of home water heaters. Although these heaters are often called "boilers" in some countries, their purpose is usually to produce hot water, and not steam. This means they run at low pressure and try to avoid actual boiling. The brittleness of cast iron makes it impractical for high-pressure steam boilers. (7) Service restrictions limit steam boilers to pressures not exceeding 1 bar (15 pounds per square inch-psi), and hot water boilers to pressures not exceeding 10-11 bar (About 160 psi) and/or temperatures not exceeding 121°C (250°F).

Figure 4 Cast iron boiler (Courtesy of Warga Boilers) (116)

Cast iron boilers (Figure 4) can be constructed in different configurations. The three most commonly used designs are as follows:

- *Vertical sectional*: made up of individual cast iron sections assembled like slices in a loaf of bread and probably the most common configuration

- *Horizontal sectional*: made up of individual cast iron sections assembled like a stack of pancakes
- *One piece or mono-bloc*: a single casting with no assembly joints, and usually small in size

Firetube boilers

Firetube boilers, more common in the 1800s, were the engines of steam locomotives. They consist of a tank of water perforated with tubes. The hot gases from a coal or wood fire run inside the tubes to heat the water in the tank, as shown in the simplified diagrams in Figure 7 and Figure 8 .

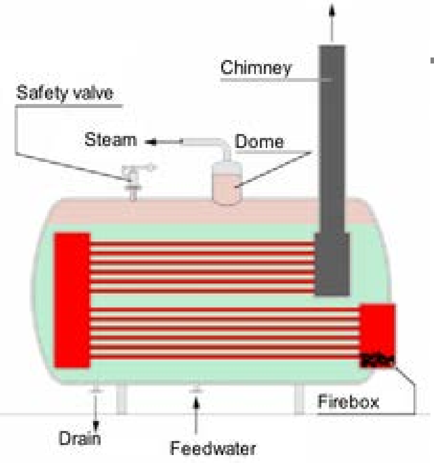


Figure 5 Firetube boiler (Wikipedia)

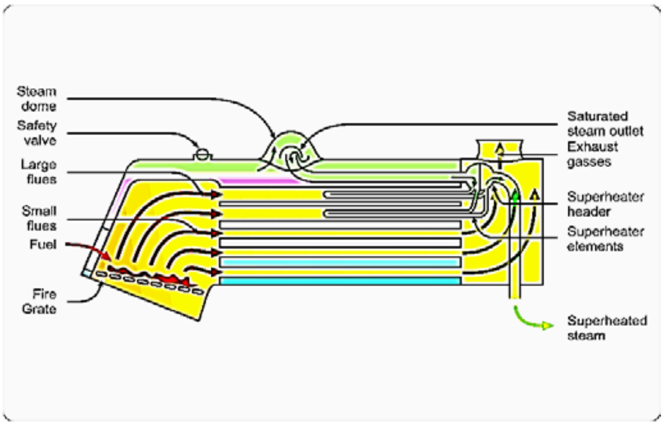


Figure 6 Locomotive boiler schematic Wikipedia (234)

The heat is transferred to the water between the tubes and the outer shell. Firetube boilers are often characterized by the number of passes, referring to the number of times the combustion (or flue) gases flow the length of the pressure vessel as they transfer heat to the water and are discharged to the stack. Since the entire tank is under pressure, overheating can result in tank explosion. The reversal chamber, where gases change direction, is a critical part of a firetube boiler. Higher or lower temperatures than designed for can result in cracking of tubes or plates.

To more efficiently reverse the hot gases through a wet-back boiler configuration, the reversal chamber can be surrounded by the water. This allows for more heat to be transferred to the water, and improves the boiler's performance.

A further development of the two-pass boiler resulted in the creation of a three-pass wet-back boiler, which is a standard configuration used today (see Figure 8

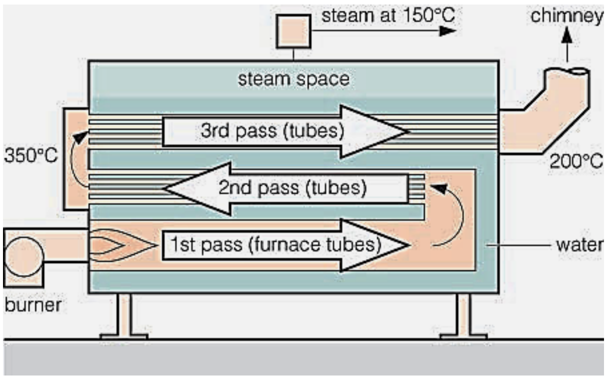
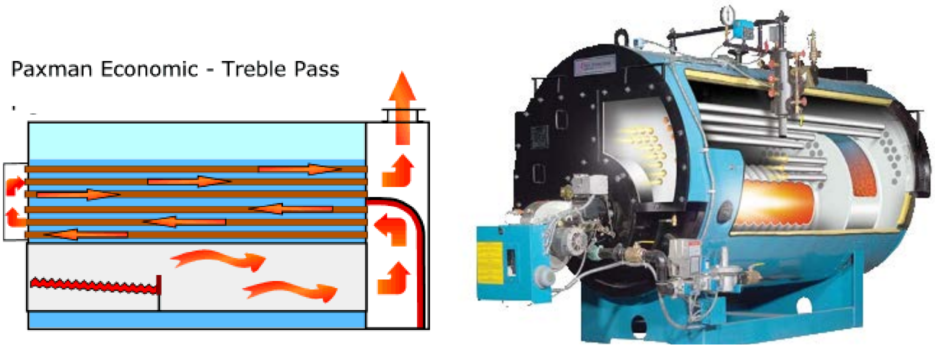


Figure 7 Schematic of a three pass boiler



Old three-pass boiler diagram (Courtesy ofPaxman bOILERS) (214)

Modern Three-pass Firetube boiler – EERE (from AESYS technologies) (20)

Figure 8 Old and modern three-pass boilers

This design has evolved as materials and manufacturing technology have advanced: thinner metal tubes have been introduced, allowing more tubes to be accommodated; heat transfer rates have been improved; and the boiler itself has become more compact.

Firetube boilers have the following advantages:

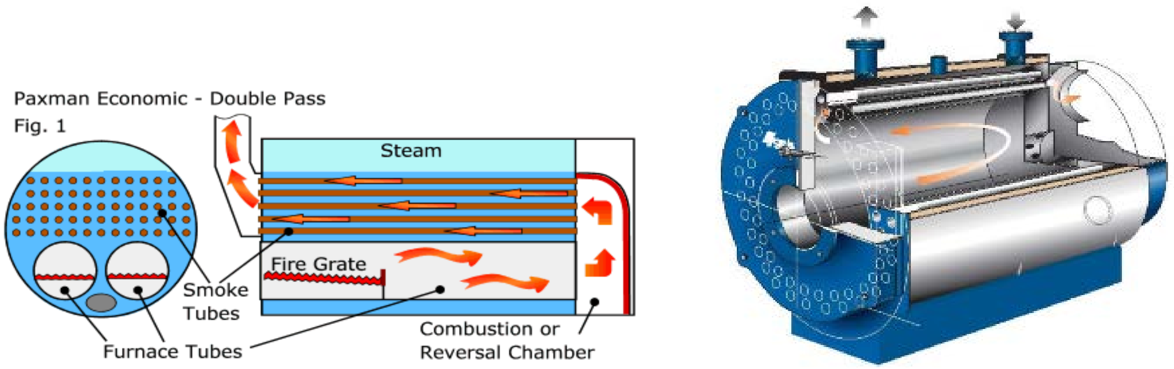
- relatively inexpensive
- easy to clean
- compact
- available in sizes from 600,000 British thermal units/hour (Btu/hr) to 50 million Btu/hr (63 megajoules, MJ, to 53 gigajoules, GJ)
- easy to replace tubes
- well suited for space heating and industrial process applications

Boiler configurations

Firetube boilers can be constructed in different configurations, of which the most common are discussed below. (8)

Horizontal return tubular (HRT)

This is an old and very simple design that is still being manufactured. The boiler consists of a shell, a tube sheet on each end of the shell, and tubes connecting the two tube sheets. The boiler is mounted above a steel or masonry furnace. The products of combustion leave the furnace and are directed through the tubes at one end of the boiler. After passing through the tubes, the products of combustion exit the opposite end of the boiler and are directed to the stack or chimney. Diagrams of an old two-pass boiler (dry-back) and a modern one are shown in Figure 9 Firetube boiler evolutionThis type of boiler includes locomotive boilers as well as what are sometimes called "firebox" boilers. The products of combustion pass once through a locomotive boiler, classifying it as a one-pass boiler. Some firetube firebox boilers may be two-pass or three-pass depending upon the arrangement of baffles and tubes. The common characteristic of all firebox boilers is that



Old Two-pass boiler schematic – courtesy of Paxman boilers (214)

Modern Two-pass reverse flue firetubes hot water boiler -courtesy of Warga boilers) (116)

Figure 10 Firetube boiler evolution

Figure 9 Scotch boiler (Wikipedia) (233)

the furnace is at least partially contained within the boiler and is water cooled for a large portion of its surface area. Multi-pass firebox boilers are common, and many older examples are found in schools to heat water or produce steam for space heating applications.

Scotch Marine

Often referred to as a scotch marine boiler (see Figure 10), this is the most common type of industrial firetube boiler. It is an industry workhorse due to its low initial cost, and advantages in efficiency and durability. In a scotch boiler, the furnace is a large diameter tube, within the boiler, surrounded by water. Some older, large scotch boilers had two or three furnaces but modern boilers typically have only one. Scotch boilers may be two-pass, three-pass, or four-pass depending upon the arrangement of baffles and tubes. Four passes are generally recognized as the practical maximum when balancing economic heat transfer and condensation-induced corrosion. Each pass through the boiler transfers heat from the products of combustion to the water in the boiler. After a number of passes, it becomes more difficult to economically extract heat from the cooling products of combustion. Additionally, if the products of combustion are cooled too much, the combustion gases will condense, which can cause corrosion.

Figure 11 Vertical Boiler tractors (Wikia) (218)

A further sub-classification of scotch boilers describes the end closure opposite the burner end of the boiler. A wet-back means the end closure is water cooled; and a dry-back means the end closure is not water cooled and relies on fire brick, refractory, or a combination of both to prevent the end closure from overheating.

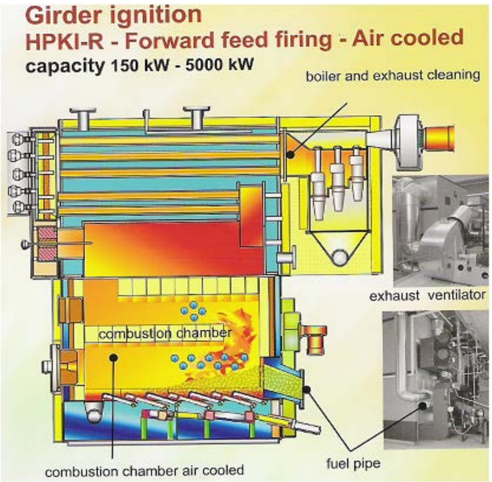


Figure 12 Wood-fired firetube packaged boiler (Ministry of Environment-British Columbia) (14)

Scotch marine boilers contain relatively large amounts of water, which enables them to respond to load changes with relatively little change in pressure. However, since the boiler typically holds a large water mass, it requires more time to initiate steaming and more time to accommodate changes in steam pressure. Scotch marine boilers generate steam on the shell side, which has a large surface area, limiting the amount of pressure they can generate. In general, Scotch marine boilers are not used where pressures above 300 pounds per square inch gauge (psig; 20 bar) are required.

Vertical Boilers

This one-pass boiler has the furnace at the bottom and tubes running between the lower and upper tube sheets (see Figure 11). The furnace can be enclosed on its sides with a water-cooled jacket or it can be made up of masonry. The top tube sheet in a steam boiler can be above or below the water line. When it is above, it is called a dry-top and when it is below, it is called a wet-top. A vertical boiler has a small "footprint" and can be installed in boiler

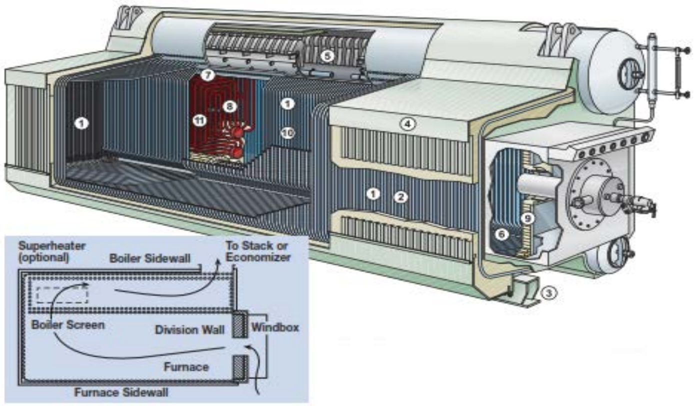


Figure 13 Watertube boiler (Courtesy of B&W) (15)

rooms with limited space. Vertical boilers are very popular in the dry cleaning industry.

Packaged boilers

The term "package" boiler evolved in the early- to mid-20th century from the practice of delivering to site boiler units already fitted with insulation, electrical panels, valves and gauges. This was in contrast to the earlier practice of delivering little more than the pressure vessel and fitting the ancillary components on-site. (10)

- Packaged boilers have the following features: (11)
- 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 draught systems, resulting in good combustion efficiency.
- a number of passes, resulting in better overall heat transfer.
- higher thermal efficiency levels compared with other boilers.

These boilers are classified by the number of passes — the number of times the hot combustion gases pass through the boiler. The combustion chamber is considered 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, with the exhaust gases exiting through the rear of the boiler. Packaged boilers are available for different fuels and for different types. Figure 12 and Figure 13 show examples of wood firetune and oil watertube packaged boilers.

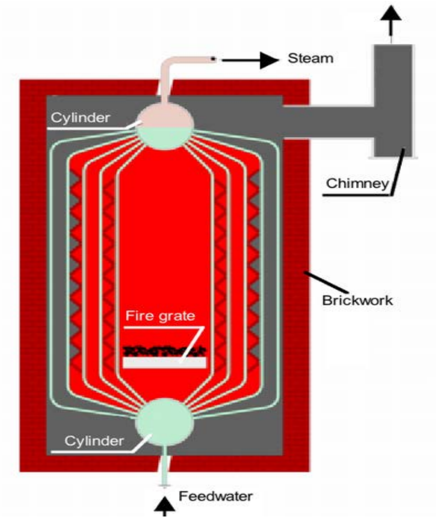


Figure 14 Watertube boiler (Wikipedia) (7)

Watertube boilers

The performance characteristics of watertube boilers make them highly favourable in process industries, including chemical manufacturing, pulp and paper manufacturing, and refining. Although firetube boilers account for the majority of boiler sales in terms of units, watertube boilers account for the majority of total boiler capacity. In watertube boilers, the water runs through a rack of tubes positioned in the hot gases from the fire. Watertube boilers differ from firetube boilers in that the water is circulated inside the tubes, with the heat source surrounding them. Figure 14 shows a typical watertube boiler. A more detailed view of the main boiler components is depicted in **Error! Reference source not found.** (12). Figure 16 shows some details of a modern packaged watertube boiler, and a coil type watertube boiler is shown in Figure 17.

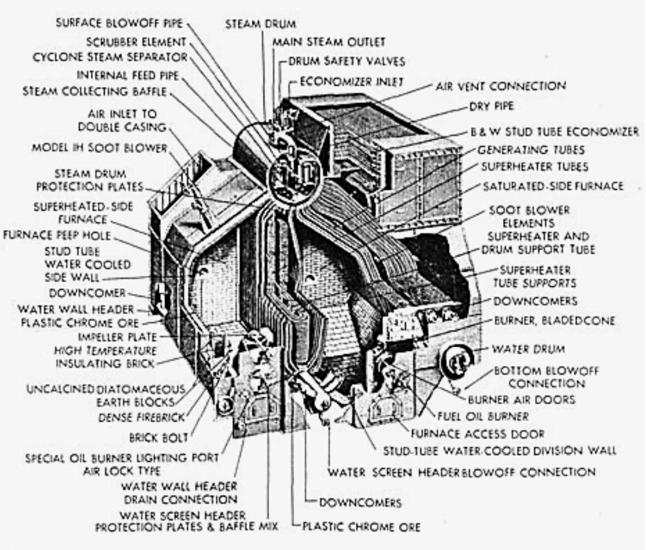


Figure 15 Watertube boiler (Courtesy of B&W)

Boiler water passes through the tubes while the exhaust gases remain in the shell side, passing over the tube surfaces. Because tubes can typically withstand higher internal pressure than the large chamber shell in a firetube boiler, watertube boilers are used when high steam pressures (3,000 psi and higher; more than 200 bar) are required. Watertube boilers are also capable of high efficiencies and can generate saturated or superheated steam. The ability of watertube boilers to generate superheated steam makes them particularly attractive in applications that require dry, high-pressure, high-energy steam, including steam turbine power generation. They can range from hundreds of tons/hour of steam to more than 1000 tons/hour.
Manufacturing details of watertube boilers are illustrated in Figure 18, Figure 19 and Figure 20.

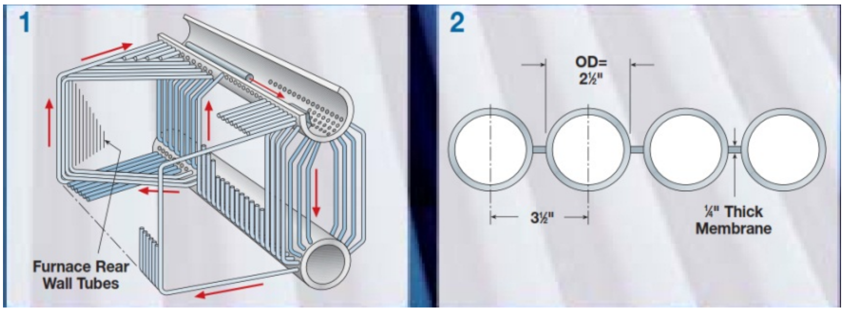


Figure 16 Details of a packaged watertube boiler (Courtesy of B&W) (135)

Figure 17-Coil Type Watertube boiler (EERE - illustration from Bob Forslund -VapoUr power) (20)

Figure 18 Assembled watertube boiler (Novasigma, Italy) (213)

Figure 19 Watertube boiler upper and lower drums-downcomers (Novasigma, Italy) (213)

Figure 20 - Installed watertube boiler (LBL Italy) (185)

Watertube boilers also host various fittings and accessories, including:

- *Safety valve*: A safety value is used to release pressure to prevent boiler explosions.
- *Water level indicators*: The boiler operator monitors the level of water or fluid in the vessel with the help of water level indicators.
- *Bottom blowdown valves*: These valves help remove the condensed solid particles that accumulate in the boiler during the heating process. As its name suggests, this valve is normally located in the bottom of the boiler.
- *Continuous blowdown valve*: This valve allows for a continuous release of water from the boiler to prevent it from becoming saturated.
- *Hand holes*: For the purpose of inspection and checking, these steel plates are installed in the header.

Additional fittings and accessories are described in *Boiler components and accessories*.

Large and sophisticated watertube boilers for power generation work according to the Rankine thermodynamic cycle (for more details, see ANNEX 7). Their dimensions can exceed 60 metres in height and 30 metres in width (see Figure 21), and they can work at supercritical conditions (pressure of above 220 bar).

Figure 21 160 M

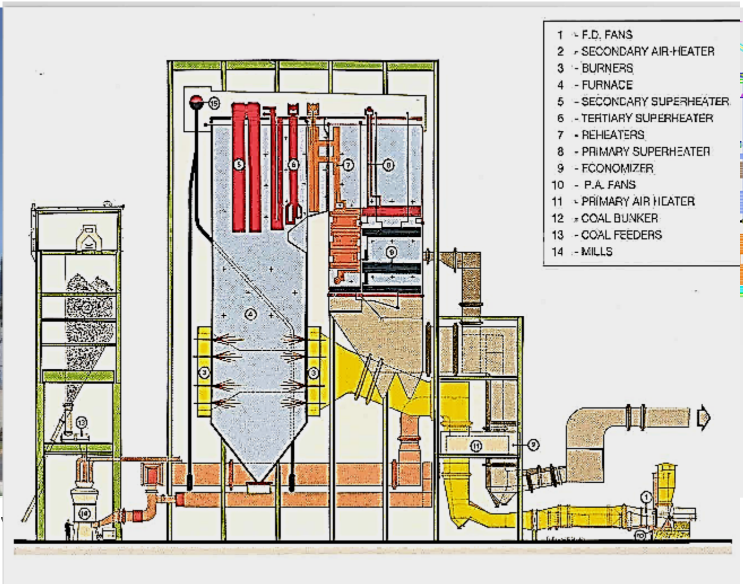


Figure 22 Supercritical boiler-Courtesy of Ansaldo-Italy

Classification of boilers by fuel feeding system

Since the shape and equipment of a boiler depend on the type of fuel it uses, industrial boilers can also be classified by fuel type:

- *Liquid fuel boilers*: include burning of oil products such as gasoline, distillate, or diesel oil, and heavy fuel oils of various viscosities;
- *Gaseous fuel boilers*: include burning of natural gas, LPG, and other gaseous fuels such as refinery downstream gases;
- *Solid fuel boilers*: include burning of coal, biomass, and waste;

Liquid and gaseous fuels

Liquid and gaseous fuels need burners, devices that mix air and fuel together to ensure good combustion. Typical oil burners are shown in Figure 23 and Figure 24.

Figure 23 Typical oil burner for small boilers

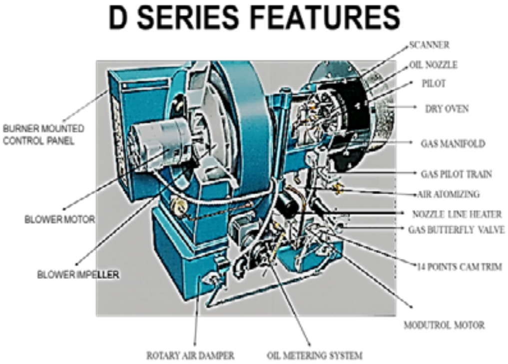


Figure 24 Oil burner components (Courtesy of Enertech Philippines)

The main components of a burner (see Figure 24) are:

- fuel pump
- blower motor
- air damper, and
- fuel nozzle.

The main functions of an oil burner are to:

- atomize fuel to microns of droplets (10-100 microns, approximately 10 billion droplets per litre for good combustion);
- ensure thorough mixing of atomized fuel with combustion air;
- burn fuel completely so there is no carbon monoxide in flue gas;
- burn fuel completely with minimum amount of excess air; and

Figure 25 Fixed grate boiler

- burn fuel with no flame impingement on furnace wall.

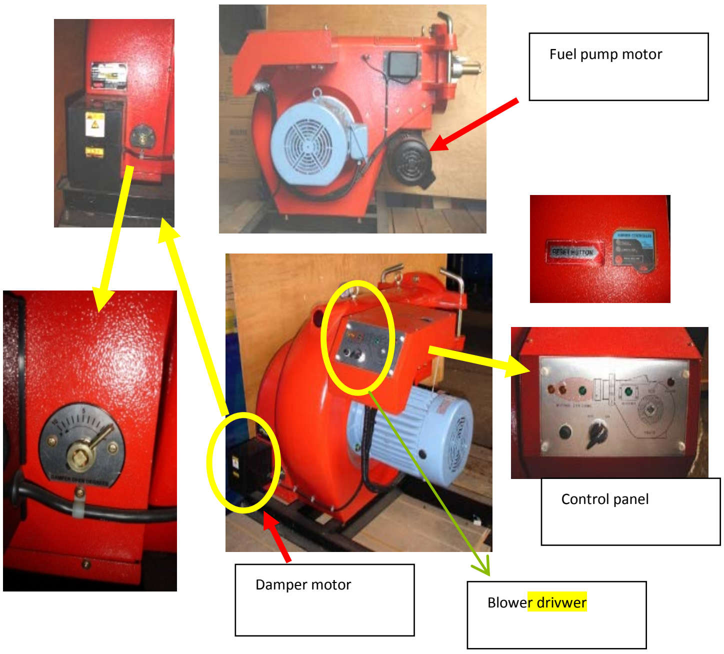


Figure 26 Burner parts (Courtesy of Enertech)

Solid fuel feeding systems

Solid fuels are normally fed into the boiler/furnace by using devices such as hoppers and belt conveyors. Solid fuel boilers can be classified by fuel feeding system as fixed grate boilers and travelling grate boilers.

Fixed grate boilers

Combustion of fuel in fixed grate boilers is concentrated near the fuel feeding openings, and may result in nonhomogeneous distribution of heat release along the furnace with a negative effect on combustion efficiency. Fixed grate boilers include flat grates, dumping grates, vibragrates, reciprocating grates, and inclined and sloping grates. Figure 26 shows a fixed grate boiler, fuelled with wood.

Step and Travelling grate boilers

The most efficient feeding system is the travelling grate, which ensures homogeneous burning along the furnace. Travelling grate boilers include step grates and screw-type underfeed grates. Figure 27 schematically shows a travelling grate device where the fuel (biomass) is burnt. As the grate moves along the length of the furnace, the fuell burns before dropping off at the end as ash. Some degree of skill is required to ensure clean combustion and leave the minimum amount of unburnt carbon in the ash, particularly when setting up the grate, air dampers, and baffles.

Figure 27 Travelling grate burning-Wikipedia (247)

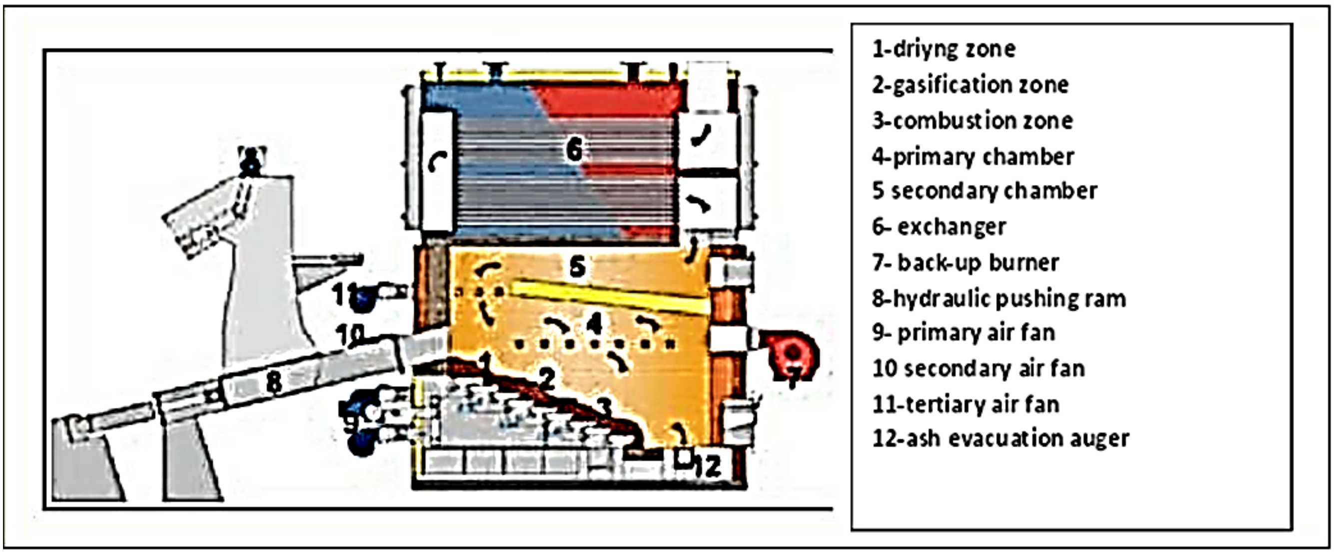


Figure 28 Step Grate boiler-Galenergy-Italy (245)

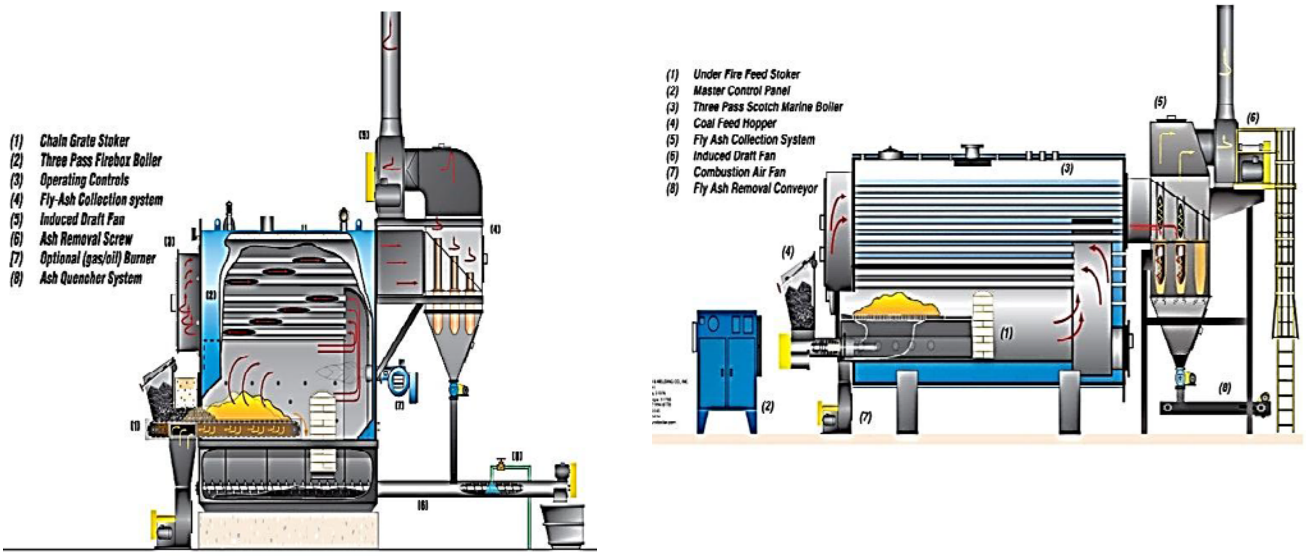


Figure 29- Overfeed and underfeed travelling grate boilers (courtesy of Hurst boilers) (123)

The fuel-feed hopper runs along the entire fuel-feed end of the furnace. A fuel gate is used to control the rate at which coal is fed into the furnace by controlling the thickness of the fuel bed. The fuell must be uniform in size as large lumps will not burn out completely by the time they reach the end of the grate. (11)

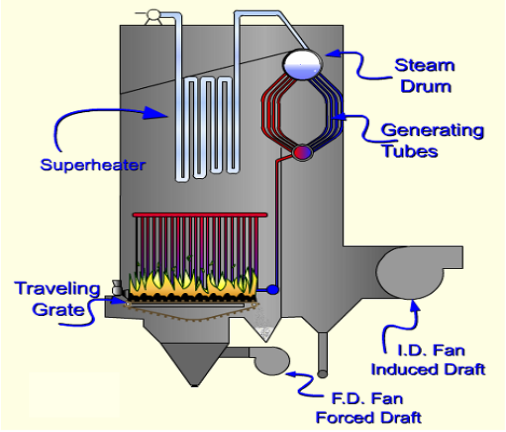


Figure 30 Travelling grate boiler-UNEP (11)

The steam is generated in the steam drum where the water and steam are separated. The steam is then sent to a superheater, a bundle of tubes where the steam is heated at higher pressures and temperatures. The superheater is typically used for electricity production, as the steam turbine that rotates the generator needs high-quality steam. Forced and induced draught fans provide the air necessary for the combustion process. Figure 28 shows a step grate boiler, which is mostly used for waste and biomass burning

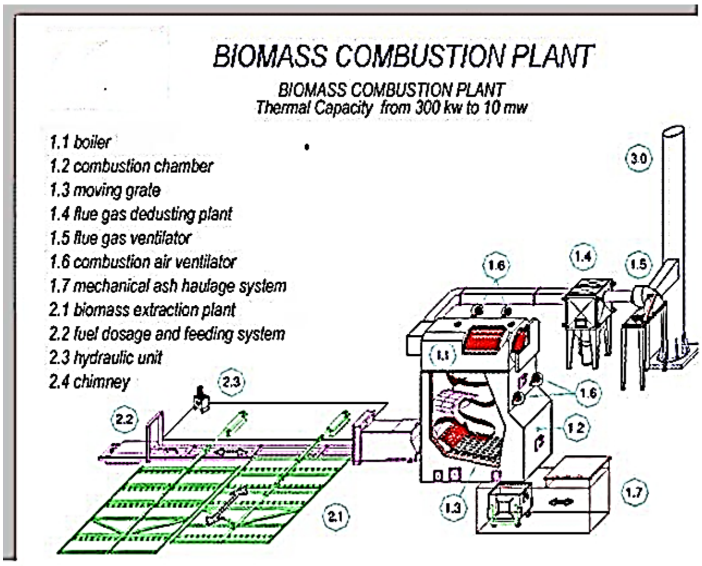


Figure 31 Biomass plant equipped with step grate boiler-
Courtesy of Pelucchi Caldaie -Italy (246)

Overfeed and underfeed travelling grate boilers are shown in Figure 29 A travelling grate boiler, complete with superheater and steam drum, is illustrated in Figure 30. **Figure 31** shows a biomass combustion plant equipped with a step grate boiler

Other types of boilers

Other types of boilers include fluidized bed boilers and gasifiers or two-stage combustors.

Fluidized bed boilers

Fluidized bed combustion (FBC) (13) (14) is a technology used in industrial and power plants. Fluidized beds suspend solid fuels on upward-blowing jets of air during the combustion process (see Figure 32). The result is a turbulent mixing of gas and solids. The tumbling action, much like a bubbling fluid, provides more effective chemical reactions and heat transfer. FBC plants are more flexible than conventional plants in that they can be fired on coal and biomass, among other fuels.

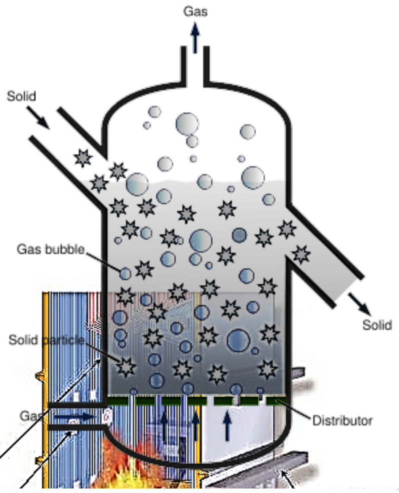


Figure 32 Fluidized bed reactor-Wikipedia **(248)**

In fluidized bed burners, the fuel is introduced into a bed of (usually) hot sand, which provides a very homogeneous temperature and improved combustion dynamics. Pumped combustion air fluidizes the bed and creates conditions for complete gasification and combustion of the fuel within the bed. The high heat transfer, combined with the high thermal inertia effect, allows higher moisture wood and sludge fuels to maintain self-sustained combustion without adding fossil fuels (i.e., the technology is flexible with respect to biomass fuel types and qualities). The special design of the air nozzles at the bottom of the bed allows air flow without clogging. Primary air fans provide preheated fluidizing air. Secondary air fans provide preheated combustion air. Nozzles in the furnace walls at various levels distribute the combustion air in the furnace (Figure 33).

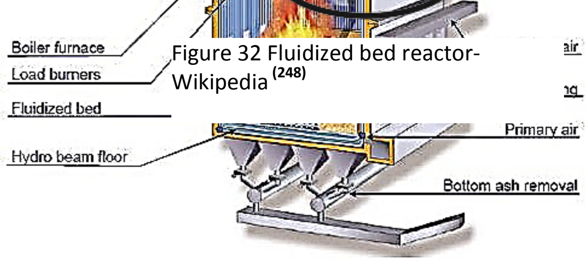


Figure 33 Fluidized bed diagram (Bosky boilers)

The advantage of a FBC boiler is that it reduces the amount of sulphur emitted in the form of sulphur oxide (SO_x) emissions. Limestone is used in the bed to precipitate out sulphate during combustion, which also allows more efficient heat transfer. More than 95% of the sulphur pollutants in coal can be captured inside the boiler by the sorbent. The bed, coming in direct contact with the tubes (heating by conduction), increases the efficiency. Since this allows coal plants to burn at cooler temperatures (760 °C to 930 °C, or 1400 °F to 1700 °F), less nitrogen oxides (NO_x) are also emitted than with grate burners because the threshold at which nitrogen oxides form is approximately 1400 °C (2500 °F). Commercial FBC units operate at competitive efficiencies with NO_2 and SO_2 emissions below levels mandated by national pollution standards.

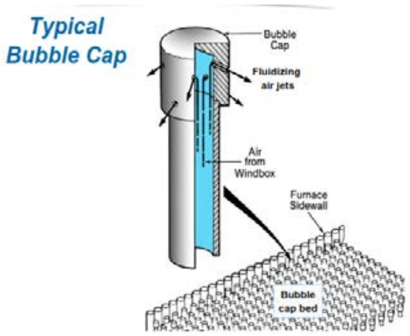


Figure 35 Fluidized bed air jets (Courtesy of B&W) (137

Disadvantages of FBCs include erosion on the tubes inside the boiler, uneven temperature distribution caused by clogs on the air inlet of the bed, lengthy start-up times reaching up to 48 hours in some cases, and increased polycyclic aromatic hydrocarbon emissions because of the low

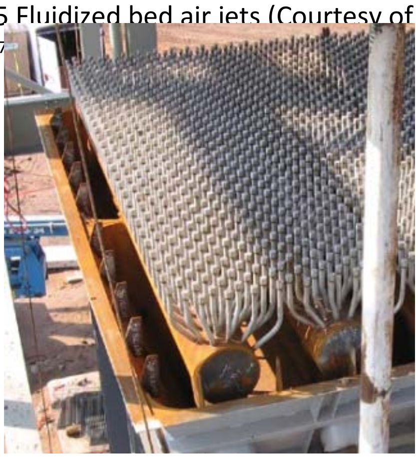


Figure 34 Fluidized Bed Bubbling device (Courtesy of B&W) (188)

temperatures used. Figure 35 shows a typical FB air jet, and Figure 34 shows a bubbling device. (15) Figure 37 depicts the conditions of the fluidized bed during start-up (not operating/operating with air only/operating with addition of fuel).

FBC systems fit into essentially two major groups, atmospheric systems and pressurized systems, and into two minor subgroups, bubbling fluidized beds and circulating fluidized beds.

Atmospheric fluidized bed combustion (AFBC)

Atmospheric fluidized beds, which are commonly used in industrial boilers, use limestone or dolomite to capture sulphur released by combustion of coal. Jets of air suspend the mixture of sorbent and burning coal during combustion, converting the mixture into a suspension of red-hot particles that flow like a fluid. These boilers operate at atmospheric pressure. Two types of beds, as shown in Figure 37, are used:

- *Bubbling fluidized bed combustion (BFBC)*: mainly used for smaller-scale applications with fuels of lower heat content such as sludge and wet wood waste fuels.
- *Circulating fluidized bed combustion (CFBC)*: typically restricted to larger units and high heat content fuels, and used for electricity generation. (16)

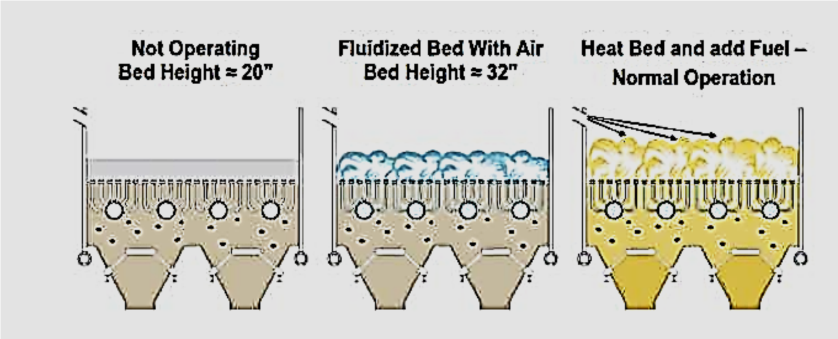


Figure 37 Fluidized bed boilers basic operation (Courtesy B&W) (137)

In circulating beds, fine particles of partly burned coal, ash, and bed material are carried along with the flue gases to the upper areas of the furnace, and then into a cyclone. In the cyclone, the heavier particles separate from the gas, fall to the hopper, and return to the furnace for recirculation. The hot gases from the cyclone pass to the heat transfer surfaces and leave the boiler.

Since CFBC boilers use crushed coal of 3 millimetres (mm) to 6 mm in size, they require a crusher rather than a pulverizer. From storage hoppers, conveyer and feeders transport the coal to feed chutes in the furnace. Start-up is by oil burners in the furnace. Ash spouts in the furnace remove the ash from the bottom of the furnace. Figure 36 shows a CFBC boiler in more detail.

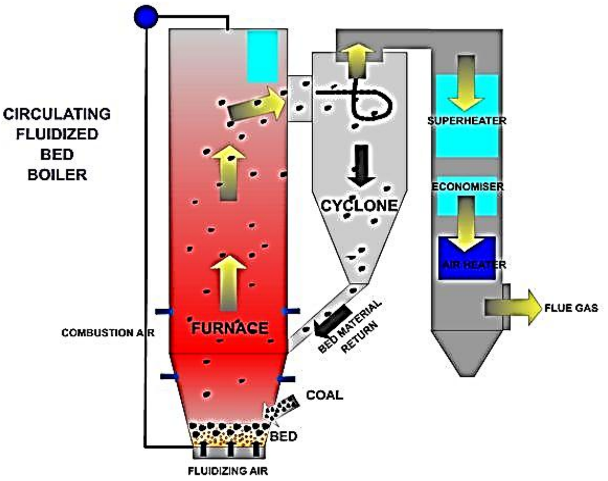


Figure 36 Circulating fluidized bed (from Bright Hub) (118)

Although different boiler manufacturers adopt different methods of cyclone separation, fluidizing nozzles, etc., the basic principles of CFBC boilers remain the same. Like grate burners, fluidized bed burners also combust the biomass (in contrast to gasification). However, the temperature in the combustion zone is a lot more homogeneous and the combustion process is better controlled, ensuring a more complete burnout. This results in lower emissions of volatile organic compounds (VOCs) and ash carbon content than for grate burners. Considerably less ash is carried over into the flue gas because of much reduced char formation due to the higher combustion efficiency, although all ash leaves the furnace as carryover. The more complete burnout also increases boiler efficiency compared to a grate burner. However, uncontrolled particulate emissions are considerable, and additional emissions are caused by the gradual disintegration of the material in the fluidized bed itself.

Fluidized combustion boilers are mostly used for biomass and solid fuels, such as coal, but also to burn waste. Their advantages over firetube and watertube boilers are higher efficiency, lower emissions, and greater flexibility with different fuels. On the other hand, they have higher capital costs and a more complicated operation, particularly during start-up. Fluidized beds are not suitable for daily operation. The bed material at start-up is sand. Some portion is lost in the ash during the operation and this has to be made up. In coal-fired boilers, the ash from the coal itself is the make-up material. When firing biofuels with very low ash content, the make-up bed material will be sand. For high sulphur coal, adding limestone to the bed material reduces SO_2 emissions.

Pressurized fluidized bed combustion (PFBC)

PFBC systems also use a sorbent and jets of air to suspend the mixture of sorbent and burning coal during combustion. However, these systems operate at elevated pressures and can produce high-pressure steam. Steam generated from the heat in the fluidized bed is sent to a steam turbine, creating a high-capacity and highly efficient combined cycle system that produces both steam and electricity. The high pressure of the steam generated to produce electricity justifies the higher capital costs of this type of system.

Advantages (17)

PFBC boilers have the following advantages:

- *High efficiency*: They can burn fuel with a combustion efficiency of over 95% irrespective of ash content, and can operate with overall efficiency of 84% (±2%).
- *Reduction in boiler size*: High heat transfer rates over a small heat transfer area immersed in the bed result in overall size reduction for the boiler.
- *Fuel flexibility*: They can be operated efficiently with a variety of fuels, even flotation slimes, washer rejects, and agro waste. These can be fed either independently or in combination with coal into the same furnace.
- *Ability to burn low-grade fuel*: They give a rated output even with an inferior quality fuel (e.g., coal with ash content as high as 62% and calorific value as low as 2500 kcal/kg). Even carbon content of only 1% by weight can sustain the fluidized bed combustion.
- *Ability to burn fines*: Coal containing fines below 6 mm can be burned efficiently in an FBC boiler, something that is very difficult to achieve in conventional firing systems.
- *Pollution control*: SO_2 formation can be greatly minimized by addition of limestone or dolomite for high sulphur coal (3% limestone is required for every 1% sulphur in the coal feed). Low combustion temperature eliminates NO_x formation.
- *Low corrosion and erosion*: The corrosion and erosion effects are less due to lower combustion temperature, softness of ash, and low particle velocity (around 1 metre/second).
- *Easier ash removal and no clinker formation*: Since the temperature of the furnace is in the range of 750 °C to 900 °C, even coal of low ash fusion temperature can be burned without clinker formation. Ash removal is easier as the ash flows like liquid from the combustion chamber; hence less manpower is required for ash handling.

- *Less excess air and higher CO_2 in flue gas*: The carbon dioxide (CO_2) in the flue gases will be of the order of 14% to 15% at full load. Hence, these boilers can operate at low excess air of only 20% to 25%.
- *Simple operation and quick start-up*: High turbulence of the bed facilitates quick start-up and shutdown. Full automation of start-up and operation using reliable equipment is possible.
- *Fast response to load fluctuations*: Inherent high thermal storage characteristics can easily absorb fluctuation in fuel feed rates. The response to changing load is comparable to that of oil-fired boilers.
- *No slagging in the furnace or sootblowing*: Volatilization of alkali components in ash does not take place and the ash is not sticky. This means that there is no slagging or sootblowing.

Disadvantages (18)

As with any design, PFBC boilers have their drawbacks, which reactor designers must take into consideration:

- *Increased reactor vessel size*: Because of the expansion of the bed materials in the reactor, a larger vessel is often required than that for a packed bed reactor. This larger vessel means that initial capital costs are greater.
- *Pumping requirements and pressure drop*: The requirement for the fluid to suspend the solid material means that a higher fluid velocity is attained in the reactor. More pumping power and thus higher energy costs are needed. In addition, the pressure drop associated with deep beds also requires additional pumping power.
- *Particle entrainment*: The high gas velocities present in this style of reactor often result in fine particles becoming entrained in the fluid. These captured particles are then carried out of the reactor with the fluid, where they must be separated. This can be a very difficult and expensive problem to address, even with entrainment reducing technologies, depending on the design and function of the reactor. *Limited understanding*: Current understanding of the actual behaviour of the materials in a fluidized bed is rather limited. Since it is very difficult to predict and calculate the complex mass and heat flows within a bed, new processes require pilot plants. Even with pilot plants, however, the scale-up can be very difficult and may not reflect what was experienced in the pilot trial.
- *Erosion of internal components*: The fluid-like behaviour of the fine solid particles within the bed eventually results in the wear of the reactor vessel. This can require expensive maintenance and upkeep for the reaction vessel and pipes.
- *Pressure loss scenarios*: If fluidization pressure is suddenly lost, the surface area of the bed may be suddenly reduced. This can either be an inconvenience (e.g., making bed restart difficult), or may have more serious implications, such as runaway reactions (e.g., for exothermic reactions in which heat transfer is suddenly restricted).

Gasifiers or two-stage combustors

Gasification is used to split up the combustion process, resulting in so-called “two-stage combustion” (14). By creating a syngas composed of all material in the fuel feedstock and leaving behind the ash, this technology promises better process control and lower particulate emissions. It is becoming more and more popular for new biomass energy installations. Gasifiers are classified as fixed bed (downdraught and updraught), fluidized bed, and entrained flow. Figure 38 shows a fixed bed gasifier developed by

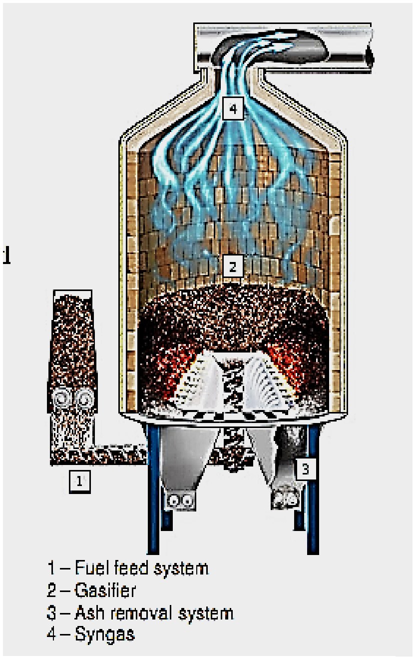


Figure 38 Nexterra fixed bed gasifier -Ministry of Environment-British Columbia (181)

Nexterra-Canada, and Figure 39 compares the three main technologies and their plant capacity application ranges.

In an updraught (or "counter flow") gasifier, the biomass fuel enters the top of the reaction chamber while steam and air (or oxygen) enter from below a grate. The type of gasifier, whether it is updraught, downdraught, bubbling or fluidized bed, can have an impact on air emissions. Gas velocity through the bed, and the ability to control the gasification process, is one of the key variables. In downdraught (co-flow) gasifiers, both biomass and combustion air come from above. Downdraught versions have been shown to be the cleaner of the two varieties in terms of particulate and tar emissions in the product.

Fixed bed gasifiers are used for well-defined feedstock and smaller plant sizes (up to around 10 megawatt (MW) output). They are simpler in design, do not require secondary material, such as sand, and are less costly to purchase and operate than the other types.

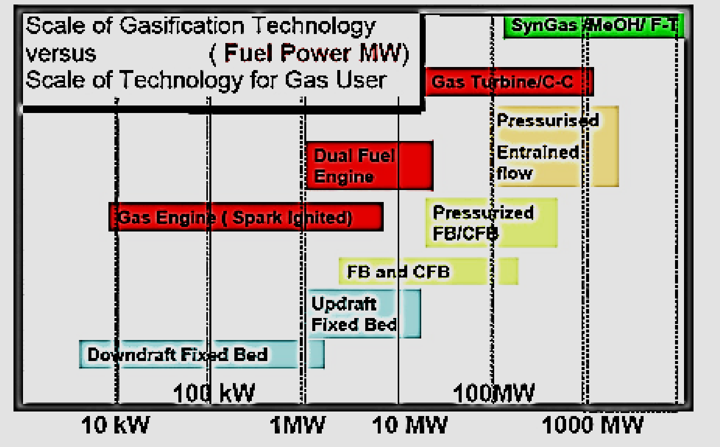


Figure 39 Gasification technologies and their size application -Ministry of Environment-British Columbia (181)

Fluidized bed gasifiers, just like burners, use sand or a similar material to mix up biomass and add a fluidized bed of a uniform temperature. They can be pressurized (larger systems) or at atmospheric pressure. The turbulence created through this process increases the tar content of the syngas compared to a fixed bed gasifier. In a bubbling fluidized bed gasifier, the bed material is agitated by gases flowing through it. Circulating fluidized bed gasifiers employ a system where the bed material circulates between the gasifier and a secondary vessel. Various designs are possible, with biomass fuels being fed into the top, bottom or middle of the moving bed. Syngas typically exits these systems at a high temperature, and has relatively high particulate contents due to the turbulence within the reactor. Due to the high temperatures involved, the syngas may also contain vaporized alkali salts. Tars will also be present in the gas in varying amounts depending on the specifics of the operation. Fluidized beds are more tolerant with respect to the feedstock and are available up to a very large scale.

In an entrained bed gasifier, the solids are entrained in the gas flow at high velocities. This is a pressurized process with high capital and operating costs. Entrained flow gasifiers are being discussed for large-scale biomass conversion with syngas cleanup in a Fischer-Tropsch process, but are currently only used commercially for coal as a fuel. They can use different fuels, but may require additives for ash/slag management.

Thermal Oil Heaters

Thermal oil Heaters are not real boilers, because do not “boil” water as use special oils which reach high temperatures, but are often referred as boilers and largerly used in some industrial sectors, therefore they are briefly mentioned in this Guide. Thermal oil Heaters offer the user the capability of high temperature operation (up to 300 °C - about 600 °F- with organic thermal oils and more than 400 °C -about 800 °F -with certain synthetics) at very low pressures. Due to the low operating pressure and properties of thermal fluids, most heaters are built to

Figure 40 Thermal oil boiler- Courtesy of Giberti srl - Italy (244)

ASME Section IV, and a licensed boiler operator is not typically required (**Figure 40**).

If steam is required for special functions, a steam generator can be added. In that case, the thermal fluid also circulates through the tubes inside the steam generator. The tubes heat water surrounding them, converting the water into steam. Unlike a fired boiler, the heated tubes in the steam generator never get hotter than the thermal fluid flowing through them.

Thermal oil heaters have advantages and disadvantages compared to “regular” boilers:

Advantages:

- High temperature at atmospheric pressure
- No restrictive regulations
- Low corrosion rates
- No operator attendance required (depending on local regulations)

Disadvantages

- More expensive than standard boilers
- Higher risk of fire
- Need for circulating pump

Boiler components and accessories

A boiler is normally supplied with a number of accessories and auxiliary systems that ensure its proper and safe operation. This section introduces and briefly discusses the main boiler components and accessories.

Boiler control systems

Boiler control systems are designed to protect the boiler and to ensure proper boiler operation. These include the combustion control, feedwater, combustion air, fuel control, and blowdown systems. If a deaerator is present, it can be considered either as part of the feedwater system or as a separate system. Since a deaerator is not usually present in most small boilers, it will be discussed here as a separate system.

Combustion control system

The combustion control system (see Figure 41) regulates the fuel and air mixture to achieve safe and efficient combustion, and maintain proper steam system pressure. Control systems have varying levels of sophistication. Simple systems use a fixed linkage between the fuel-regulating valve and the combustion air damper. This is called single point positioning. A change in steam pressure causes a proportional change in the combustion air and fuel. Modern systems rely on signals from digital transmitters to determine independent fuel valve and air damper positions, and typically provide alarms for out-of-specification conditions for investigation and remedy. This is called a full monitoring system.

Figure 41 Burner control device (Courtesy of Enertech-PH)

Flame safeguard system

The flame safeguard system is an arrangement of flame detection systems, interlocks, and relays, which sense the presence of a proper flame in a furnace and cause fuel to be shut off if a hazardous condition develops. Modern combustion control systems are closely interlocked with flame safeguard systems, pressure-limit switches, low-water level cutoffs, and other safety controls that stop the energy input to a boiler when an unsafe condition develops. The flame safeguard system also programs the operation of a burner system so that motors, blowers, ignition, and fuel valves are energized only when they are needed and then in proper sequence.

Safety shutoff valve

Safety shutoff valves isolate the fuel supply to the boiler in response to certain conditions such as low or high gas pressure or satisfied load demand. Safety shutoff valve types and settings are often determined by code or insurance requirements.

Water-level control system

The water-level control system ensures a safe water level in the boiler. Typically, the control system provides a signal to the feedwater control valve to regulate the feed rate. Simple water-level control systems that only sense water level are single-element systems. More complex systems, which incorporate additional data such as steam flow rate (dual-element system) and feedwater flow (triple-element system), provide better water-level control during abrupt load changes.

Safety valve

The safety valve is the most important valve on the boiler and keeps the boiler from exceeding its maximum allowable working pressure (MAWP).

Steam-pressure control

Steam-pressure controls regulate the combustion equipment to maintain a constant pressure in the steam header. As the pressure rises above or falls below the pressure setting, the control adjusts the burner firing rate to bring the pressure back to the setpoint.

Non-return valve

The non-return valve is a combination shutoff and check valve that allows steam out of the boiler, but prevents backflow from the steam header in the event the boiler pressure drops below that of the header. The valve is opened only when the pressure inside the boiler rises slightly above the steam header pressure.

Steam flowmeter

Steam flowmeters can provide useful data for assessing boiler performance, calculating boiler efficiency, and tracking the amount of steam required by the system. In some systems, steam flowmeters provide a measurement signal for the boiler control system. Additionally, steam flowmeters can be useful in benchmarking efforts (Figure 42.

There are three basic types of steam flowmeters:

- *Differential pressure (DP) flowmeters*: rely on the change in pressure as steam flows by an element such as a nozzle, orifice, or Venturi. This pressure difference provides an indication of flow velocity, which, in turn, can be used to determine the flow rate.
- *Vortex flowmeters*: rely on the principle that flow past an element creates vortices with frequencies that correspond to the flow velocity.
- *Coriolis flowmeters*: rely on tubes placed in the steam flow path that twist according to the velocity of the flow.

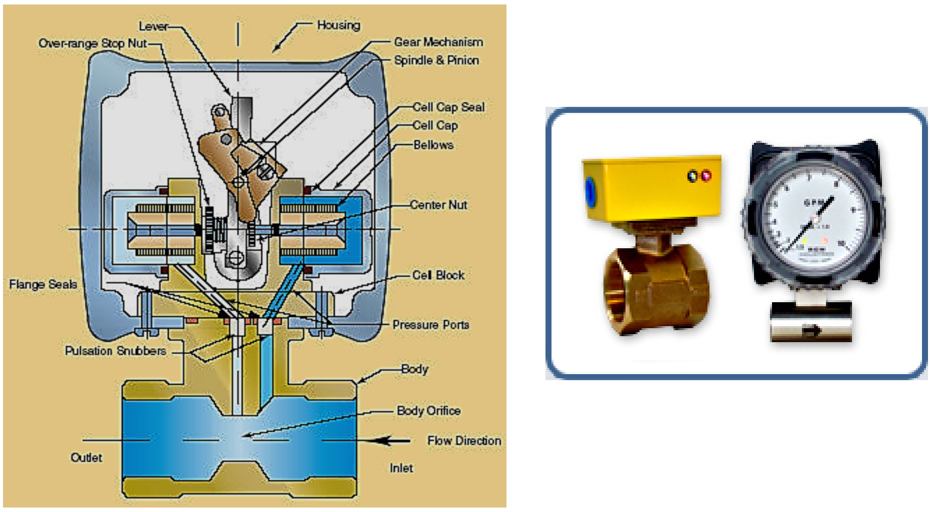


Figure 42 Steam flowmeter- RCM Industries (249)

Boiler feedwater system

Boiler feedwater systems supply water to the boiler. Sources of feedwater include returning condensate and make-up water. Feedwater is typically stored in a collecting tank to ensure that a steady supply of heated water is available to the boiler regardless of momentary fluctuations in availability of condensate return or fresh water supply pressure. In open systems, where all of the produced steam is used by the process or wasted to the environment, there are no condensate return lines The main components of a feedwater system are described below.

Feedwater flow control valve

Modulating feedwater flow control valves move up or down in response to the water level transmitter(s). On smaller firetube boilers, it is not uncommon for the feedwater valve to operate in a closed or open position, depending on the water level transmitter signal. In modern industrial boilers, the controls may also account for significant variations in steam demand.

Pretreatment equipment

Pretreatment equipment improves the quality of the incoming water so that it may be used in the boiler without excessive scaling or foaming, which can reduce boiler efficiency and cause tube failure. Pretreatment equipment includes, but is not limited to, clarifiers, filters, softeners, dealkalizers, decarbonators, reverse osmosis (RO) units, and demineralizers (Figure 43).

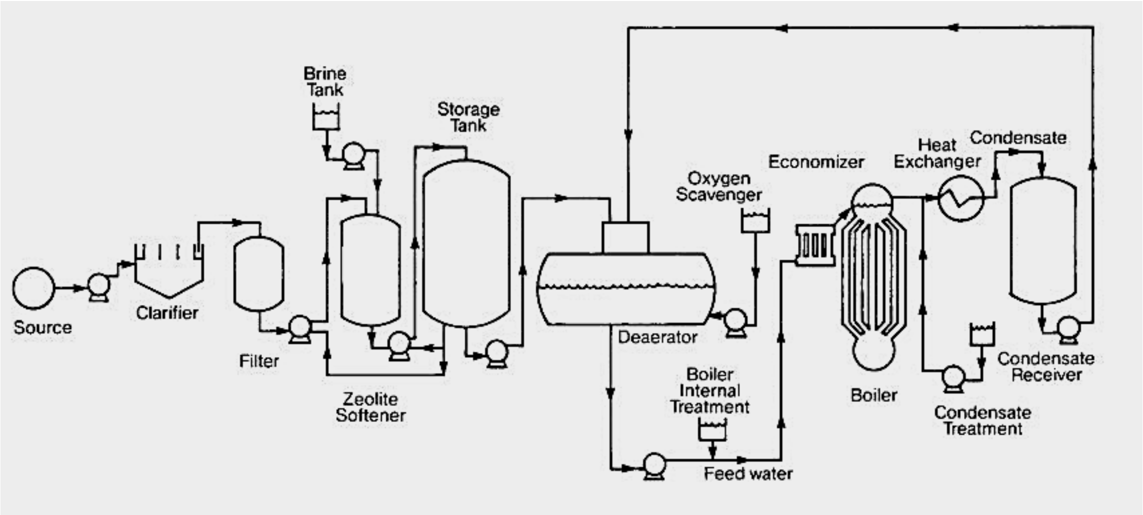


Figure 43 Typical boiler water treatment system-Courtesy of Clean Boiler [250]

Softener

Softeners remove calcium, magnesium, and iron, which are often referred to as "hardness minerals", from a water supply. Their presence in boiler water can lead to many problems, including scale build-up and foaming, which reduce boiler efficiency and can cause tube failure. Softeners reduce this problem through an ion-exchange process. As the hard water passes through a chamber filled with resin, an exchange occurs that removes hardness minerals from the water. The sodium that replaces the hardness minerals has a higher solubility in water and generally will not form scale.

Feedwater pump

Feedwater pumps transfer water from the deaerator to the boiler. Feedwater pumps are driven by electric motors or by steam turbines (in large boilers). In a modulating feedwater system, the feedwater pumps run constantly instead of the on/off operation used in relatively small boilers.

Collecting/storage tank

In condensate recovery systems, the return of condensate is often erratic due to the changing steam requirements of the end users. The condensate is usually returned to a condensate receiver or directly to the deaerator if the system does not have a receiver. Pretreated water may also be stored in a tank prior to use. This provides the boiler system with additional water capacity in case the pretreatment equipment malfunctions. The condensate and pretreated water, or make up, are transferred from the storage tanks to the deaerator before being sent to the boiler.

Deaerators

Deaerators (19) are mechanical devices that remove dissolved gases from boiler feedwater (see Figure 44). Deaeration protects the steam system from the effects of corrosive gases by reducing the concentration of dissolved oxygen and carbon dioxide to a level where corrosion is minimized. A dissolved oxygen level of 5 parts per billion (ppb) or lower is needed to prevent corrosion in most high-pressure (>200 psi, or 14 kg/cm^2) boilers. While oxygen concentrations of up to 43 ppb may be tolerated in low-pressure boilers, equipment life is extended at little or no cost by limiting the oxygen concentration to 5 ppb. Dissolved carbon dioxide is essentially completely removed by the deaerator. Since deaerators are important devices for medium/large boilers, they are discussed in more detail below.

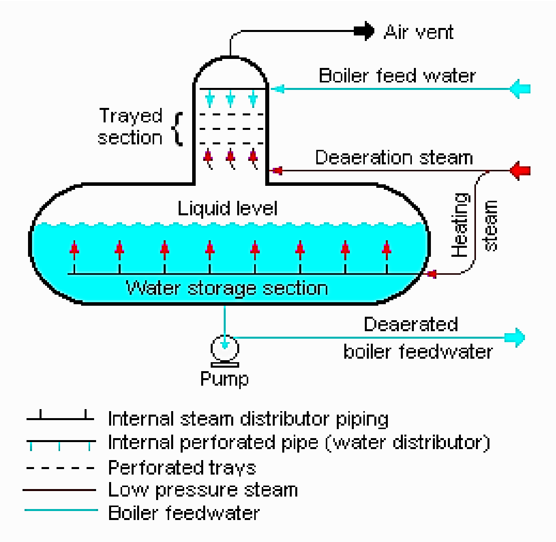


Figure 44-Deaerator (Wikipedia) (235)

How they work

The design of an effective deaeration system depends upon the amount of gases to be removed and the final oxygen gas concentration desired. This, in turn, depends upon the ratio of boiler feedwater make-up to returned condensate and the operating pressure of the deaerator. Deaerators use steam to heat the water to the full saturation temperature corresponding to the steam pressure in the deaerator, and to scrub out and carry away dissolved gases. Steam flow may be parallel, cross, or counter to the water flow. The deaerator consists of a deaeration section, storage tank, and vent. In the deaeration section, steam bubbles through the water, both heating and agitating it. Steam is cooled by incoming water and condensed at the vent condenser.

No condensable gases and some steam are released through the vent. Steam provided to the deaerator provides a physical stripping action and heats the mixture of returned condensate and boiler feedwater make-up to saturation temperature. Most of the steam will condense, but a small fraction (usually 5% to 14%) must be vented to accommodate the stripping requirements. Normal design practice is to calculate the steam required for heating and then make sure that the flow is sufficient for stripping as well. If the condensate return rate is high (>80%), and the condensate pressure is high in comparison to the deaerator pressure, then very little steam is needed for heating and provisions may be made for condensing the surplus flash steam.

Deaerators are designed to remove oxygen that is dissolved in the entering water, not entrained air. Sources of “free air” include loose piping connections on the suction side of pumps and improper pump packing.

Deaerator steam consumption

The deaerator steam consumption is equal to the steam required to heat incoming water to its saturation temperature, plus the amount vented with the noncondensable gases, less any flashed steam from hot condensate or steam losses through failed traps. The heat balance calculation is made with the incoming water at its lowest expected temperature. The vent rate is a function of deaerator type, size (rated feedwater capacity), and the amount of make-up water. The operating vent rate is at its maximum with the introduction of cold, oxygen-rich make-up water.

Additional benefits

Deaerators provide the water storage capacity and net positive suction head necessary at the boiler feed pump inlet. Returned condensate is mixed with make-up water within the deaerator. Operating temperatures range from 215 °F to more than 350°F, which reduces the thermal shock on downstream preheating equipment and the boiler.

Insulation

The deaerator section, storage tank, and all piping conveying hot water or steam should be adequately insulated to prevent the condensation of steam and loss of heat.

Pressure fluctuations

Sudden increases in free or "flash" steam can cause a spike in deaerator vessel pressure, resulting in re-oxygenation of the feedwater. A dedicated pressure-regulating valve should be provided to maintain the deaerator at a constant pressure.

Atmospheric deaerators are typically found in smaller, lower-pressure boiler systems. Since they operate at atmospheric pressure, the maximum operating temperature is 100 °C (212 °F) with most operating at temperatures lower than this. Atmospheric deaerators cannot achieve the same level of oxygen removal as deaerators and deaerating heaters, and typically provide water with oxygen levels of 0.5 to 1 part per million (ppm).

Combustion air systems

The air needed for combustion of fuels is provided by air systems that are composed of fans, dampers, ducts, and proper instrumentation.

Fans

Most boilers now depend on mechanical draught equipment rather than natural draught(98) (20). This is because natural draught is subject to outside air conditions and the temperature of flue gases leaving the furnace, as well as the chimney height. All these factors make proper natural draught hard to attain and mechanical draught equipment much more economical.

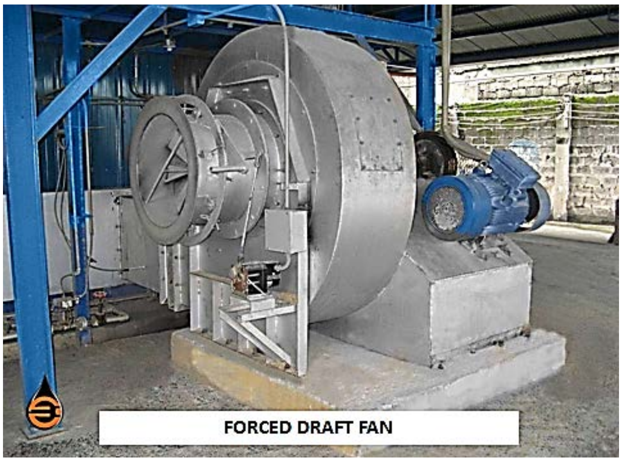


Figure 45 Forced draught fan-(Courtesy of Enertech –Philippines)

There are three types of mechanical draught:

- *Induced draught*: Draught is obtained by using an induced draught (ID) fan that removes flue gases from the furnace and forces it up the stack. Located on the outlet gas side of the boiler, induced draught fans create a slightly negative furnace pressure that is controlled by outlet dampers on the boiler. For systems involving a baghouse, mechanical collector, or precipitator, special consideration should be given to sizing and selection of this fan.
- *Forced draught*: Draught is obtained by forcing air into the furnace by means of a forced draught (FD) fan (see Figure 45) and a duct system. Air is often passed through an air heater, which, as the name suggests, heats the air going into the furnace to increase the overall efficiency of the boiler. Dampers are used to control the quantity of air admitted to the furnace. Forced draught furnaces usually have positive pressure. A forced draught fan is located at the inlet of a boiler and pushes ambient air into the burner region,

ensuring that adequate air is delivered to the combustion process. These fans either pull air directly from the boiler room or connect to a duct system that allows outside air to be drawn into the boiler.

- *Balanced draught*: Balanced draught is obtained through use of both induced and forced draught. This is more common with larger boilers where the flue gases have to travel a long distance through many boiler passes. The induced draught fan works in conjunction with the forced draught fan to allow the furnace to be maintained at slightly below atmospheric pressure.

Dampers

Dampers control the amount of air allowed into and out of a combustion chamber. Dampers, in combination with fuel regulating devices, are positioned by the combustion control system to achieve certain fuel-to-air ratios. Dampers on the boiler outlet are used to regulate the negative furnace draught.

Fuel systems

Since many types of fuels are used in boilers, different types of fuel handling systems are required (see *Classification of boilers by fuel feeding systems* section):

- *Biomass fuels*: provide emission options that are carbon neutral.
- *Fossil fuels*: are most commonly used e.g., coal, oil, gas.
- *Waste fuels*: are used in many industries, particularly forest products, petroleum refining, and chemical manufacturing, where there is an available supply of waste products such as bark, wood chips, black liquor, and refinery gas.

The major components of a fuel system are described below.

Fuel regulating valve

For gaseous and liquid fuels, regulating valves control the fuel delivered to the boiler. In many systems, these valves can be quickly shut in response to an operating problem.

Fuel flowmeter

Fuel meters measure the amount of fuel delivered to a boiler, and provide essential data in determining boiler efficiency. Since fuel flowmeters measure volume or mass of fuel, it is important to know the energy content of the fuel when determining boiler efficiency.

Burner

Burners combine the fuel and air to initiate combustion. There are many types of burners due to the different types of fuels. Additionally, burners have different performance characteristics and control requirements. Some burners are on/off, while others allow precise setting of the fuel/air mixture over a range of conditions. Some burners can fire different types of fuel, allowing boiler operation to continue despite the loss of one fuel supply. A fuel oil burner vaporizes and/or atomizes the fuel oil. Fuel oil burners can in general be categorized into the three groups discussed below. (21)

Gun-type burners (pressure gun)

Gun-type burners atomize the fuel oil by forcing the oil through a nozzle and spraying it into to a gun-like airflow atomic nozzle (see Figure 23) The liquid forms microscopic particles or globules that are well mixed and partly evaporated before being ignited in the combustion chamber. These burners are very flexible and can be used within a large range of applications, from relatively small residential heaters to larger industrial heating applications. Residential gun-type burners normally requires oil pressure of 80-130 psi, while commercial and industrial gun-type burners require 100-300 psi.

Pot-type burners

In pot-type burners, the fuel evaporates into the combustion air. Gravity causes the oil to flow to the burner in atmospheric pot-type burners. In general, there are three types:

- *Natural draught burners*: rely on the natural draught in the chimney for air supply.
- *Forced draught burners*: rely on a mechanical fan and/or the chimney for air supply.
- *Sleeve burners*: are only used in small applications.

Although the pot-type burner is the most inexpensive fuel oil burner with the lowest operating cost, it also has a limited capacity, making it generally most suited for smaller applications.

Rotary-type burners

Rotary-type burners operate with low-pressure gravity and the fuel oil is supplied on and thrown off a rotary disc in a fine spray by centrifugal force. They are best suited for large applications. Rotary burners can be classified as:

- *Rotary nozzle*: a nozzle assembly rotates at high speed and oil is supplied through the shaft.
- *Rotary cup*: a cone-shaped cup rotates around a central tube where the fuel oil is supplied.

The following types of rotary oil burners are available:

- vertical rotary burners
- horizontal rotary burners
- wall-flame rotary burners

Blowdown systems

The boiler blowdown system includes the valves and the controls for the continuous blowdown and bottom blowdown services (see Figure 46).

Continuous blowdown removes a specific amount of boiler water (often measured in terms of percentage of feedwater flow) to maintain a desired level of total dissolved solids in the boiler. Setting the flow for the continuous blowdown is typically done in conjunction with the water treatment program. Some continuous blowdown systems rely on the input of sensors that detect the level of dissolved solids in the boiler water.

Figure 46 Boiler Blowdown valves (Courtesy of Enertech-Philippines)

Bottom blowdown is performed to remove particulates and sludge from the bottom of the boiler. Bottom blowdowns are periodic and are typically performed a certain number of times per shift or according to a set schedule. In some systems, they are controlled by an automatic timer. Bottom blowdown should only be permitted if recommended by the boiler manufacturer. This is because it may cause water starvation in some portions of the boiler circuit in higher-pressure boilers, especially those above 700 psig (48 bar).

Blowdown heat exchangers and flash tank

The continuous blowdown water has the same temperature and pressure as the boiler water. Before this high-energy water is discharged into the environment, it is often sent to a heat exchanger and flash tank. Flash tanks permit the recovery of low-pressure flash steam, which can be used in deaeration or process heating. They also permit the use of a smaller heat exchanger than would be required without the flash tank. Blowdown heat exchangers are most often used to preheat boiler make-up water.

Steam distribution systems

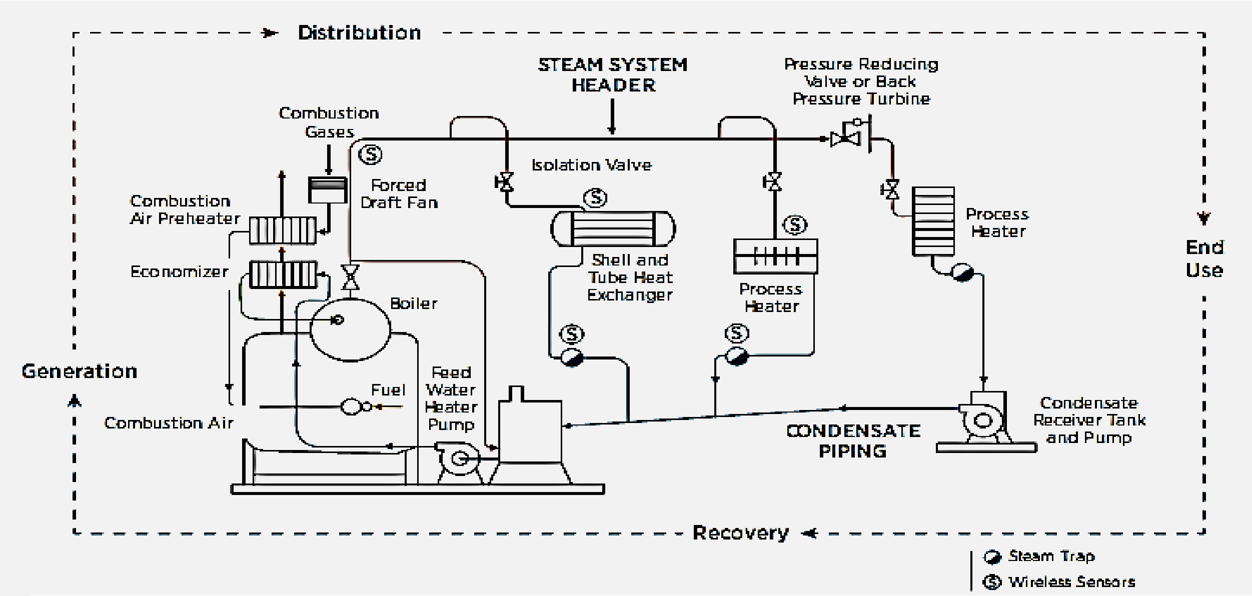


Figure 47 Steam production and distribution (US–EERE) (22)

This general discussion focuses on steam systems (steam lines and auxiliaries) commonly used in industrial boilers for the manufacturing sector, which include combined production of power and steam. A variety of solutions are available depending on the sector and the goods produced. Figure 47 and Figure 48 show examples

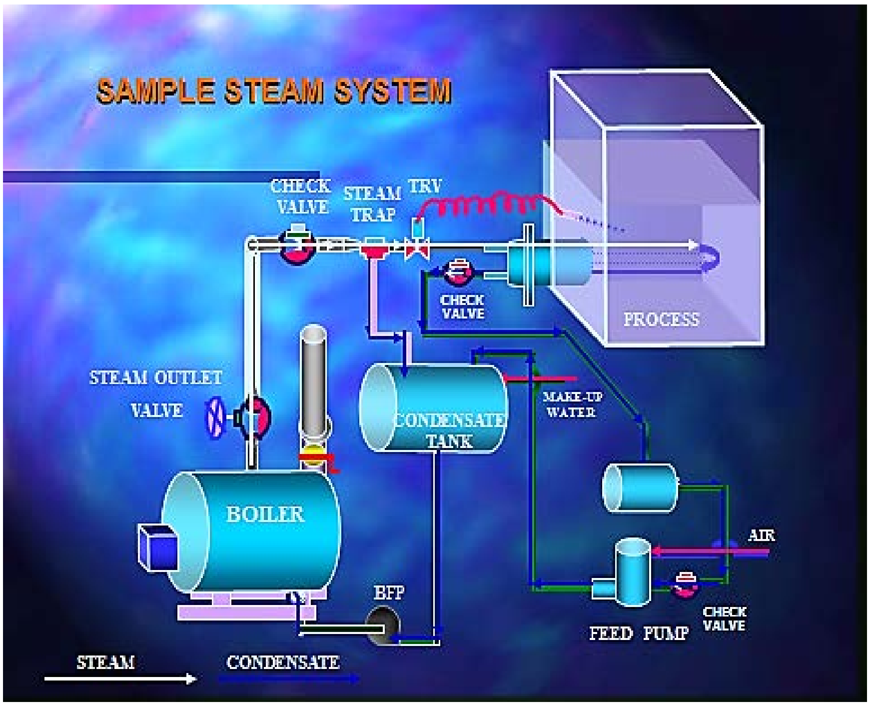


Figure 48 Boiler systems (Courtesy of Enertech–Philippines)

of a steam production and distribution system. In a factory, the boiler is normally considered as a secondary part of the manufacturing process. Its function is to produce all the steam/heat that the main process (production of goods) demands. The boiler is therefore a “slave” to the manufacturing process to which it must deliver steam, and must comply with production process needs. For this reason, boiler and steam distribution systems are often neglected during production cost evaluations.

Steam production systems in a manufacturing process can be classified as once through or condensate recovery systems.

Once through systems

The steam produced is delivered straight to the process, which completely uses it and its intrinsic energy or partially disperses it to the environment. The steam is not returned to the boiler as condensate water. This system does not have condensate return lines and related accessories (Figure 49).

Once through systems are more common in small boilers where the amount of steam produced sometimes does not warrant the cost of condensate recovery components, and in manufacturing processes where the steam is completely used. Current rising prices of fuel, water and chemicals for water treatment make the once through system less economically attractive. The need to reduce groundwater pollution and save water resources also discourages its adoption.

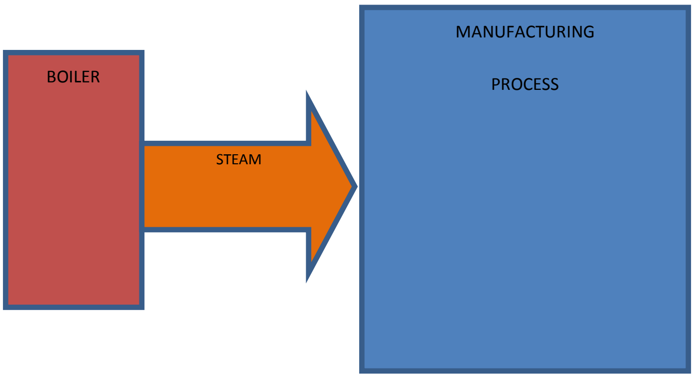


Figure 49 Once through system

Condensate recovery systems

The steam is delivered to the process, where a heat exchanger transfers its energy to the process; the condensate water is then returned to the boiler inlet to be reused (closed cycle; see Figure 50. The temperature of the condensate water ranges between 40 °C and 80 °C. These systems are more efficient and environmentally sustainable than once through systems, but more complex and expensive because they need more components such as condensate return pumps and a heat recovery \ exchanger. Condensate recovery systems are more capital expensive, but result in lower annual fuel bills. The condensate recovery investment payback depends on the type of boiler and factory production process; the investment can often be recovered in two or three years.

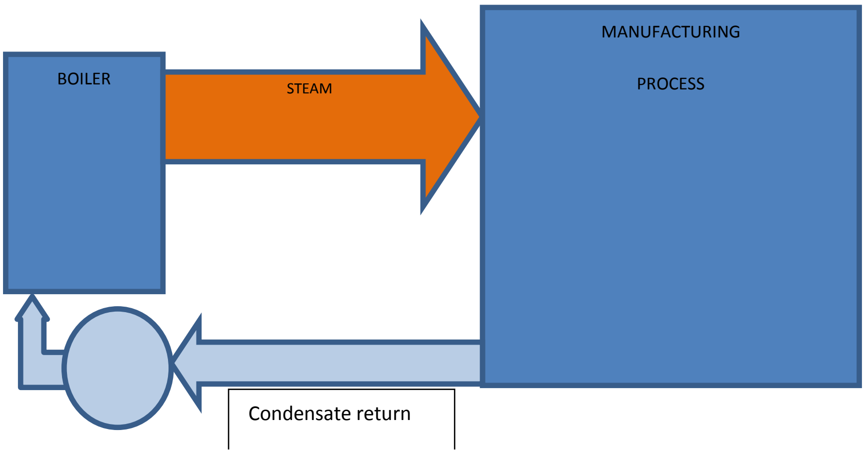


Figure 50 Condensate recovery system

Main system components

This section discusses some of the main auxiliaries of a steam production system. Further details can be found in the references for this Chapter. (22) The distribution system transports steam from the boiler to the various end uses. Although distribution systems may appear to be passive, they regulate the delivery of steam and respond to changing temperature and pressure requirements. Consequently, proper performance requires careful design practices and effective maintenance. The piping should be properly sized, supported, insulated, and configured with adequate flexibility. Pressure-regulating devices such as pressure-reducing valves and backpressure turbines should be configured to provide proper steam balance between the various steam headers. Additionally, the distribution system should be configured to allow adequate condensate drainage, which requires appropriate drip leg capacity and steam trap selection.

Piping

Steam piping transports steam from the boiler to the end use services. Important characteristics of well-designed steam system piping are that it is adequately sized, configured, and supported. Installation of larger pipe diameters may be more expensive, but can create less pressure drop for a given flow rate. Additionally, larger pipe diameters help to reduce the noise associated with steam flow. As such, consideration should be given to the type of environment in which the steam piping will be located when selecting the pipe diameter. Important configuration issues are flexibility and drainage. With respect to flexibility, piping (especially at equipment connections) needs to accommodate thermal reactions during system start-ups and shutdowns. Piping should be equipped with a sufficient number of appropriately sized drip legs to promote effective condensate drainage. Additionally, the piping should be pitched properly to promote the drainage of condensate to these drip lines. Typically, these drainage points experience two very different operating conditions, normal operation and start-up; both load conditions should be considered in the initial design.

Insulation

Thermal insulation provides important safety, energy savings, and performance benefits. In terms of safety, insulation reduces the outer surface temperature of the steam piping, which lessens the risk of burns. A well-insulated system also reduces heat loss to ambient workspaces, which can make the work environment more comfortable. Consequently, the energy saving benefits include reduced energy losses from the steam system and reduced burden on the cooling systems that remove heat from workspaces. Insulation also increases the amount of steam energy available for end uses by decreasing the amount of heat lost from the distribution system.

Important insulation properties include the following:

- *Thermal conductivity*: a measure of heat transfer per unit thickness. Since thermal conductivity of insulation varies with temperature, it is important to know the right temperature range when selecting insulation.
- *Strength*: a measure of the insulation’s ability to maintain its integrity under mechanical loads.
- *Abrasion* resistance: ability to withstand shearing forces.
- *Workability*: a measure of the ease with which the insulation is installed.
- *Resistance to water absorption*: the tendency of the insulation to hold moisture.

Some common insulating materials used in steam systems include calcium silicate, mineral fibre, fibreglass, perlite, and cellular glass. Insulation blankets (fibreglass and fabric) are commonly used on steam distribution components (valves, expansion joints, turbines, etc.) to enable easy removal and replacement for maintenance tasks.

Valves

The principal functions of valves in steam systems are to isolate equipment or system branches, regulate steam flow, and prevent over-pressurization. The main types include gate, globe, swing check, pressure reducing, and pressure relief valves. Gate, globe, and swing check valves typically isolate steam from a system branch or a component. Pressure reducing valves typically maintain certain downstream steam pressure conditions by controlling the amount of steam that is passed. These reducing valves are often controlled by transmitters that monitor downstream conditions. Pressure relief valves release steam to prevent over-pressurization of a system header or equipment.

Steam separators

In some steam systems, wet steam is generated. This wet steam contains water droplets that can reduce the effectiveness of the steam system. Water droplets erode piping elbows, turbine blades and passages, and pressure reducing valves, thus reducing efficiency and life. Liquid water can also significantly reduce heat transfer rates in heat exchange components, as well as result in water hammer. Removing water droplets before they reach end-use equipment is necessary. Steam separators remove water droplets, generally relying on controlled centrifugal flow. This action forces the entrained moisture to the outer wall where it is removed from the separator. The means of moisture removal could be a steam trap or a drain. Some manufacturers include the trap as an integral part of the unit. Additional accessories include water gauge connections, thermometer connections, and vent connections.

Steam separators can be installed in either a horizontal or vertical line. They are capable of removing 99% of particulate entrainment 10 microns and larger over a wide range of flows.

Steam traps

A steam trap (see Figure 51) is a device used to discharge condensate and non-condensable gases with a negligible consumption or loss of live steam. Most steam traps are nothing more than automatic valves. They open, close or modulate automatically. Others, like Venturi traps, are based on turbulent two-phase flows to obstruct the steam flow (23). The three most important functions of steam traps are to:

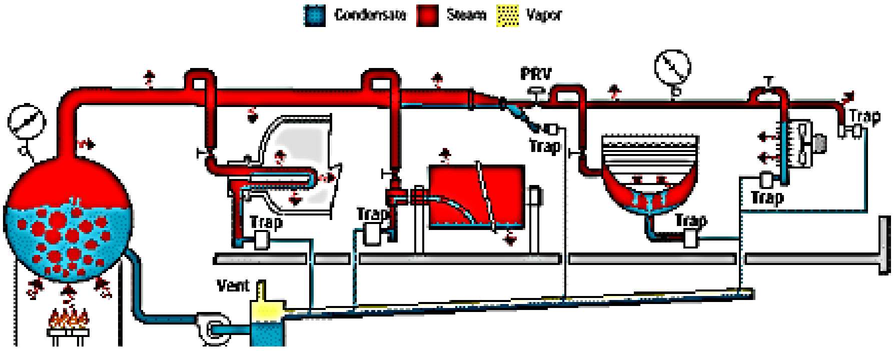


Figure 51 Steam traps in a steam process (Courtesy of Armstrong international) (192)

- discharge condensate as soon as it is formed
- have a negligible steam consumption, and
- possess the capability to discharge air and other non-condensable gases.

The best and simplest form of a steam trap is a disc or short solid pipe nipple, with a small hole drilled through it, installed at the lowest point of the equipment. Since steam condensate will collect at the lowest point and live steam is about 1,200 times greater in volume than this hot liquid, condensate is effectively removed and steam is blocked. Mechanical steam traps basically open when condensate needs to be removed, and close when there is only steam present.

Steam traps work best when sized specifically for the application on which they are used. Generally, it is better to over-size as they will still discharge condensate when present, and close or obstruct for live steam. However, an over-sized steam trap will wear quickly, waste energy (use steam), and, if drastically oversized, cause process issues.

There are three main types of traps: thermostatic, mechanical, and thermodynamic.

Thermostatic traps

Thermostatic traps use temperature differential to distinguish between condensate and live steam. This differential is used to open or close a valve. Under normal operating conditions, the condensate must cool below the steam temperature before the valve will open. Common types of thermostatic traps include bellows and bimetallic traps.

Bellows traps: These traps (see Figure 52) include a valve element that expands and contracts in response to temperature changes. Often a volatile chemical such as alcohol or water is inside the element. Evaporation provides the necessary force to change the position of the valve. At start-up, the bellows trap is open due to the relatively cold condition. This operating condition allows air to escape and provides maximum condensate removal when the load is the highest. Bellows traps can fail in either the open or closed position.

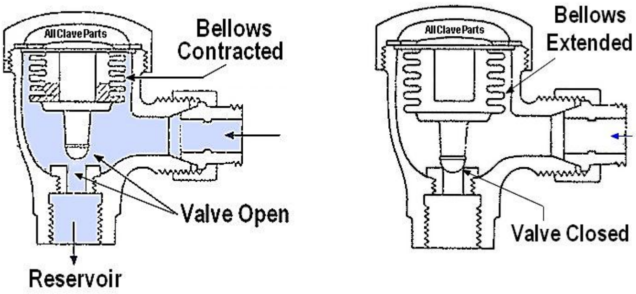


Figure 52 Bellows steam trap-AllClave parts (251)

- *Bimetallic traps*: These traps (see Figure 53) rely on the bending of a composite strip of two dissimilar metals to open and close a valve. Air and condensate pass freely through the valve until the temperature of the bimetallic strip approaches the steam temperature. After steam or relatively hot condensate heats the bimetallic strip and causes it to close the valve, the trap remains shut until the temperature of the condensate cools sufficiently to allow the bimetallic strip to return to its original shape and thereby open the valve. Bimetallic traps can fail in either the open or closed position.

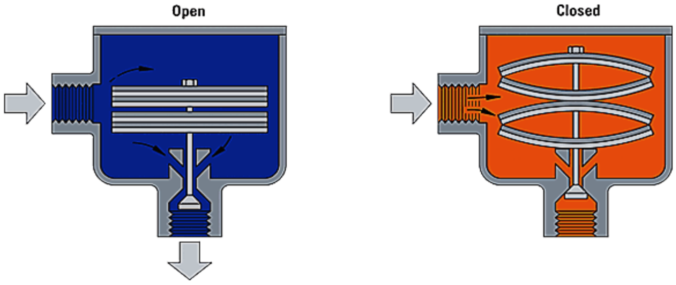


Figure 53 Bimetallic steam trap-from Iklimnet.com (239)

Mechanical traps

Mechanical traps use the difference in density between condensate and live steam to produce a change in the position of a float or bucket. This movement causes a valve to open or close. Mechanical trap designs that are based on this principle include ball float, float and lever, inverted bucket, open bucket, and float and thermostatic traps.

Ball float traps: These traps (see Figure 54) rely on the movement of a spherical ball to open and close the outlet opening in the trap body. When no condensate is present, the ball covers the outlet opening, thereby

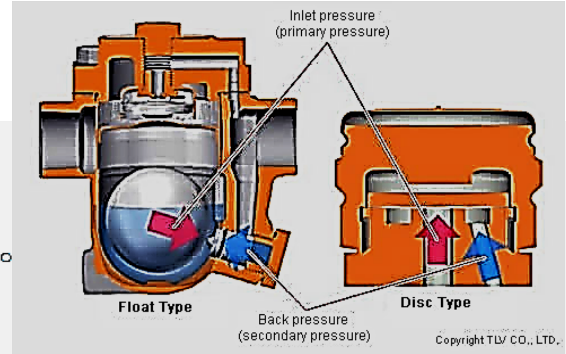
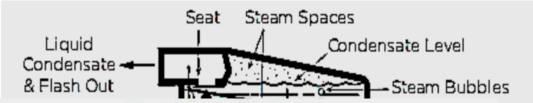


Figure 54 Ball float and disc traps (TLV) (189)

Figure 55 Float and Thermostatic Trap (EERE-USA) keeping air and steam from escaping. As condensate accumulates inside the trap, the ball floats and uncovers the outlet opening. This movement allows the condensate to flow continuously from the trap. Unless they are equipped with a separate air vent, ball float traps cannot vent air on start-up.

Float and lever traps: These traps (see Figure 55) are similar in operation to ball float traps except the ball is connected to a lever. When the ball floats upward due to accumulation of condensate inside the trap body, the attached lever moves and causes a valve to open. This action allows condensate to continuously flow from the trap. If the condensate load decreases and steam reaches the trap, downward ball movement causes the valve to close, thereby keeping steam from escaping. Unless they are equipped with a separate air vent, float and lever traps cannot vent air on start-up. See the discussion on float and thermostatic traps.

Inverted bucket traps: These traps (see Figure 56 and Figure 57) are more complicated than float and lever traps. At start-up, the inverted bucket inside the trap is resting on the bottom of the trap body, and the valve to which the bucket is linked is wide open. The trap is initially filled with condensate. As steam enters the trap and is captured inside the bucket, it causes the bucket to move upward. This upward movement closes the valve and keeps steam from escaping. When the condensate collects and cools the steam, the bucket moves downward. This movement causes the valve to open, thereby allowing the condensate to escape. Unlike closed float traps, inverted bucket traps have intermittent discharge. These traps can be depleted of their condensate seal when applied in superheated steam service. If this occurs, the trap will continuously discharge live steam. This trap type is not recommended for superheated steam service, unless special installation conditions are met.



) (22)

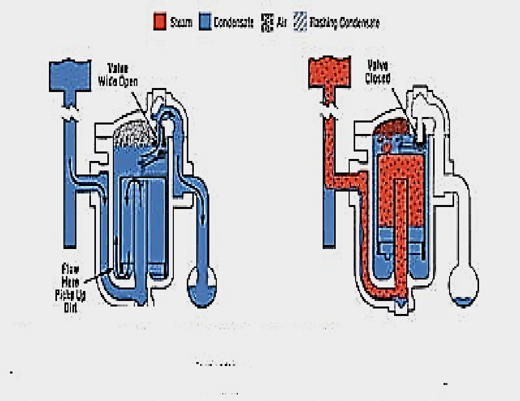


Figure 57 Inverted bucket traps (Thomas K, Lago) (190)

Float and thermostatic (F&T) traps: These traps (see Figure 58) are similar to float and lever traps except they include a thermostatic element that allows air to be discharged at start-up and during operation. The thermostatic elements used in these traps are the same as those used in thermostatic traps.

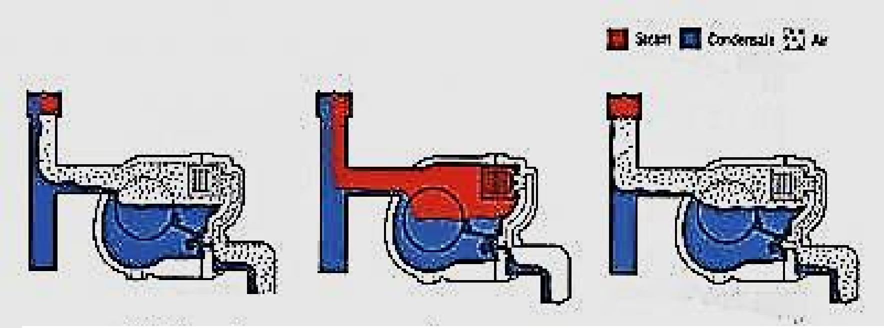


Figure 58 Float and thermostatic traps (Thomas K. Lago) (190)

Thermodynamic traps

Thermodynamic traps use the difference in kinetic energy (velocity) between condensate and live steam to operate a

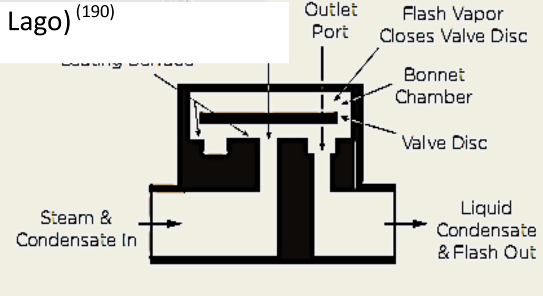


Figure 59 Disc Trap (EERE–USA)

valve. The disc trap is the most common, but piston or impulse traps are sometimes used.

Disc traps: These traps (see Figure 59)_use the position of a flat disc to control steam and condensate flow. When condensate flows through the trap, the disc is raised, thereby causing the trap to open. As steam and air pass through the trap, the disc moves downward. The force that causes the disc to move downward is generated by the difference in pressure between the low-velocity steam above the disc and the high-velocity steam that flows through the narrow gap beneath the disc. Disc traps commonly have an intermittent discharge and, when they fail, they normally fail open. Generally, their air removal capability is poor unless equipped with additional components (like the float and thermostatic trap).

Piston or impulse traps: These traps use the heat energy in hot condensate, and the kinetic energy in steam, to open and close a valve. Like disc traps, piston traps are phase detectors that sense the difference between a liquid and gas or vapour. They continuously discharge any air and condensate. Their primary failure mode is open (**Figure 60**).

Lever traps: These traps are a variation of the thermodynamic piston trap. They operate on the same principle as piston traps but with a lever action to pass large amounts of condensate and air on a continuous basis. Their primary failure mode is open.

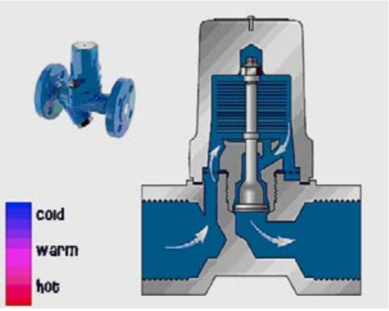


Figure 60 Piston thermodynamic trap- www.scratch.mit.edu (254)

Orifice traps: These traps are of two basic types, orifice plate and short tube, which operate under the same principles. An orifice plate steam trap consists of a thin metal plate with a small diameter hole (orifice) drilled through the plate. When installed, condensate that accumulates is continuously removed as the steam pressure forces the condensate through the orifice. During conditions when no condensate is present, a limited amount of steam flows through the orifice (**Figure 61**).

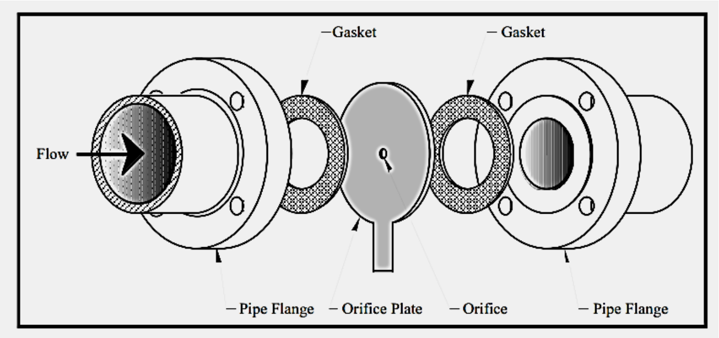


Figure 61 Orifice plate steam trap installation-Olland-EERE-USA (240)

Condensate recovery

The recovery components of a steam system (20) collect and return condensate back to the generation part of the system. Condensate recovery provides thermal and water treatment benefits. Condensate that is not returned must be compensated for by the addition of make-up water, which is generally much cooler than condensate; however, it is becoming less commonly available. Condensate temperature often exceeds 93 °C (200 °F), while make-up water temperature may range between 10° C and 25°C (50 °F and 80 °F). As a result, the enthalpy difference between condensate and make-up water is generally over 120 Btu/lb (0.28MJ/kg), an amount of energy that is often more than 10% of the energy in the boiler-generated steam.

Additionally, make-up water is generally treated with chemicals that remove minerals and establish certain pH levels in the boiler water and in the system. Reducing the amount of make-up water added to the system reduces chemical use. Moreover, some of the treatment chemicals that are contained in condensate are problematic for a plant’s wastewater treatment facility. Industrial steam plants often extend across large areas. Recovering condensate from steam systems requires piping, collecting tanks, pumping equipment, and, in many cases, flash steam separators, meters, and filtration/cleanup equipment. However, the cost savings available from avoiding the purchase, treatment, and heating of make-up water often make investments in condensate recovery systems highly feasible.

Steam accumulators

A steam accumulator is a large insulated pressure vessel, partially filled with hot water (saturated liquid). When steam supply exceeds demand, the excess high-pressure steam is charged into the accumulator through special charging nozzles. The steam is condensed, giving up its latent heat, to raise the pressure, temperature, and heat content of the water body. When the steam demand exceeds the supply, the pressure in the accumulator drops and the additional required steam flashes from the water, taking back the heat previously stored. A simple system of control valves and check valves regulates the charging and discharging. The excess steam is charged quietly and smoothly, and, when steam is needed, it is available with the speed of a control valve operation. There is also an accumulator design that stores hot water for use as boiler feedwater.

Additional components for efficiency improvement

Economizers

Economizers are mechanical devices intended to reduce energy consumption or to perform another useful function such as preheating a fluid. In simple terms, an economizer is a heat exchanger. In boilers, economizers are heat exchange devices that heat fluids, usually water, up to but not normally beyond the boiling point of that fluid. Economizers are so named because they can make use of the enthalpy in fluid streams that are hot, but not hot enough to be used in a boiler, thereby recovering more useful enthalpy and improving the boiler's efficiency. In industrial boilers, they are devices fitted to a boiler that save energy by using the exhaust gases from the boiler to preheat the feedwater.[100] Figure 62 shows a typical position of an economizer for small boilers

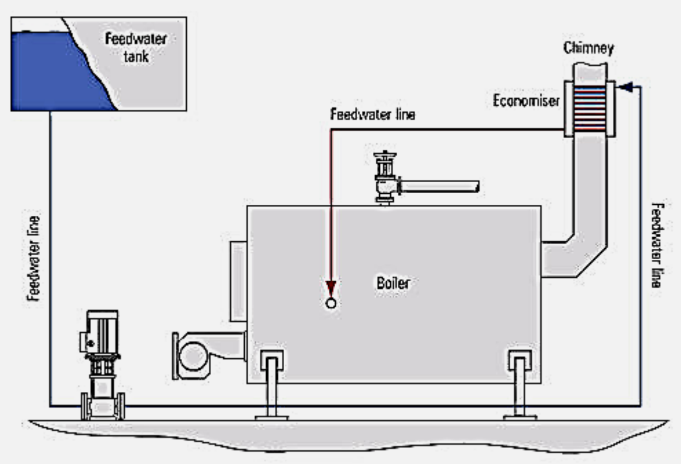


Figure 62 Economizer installation- Courtesy of Clean Boiler [(252)]

Air preheaters

An air preheater is a general term to describe any device designed to heat air before another process (for example, combustion in a boiler), with the

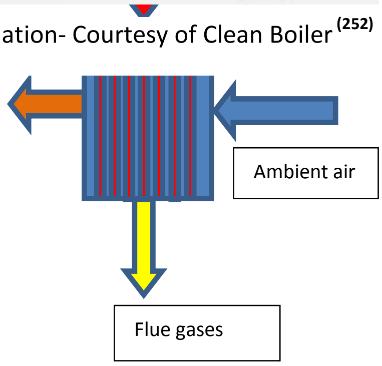


Figure 63 Economizer schematic

primary objective of increasing the thermal efficiency of that process. The main purpose of the air preheater is to recover the heat from the boiler flue gas, which increases the thermal efficiency of the boiler by reducing the useful heat lost in the flue gas. As a consequence, the flue gases are also sent to the flue gas stack (or chimney) at a lower temperature, allowing simplified design of the ducting and the flue gas stack. The air preheater also allows control over the temperature of gases leaving the stack (to meet emissions regulations, for example). (24)

The heat exchange in an air preheater occurs between the flue gas and water. The heat exchange coefficient is lower than for water to water or steam to water, resulting in the need for greater exchange surfaces. Two types of air heaters are normally used in large boilers, such as those used for electricity generation: tubular and regenerative.

Tubular preheaters

Tubular preheaters consist of straight tube bundles that pass through the outlet ducting of the boiler and open at each end outside of the ducting. Inside the ducting, the hot furnace gases pass around the preheater tubes, transferring heat from the exhaust gas to the air inside the preheater (**Figure 64**). Ambient air is forced by a fan through ducting at one end of the preheater tubes. At the other end, the heated air from inside the tubes emerges into another set of ducting, which carries it to the boiler furnace for combustion. The tubular preheater ducting for cold and hot air requires more space and structural supports than a rotating preheater design. Further, due to dust-laden abrasive flue gases, the tubes outside the ducting wear out faster on the side facing the gas current. Many advances have been made to eliminate this problem such as the use of ceramic and hardened steel.

Many new circulating fluidized bed and bubbling fluidized bed steam generators incorporate tubular air heaters, which offer an advantage with respect to the moving parts of a rotary type. (24)

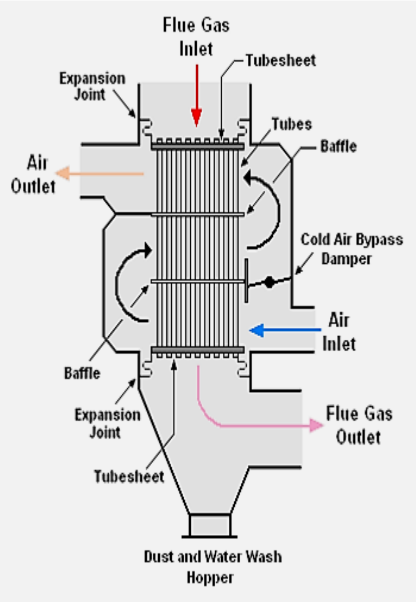


Figure 64 Typical tubular air preheater - APEC (241)

Regenerative preheaters

Regenerative preheaters consist of a central rotating-plate element installed within a casing that is divided into two (bi-sector type), three (tri-sector type) or four (quad-sector type) sectors containing seals around the element. The seals allow the element to rotate through all the sectors, but keep gas leakage between sectors to a minimum while providing separate gas air and flue gas paths through each sector. Regenerative air preheaters are normally found in large utility boilers, due to hardware complexity and maintenance needs.

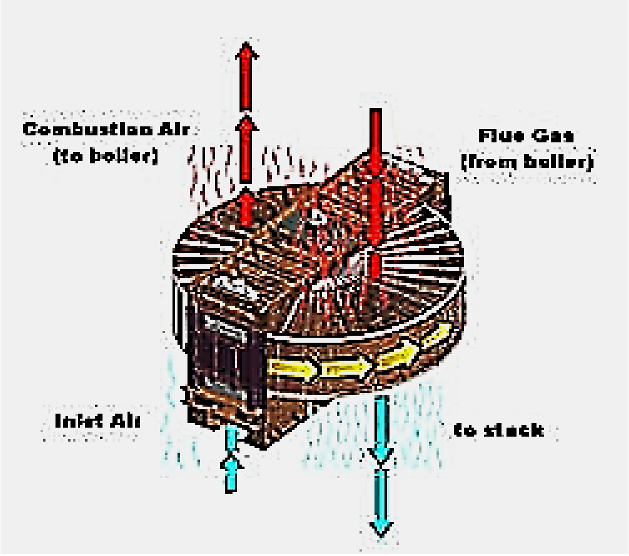


Figure 65 Rotating air preheater (Courtesy of Clean Boilers-USA) (193)

Tri-sector types are the most common in modern power generation facilities.[11] In the tri-sector design, the largest sector (usually spanning about half the cross-section of the casing) is connected to the boiler hot gas outlet. The hot exhaust gas flows over the central element, transferring some of its heat to the element, and is then ducted away for further treatment in dust collectors and other equipment before being expelled from the flue gas stack. The second (smaller) sector is fed with ambient air by a fan, which passes over the heated element as it rotates into the sector, and is heated before being carried to the boiler furnace for combustion. The third (smallest) sector heats air that is routed into the pulverizer and used to carry the coal-air mixture to coal boiler burners. Thus, the total air heated provides heating air to remove the moisture from the pulverized coal dust, carrier air for transporting the pulverized coal to the boiler burners, and primary air for combustion.

The rotor itself is the medium of heat transfer in this system, and is usually composed of some form of steel and/or ceramic structure. It rotates quite slowly (around 3-5 revolutions per minutes, RPM) to allow optimum heat transfer, first from the hot exhaust gases to the element, and, then as it rotates, from the element to the cooler air in the other sectors.

Critical components

In general, the critical components (25)are those whose failure will directly affect the reliability of the boiler. They can be prioritized by their impact on safety, reliability, and performance.

Drums

The steam drum is the single most expensive component in the boiler. Consequently, any maintenance program must address the steam drum, as well as any other drums, in the convection passes of the boiler. In general, problems in the drums are associated with corrosion. In some instances, where drums have rolled tubes, rolling may produce excessive stresses that can lead to damage in the ligament areas. Problems in the drums normally lead to indications that are seen on the surfaces, either inside diameter or outside diameter.

Headers

Boilers designed for temperatures above 482 ˚C (900 ˚F) can have superheater outlet headers that are subject to creep – the plastic deformation (strain) of the header from long-term exposure to temperature and stress. However, industrial boilers are more typically designed for temperatures lower than that. Lower temperature headers are subject to corrosion or possible erosion. Additionally, cycles of thermal expansion and mechanical loading may lead to fatigue damage.

Tubing

The majority of forced outages in all types of boilers are caused by tube failures. Failure mechanisms vary greatly from the long term to the short term. Superheater tubes operating at sufficient temperature can fail long term (over many years) due to normal life expenditure. However, most industrial boiler tubes do not have a finite life due to their temperature of operation under normal conditions. Tubes are more likely to fail because of abnormal deterioration such as water/steam-side deposition retarding heat transfer, flow obstructions, tube corrosion (inside and/or outside diameter), fatigue, and tube erosion.

Piping

Main steam piping

For lower temperature systems, the piping is subject to the same damage as noted for the boiler headers. In addition, the piping supports may experience deterioration and become damaged from excessive or cyclical system loads.

Feedwater piping

This piping system is often overlooked. Depending upon the operating parameters of the feedwater system, the flow rates, and the piping geometry, the pipe may be prone to corrosion or flow assisted corrosion (FAC). This is also referred to as erosion-corrosion. If susceptible, the pipe may experience material loss from internal surfaces near bends, pumps, injection points, and flow transitions. Ingress of air into the system can lead to corrosion and pitting. Out-of-service corrosion can occur if the boiler is idle for long periods.

Deaerators

Overlooked for many years in condition assessment and maintenance inspection programs, deaerators have been known to fail catastrophically in both industrial and utility plants. The damage mechanism is corrosion of shell welds, which occurs on the inside diameter surfaces.

Air supply to boiler houses

For proper combustion and safety reasons, the boiler room should have appropriate openings for fresh air supply (26). Temporary air intakes such as windows and doors should be avoided since they may be closed (and often they are when people in the boiler room are feeling cold), thus cutting off the boiler's air supply. If combustion air supply is limited, the fire will start to smoke. Incomplete combustion will occur and carbon monoxide generated. If the fire goes out before the flame detection system acts to close the fuel safety shutoff valve, accumulated fuel may re-ignite when oxygen seeps in through cracks and crevices. A furnace explosion may occur with disastrous effects on personnel and property.

Adequate air supply is required to minimize the possibility of explosion

Boiler manufacturing

Careful manufacturing of a boiler according to the most stringent standards ensures good performance, a long lifetime, and reduced maintenance. International standards, such as ASME (Amerrican Society Mechanical Engineers) (ASTM) American Society for Testing and Materials, EN (Euro Norm) have been developed over the years and optimized to incorporate the experience gained in the field by boiler manufacturers and operators.

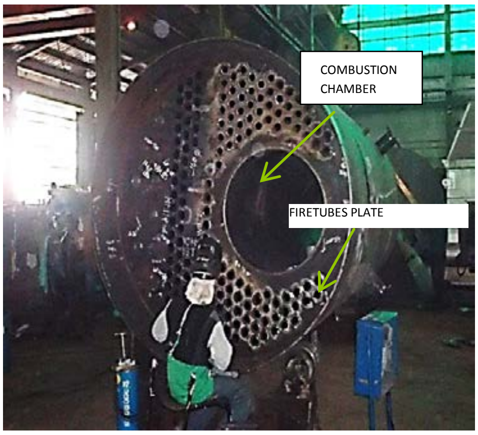
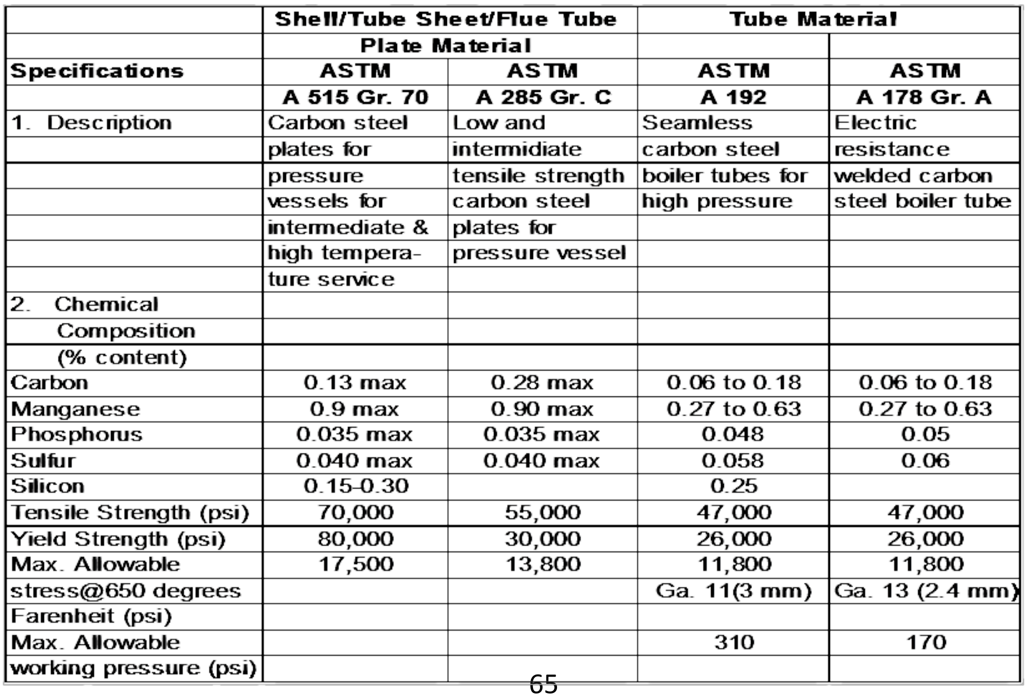


Figure 67 Firetube welding on the perforated plate (courtesy of Enertech-Philippines) (27)

Figure 66 Preparation of boiler drum (Courtesy of Enertech-Philippines) (27)

During a boiler purchasing process, the vendor must indicate the procedures used for boiler fabrication. Figure 66 and Figure 67 show the main phases of a boiler manufacturing process (27) and some details of internal components manufacturing. During manufacturing, different materials are used, according to the temperature and pressure of the boiler and to adopted standards. An example of the materials used in boiler manufacturing, according to ASTM standards, is provided in Table 3 (27)

Table 3 Boiler manufacturing ASTM standards for shell and tubes



	Shell/Tube Sheet/Flue Tube		Tube Material	
	Plate Material			
Specifications	**ASTM**	**ASTM**	**ASTM**	**ASTM**
	A 515 Gr. 70	**A 285 Gr. C**	**A 192**	**A 178 Gr. A**
1. Description	Carbon steel	Low and	Seamless	Electric
	plates for	intermidiate	carbon steel	resistance
	pressure	tensile strength	boiler tubes for	welded carbon
	vessels for	carbon steel	high pressure	steel boiler tube
	intermediate &	plates for		
	high tempera-	pressure vessel		
	ture service			
2. Chemical				
Composition				
(% content)				
Carbon	0.13 max	0.28 max	0.06 to 0.18	0.06 to 0.18
Manganese	0.9 max	0.90 max	0.27 to 0.63	0.27 to 0.63
Phosphorus	0.035 max	0.035 max	0.048	0.05
Sulfur	0.040 max	0.040 max	0.058	0.06
Silicon	0.15-0.30		0.25	
Tensile Strength (psi)	70,000	55,000	47,000	47,000
Yield Strength (psi)	80,000	30,000	26,000	26,000
Max. Allowable	17,500	13,800	11,800	11,800
stress@650 degrees			Ga. 11(3 mm)	Ga. 13 (2.4 mm)
Farenheit (psi)				
Max. Allowable			310	170
working pressure (psi)				

Figure 68 Watertube heat exchanger (Courtesy of Enertech –Philippines)

Figure 69 Heat exchanger header manufacturing (Courtesy of Enertech–Philippines)

The manufacturing of a boiler is shown inFigure 68. The manufacturing of a watertube heat exchanger is shown in Figure 69 and Figure 71. A small boiler, already equipped with fittings and valves, is shown in Figure 72.

Figure 70 Boiler manufacturing-combustion chamber and tube sheet (Courtesy of Enertech-Philippines)

Figure 71 Small
fittings (Courtes

Figure 72 Wateretube boiler-Tube walls connected to downcomer (Courtesy of Enertech-Philippines)

Boiler purchase

The purchase of a boiler should be done by referring to the above said international standards (ASME, EN etc,) which envisage rules for material quality and testings, for fabrication, assembling, Non Destructrive Examinations (NDE), Installation and Commissioning.

It is of paramount importance that the purchaser organizes inspections during the different manufacturing phases to check that the agreed quality/Code is actually implemented. With reference to ASME Code, some of the necessary inspections stages in the production of the fire tube boilers from the examination of certification of procurement sources to the final inspection, preservation and packing to dispatch to site are reported below (28).

This content may be useful for second party inspectors, Fire Tube Boiler manufacture quality control personnel, engineering companies and purchasers as well.

- All Boiler inspections and tests shall be carried out against the approved drawings, purchase order specifications, purchasers or company standards, and within the practices and rules of the country, state or province and any government decrees, laws, ordinance or regulation as may apply.
- The applicable codes and specifications for the Fire Tube Boiler which is under construction process are:
    - Design code
    - Purchase order specification
    - Purchaser's standards
    - Approved drawings
- And the applicable codes and standards are:
    - ASME I Rules for construction of power boilers
    - ASME V Non Destructive Examination NDE
    - ASME IX Welding Brazing Qualifications
- The applicable codes and standard may be based other international standards such as BS 2790 and etc.; this content is general and can be useful if even the design code is different from ASME Code.
- Required Documents for Third Party Inspector Review:
  The list of documents normally is agreed in the Pre Inspection meeting which is hold several weeks before actual commencement of inspection work. The parties which are participated in this meeting are manufacture, purchaser and third party inspection agency representatives.
  These are the list of documents which are normally agreed to be presented to the inspector (the following list is an example of documents requested for firetubes boilers, but can be extended to watertubes boilers as well with some integrations):
    - Fire Tube Boiler Manufacture Quality Control Plan
    - Fire Tube Boiler Inspection and test plan
    - Fire Tube Boiler Data Sheet
    - Fire Tube Boiler Approved Drawings
    - Fire Tube Boiler Strength calculation sheets
    - Fire Tube Boiler Material Test Reports
    - Fire Tube Boiler Welding Specification Procedures (WPS) and Procedure Qualification Records(PQR)
    - Fire Tube Boiler Welding Map
    - Fire Tube Boiler Repair Procedure
    - Fire Tube Boiler Welders Qualifications Reports

- Fire Tube Boiler NDE procedures
- Fire Tube Boiler NDE Personnel qualifications Reports
- Fire Tube Boiler Heat treatment procedure
- Fire Tube Boiler Calibration Certificates for Test Equipment
- Fire Tube Boiler Hydrostatic Testing Procedure and Water Quality Document
- Fire Tube Boiler Preparation and Painting Procedure
- Fire Tube Boiler Preservation, Packing and Shipping Procedure
- Fire Tube Boiler Packing List

The presence of an inspector is strongly recommended for some important tests (Non Destructive Examinations and Hydrostatic tests).

Boiler emissions

The quantity and quality of emissions of pollutants depend on the type of boiler and the fuel used (see Chapter 2). This section deals briefly with emissions from boilers fired by coal, fuel oil, natural gas, and non-fossil fuel. Emissions are discussed in more detail in Chapter 3.

Coal-fired boiler emissions

Coal is burned extensively in utility and large industrial boilers with heat input capacities of more than 100 MBtu/h (about 100 MW). Coal is not used in many smaller industrial boiler applications because of the added costs of coal handling, ash disposal, and emission control equipment compared to fuel oil or natural gas. Coal-fired boilers must have larger combustion chambers than oil-fired or gas-fired boilers of the same capacity, the velocities of the combustion gases in the convection passes must be lower, and emission control equipment for flue gas treatment is generally required. These features, combined with coal storage and ash disposal requirements, increase the land area needed to site a coal-fired boiler (29).

In situations where coal combustion is economically attractive and environmentally acceptable, various firetube and watertube boilers can be selected. Firetube boilers that burn coal typically include an underfeed stoker to automatically supply fuel to the unit; but, in special cases where automatic control is not essential, hand firing may be a viable option worth further consideration.

There are three main classes of coal-fired watertube boilers: pulverized coal-fired (PC-fired), stoker-fired, and FBC boilers. They differ in how the fuel is supplied to the boiler, the approach used to burn the fuel, and the method used to remove ash after combustion has occurred. Stoker-fired boilers are generally less expensive than PC-fired boilers with the same output because they do not require special equipment to pulverize the coal. However, a properly designed PC-fired boiler can have an efficiency advantage due to unburned carbon of less than 0.4% compared to stoker-fired boilers that can exhibit up to 8% carbon loss. Carbon that is not burned is undesirable because it represents wasted energy. Due to their complexity, PC -fired boilers are more suitable for medium or large industrial boilers.

Stoker-fired boilers have an advantage over PC-fired boilers in the equipment required for controlling particulate matter (PM) emissions. Larger ash particles produced by stoker-fired boilers can often be effectively removed using less costly mechanical collectors, such as cyclone separators, rather than more complex electrostatic precipitators (ESPs), fabric filters (baghouses), or wet scrubbers. SO_2 emissions from PC-fired boilers are typically less than from stoker-fired boilers, especially when sulphur-bearing materials such as pyrite are removed from the coal during pulverization. Both firing systems are equally capable of controlling NO_x emissions.

The primary driving force for using FBC boilers is reduced SO_2 and NO_x emissions. These boilers are designed to burn coal at low enough temperatures to minimize NO_x formation and at the optimum temperature level for calcining limestone, which enhances the capture of SO_2. By adding limestone or dolomite to the bed to serve as a sorbent, it is possible to burn high-sulphur coal without the need for expensive post-combustion sulphur removal equipment. If additional reductions in NO_x emissions are required, the combustion air within the boiler can be staged and flue gas can be recirculated. Due to the fineness of PM emissions from FBC boilers, fabric filters, which are less sensitive to ash properties than ESPs, are normally selected. Most FBC boilers are watertube boilers, especially among the larger units, but some firetube FBC boilers are also available. When very low SO_2 and NO_x emissions are required, circulating fluidized beds are preferred to bubbling fluidized beds.

Fuel oil-fired and gas-fired boiler emissions

For environmental and economic reasons, many industrial boilers are fired by fuel oil, natural gas, or a combination of these fuels. Boiler designs for these fuels are very similar with many units capable of firing the two fuels separately or in combination. Although more compact than coal-fired boilers, large fuel oil-fired or natural gas-fired watertube boilers are field erected with features similar to PC-fired boilers. These units are typically either wall-fired or tangential-fired with multiple burners (29).

Small watertube boilers are normally manufactured as package units with either an "A," "D," or "O" tube configuration. Firetube boilers that burn fuel oil or natural gas are almost all supplied as package units with a single burner. Scotch, HRT, and firebox boilers are the most common types of firetube boilers commercially available for burning fuel oil and natural gas.

Fuel oil is a widely available fossil fuel with characteristics that make it suitable for combustion in industrial boilers. It burns cleaner than coal, can be stored in tanks at the site, can be piped directly to the burner, and can be atomized to burn like natural gas. Steam, compressed air, and mechanical methods, including pressure, are used to atomize fuel oil; but most grades (except No. 2) require heating to lower the viscosity for improved handling and atomization.

The types of emissions that must be controlled when fuel oil is burned depend on its properties and the proportions of undesirable nitrogen-, sulphur-, and ash-bearing compounds that it contains. When fuel oil is burned, NO_x formed by fuel-bound nitrogen can account for 20% to 80% of the total NO_x emissions. Switching to fuel oil with lower nitrogen content typically results in reduced NO_x emissions. Likewise, using lower sulphur fuel oil is a cost-effective way to reduce SO_2 emissions. Selecting appropriate combustion and post-combustion emission control techniques for fuel oil-fired boilers often requires a laboratory analysis of the fuel to determine its exact composition. Because certain fuel oils contain greater proportions of undesirable constituents, it is often more cost effective to burn low-sulphur residual or distillate oil rather than high-sulphur residual oil. Depending on emission requirements, switching often minimizes or eliminates the need for post-combustion emission control equipment.

Natural gas is the most desirable fossil fuel for industrial boiler applications. It burns cleaner than coal and fuel oil, it is easy to handle, it mixes well with combustion air, and it contains very little sulphur and virtually no ash. Because natural gas is delivered by pipeline, onsite storage is typically not required. With no sulphur or ash, the emissions of concern include carbon monoxide (CO), VOCs, and NO_x. Gas supply is still a problem in countries without gas pipeline networks. Although natural gas can be transported in liquid state, this needs very high pressures or very low temperatures (- 160 °C). Other fuels such as LPG, which can be stored at ambient temperatures with low pressure, are used in small boilers.

Non-fossil-fuel-fired boiler emissions

Although many different non-fossil fuels are used to fire boilers, two of the most common are biomass and refuse derived fuel (RDF). Equipment for firing these two fuels is generally divided into stoker-fired and FBC boilers, which may be either watertube or firetube designs with features similar to those of coal-fired boilers (29).

Biomass fuel

Fuels classified as biomass encompass a variety of non-fossil materials including wood (see Chapter 2). Biomass fuel can be burned on a moving grate like stoker coal, or introduced to the boiler by another type of conveying system. It is also possible to burn biomass fuel along with PC, fuel oil, or natural gas. When used in combination with these fuels, the individual biomass particles are generally supplied by a stoker, and the other fuels are introduced into the boiler using low NO_x burners of an appropriate design. If biomass particles are sufficiently fine, it is sometimes possible to fire the fuel using burners that are similar in design and operation to PC burners.

Although biomass typically burns cleaner than coal, NO_x, SO_2, and PM emissions from biomass-fired boilers must be controlled. Biomass burning is considered carbon neutral, because the CO_2 emitted from its combustion is balanced by the CO_2 absorbed during its growth.

Refuse Derived Fuels (RDF)

Boilers that burn Refuse Derived Fuels (RDF) usually require a certain level of fuel processing prior to combustion. Fuel preparation efforts typically range from simple removal of noncombustible and bulky materials to shredding. The objective of these operations is to create a mixture of highly combustible fuel particles. When RDF is burned in a Fluidized Bed Combustion boiler, it is often necessary to reduce the material to a maximum size of 2 inches so that the individual particles can be conveyed into the combustion chamber and burned uniformly in the bed.

Combustion of RDF typically generates low levels of NO_x, SO_2, and PM emissions because of relatively cool combustion temperatures and low levels of fuel-bound nitrogen, sulphur-bearing compounds, and ash. When NO_x emissions are a concern, it may be necessary to install selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR) equipment to treat the flue gas before it enters the atmosphere (see Chapter 4). Particulate collection equipment, such as cyclone separators, ESPs, baghouses, and wet scrubbers, is required to clean the flue gas and thereby minimize PM emissions.

Combustion of RDF also generates considerable amounts of harmful pollutants such as cadmium, lead, mercury, hydrogen chloride, and dioxins/furans. Techniques for reducing emissions of these pollutants must be adopted. Due to the difficulty of achieving low emission rates, RDF is more often burned in incinerators than in boilers.

Boiler selection considerations

Selection of a new boiler is critical because it will affect steam production characteristics and costs for the next 20 to 30 years. Important factors to consider include (29):

- geographical location and site accessibility;
- plan area and height requirements;
- fuel type, price, and availability;
- boiler type, size, efficiency, price, and reliability;
- heating loads and load variations including:
  - acceptable pressure and temperatures ranges, and
  - required rates of heat delivery;
- state and local environmental regulations;
- regional air quality standards;
- emission limitations and options for controlling regulated pollutants; and
- construction and operating permit requirements.

The types of fuels to be used will also influence boiler selection. Various boiler and fuel feed system combinations for watertube and firetube boilers are identified in Table 4.

Table 4 Common boiler and fuel system combination (29)

Watertube boilers	**Firetube boilers**
Fuel feeding system	*Fuel feeding system*
Coal-fired, stoker-fed boilers	**Coal-fired, stoker-fed boilers**
PC-fired boilers	**Fuel oil-fired boilers**
Coal-fired FBC boilers	**Natural gas-fired boilers**
Fuel oil-fired boilers	**Biomass-fired, stoker-fed boilers** **Natural gas-fired boilers**
RDF-fired, stoker-fed boilers	**Biomass-fired, stoker-fed boilers**
Biomass-fired FBC boilers **RDF-fired, stoker-fed boilers**	**RDF-fired, stoker-fed boilers** **Biomass-fired, stoker-fed boilers**
RDF-fired FBC boilers	

The process of selecting a low-emission boiler and combustion equipment is strongly influenced by the fuel that is chosen and the emission limitations that are imposed. For new boiler applications, and modifications to existing boiler installations that must meet stringent emission regulations, fuel selection is the most important consideration. (29) Although criteria for fuel selection generally focus on cost, availability, and environmental compliance, choosing a boiler that is capable of burning multiple fuels or fuel combinations has two main advantages: it provides backup and allows fuel switching for cost savings.

The next step in the process is to choose an appropriately sized boiler based on steam or hot water demand and a suitable fuel feed system. The required features of the fuel feed system depend primarily on whether the fuel is a solid, liquid, or gas. Some fuel feed systems are designed to handle fossil fuels such as coal, oil, or natural gas, while others can accommodate non-fossil fuels such as biomass or RDF.

Discussions with boiler and combustion equipment manufacturers are often necessary to understand design details and performance history for specific boiler designs. Manufacturers can provide meaningful assistance in identifying candidate boilers and fuel feed systems that are suitable for use with various fuels.

Selecting emission control equipment can be influenced by the layout of the facility, the type and amount of fuel that is burned, the configuration of the boiler and fuel feed system, and the required level of emissions reduction. Additional factors to consider in selecting a low-emission boiler that burns either fossil or non-fossil fuel are discussed in the next sections.

Co-generation: Combined production of steam and electricity

Cogeneration, also known as combined heat and power, or CHP, is the production of electricity and heat in a single process for dual output streams. In conventional electricity generation, on average 35% of the energy potential contained in the fuel is converted into electricity, while the rest is lost as waste heat (30). Even the most advanced technologies do not convert more than 55% of fuel into useful energy (Figure 73).

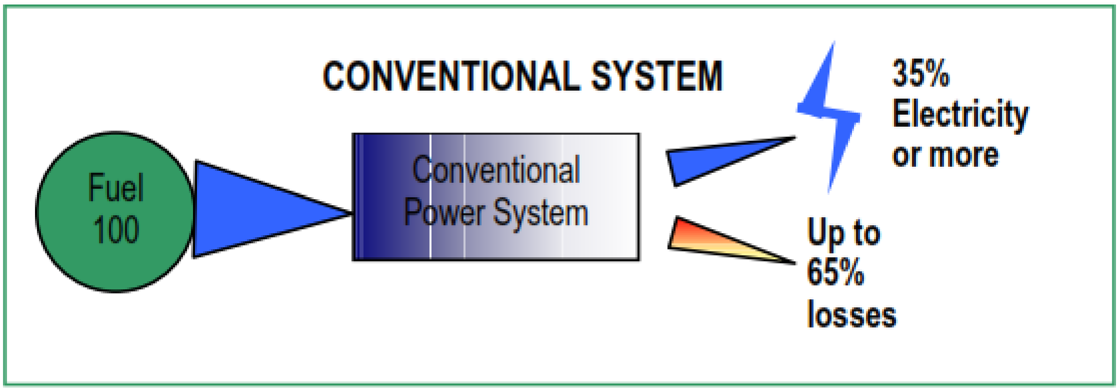


Figure 73 Schematic of conventionaL system efficiency-UNEP (240)

Since cogeneration uses both electricity and heat, it is the most efficient way to use fuel, achieving up to 90% efficiency (Figure 74). This translates into energy savings of between 15% and 40% when compared with the separate production of electricity from conventional power stations and of heat from boilers. Cogeneration also helps lower energy costs, improves the security of the energy supply, and creates jobs. A typical cogeneration system consists of an engine, steam turbine, or combustion turbine that drives an electrical generator. A waste heat exchanger recovers waste heat from the engine and/or exhaust gas to produce hot water or steam.

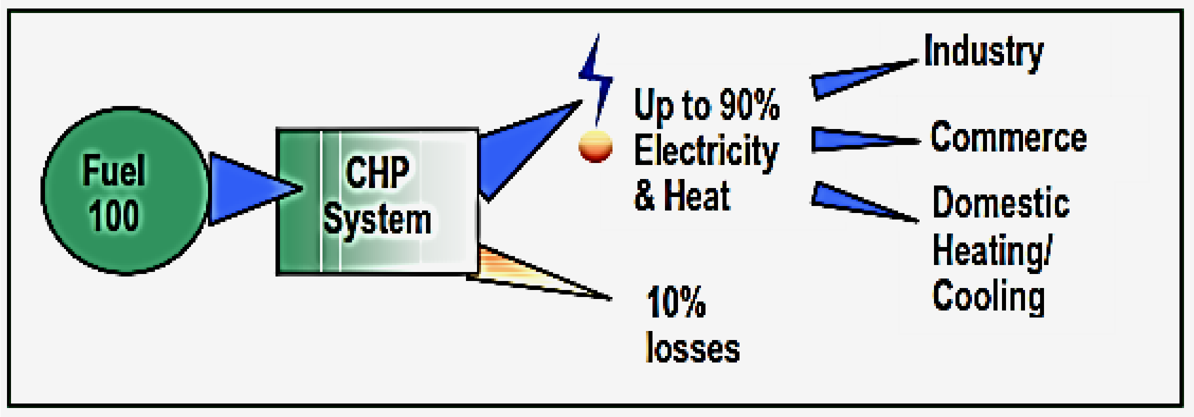


Figure 74 Schematic of a cogeneration system efficiency-UNEP (30)

Cogeneration produces a given amount of electric power and process heat with 10% to 30% less fuel than it takes to produce the electricity and process heat separately.

The heat produced by cogeneration can be delivered through various media, including warm water (e.g., for space heating and hot water systems); steam; or hot air (e.g., for commercial and industrial uses). Trigeneration is also possible: the production of electricity, heat, and cooling (through an absorption chiller) in a single process. This is an attractive option for production processes with cooling requirements. Cogeneration schemes are usually sited close to the heat and cooling demand, and, ideally, are built to meet this demand as efficiently as possible. Under these conditions, more electricity is usually generated than is needed. The surplus electricity can be sold to the electricity grid or supplied to another customer via the distribution system.

In recent years, cogeneration has become an attractive and practical proposition for a wide range of applications. These include the process industries (pharmaceuticals, paper and board, brewing, ceramics, brick, cement, food, textile, minerals, etc.); commercial and public-sector buildings (hotels, hospitals, leisure centres, swimming pools, universities, airports, offices, barracks, etc.); and district heating schemes.

Cogeneration technologies

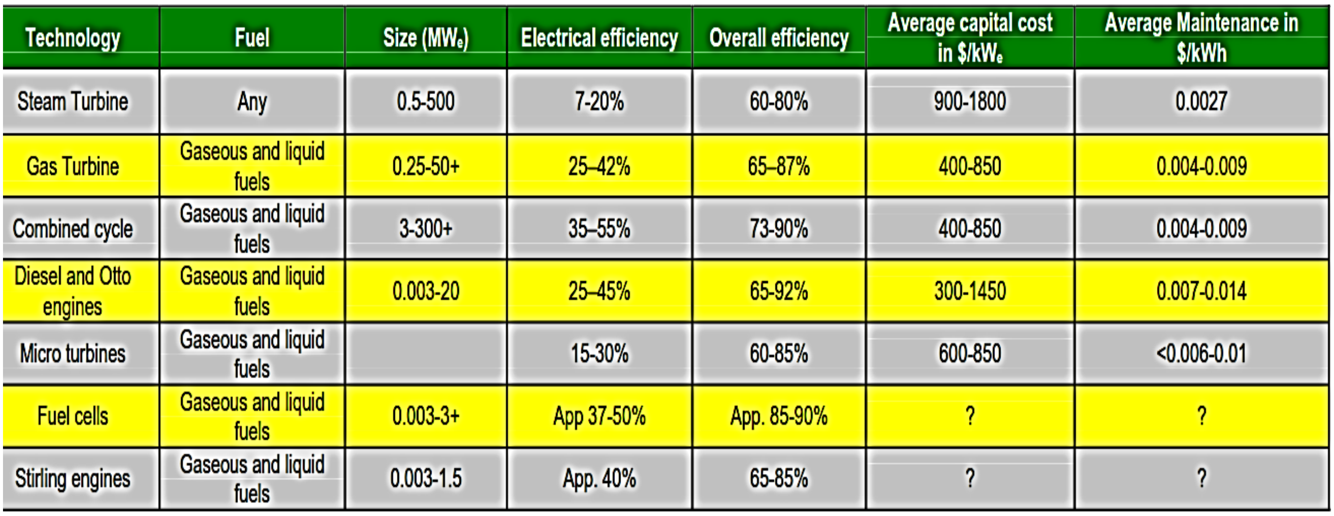
A range of technologies can be applied to cogenerate electricity and heat. All cogeneration schemes include an electricity generator and a system to recover the heat. The technologies currently in widespread use are readily available, mature, and reliable:

- steam turbines
- gas turbines
- combined cycle (gas and steam turbines)
- Diesel and Otto Engines

Technologies that have recently appeared on the market, or are likely to be commercialized within the next few years, include:

- microturbines
- fuel cells, and
- Stirling engines.

Figure 75 comparison of cogeneration technologies



Technology	Fuel	Size (MW_e)	Electrical efficiency	Overall efficiency	Average capital cost in $/$kW_e$	Average Maintenance in $/kWh
Steam Turbine	Any	0.5-500	7-20%	60-80%	900-1800	0.0027
Gas Turbine	Gaseous and liquid fuels	0.25-50+	25–42%	65–87%	400-850	0.004-0.009
Combined cycle	Gaseous and liquid fuels	3-300+	35–55%	73-90%	400-850	0.004-0.009
Diesel and Otto engines	Gaseous and liquid fuels	0.003-20	25–45%	65-92%	300-1450	0.007-0.014
Micro turbines	Gaseous and liquid fuels		15-30%	60-85%	600-850	<0.006-0.01
Fuel cells	Gaseous and liquid fuels	0.003-3+	App 37-50%	App. 85-90%	?	?
Stirling engines	Gaseous and liquid fuels	0.003-1.5	App. 40%	65-85%	?	?

Cogeneration schemes can have different sizes, ranging from an electrical capacity of less than 5 kW (e.g., small engines for a single dwelling) to 500 MW (e.g., district heating systems or industrial cogeneration). Cogeneration can be based on a wide variety of fuels, and individual installations may be designed to accept more than one fuel. While solid, liquid, and gaseous fossil fuels are currently dominant, cogeneration from biomass fuels is becoming increasingly important. The cost efficiency of cogeneration schemes can be increased by using fuels that would otherwise constitute waste, e.g., refinery gases, landfill gas, agricultural waste, or forest residues. A comparison of the various technologies and sizes is given Figure 74. (31)

Costs and profitability

A well-designed and -operated cogeneration scheme is always more energy efficient than a conventional plant, and leads to both energy and cost savings. Cost savings depend on the cost of the primary energy fuel and the price of the electricity that the scheme avoids using. However, although the profitability of a cogeneration project generally results from its cheap electricity, its success depends on using recovered heat productively; the heat requirement is thus a prime criterion. As a rough guide, cogeneration is likely to be suitable if there is a fairly constant demand for heat for at least 4,500 hours in the year.

Total investment in a cogeneration project depends upon the size, design, and characteristics of the installation. Under favourable conditions, payback periods of 3 to 5 years can be achieved on most cogeneration installations (operating life can reach 20 years).

Industry and market trends

Cogeneration accounts for around 7% of total global power production, but more than 40% of power production in some European countries. There are many suppliers of conventional cogeneration technologies, but new technologies (microturbines, fuel cells, Stirling engines) are produced by only a few companies. Future expansion of the market for small-scale cogeneration schemes, particularly for microturbines, is likely. In many countries, the current market situation of cogeneration could be better. The European experience shows that rising gas and falling electricity prices make it difficult for cogenerators to operate profitably in the utility sector.

The availability of natural gas to drive gas turbines remains an important factor for combined cycle gas turbine systems (discussed below). Uncertainties created through reforms in energy sector tariffs can be a significant barrier. Global policies to reduce greenhouse gas emissions, liberalization of energy markets, and emerging needs for decentralized energy in emerging markets should improve the prospects for cogeneration.

Types of co-generation systems

Two main heat/electricity combined production systems can be identified for industrial use:

- combined cycle gas turbines
- diesel heat recovery steam devices

Combined cycle gas turbines (CCGT)

Gas turbines are essentially jet engines driving large turbo generators instead of large aircraft. Their exhaust may contain substantial amounts of residual heat that used to be lost to the atmosphere. This heat can be recovered by inserting a heat exchanger along the flue gas duct. The steam produced is used in the production process, often delivered to a steam turbine where it is used to drive a generator and produce electricity. Multistage heat recovery steam generators use the heat to produce superheated steam, high-pressure steam, low-pressure steam, and even hot water as the hot exhaust gradually loses its temperature. This type of heat recovery is normally used in large steam production plants, but recently small turbines have been available for smaller plants. Figure 76 shows how a CCGT works (Brayton cycle).

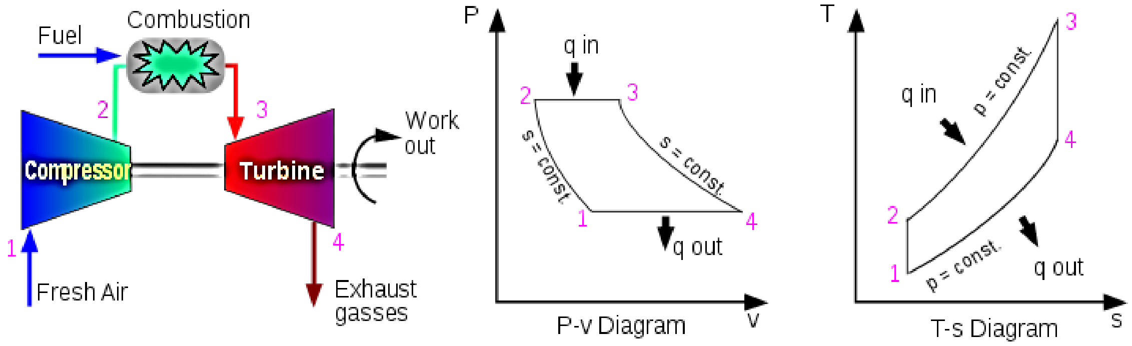


Figure 76 Gas turbine and Brayton Cycle (Wikipedia) (231)

The energy conversion of combustion turbines typically ranges between 25% and 35% efficiency as a simple cycle. The simple cycle efficiency can be increased by installing a recuperator or waste heat boiler onto the turbine's exhaust. A recuperator captures waste heat in the turbine exhaust stream to preheat the compressor discharge air before it enters the combustion chamber. A waste heat boiler generates steam by capturing heat from the turbine exhaust (see below for a discussion of heat recovery steam generators (HRSG. High-pressure steam from these boilers can also generate power with steam turbines, which is called a combined cycle (steam and combustion turbine operation). Recuperators and HRSGs can increase the overall energy cycle efficiency of combustion turbines by up to 80%.

Diesel engines

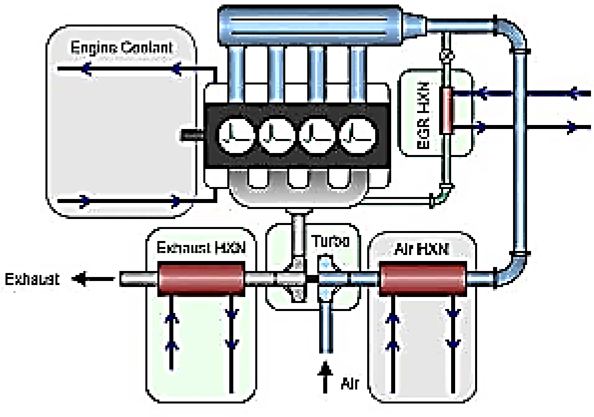


Figure 77 Waste heat recovery from diesel engine (EERE USA) (122)

The same process used for gas turbines can be put to work on large diesel engines used in cogeneration. The diesel drives a generator for economical electricity production, and then the hot exhaust produces steam to drive another electrical generator or to provide heat for process operations as either steam or hot water (see Figure 77).

Heat recovery steam generators

The ultimate goal of every multistage heat recovery steam generator (see Figure 78 Heat recovery steam generatoris to effectively extract every Btu of heat that would exceed normal atmospheric temperature in the final effluent stream of gas, and put it to work either producing electricity or usable heat in another application such as hot water. Even using small amounts of heat to warm incoming cold water can result in substantial savings over the long term. (32) HRSGs (formerly known as waste heat boilers or waste heat generators) use heat from the hot flue gas from one process operation to produce steam, which is then used to power a different process operation. For example, the steam can be used to drive turbo-electric generators or in other energy-intensive operations such as making paper. They recover the energy that used to be lost to the atmosphere through the stack to perform useful work. They have become more accepted and popular in industry as rising energy costs and climate change have garnered more attention.

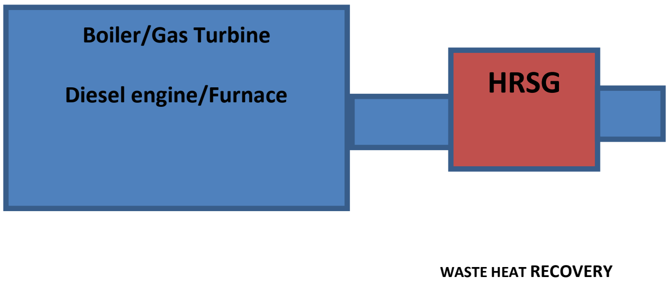


Figure 78 Heat recovery steam generator

There are two main types of cogeneration techniques:

- topping cycle plants
- bottoming cycle plants

Topping cycle plants

Topping cycle plants generate electricity or mechanical power first. Facilities that generate electrical power may produce the electricity for their own use, and then sell any excess power to a utility. There are different types of topping cycle cogeneration systems. The first type burns fuel in a gas turbine or diesel engine to produce electrical or mechanical power. The exhaust provides process heat, or goes to a heat recovery boiler to create steam to drive a secondary steam turbine. This is a combined-cycle topping system (see Figure 79).

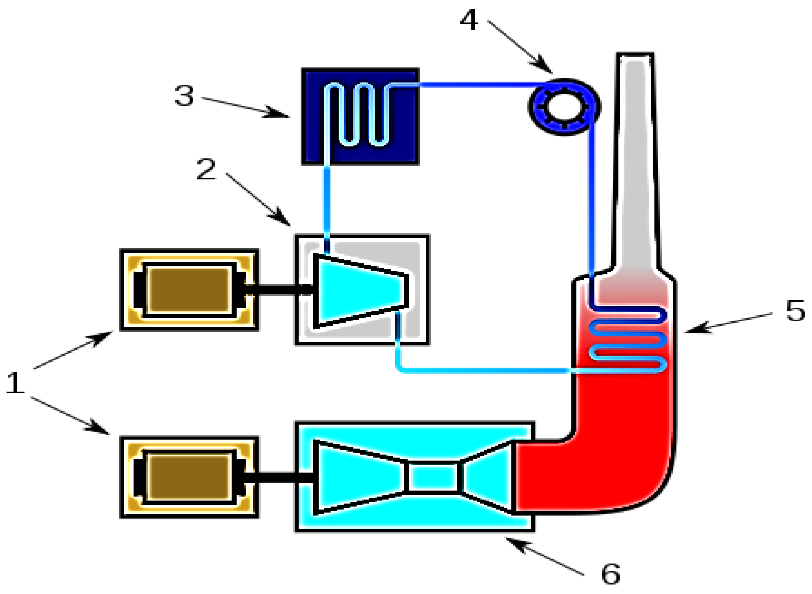


Figure 79 CCGT- Working principle of a combined cycle power plant [(150)]

(Legend: 1-Electric generators, 2-Steam turbine, 3-Condenser, 4-Pump, 5-Boiler/heat exchanger, 6-Gas turbine)

The compressor-gas turbine topping system is an open system, using air as media. The air enters the compressor, which compresses and delivers it to fuel combustors (one or more combustors placed around the gas turbine), where fuel is added. The exhaust gases are discharged to the atmosphere at temperatures of about 450 °C to 500 °C. The heat of the flue gases at the exhaust of the gas turbine is recovered by a heat recovery steam generator. The steam is delivered to a steam turbine that drives a generator. The steam at the exhaust of the steam turbine is then condensed to water. The water is delivered back, by a water feed pump, to the heat exchanger. In this system the recovered heat is used to produce electricity (Figure 79).

Bottoming cycle plants

Bottoming cycle plants are much less common than topping cycle plants. These plants exist in heavy industries such as glass or metals manufacturing where very high-temperature furnaces are used. A waste heat recovery boiler recaptures waste heat from a manufacturing heating process. This waste heat is then used to produce steam that drives a steam turbine to produce electricity. Since fuel is burned first in the production process, no extra fuel is required to produce electricity. The steam generated can, alternatively, be delivered to the production process. In this case, the plant is less sophisticated . Figure 80 shows an example of bottoming cycle.

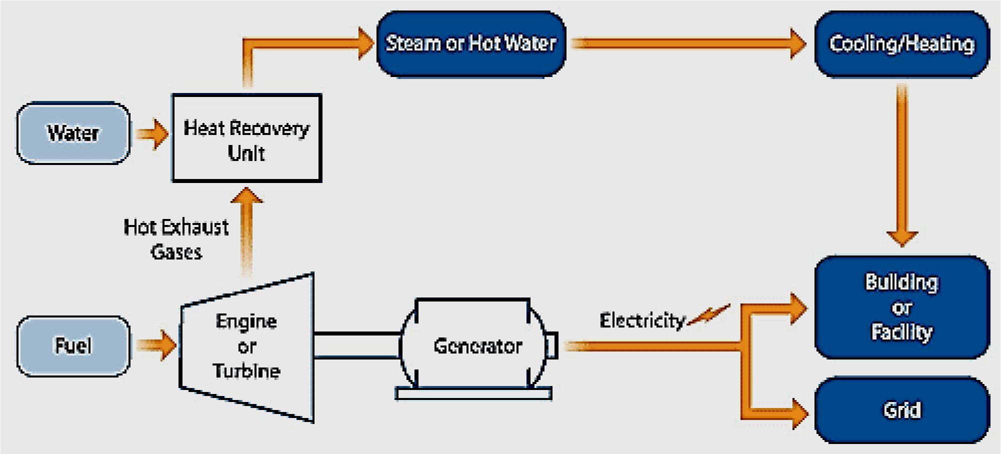


Figure 80 Bottoming cycle-Waste heat recovery – US-EPA (243)

CHAPTER 2 – FUELS

SUMMARY

This Chapter discusses the various fuels that can be burned in a boiler, including their origin, main characteristics, and environmental effects. These include coal, oil and oil products, natural gas, and new fuels such as biodiesel, spent fuels (used lube oil), refuse derived fuels, DME, and microemulsions. The Chapter also explains how the fuel type affects the characteristics and performance of boilers.

Fuels, emissions, and efficiency

Conversion of water to steam requires sufficient heat to cause the water to boil. Although a variety of energy sources, including nuclear energy and solar radiation, can produce the required amount of heat, combustion of a fuel in the presence of oxygen is the most common source. Combustion is a rapid chemical reaction between oxygen and a solid, liquid, or gaseous fuel. Oxygen required for this reaction is readily available in the air. As air and fuel are mixed at elevated temperatures, the oxygen reacts with carbon, hydrogen, and other elements in the fuel to produce heat. As long as fuel and air are both available, combustion will continue, and heat will be generated (30). The combustion mechanism is shown in Figure 81.

Heat produced during combustion is useful for a wide variety of applications; however, atmospheric emissions, which are also generated as by-products of the combustion process, must be controlled. Common gaseous emissions include sulphur dioxide (SO_2), nitrogen oxides (NO_x), water vapour, carbon dioxide (CO_2), and carbon monoxide (CO). The principal solid by-product of combustion is ash, the inorganic residue remaining after ignition of combustible materials, which is either deposited to the bottom of the combustion chamber (the heavier compounds) or released to the stack as fly ash.

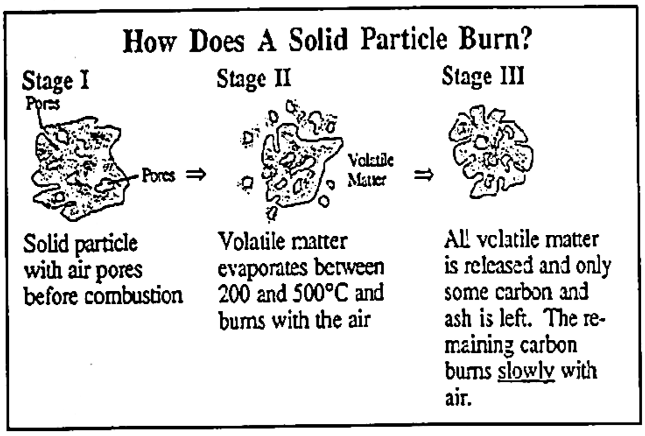


Figure 81 Combustion mechanism

This Chapter focuses on fuels commonly fired in boilers to generate steam or hot water, atmospheric emissions associated with fuel combustion, and factors that influence how effectively the energy content of the fuel is transferred into usable heat and then steam. It is important to know the combustion mechanism of different fuels and how fuel characteristics affect both boiler efficiency and emissions.

Many different solid, liquid, and gaseous fuels are fired in boilers. Sometimes, combinations of fuels are used to reduce emissions or improve boiler performance. Fuels commonly fired in boilers include the following:

- *Fossil fuels:* include coal, petroleum-based oils, natural gas, and other forms of solid, liquid, or gaseous fuel derived from these fossil fuels.

- *Biomass:* renewable organic matter, including fast-growing trees and plants, wood and wood waste, agricultural crops and residue, aquatic plants and algae, animal wastes, and organic municipal and industrial wastes.
- *RDF:* municipal solid waste (MSW) that has been processed using size reduction and material recovery techniques to eliminate materials such as aluminium, steel, glass, plastic, and rock.

Coal

Coal (33) is a brown-to-black combustible, sedimentary rocklike material composed primarily of consolidated and chemically altered plant material that grew in prehistoric forests. The chemical composition of coal varies by location, depending on the vegetation from which it was formed, and on the environmental conditions (such as temperature and pressure) to which it was exposed. (29) In addition to its major chemical constituents of carbon, hydrogen, nitrogen, and oxygen, coal also contains some water and impurities of which ash, mercury, and sulphur are major emission concerns.

Coal is a nonrenewable energy source because it takes millions of years to create. The energy in coal comes from the energy stored by plants that lived hundreds of millions of years ago, when the Earth was partly covered with swampy forests. For millions of years, a layer of dead plants at the bottom of the swamps was covered by layers of water and dirt, trapping the energy of the dead plants. The heat and pressure from the top layers helped the plant remains to turn into what we today call coal (Figure 82).

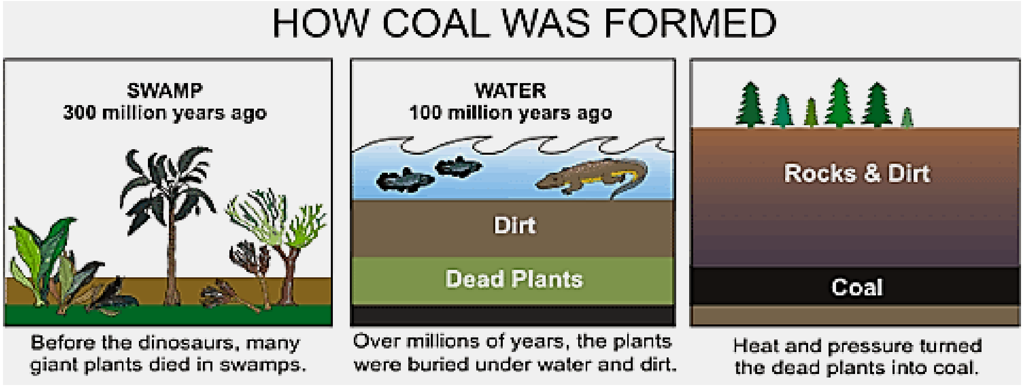


Figure 82 Coal Formation (EIA-USA) (33)

The properties of coal are determined by laboratory analysis of representative coal samples using test methods established by regulatory bodies such as the American Society for Testing and Materials (ASTM). Important coal properties that influence combustion performance include:

- moisture;
- proximate analysis (fixed carbon, volatile matter, ash);
- ultimate analysis (carbon, hydrogen, nitrogen, oxygen, sulphur, and chlorine);
- gross caloric value (as received and on a dry basis);
- mineral matter in coal (ash, major and minor elements, fusibility of ash, trace elements, mercury, fluorine, arsenic, selenium, and sulphur in ash);
- petrographic analysis;
- grindability;
- free-swelling index;
- CO_2;
- forms of sulphur (pyritic, sulphate, organic); and

- ash abrasiveness.

The chemical composition of coal can also be determined in a laboratory by chemical analysis. Results of these analyses are used for heat-balance calculations and the determination of theoretical air requirements for optimal combustion.

Moisture represents an impurity that adds to the weight of coal but not to its heating value. The moisture may be a constituent of the coal, or it may be present on the surface of the coal because of precipitation or coal cleaning operations. Moisture content, which is expressed as a percentage, is defined as the difference between the weight of a coal sample before and after the sample is maintained in an oven at 220 °F for 1 hour.

When coal is burnt, its moisture is heated. Some of the heat generated by the combustion process must be used to convert the water to steam. Normally, it is more economical to burn coal with low moisture content; but, when coal is burned on certain grates, certain conditions make it advantageous to have small amounts of moisture present. Moisture tends to accelerate the combustion process, keep the fuel bed even, and promote uniform burning. Coals with moisture content of 7% to 12% are recommended for use in chain grate and travelling grate stokers. The addition of moisture to coal to enhance the combustion process is referred to as tempering.

When coal is heated, the gaseous substance that is driven off is “volatile matter.” This matter, which consists mostly of hydrocarbon gases, burns in the combustion space above the fuel. Coal with a relatively high percentage of volatile matter is termed “soft;” and coal with a relatively low percentage of volatile matter is termed “hard.”

When soft coal is burned in a pulverized form, the volatile matter is distilled off and burns as a gas. This makes soft coal relatively easy to burn because ignition is maintained and complete combustion is achieved with minimum flame travel. Combustion of pulverized hard coal, which has less volatile matter, is more difficult to accomplish. To improve combustion, it may be necessary to pulverize hard coals with low volatility to a smaller particle size than for soft coals, or to use more intense firing methods.

Inert solid matter that remains after combustion is called ash. It includes mineral or inorganic material, such as silica, that was introduced as the coal was being formed. Clay, silt, sand, shale, slate, and pyrite particles are other ash-forming materials commonly found in the stratified layers of coal seams. Because ash is inert, coal with high ash content may have a lower heating value. The ash recovered at the bottom of a boiler burning solid wastes may contain products other than the materials entrained in the coal. The most important are discussed below.

Combustibles are generated from a non-optimal combustion of the fuel in the boiler. As a result of an improper air-to-fuel ratio, some fuel does not burn entirely and particles of it are carried with the flue gas and collected together with ash.

Dioxins are not present in the coal matrix (but their precursor, chlorine, can be present). If chlorine is present in the fuel, dioxins can be generated in the combustion chamber and transported along with ash in the flue gases, and found in ash analysis.

For these reasons, ash is usually considered a waste product and must be transported for disposal. It has been used as construction material. For example, fly ash has been used as a base for roadways, structural fill, waste stabilization, soil modification, and backfill. Fly ash that is produced in some coal-fired boilers may be suitable for use as a mineral component in concrete.

Sulphur is an impurity in coal that occurs in three forms:

- *Organic sulphur*: is part of the plant's molecular structure.
- *Pyritic sulphur*: occurs as iron sulphide and is better known as the mineral pyrite.
- *Sulphate sulphur*: is primarily from iron sulphate.

Bituminous coals that are found in places where oceans once covered the region are high in sulphur.

When selecting coal and the equipment used for its combustion, consideration must be given to the sulphur content of the coal. The corrosive effects of sulphur can influence material selection, and the amount of SO_2 that is discharged into the atmosphere can dictate the need for pollution control equipment. In particularly corrosive environments, such as those where low-temperature flue gas is present, corrosion-resistant materials are sometimes needed to minimize or avoid corrosion damage. National regulations on emissions may also require installation of SO_2 scrubbing systems that remove more than 90% of the SO_2 in the flue gas, depending on the sulphur content of the coal. Switching from high- to low-sulphur coal can be an effective method for existing units to deal with sulphur-related issues.

Classes of coal

The ASTM classification system for distinguishing coals, covers anthracitic, bituminous, sub-bituminous, and lignite coals. Classification, using standard test methods, is according to fixed carbon and gross caloric value expressed in British thermal units per pound (Btu/lb). Higher-ranking coals with at least 69% fixed carbon are classified on the dry basis. Lower-ranking coals with a caloric value up to 14,000 Btu/lb are classified on the moist basis.

Lignite coal

Lignite is the lowest ranking coal with a heating value of 8,300 Btu/lb (19.2 megajoules per kilogram, MJ/kg) or less, and a moisture content of as high as 35%. Lignite coals have a high content of volatile matter, which makes them relatively easy to ignite, especially when the combustion air is preheated. Because lignite has a relatively low sulphur content, it emits low amounts of SO_2 (Figure 83).

Figure 83 Lignite (Wikipedia) (4)

Sub-bituminous coal

The heating values of sub-bituminous coals, of between 8,300 and 11,500 Btu/lb (19.2 and 26.7 MJ/kg), are higher than lignite coals. They also have less ash and burn cleaner than lignite coals, but the moisture content is relatively high, usually between 15% and 30%. Combustion of sub-bituminous coal results in reduced NO_x emissions, but generally exhibits high fouling and slagging ash characteristics. Optimal burning of sub-bituminous coal in a boiler designed for a different class of coal may require changes in boiler design or operation.

Fig
coa

Bituminous coal

Bituminous coals are used routinely by electric utilities, and, in some industrial applications, to fire steam-generating boilers even though their sulphur content can be relatively high. Compared to lignite and sub-bituminous coals, the heating value of bituminous coals ranges between 10,500 and 14,000 Btu/lb (24.4 and 32.5 MJ/kg) (Figure 84). The higher heating value and relatively high volatile matter enable bituminous coals to burn easily when fired as pulverized coal.

Figure 85 Anthracite - Wikipedia (4)

Anthracitic coal

Anthracitic coals (see Figure 85) are the highest ranking fuel with fixed carbon contents, ranging from 86% to 98%. The moisture content is only about 3%, and the heating value can be as high as 15,000 Btu/lb (34.9 MJ/kg). Anthracitic coals are characterized as slow-burning fuels that are low in sulphur and volatile matter. These coals are used mostly to make coke for metallurgical processes.

Coal cleaning

If coal quality from a particular location does not meet the applicable fuel specification, it can be processed in different ways to upgrade its quality. Operations such as washing, drying, sizing, and blending of coals from different sources are techniques that may be used to produce acceptable coal, but other methods that involve separation of foreign materials, such as slate and pyrites, from the coal may be necessary. Although one or more of these methods may produce coal with the desired quality, special equipment may be required to perform the operations.

Coal cleaning operations are usually done at mine mouth. Coal cleaning technologies vary from coal washing at mine mouth to eliminate pyrites and other unwanted material, to sophisticated technologies such as gasification and liquefaction to produce clean gaseous and liquid fuels from coal.

Coal storage and handling

The disadvantages of coal storage (Figure 86) include build-up of inventory, space constraints, deterioration in quality over time, and potential fire hazards. Other losses associated with the storage of coal include oxidation, wind, and carpet loss (34). Measures to minimize spontaneous combustion include:

- releasing stagnant trapped air in stacked coal by inserting perforated pipes in coal heaps;
- sprinkling water occasionally as needed, especially in the hot summer months; and
- adopting "first in, first out" principles for coal use and avoiding long durations of coal stacking/storage.

Figure 86 Coal storage

Measures to reduce carpet losses include:

- preparing a hard surface for coal to be stacked upon;
- preparing standard storage bays made of concrete and brick; and
- controlling the height of coal heaps in storage.

Coal preparation

Sizing

Proper coal sizing, to match the specifications of the type of combustion system, helps to maintain even burning, reduce ash losses, and achieve better combustion efficiency. To ensure proper coal sizing in accordance with manufacturer specifications, proper maintenance and upkeep of equipment like crushers, screens, and mills are essential. Using undersized coal leads to increased loss through unburnt coal, and using oversized coal can lead to clinker formation losses apart from increases in unburnt losses.

Conditioning

Segregation of fine particles from larger coal pieces can be reduced to a great extent by conditioning coal with water. Water helps fine particles to stick to the bigger lumps due to surface tension of the moisture, thus stopping fines from falling through grate bars or being carried away by the furnace draught.

Blending

When coal lots have excessive fines, it is advisable to blend the predominantly lumped coal with lots containing excessive fines. Coal blending may thus help limit the proportion of fines in coal being fired to 25% or less. Blending different qualities of coal may also help supply a uniform coal feed to the boiler.

Heating values of standard grades of coals

The average heating values of standard grades of coal are shown in Table 5, expressed in Btu/lb and kJ/kg. (35)

ANNEX 8 shows more information on coal classification

Table 5 Heating values of standard coal grades

Coal Grade	Heating Value	
	(Btu/lb)	(MJ/kg)
Anthracite	12910	30
Semi-Anthracite	13770	32
Low-volatile bituminous	14340	33
Medium-volatile bituminous	13840	32
High-volatile bituminous A	13090	30
High-volatile bituminous B	12130	28
High-volatile bituminous C	10750	25
Sub-bituminous B	9150	21
Sub-bituminous C	8940	21
Lignite	6900	16

Oil and oil products

Oil (33) was formed from the remains of animals and plants (diatoms) that lived millions of years ago in a marine (water) environment before the dinosaurs. Over millions of years, the remains of these animals and plants were covered by layers of sand and silt. Heat and pressure from these layers helped the remains turn into what we today call crude oil (Figure 87). The word "petroleum" means "rock oil" or "oil from the earth."

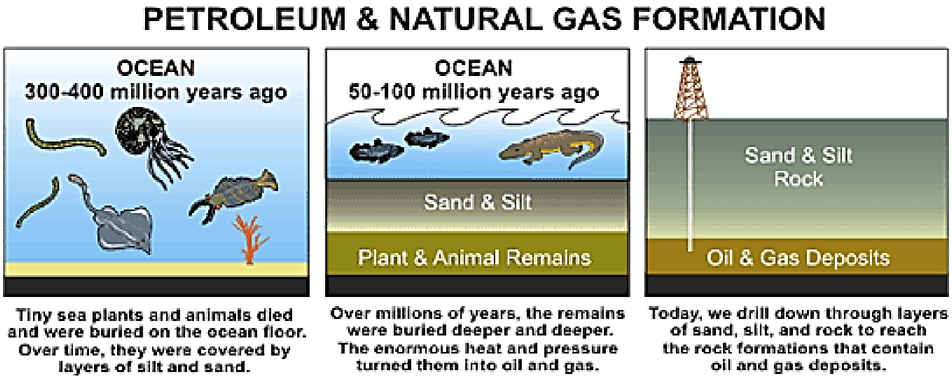


Figure 87 Petroleum and natural gas formation (DEIA USA) (33)

Petroleum is a naturally occurring black liquid found floating on subterranean lakes of salt water and located beneath dome-shaped nonporous rock formations. These deposits consist of natural gas, crude oil, and salt water separated into layers by virtue of their difference in specific gravity. When a well is drilled through the rock formation, natural gas flows to the surface where it is either burned or transported by pipeline to a processing facility. Depending on the pressure, the crude oil either flows to the surface or is removed by pumping. Once above ground, the crude oil is transported by pipeline, truck, rail, barge, or ship to a refinery. At the refinery, the crude oil is processed into any number of petroleum-based products, including fuel oils.

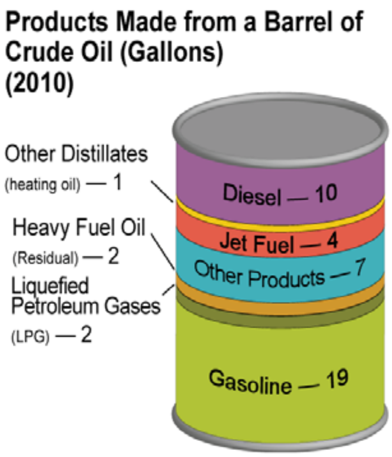


Figure 88 Products made from a barrel of oil (EIA-USA)

Classes of oil products

Fuel oils burned in boilers include the heavier petroleum products that are less volatile than gasoline. They are divided into two classes: distillate and residual. Distillate oils are lighter than residual oils with a consistency between kerosene and lubricating oil. They have a low viscosity and are typically sediment and ash free. Because distillate oils are relatively clean fuels, they are used primarily for home heating and industrial applications where low ash and low sulphur are important. Smaller amounts of distillate oil are used in steam generation applications as a start-up or supplemental fuel for certain solid fuel combustion processes.

Residual oils are products that remain after the more volatile hydrocarbons have been extracted. Residual oils, which are highly viscous, are usually free from moisture and sediment after processing. Some of the heavier residual oils must be heated to make the fuel easier to handle and burn. Sometimes, distillate and residual oils are blended to create a mixture with proportions that meet a desired fuel specification. As a liquid, fuel oils are relatively easy to handle and burn. In most oil burners, the oil is atomized with air, steam, or pressure to enhance combustion. The characteristics of atomized oil approximate those of natural gas.

The main constituents of fuel oils are hydrogen and carbon. Other constituents include nitrogen, sulphur, ash, and impurities such as moisture and sediment. Compared to coal, the nitrogen and ash contents of most fuel oils are very low. Residual oils tend to have higher nitrogen contents than distillate oils. Grade No. 2 fuel oil is considered a premium steam-generating fuel because its cleanliness and ease of handling are often used to justify its relatively high cost. The cost of Grade No. 6 is relatively low, but heating of the fuel is required to facilitate handling and burning.

The names of fuel oils can vary, depending on the countries where they are used. To identify the characteristics of a fuel oil, it is advisable to refer to its viscosity. Table 6 gives the main characteristics of fuel oils according to ASTM standards.

Table 6 Fuel oil grades established by ASTM (30)

Fuel oil	Description
Grade No. 1	Distillate fuel for use in domestic and small industrial burners. This grade is particularly adapted to vaporizing burners in which the oil is converted to a vapour by contact with a heated surface or by radiation or where storage conditions require low-pour-point fuel. High volatility is necessary to ensure that evaporation proceeds with a minimum of residue. The maximum allowable sulphur content is 0.5% by mass. The maximum allowable ash content is not specified.
Grade No. 2	Distillate fuel for use in domestic and small industrial burners. This grade is particularly adapted to vaporizing burners in which the oil is converted to a vapour by contact with a heated surface or by radiation or where storage conditions require low-pour-point fuel. High volatility is necessary to ensure that evaporation proceeds with a minimum of residue. The maximum allowable sulphur content is 0.5% by mass. The maximum allowable ash content is not specified.
Grade No. 4 (light)	Heavy distillate fuel or distillate/residual fuel blend used in commercial/industrial burners equipped for this viscosity range. This grade of fuel oil is intended for use both in pressure-atomizing commercial-industrial burners not requiring higher cost distillates and in burners equipped to atomize oils of higher viscosity. Its permissible viscosity range allows it to be pumped and atomized at relatively low storage temperatures. The maximum allowable sulphur content is not specified. The maximum allowable ash content is 0.05% by mass
Grade No. 4	Heavy distillate fuel or distillate/residual fuel blend used in commercial/industrial burners equipped for this viscosity range. This grade of fuel oil is intended for use in burners equipped with devices that atomize oils of higher viscosity than domestic burners can handle. Its permissible viscosity range allows it to be pumped and atomized at relatively low storage temperatures. Thus, in all but extremely cold weather, it requires no preheating for handling. The maximum allowable sulphur content is not specified. The maximum allowable ash content is 0.10% by mass.
Grade No. 5 (light)	Residual fuel oil used in industrial burners with an increased viscosity and boiling range compared to Grade No. 5 (light). Preheating may be necessary in some types of equipment for proper atomization and in colder climates for handling. The maximum allowable sulphur content is not specified. The maximum allowable ash content is 0.15% by mass.
Grade No. 6	Residual fuel oil used in industrial burners with an increased viscosity and boiling range compared to Grade No. 5 (heavy). Preheating is required for handling and proper atomization. Extra equipment and maintenance required to handle this fuel usually preclude its use in smaller installations where cleanliness and ease of handling are important. The maximum allowable sulphur content and the maximum allowable ash content are not specified.

The viscosity of oil products varies with temperature. The relationship between viscosity and temperature is given in Annex 9.

Sulphur found in fuel oil is undesirable. Its products of combustion are very acidic and can cause corrosion in economizers, air heaters, induced draught fans, flue gas ducts, and stacks. The sulphur content of fuel oil can vary from a low of 0.01% for Grade No. 1 to as high as 3.5% for Grade No. 6. During combustion, some of the sulphur accumulates in the ash, but most is discharged with the flue gas into the atmosphere. If uncontrolled SO_2 emissions exceed established limits, it may be necessary to switch to a lower sulphur oil or install SO_2 scrubbers to meet applicable national emission standards.

Heating values of fuel oil grades

The heating or combustion value of fuel oil is derived primarily from its two main constituents, hydrogen and carbon. Most fuel oils have a hydrogen content that ranges between 10% and 14%, and a carbon content that ranges between 86% and 90%.[18] The heating value of a fuel can be expressed as the quantity of heat released during the combustion process where oxygen from the air reacts with the hydrogen and carbon in the fuel. Heating values for fuel oils are expressed in several units: Btu/lb and Btu/gal at 60 °F, or MJ/kg and kcal/kg at 15 °C. Heating values for commercial fuel oils vary from approximately 17,500 Btu/lb to nearly 20,000 Btu/lb (40 MJ/kg to 46 MJ/kg). Combustion or heating value for some common fuel oil grades are indicated in Table 7 (36)

Table 7 Heating values of fuel oils

Grade	Heating Value (Btu/US gal)*		Heating Value MJ/Liter		Comments
	min	max	min	max	
Fuel Oil No. 1	132,900	137,000			Small Space Heaters
Fuel Oil No. 2	137,000	141,800	38	40	Residential Heating
Fuel Oil No. 4	143,100	148,100	40	41	Industrial Burners
Fuel Oil No. 5 (Light)	146,800	150,000	41	42	Preheating in General Required
Fuel Oil No.5 (Heavy)	149,400	152,000	42	42	Heating Required
Fuel Oil No. 6	151,300	155,900	42	43	Bunker C

** 1 Btu/US gal = 278.7 J/litre*

Oil storage

Oil is usually stored in cylindrical vessels, which can be positioned either underground (small vessels) or on the ground. Depending on classification, oil storage requires safety measures against fire and explosions. Normally, the storage tank needs a containment basin to collect and safely contain the fuel in case of tank leakages. Tanks may have fixed roofs or floating roofs, depending on the type of fuel. Safe distances must be kept from other plant devices. For heavy oils, preheating is necessary and can be implemented by using steam/hot water from the boiler itself or from auxiliary systems if the fuel storage area is far from the boiler. Deposits tend to settle down to the bottom of storage tanks, together with water.

Salt water can be present in the fuel if it is transported by sea in oil tankers. Salt water accumulates on the bottom of the tank and must be drained by bottom drainage valves. The presence of sea water or deposits in the fuel feeding line to the combustor results in combustion stability problems and in potential production and release of dioxins. Data on oil storage tanks are provided in ANNEX 10.

Emissions from burning oil products

When petroleum products are burned as fuel, they give off the following emissions, of which nearly all have negative impacts on the environment and human health:

- *Carbon dioxide* : a greenhouse gas and a source of global warming
- *Carbon monoxide*
- *Sulphur dioxide*: causes acid rain, which is harmful to plants and animals that live in water, and it worsens or causes respiratory illnesses and heart diseases, particularly in children and the elderly.
- *Nitrogen oxides and volatile organic compounds (VOC)*: contribute to ground-level ozone, which irritates and damages the lungs.
- *Particulate matter (PM)*: results in hazy conditions in cities and scenic areas, and, along with ozone, contributes to asthma and chronic bronchitis, especially in children and the elderly. Very small or "fine PM" is also thought to cause emphysema and lung cancer.
- *Lead and various air toxics*: may be emitted when some types of petroleum are burned. Lead can have severe health impacts, especially for children, and air toxics (e.g., benzene, formaldehyde, acetaldehyde, and 1,3-butadiene) are known or probable carcinogens.

  Dioxins: are emitted during combustion if chlorine is present in the fuel matrix. The presence of sea water, which contains chlorine, in the fuel feeding line to the combustor may also increase production of dioxins. Dioxins are highly toxic to humans and animals.

Natural gas

Natural gas (30) is a colourless hydrocarbon fuel consisting primarily of methane (CH_4) and ethane (C_2H_6), its two principal combustible components. It is typically found under the earth's surface in porous rock and shale formations or above crude oil deposits located beneath dome-shaped nonporous rock formations. When a well is drilled through the formation, natural gas, which is under pressure, flows to the surface where it is either burned or transported by pipeline to a processing facility. This characteristic makes natural gas a very desirable boiler fuel because it can be piped directly into the boiler. In addition to its ease of distribution, natural gas-fired boilers require a relatively small boiler space, and the overall plant design is typically compact and simple. With a heating value of about 1,000 Btu/ft3 (37 MJ/m^3) under standard conditions of 15 °C (60 °F) at atmospheric pressure, and low excess-air requirements that contribute to high efficiency, natural gas is perhaps very close to being an ideal fuel.

Emissions from natural gas

From an emissions point of view, natural gas is an excellent fuel choice. Although natural gas from some sources contains noncombustible gases such as nitrogen and carbon dioxide, it is practically free from solid residue. Because it is free of ash and mixes easily with air, combustion is usually complete without objectionable smoke or soot. The only significant problem with using natural gas as a fuel for boilers is related to its chemical composition. Natural gas has relatively high hydrogen content (greater than 20% by weight) compared to other fossil fuels such as oil and coal. During combustion, the hydrogen in natural gas combines with oxygen to form water vapour. As discussed in Chapter 5, formation of relatively large quantities of water vapour results in lower boiler efficiency.

Heating values of common gases

Although other types of gases can also be used as fuels for boilers, their processing costs generally make them too expensive for most large-scale applications. By-product substitutes for natural gas include producer gas, coke-oven gas, water gas, and blast-furnace gas derived from coal; refinery gas and oil gas derived from oil; and liquefied petroleum gas, including propane and butane, derived from either natural gas or oil. The heating values of some common gases are reported in Table 8.

Table 8 Heating values of gases

Fuel Gas	*(kcal/kg)*		*(kcal/Nm^3)* *	
	Gross Heating Values	Net Heating Values	Gross Heating Values	Net Heating Values
Hydrogen	33,889	28,555	3,050	2,570
Methane	13,284	11,946	9,530	8,570
Ethane	12,400	11,350	16,700	15,300
Ethylene	12,020	11,270	15,100	14,200
Natural Gas	~12,000	~11,000	~9,000	~8,000
Propane	12,030	11,080	24,200	22,250
Propylene	11,700	10,940	22,400	20,900
n-Butane	11,830	10,930	31,900	29,400
Iso-Butane	11,810	10,900	31,700	29,200
Butylene-1	11,580	10,830	29,900	27,900
Iso-Pentane (liquid)	11,600	10,730		
Liquefied Petroleum Gas (average)	11,920	10,997	28,000	25,775
Acetylene	11,932	11,514	13,980	13,490
Carbon Monoxide	2,411	2,411	3,014	3,014

**1 kJ/kg = 1 J/g = 0.4299 Btu/ lb$_m$ = 0.23884 kcal/kg*

***) Nm^3 = Normal cubic metre*

Natural gas storage

Storage of natural gas is not normally used for power and industrial boilers because it needs high pressures or, alternatively, very low temperatures or underground wells. Natural gas for large power stations is currently supplied by pipelines. If a gas pipeline does not exist, natural gas is transported in liquefied form by ship carriers at very low temperatures (-163 °C) and then re-gasified at the power plant location before being fed to the boilers. This expensive technology is only economically feasible when large amounts of gas are involved. It is not yet viable for industrial boilers.

Liquefied petroleum gas (LPG)

LPG is a mixture of 60% butane and 40% propane. It is derived from the distillation of crude oil in the refining process, in the same manner that other liquid fuels, such as kerosene, gasoline, and diesel, are extracted. LPG, mainly commercial butane and commercial propane, is commonly used by homes and industrial boilers. LPG may be liquefied by moderately increasing the pressure or reducing the temperature. Gas suppliers only use refrigerated storage when large volumes of LPG are involved.

LPG storage

LPG is mainly stored in special pressure tanks, also known as “bulk tanks” or “LPG bullets” (see Figure 89). Because LPG has a high coefficient of expansion in its liquid phase, the tanks are never completely filled with liquid; instead, they are filled to approximately 85% of their water capacity. The remaining space is taken up with vapour (often referred to as the “vapour space”) to facilitate expansion without allowing the liquid to become 100% full (often known as “hydraulically full”).

As LPG gas (vapour) is drawn from the tank, the vapour pressure in the tank falls and the liquid boils, producing more vapour and restoring the pressure. To maintain boiling, the liquid absorbs heat from itself, from the metal walls of the tank in contact with the liquid (known as the wetted surface area), and from the air surrounding the tank. The available gas offtake, therefore, is dependent upon the surface area of the tank, the quantity of liquid within the tank, and the temperature.

The low temperature of the liquid (often indicating excess offtake) may be indicated as “sweating” (where the water vapour in air condenses on the wetted surface area of the tank), and, if the offtake is large enough, “frosting” (where the condensed water vapour freezes) on the walls of the tank. When the liquid temperature rises, the vapour pressure increases. Conversely, when the liquid temperature drops, the vapour pressure drops. Under normal conditions the pressure range will be between 2 bar and 9 bar.

Figure 89 LPG tank

Steel used for the tank and its fittings meets the low temperature carbon steel criteria, and is tested thoroughly before fabrication. During fabrication, stringent quality norms are followed. Storage tanks are equipped with standard instruments and controls like excess flow check valves and safety valves. Water sprinkling systems, gas leak detection systems and a suitable control panel can also be supplied as integral parts of larger storage systems.

Most LPG storage tanks in standby-plant service are steel, non-refrigerated pressure vessels. Tanks are available in many sizes for both aboveground and underground service. New propane tanks are built to American Society of Mechanical Engineers (ASME) standards and are designed for at least 250 pounds per square inch gauge (psig, or 17 bar) working pressure. Tanks are available in many sizes, depending on customer needs, and dedicated LPG trucks are used for refilling.

LPG is flammable when mixed with air (oxygen) and can be ignited by many sources, including open flames, smoking materials, electrical sparks, and static electricity. Since LPG vapours are heavier than air, they may accumulate in low-lying areas such as basements, crawl spaces, and ditches, or along floors. However, air currents can sometimes carry propane vapours elsewhere within a building. To make propane easier to detect in the event of a leak or spill, manufacturers deliberately add a chemical compound to give it a distinctive smell. Due to its high flammability, LPG must be stored and used safely, in compliance with local and international safety rules.

Biomass

Biomass (30) is organic material made from plants and animals (microorganisms). Biomass contains stored energy from the sun. Plants absorb the sun's energy in a process called photosynthesis (Figure 91). The chemical energy in plants gets passed on to animals, and the people that eat them. Biomass is a renewable energy source because we can always grow more trees and crops, and waste will always exist. When burned, the chemical energy in biomass is released as heat.

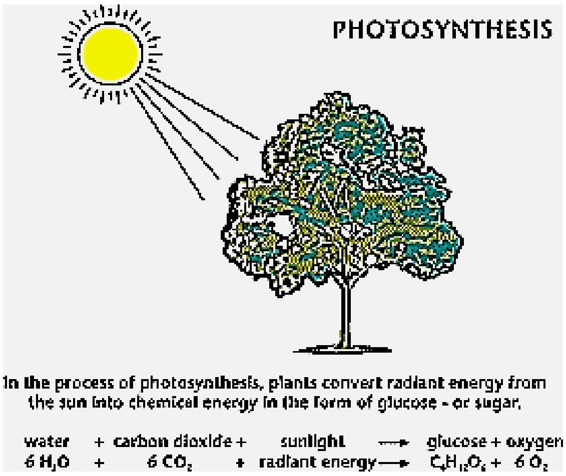
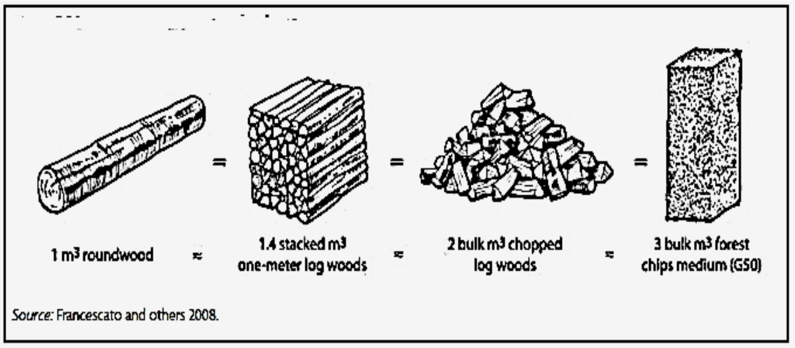


Figure 91 Photosynthesys (EIA USA) (33)



Source: Francescato and others 2008.

Figure 90 Biomass appearance and volume (World Bank) (132)

Biomass is a non-fossil fuel suitable for steam generation in boilers. It is derived from plant material including wood, bagasse, nut hulls, rice hulls, corncobs, coffee grounds, and tobacco stems. Use of these by-product materials as fuel can be cost-effective, especially when solving a waste disposal problem.

Wood is a complex vegetable tissue composed principally of cellulose. Most wood burned in boilers is a by-product from manufacturing operations such as sawmills, paper mills, and factories that manufacture wood products. By-products from these operations may take the form of bark, sawdust, sander- dust, chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest products. Care must be used when burning fine wood dust because it can ignite quickly under certain conditions. Depending on the species and moisture content, the heating value of wood can vary widely. Although certain types of wood are more suitable for steam production, sufficient supplies of the fuel may not always be available (seasonal availability). In these situations, it may be necessary to burn supplementary fuels along with the wood to meet the total steam demand.

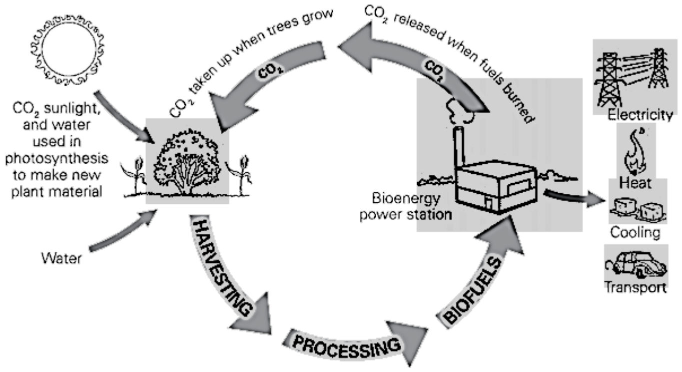


Figure 92 Biomass carbon loop (State of New South Wales–Australia)

Although most biomass is available as wood, some agriculture residues, such as rice husks, may also be used as fuel. Some biomass can also be produced as a residue of agro-industrial activities, such as bagasse from sugar production processes, and palm residue from palm oil production processes. Bagasse is a by-product fuel produced when the juice is removed from cane in a sugar mill. Although its heating value can be as high as 8,000 Btu/lb to 9,000 Btu/lb (5,000 MJ/kg to 6,000 MJ/kg), combustion of bagasse is only feasible in places where sugar cane is processed. When bagasse is burned, it is usually supplemented with auxiliary fuels.

The use of biomass as a fuel is considered to be carbon neutral because plants and trees remove CO_2 from the atmosphere and store it while they grow. Burning biomass in homes, in industrial processes, for energy generation, or for transport activities returns this sequestered CO_2 to the atmosphere. At the same time, new plant or tree growth keeps the atmosphere's carbon cycle in balance by recapturing CO_2 (Figure 92).

This net-zero or carbon-neutral cycle can be repeated indefinitely, as long as biomass is re-grown in the next management cycle and harvested for use. The sustainable management of the biomass source is thus critical to ensuring that the carbon cycle is not interrupted. In contrast to biomass, fossil fuels such as gas, oil, and coal are not regarded as carbon neutral because they release CO_2 that has been stored for millions of years. (17) The appearance of some types of biomass fuels is shown in Figure 90. (17) Biomass varieties currently used in South Asia are shown in Table 9

Table 9 Biomass varieties in South Asia (17)

Agricultural and Farm Biomass	**Agro-industrial Biomass**	**Forest Residues and Plantation**
Babul stems	Coffee husks	Firewood
Chili stalks	Bagasse	Forest residues
Coconut husks	De-oiled bran	Julie flora
Coconut pith	Groundnut husks	Other woody biomass chips
Corncobs	Groundnut shells	
Cotton stalk	Rice husks	
Maize stems	Sawdust	
Mango residues		
Mustard stalks		
Palm leaf		
Prosopis		
Rai stems		
Sugarcane trash		
Tamarind husks		
Til stems		
Casurina branches and fruit		

Different types of biomass may have different heating values and burning characteristics (see Figure 93). The heating values of other biomass fuels are as follows:

- *Nut hulls*: about 7,700 Btu/lb (18 MJ/kg)
- *Corncobs*: between 7,500 Btu/lb and 8,300 Btu/lb (17.4 MJ/kg and 19.2 MJ/kg)
- *Coffee grounds from instant coffee production*: between 4,900 Btu/lb and 6,500 Btu/lb (11.4 MJ/kg and15.1 MJ/kg)

The composition and heating values of some biomass fuels, referred to as coal characteristics, are listed in Table 10. It is important to note that biomass contains some moisture, which is evaporated during the combustion process. Some of the energy content of the biomass goes to evaporate its moisture content. The real heating values of biomass are therefore lower, as shown for wood in Table 11. (37)

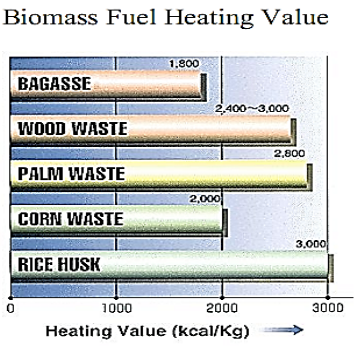
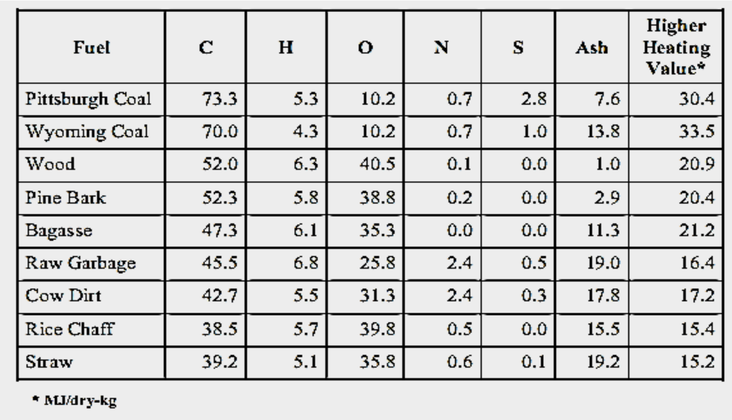


Figure 93 Types of biomass FUELS (Courtesy of APO) (17)

Table 10 Composition and heating values of some biomass



Fuel	C	H	O	N	S	Ash	Higher Heating Value*
Pittsburgh Coal	73.3	5.3	10.2	0.7	2.8	7.6	30.4
Wyoming Coal	70.0	4.3	10.2	0.7	1.0	13.8	33.5
Wood	52.0	6.3	40.5	0.1	0.0	1.0	20.9
Pine Bark	52.3	5.8	38.8	0.2	0.0	2.9	20.4
Bagasse	47.3	6.1	35.3	0.0	0.0	11.3	21.2
Raw Garbage	45.5	6.8	25.8	2.4	0.5	19.0	16.4
Cow Dirt	42.7	5.5	31.3	2.4	0.3	17.8	17.2
Rice Chaff	38.5	5.7	39.8	0.5	0.0	15.5	15.4
Straw	39.2	5.1	35.8	0.6	0.1	19.2	15.2

* MJ/dry-kg

Table 11 Wet and dry wood-Combustion values

Condition of Wood	**Approximate Combustion Values**		
	Btu/lb	***kJ/kg***	***kcal/kg***
Wet*	**4,000**	**9,300**	**2,220**
Dry**	**7,000**	**16,300**	**3,890**

*11.6 lb wet wood = 1 Boiler Horse Power

**6.3 lb dry wood = 1 Boiler Horse Power

The relationship between the moisture content and usable energy for wood is shown in Table 12. (37) By volume, wet wood has about 85% of the energy of oven-dry wood; by weight, wet wood has less than half (42%) of the energy of oven-dry wood.

Table 12 Relationship between moisture content and usable energy for wood

Moisture Content and Usable Energy		
Moisture Content %	Energy by Volume Unit %	Energy per Weight Unit %
0 (oven dry)	**100**	**100**
20 (air-dry)	**97**	**81**
50 (green)	**92**	**62**
100 (wet)	85	42

Biomass storage

As biomass tends to decompose with time, its storage is feasible for limited periods, depending on the type of biomass used. Biomass should be stored in places protected from rain and wind. When biomass becomes wet, its heating value lowers because some of the heat generated from combustion goes to evaporate the entrained water. It also tends to self-ignite in the bulk due to the combined effect of pressure and humidity. Figure 94 shows an open air storage for rice hulls. Open air storage is subject to dust release and rain in the rainy season, which have a negative impact on fuel characteristics (handling and heating value).

Figure 94 Biomass open air storage

Moreover, when wet, biomass tends to decompose earlier. As most biomass is available seasonally, the storage area should be sized according to evaluations of the length of time for which the biomass needs to be used. Small bulks are preferable to big bulks, to limit decomposition.

Different types of biomass may be used over a year to overcome their limited seasonal availability. But this is feasible only where different types of biomass are available in different seasons. The use of different types of biomass can result in complications in the fuel feeding lines, burning systems, and boiler performance. Biomass can be economically transported for short distances, of normally 30 kilometres (km) to 40 km. For longer distances, transportation costs rise, making other fossil fuels cost competitive.

Biomass and the environment

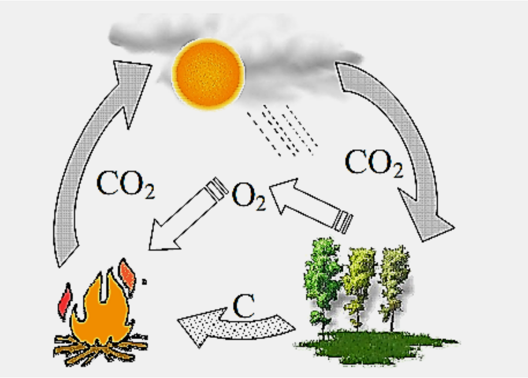


Figure 95 Carbon dioxide cycle for biomass burning (133)

Renewable energy can be defined as energy that comes from natural resources such as sunlight, wind, rain, tides, and geothermal heat, which are renewable (naturally replenished). (38) But, as with all energy sources, the environmental risks of biomass need to be mitigated. If not managed carefully, biomass for energy can be harvested at unsustainable rates, damage ecosystems, produce harmful air pollution, consume large amounts of water, and produce net greenhouse emissions. The carbon dioxide produced by burning biomass is compensated for by the carbon dioxide absorbed by the biomass during its lifecycle, as shown in Figure 95.

Biomass power, derived from the burning of plant matter, raises more serious environmental issues than any other renewable resource except hydropower. Combustion of biomass and biomass-derived fuels produces air pollution; beyond this, there are concerns about the impacts of using land to grow energy crops. The seriousness of these impacts depends on how carefully the resource is managed. The picture is further complicated by the absence of a single biomass technology; rather a wide variety of production and conversion methods exist, each with different environmental impacts. (39)

However, most scientists believe that a wide range of biomass resources can be produced sustainably and with minimal harm, while reducing the overall impacts and risks of our current energy system. Implementing proper policy is essential to securing the benefits of biomass and avoiding its risks. (39) For example, residues from agriculture and sustainable forest logging can be considered as sustainable biomass. The cutting of virgin forest, however, which results in loss of forest and related biodiversity, is a non-sustainable activity. Care should therefore be taken when evaluating the deployment of a country's biomass resources to distinguish between sustainable and non-sustainable biomass. In the Clean Development Mechanism (CDM), only sustainable biomass is allowed to access carbon credits (see ANNEX 11).

Emissions from biomass

Biomass fuels can vary significantly in terms of ash, chlorine, and moisture content. Sulphur can be present in various types of biomass in addition to wood types. The combustion of biomass therefore results in different types of emissions, depending on the combustion technology used. Table 13 shows typical average emission values for uncontrolled biomass combustion. (40)

Table 13 Typical Biomass emissions

Emissions	kg/ton of Biomass
Particulates	**12.5 – 15**
Organic compounds	**1**
Sulphur dioxide	**1.5**
Nitrogen oxides	**5**
Carbon monoxide	**1**

Particulates, one of the most important pollutants emitted from biomass, require the use of dust abatement devices before the stack. The *Particulate matter control* section in Chapter 4 provides some data on the performance of dust abatement devices in the case of biomass burning. The formation of dioxins and furans (polychlorinated dibenzodioxins/dibenzofurans, PCCD/PCDF) are affected by

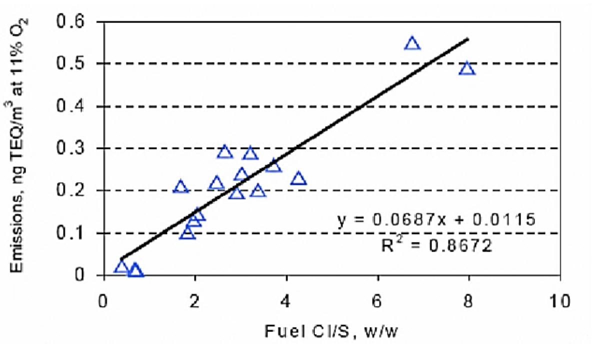


Figure 96 Relationship between dioxins emissions and chlorine-to-sulphur ratio of TDG (14)

the fuel, combustion, and post-combustion conditions. Paprican (Pulp and Paper Research Institute of Canada) has developed simplified mathematical relationships examining the impact of stack and fuel variables on dioxin emissions. The equation predicts that stack dioxin emissions increase linearly with decreasing electrostatic precipitator (ESP) efficiency or with increasing concentrations of precursor polycyclical aromatic hydrocarbon (PAH) compounds (e.g., poor combustion); increase exponentially with increasing ESP temperatures; and increase to the second order with hog salt content. Other research has also shown that the presence of sulphur in the fuel can inhibit dioxin emissions. (14) Data from Paprican on testing in Canada at a West coast pulp mill boiler burning TDG (rubber containing sulphur) show that dioxin emissions were positively correlated to the chlorine-to-sulphur ratio in the fuel, as shown in Figure 96

Densities and heat values of different types of biomass are provided in ANNEX 12.

Biomass-derived fuels

Biofuels [(33)] are transportation fuels like ethanol and biodiesel that are made (or derived) from biomass materials. Although these fuels are usually blended with the petroleum fuels, gasoline and diesel fuel, they can also be used on their own. The use of biofuels means less fossil fuel is burned. Although ethanol and biodiesel are usually more expensive than the fossil fuels they replace, they are cleaner-burning fuels that produce fewer air pollutants.

Ethanol

Ethanol is an alcohol fuel made from the sugars found in grains, such as corn, sorghum, and barley. Other sources of sugars for production of ethanol include potato skins, rice, sugar cane, sugar beets, yard clippings, bark, and switchgrass. Scientists are currently working on cheaper ways to make ethanol by using all parts of plants and trees rather than just the grain. Farmers are experimenting with "woody crops," mostly small poplar trees and switchgrass, to see if they can be grown cheaply and abundantly.

Biodiesel

Biodiesel [(33)], which is made from vegetable oils, fats, or greases (e.g., recycled restaurant grease), can be used in diesel engines without changing them. It is the fastest growing alternative fuel in the United States. A renewable fuel, biodiesel is safe, biodegradable, and produces lower levels of most air pollutants, such as particulates, carbon monoxide, sulphur dioxide, hydrocarbons, and air toxics, than petroleum-based products. However, it does slightly increase emissions of nitrogen oxides. Biodiesel does not smell as bad as regular diesel fuel when it burns, but sometimes biodiesel exhaust smells like French fries.

Biodiesel may be considered to be carbon-neutral when the plants that are used to make it, such as soybeans and palm oil trees, absorb CO_2 as they grow, thus offsetting the CO_2 produced while making and using biodiesel. However, in some parts of the world, mostly developing countries, large areas of natural vegetation and forests have been cleared and burned to grow soybeans and palm oil trees to make biodiesel. The negative environmental impacts of these activities may be greater than any potential benefits from using the biodiesel produced from the plants grown.

Biodiesel has better lubricating properties and much higher cetane ratings than today's lower-sulphur diesel fuels. Biodiesel addition reduces fuel system wear, and, in low levels in high-pressure systems, increases the life of the fuel injection equipment that relies on the fuel for its lubrication. Depending on the engine, this might include high-pressure injection pumps, pump injectors (also called unit injectors), and fuel injectors.

The calorific value of biodiesel is about 37.27 MJ/kg. This is 9% lower than regular Number 2 diesel oil. Variations in biodiesel energy density are more dependent on the feedstock used than on the production process. Still, these variations are less than for diesel oil. It has been claimed biodiesel gives better lubricity and more complete combustion, thus increasing the engine energy output and partially compensating for the higher energy density of diesel oil.

Vegetable oil fuels

Vegetable oil (42) is an alternative fuel for diesel engines and heating oil burners. For engines designed to burn diesel fuel, the viscosity of vegetable oil must be lowered to allow for proper atomization of the fuel, otherwise incomplete combustion and carbon build-up will ultimately damage the engine. To distinguish it from biodiesel, many enthusiasts refer to vegetable oil used as fuel as waste vegetable oil (WVO) if it is oil discarded from a restaurant or straight vegetable oil (SVO), or pure plant oil (PPO).

Most diesel car engines can use SVO/PPO with suitable modifications. Principally, the viscosity and surface tension of the SVO/PPO must be reduced by preheating it, typically by using waste heat from the engine or electricity; otherwise, poor atomization, incomplete combustion, and carbonization may result. One common solution is to add a heat exchanger, an additional fuel tank for "normal" diesel fuel (petrodiesel or biodiesel), and a three-way valve to switch between this additional tank and the main tank of SVO/PPO. (This aftermarket modification typically costs about 1,200 USD.) The engine is started on diesel, switched over to vegetable oil as soon as it is warmed up, and switched back to diesel shortly before being switched off to ensure that no vegetable oil remains in the engine or fuel lines when it is started from cold again. In colder climates, it is often necessary to heat the vegetable oil fuel lines and tank as the oil can become very viscous and even solidify.

Vegetable oil refining

The majority of plant and animal oils are vegetable oils that are triglycerides — suitable for refining. Refinery feedstock includes canola, algae, jatropha, salicornia, and tallow (43)**.** One type of algae, *Botryococcus braunii*, produces a different type of oil, known as a triterpene, which is transformed into alkanes by a different process.

Based on its feedstock, green diesel could be classified as biodiesel; however, based on the processing technology and chemical formula, green diesel and biodiesel are different products. The chemical reaction commonly used to produce biodiesel is known as transesterification. Vegetable oil and alcohol are reacted, producing esters, or biodiesel, and the coproduct, glycerol. When refining vegetable oil, no glycerol is produced, only fuels. Refined diesel can be produced that is chemically identical to diesel fuel and does not have the problems specific to transesterified biodiesel. Any blending ratio can be used, and no modifications or checks are required for any diesel.

Vegetable oil and the environment

Most independent evidence applies to emissions from biodiesel and SVO/PPO used in cars; however, those findings can also be largely applied to power stations. As a study commissioned by the Dutch government confirms, emissions from vegetable oil burning are relatively similar to those from burning mineral diesel, although some recent evidence suggests they may be even worse as far as nitrous oxide and carcinogenic and mutagenic PAH emissions are concerned. Overall, the emissions from a power station that burns 10,000 tons of vegetable oil a year – which is approximately what is needed to run an efficient 10 megawatt (MW) power station continuously – are roughly equivalent to adding 10,000 diesel cars to the road (44).

Spent oils

Uncontrolled combustion of spent oils can be dangerous as harmful emissions and residues are produced.

Types of spent oils

Waste vegetable oils

These are used frying oils from restaurants, hotels, and people's homes. The chemical structure of vegetable oils is modified after frying. Moreover, oil oxidizes and absorbs polluting products from food cooking residues. If discharged to the environment, WVO floats over water and is dangerous for wildlife in lakes, rivers and sea (fish and birds). It can also clog sewage systems. Recovery of WVO is therefore a very good environmental practice; it is also aimed at recycling the spent oil to produce lube oils, biodiesel, surfactants and soaps.

Light spent oils

These are waste oils produced in industrial processes. They can be easily regenerated by using a purification process such as filtration and/or centrifugal separation.

Spent lube oils

Spent lube oils, such as used lube oil from cars and trucks, are dangerous because they contain harmful compounds such as heavy metals, combustion residues, and oxides. They can be collected and burned or regenerated. Special containers should be used to handle spent oils, and avoid mixing them with other liquids (Figure 97).

Figure 97 Spent oil collection tanks

Treatment and recovery of spent oils

Spent oils can be either recovered or destroyed, depending on product characteristics. Recovery processes include the following:

- *Regeneration*: Regeneration involves producing, from spent oils, compounds for new lube oils, with the same characteristics of lube oils derived from oil refining processes. 1 kg of new lube oil can be produced from 1.5 kg of spent oil. Additional products like diesel oil, fuel oil and bitumen can also be produced from regeneration processes.
- *Combustion*: If the spent oil cannot be regenerated, it is burned. Not all furnaces are able to burn spent contaminated oil. The most suitable devices are in cement factories, where the spent oil, with a very

good heating value of around 9500 kcal/kg (40 MJ/kg), can be burned by controlling the emissions of air pollutants.

- *Treatment:* When the characteristics of the spent oil do not allow regeneration or combustion, it is possible to treat the oil in treatment plants to reach the quality needed for regeneration.
- *Incineration:* When the characteristics of spent oil do not allow its regeneration/combustion or treatment, it is sent to an incinerator, where oil is burned in devices adopting a high-efficiency flue gas filtering system to keep the emissions under allowable limits. In countries with good collection/recovery systems, less than 0.5% of recovered oil is sent to incinerators.

Refuse-derived fuel (RDF)

RDF, or solid recovered fuel/specified recovered fuel (SRF), is produced by using waste converter technology to shred and dehydrate municipal solid waste (MSW). RDF consists largely of combustible components of MSW such as plastics and biodegradable waste. (45)

Residential, commercial, and industrial solid waste transported to a landfill for disposal can be burned as fuel in waste-to-energy boilers. MSW containing mixtures of paper, wood, yard wastes, food wastes, plastics, leather, and rubber can have characteristics similar to wood. MSW can be used as a fuel by burning the as-received material, which is called mass burning; but processing is often required before it can be burned effectively. When MSW is processed using size-reduction and material recovery techniques designed to shred the waste and remove noncombustible materials, it is called RDF. (18) The highly variable nature of MSW presents challenges in designing a combustion system that can accommodate this high-ash, low-sulphur fuel.

Since the presence of plastic material favours the production of dioxins and other dangerous pollutants, waste or RDF should be burned in special furnaces/boilers (incinerators). Its combustion in industrial boilers is not advisable, unless strictly controlled in special boilers/furnaces.

Noncombustible materials such as glass and metals are removed during the post-treatment processing cycle with an air knife or other mechanical separation processing. The residual material can be sold in its processed form (depending on the process treatment), or compressed into pellets, bricks, or logs and used for other purposes, either stand-alone or in a recursive recycling process. [2]

Advanced RDF processing methods (pressurized steam treatment in an autoclave) can remove or significantly reduce harmful pollutants and heavy metals for a variety of manufacturing and related uses. RDF is extracted from MSW using mechanical heat treatment, mechanical biological treatment, or waste autoclaves.

The production of RDF may involve some, but not all, of the following steps: (45)

- preliminary liberation (not required for autoclave treatment)
- size screening (post-treatment step for autoclave treatment)
- magnetic separation (post-treatment for autoclave treatment)
- coarse shredding (not required for autoclave treatment)
- refining separation

Mixed fuels

Environmental concerns about SO_2 and PM emissions from combustion of bituminous coals have led to the development of coal cleaning techniques known as beneficiation. (18) These techniques involve removal of sulphur and mineral matter from coal prior to combustion. To achieve the cleaning level needed to meet sulphur standards, the form of the solid coal must first be altered. Most advanced cleaning processes use water as the separation medium and involve grinding the coal to fine particle size. Grinding allows pyritic sulphur and other minerals that are dispersed throughout the coal to be more easily separated from the coal. After these materials are removed, the fine, clean coal product must be dried, pelletized, or reconstituted into a coal-water slurry, which can be handled like oil prior to combustion in a boiler.

Coal-water slurries have potential as fuel oil substitutes in some combustion applications. Typical bituminous coal slurries contain approximately 70% PC, 29% water, and 1% chemical additives. Slurries prepared from coals, which have been deep cleaned, can contain coal with finer particle sizes and a lower solids content (50% to60%). Although coal-water slurries are produced from fine PC, and are handled and fired like No. 6 fuel oil, they burn somewhat differently. Burners suitable for coal-water slurry combustion are often specially designed to accommodate the unique properties of the slurry. Viscosity and flow characteristics can affect the way the fuel is atomized, and can increase wear and deterioration of piping and burner components.

Oil-water slurries can be used as fuel with combustion performance similar to residual oils. These liquid-fuel emulsions are composed of micron-size oil droplets dispersed in water. (18) Although the heating value, ash content, and viscosity of oil-water slurries are similar to residual oil, they have a relatively high sulphur content. ANNEX 13 provides a table of unit of measure conversions for different fuels.

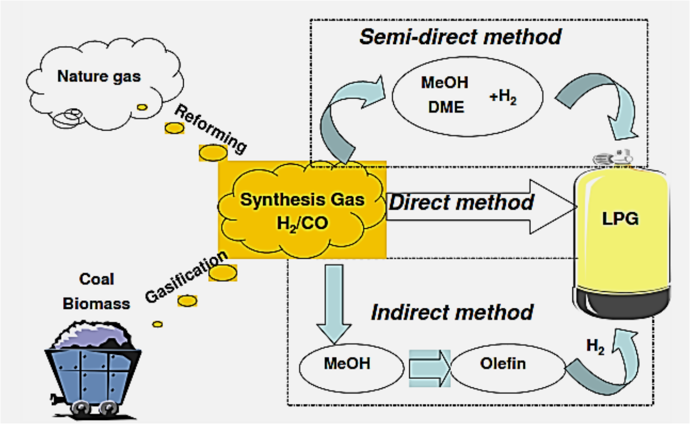


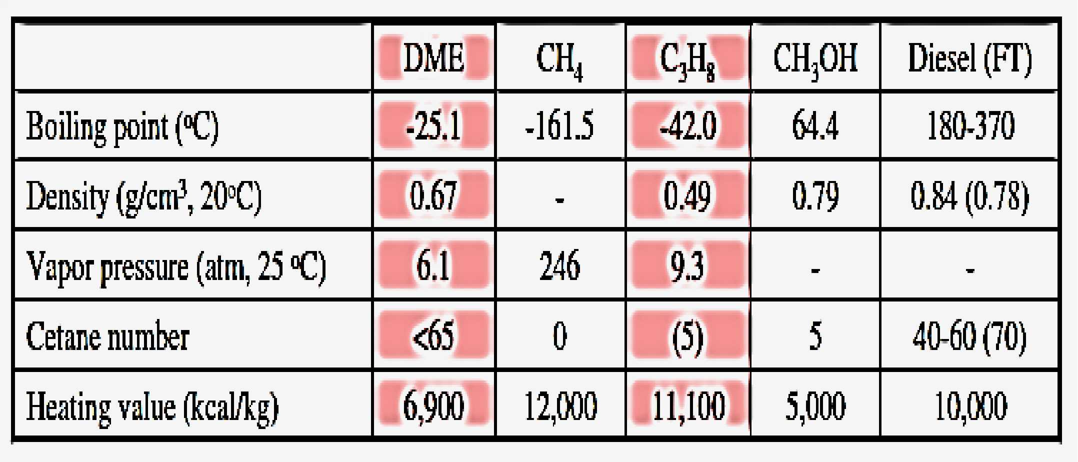
Figure 98 Schematic of potential DME production line (Karou Fujimo-Japan) [42]

Dimethyl ethylene (DME)

Due to the current high prices of fuel oils and natural gas, gas produced from coal is being considered as an alternative. DME, currently used as filler for sprays, is under evaluation as a replacement for diesel oil in trucks and small boilers. This gas can be produced by coal at coal mine mouth and transported via pipeline. DME production plants can also be built close to users with coal transported by train from the mine. DME is very similar to LPG, and can be transported as liquid under moderate pressure in special track/wagons, and bottled in small vessels (20 litres to 50 litres) for domestic applications. DME may also be produced from biomass. A potential DME production line (with LPG as the final product) is illustrated in Figure 98. (46) The characteristics of DME are shown in Table 14. (46)

Microemulsions

Table 14 Characteristics of DME compared with similar fuels (46)

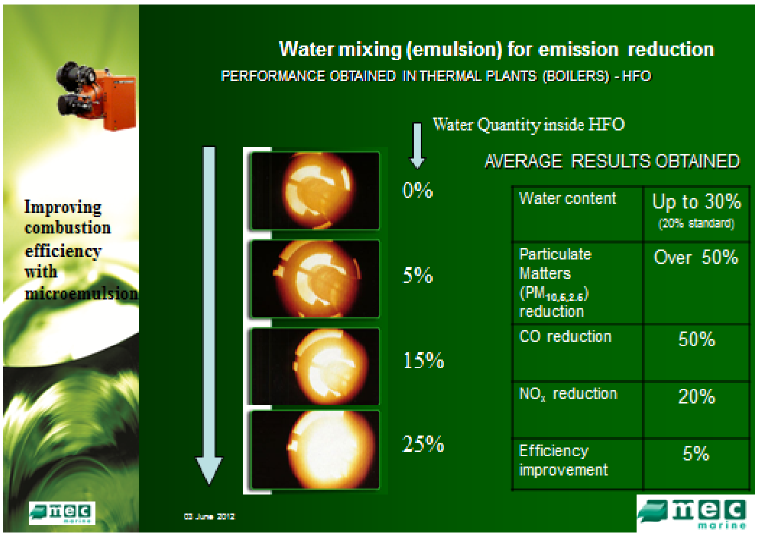


	DME	CH_4	C_3H_8	CH_3OH	Diesel (FT)
Boiling point (°C)	-25.1	-161.5	-42.0	64.4	180-370
Density (g/cm³, 20°C)	0.67	-	0.49	0.79	0.84 (0.78)
Vapor pressure (atm, 25 °C)	6.1	246	9.3	-	-
Cetane number	<65	0	(5)	5	40-60 (70)
Heating value (kcal/kg)	6,900	12,000	11,100	5,000	10,000

Microemulsions are not a new fuel; rather, they are a new technology. They were originally developed to reduce the smoke from ship engines, and are now being applied to stationary boilers to reduce the emissions of pollutants and increase efficiency. Microemulsions can be considered as a best available technique for reducing emissions in the burning of oil products

The technology consists of mixing water droplets with a liquid fuel to form an emulsion, which is then sent to the burner. The amount of water added can range from 5% to 25% depending upon the characteristics of the fuel. The improvement of combustion characteristics compensates for the loss of energy in water evaporation. The outcomes are:

- less pollutants emitted (50% less CO and 20% less NO_x)
- efficiency improvement of about 5%, and
- cleaner boiler surfaces due to absence of soot and incombustibles.



Water mixing (emulsion) for emission reduction

PERFORMANCE OBTAINED IN THERMAL PLANTS (BOILERS) - HFO

Improving combustion efficiency with microemulsion

Water Quantity inside HFO

AVERAGE RESULTS OBTAINED

Water content	Up to 30% (20% standard)
Particulate Matters ($PM_{10,5,2.5}$) reduction	Over 50%
CO reduction	50%
NO_x reduction	20%
Efficiency improvement	5%

03 June 2012

Figure 99 Emission reduction from microemulsions- (courtesy of Mec Marine–Italy)

A demonstration project in a pilot facility under the United Nations Industrial Development Organization (UNIDO) Best Available Techniques/Best Environmental Practices (BAT/BEP) project is underway to verify the effect of microemulsion systems on dioxins released from heavy oil-fuelled boilers.

Microemulsions can be selected for old boilers as well as for new boilers that cannot be retrofitted for cheaper, cleaner fuels. Preliminary results from microemulsion burning in thermal plants are illustrated in Figure 99. A microemulsion device is shown in Figure 100.

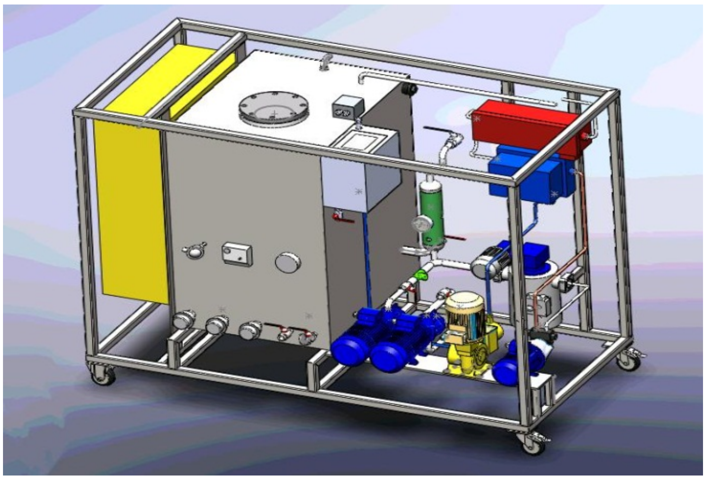


Figure 100 Microemulsion device (courtesy of Mec Marine–Italy)

CHAPTER 3 - POLLUTANTS EMITTED FROM BOILERS AND THEIR EFFECTS ON THE ENVIRONMENT

SUMMARY

This Chapter describes the characteristics and behaviour of the most common types of pollutants that can be emitted from industrial boilers, including how they are generated by combustion of specific fuels, how they are emitted from boilers and transported to the environment, and how they affect the environment. The discussions place special on dioxins and mercury, two persistent organic pollutants (POPs) that can adversely affect human health, even when emitted in small quantities.

The combustion of fossil fuels in boilers contributes to global emissions and their negative effects. Figure 101 illustrates how global emissions affect the environment.

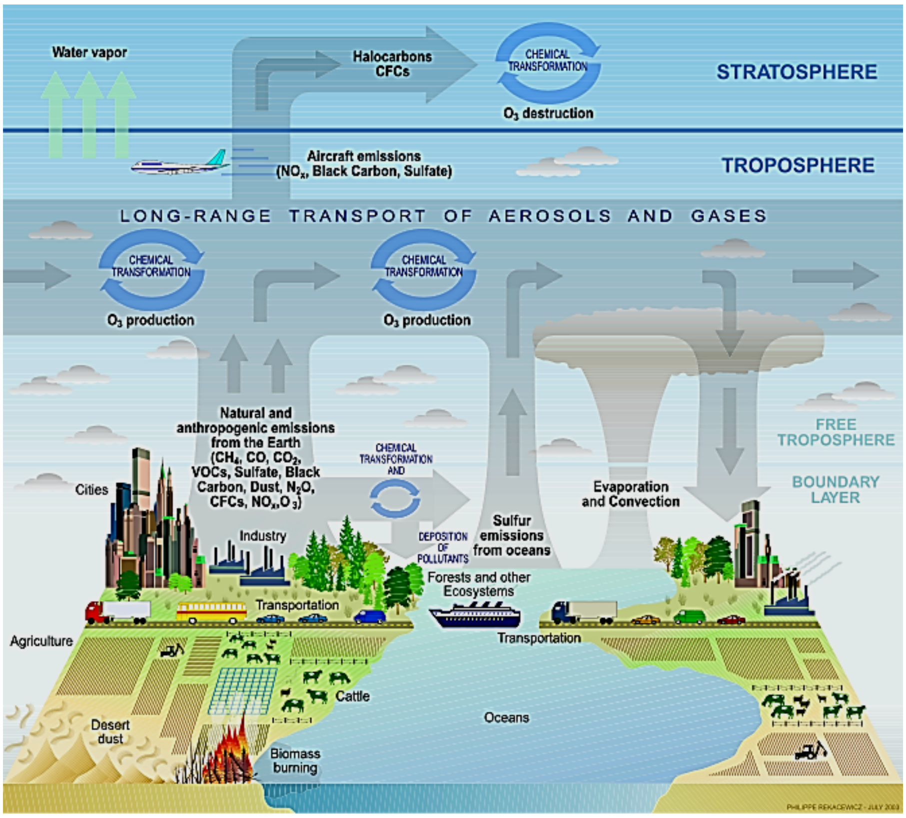


Figure 101 Global emissions in the atmosphere (Wikipedia) (200)

Since polluting gases emitted from boilers, such as sulphur oxides and nitrogen oxides, can be transported a long distance from the place of origin and affect the environment of faraway places, air pollution is increasingly becoming an international issue. All countries and individuals, therefore, must take responsibility and action to reduce emissions. Our planet is often compared to a fish bowl in which all pollutants produced ultimately remain in the bowl.

Although industrial boilers are smaller and have lower emissions than power boilers, there are many more of them operating worldwide (an estimated 300,000); thus their total contribution to environmental pollution is remarkably high. Boiler owners must reduce emissions as low as possible.

Table 15 shows the main emissions from industrial boilers, and their effects. (47) Emission levels can be provided in many different units depending on whether the measurement is volume or mass based (quantity/kilogram, quantity/normal cubic metre (Nm^3), quantity/unit energy).

Table 15 Industrial boiler emissions (CANMET-Canada)

Emission	Source	Effect
CO_2 (Carbon dioxide)	Complete combustion of carbon in fuel	Global Warming
CO (Carbon Monoxide)	Incomplete combustion of carbon in fuel	Smog
SO_2 (Sulphur Dioxide)	Combustion of sulphur in fuel (sulphur is NOT a component of natural gas)	Smog, Acid Rain
NO_x (Nitrogen Oxides)	By-product of most combustion processes	Acid Rain
N_2O (Nitrous Oxide)	By-product of some combustion processes	Global Warming
VOCs (Volatile Organic Compounds)	Leakage and evaporation of liquid fuels	Smog
CH_4 (Methane)	Natural gas leaks	Global Warming
H_2O (Water Vapour)	Hydrogen in fuel mixing with oxygen in the combustion process	Localized Fog
Particulates (Dust, Soot, Fumes)	Unburned carbon from fuel, including ash and dirt	Smog, Respiratory Hazard
Trace Elements	Impurities in fuel	Unknown and Potential Carcinogens
Halogenated and Chlorinated Compounds	Compounds in fuel or combustion air containing halogens (chlorine, fluorine, bromine and iodine)	Potential Carcinogens, Global Warming

Emission standards

The emission of pollutants to the atmosphere is usually controlled by national laws and regulations, and by international laws for transboundary pollution. Emission standards set specific limits on the amount of pollutants that can be released into the environment. Although many emission standards focus on regulating pollutants released by automobiles and other powered vehicles, they can also regulate emissions from industry, power plants, and small equipment such as lawn mowers and diesel generators. Technology standards, which are frequently used as policy alternatives to emission standards, generally regulate the emissions of nitrogen oxides (NO_x), sulphur oxides (SO_x), particulate matter (PM) or soot, carbon monoxide (CO), or volatile hydrocarbons (see carbon dioxide equivalent). (48)

Emission performance standards set thresholds above which a different type of emission control technology might be needed. While emission performance standards have been used to dictate limits for conventional pollutants such as NO_x and SO_x, they may also be used to regulate greenhouse gases, particularly carbon dioxide (CO_2). This standard is expressed in pounds of carbon dioxide per megawatt-hour (lb CO_2/MWhr) in the United States, and in kilograms of CO_2 per megawatt-hour (kg/MWhr) elsewhere in the world. (48)

A diagram of emissions from industrial, urban, and natural sources is shown in Figure 102. The emission of pollutants from the stack of an industrial boiler depends on the type of fuel used, and the type and quality of combustion. For example, coal burning results in generation of more pollutants from boilers than natural gas because coal contains more polluting compounds, such as ash, heavy metals, mercury, and chlorine, which react/separate during the combustion process and are transported with flue gases to the stack. Some compounds are trapped by ash hoppers, filter dust collection systems, and De-SO_x and De-NO_x devices (see Chapter 4).

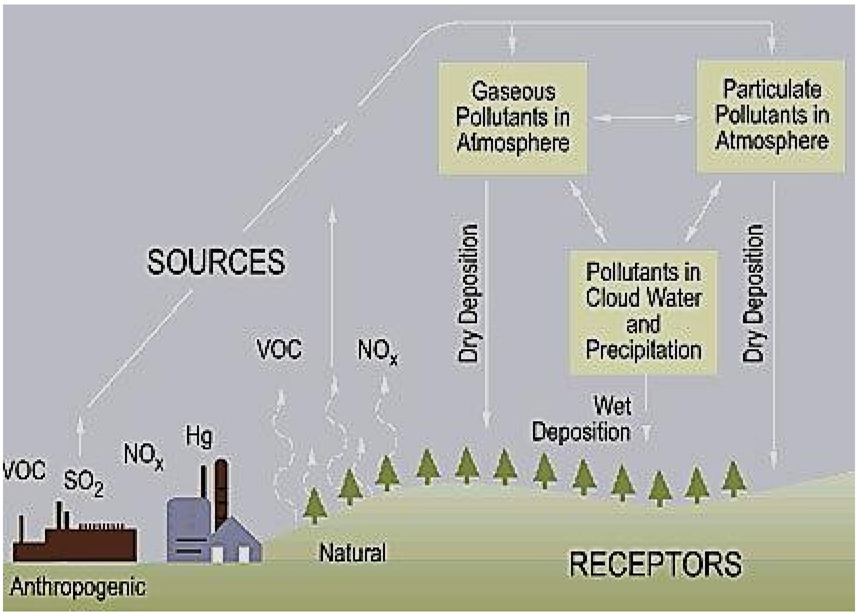


Figure 102 Emissions from antropogenic and natural activities –(US EPA) (45)

The type and quality of combustion is affected by the type of boiler and the temperature range it is designed for (e.g., fluidized bed boilers work at lower temperatures than firetube boilers); and the type and quality of combustion (e.g., low NO_x burners are designed to emit lower NO_x; bad combustion conditions, such as too much or too little combustion air, may produce incombustibles and dioxins). Table 16 clearly shows that emissions are fuel type-dependent. It lists the characteristics of fuel-dependent emission factors, based on actual emissions from power plants in the European Union, and shows the average emission for each fuel. (49) To lower the amount of pollutants emitted from combustion of fossil fuels, special abatement devices (e.g., filters, systems, operating practices) must be implemented. Therefore, the better the technologies and operating practices adopted, the lower the amount of pollutants released to the environment. Not all of the pollutants emitted are shown in the Table. Heavy metals, volatile organic compounds, and dioxins are also important pollutants from industrial boilers; as such, they will also be discussed in this Chapter. The reduction of the amounts of dioxins and mercury released by industrial boilers is part of a United Nations Industrial Development Organization (UNIDO) project in the East South East Asia (ESEA) region.

Table 16 shows the releases of pollutants — emission factors by unit of energy (the fuel amount). Emissions are given as grams or cubic metres (m^3) per gigajoule (GJ; 1 GJ = 10^9 joule). Emissions are also sometimes given per unit of weight (e.g., grams per kg of fuel) or per unit of flue gas volume (e.g., grams per m^3). The actual release to the environment depends on the type of pollution abatement devices installed in the plant. Of the fuels listed in the Table, coal produces more pollutants, and therefore needs more sophisticated and efficient pollution abatement devices to comply with emission standards.

Table 16 Fuel emission factors (EEA-European Environmental Agency)

Pollutant	Hard coal	Brown coal	Fuel oil	Other oil	Gas
CO_2 (g/GJ)	94600	101000	77400	74100	56100
SO_2 (g/GJ)	765	1361	1350	228	0.68
NO_x (g/GJ)	292	183	195	129	93.3
CO (g/GJ)	89.1	89.1	15.7	15.7	14.5
Non methane organic compounds (g/GJ)	4.92	7.78	3.70	3.24	1.58
Particulate matter (g/GJ)	1203	3254	16	1.91	0.1
Flue gas volume total (m^3/GJ)	360	444	279	276	272

Transport and dispersion of air pollutants

The transport and dispersion of air pollutants in the ambient air are influenced by many complex factors including global and regional weather patterns, local topographical conditions , and, at a more local level, wind and atmospheric stability.

Wind is the natural horizontal motion of the atmosphere. It occurs when warm air rises, and cool air comes in to take its place. Wind is caused by differences in pressure in the atmosphere. The pressure is the weight of the atmosphere at a given point. The height and temperature of a column of air determine the atmospheric weight. Because cool air weighs more than warm air, a high-pressure mass of air is made up of cool and heavy air. Conversely, a low-pressure mass of air is made up of warmer and lighter air. Differences in pressure cause air to move from high-pressure areas to low-pressure areas, resulting in wind. Wind speed can greatly affect the pollutant concentration in a local area: the higher the wind speed, the lower the pollutant concentration. Wind dilutes pollutants and rapidly disperses them throughout the immediate area.

Atmospheric stability refers to the vertical motion of the atmosphere. Unstable atmospheric conditions result in a vertical mixing. Typically, the air near the surface of the earth is warmer in the daytime because of the absorption of the sun's energy. The warmer and lighter air from the surface then rises and mixes with the cooler and heavier air in the upper atmosphere, causing unstable conditions in the atmosphere. This constant turnover also results in dispersal of polluted air. Stable atmospheric conditions usually occur when warm air is above cool air, and the mixing depth is significantly restricted. This condition is called a temperature inversion **(**see Figure 103). During a temperature inversion, air pollution released into the atmosphere's lowest layer is trapped there and can be removed only by strong horizontal winds. Because high pressure systems often combine temperature inversion conditions and low wind speeds, their long residency over an industrial area usually results in episodes of severe smog.

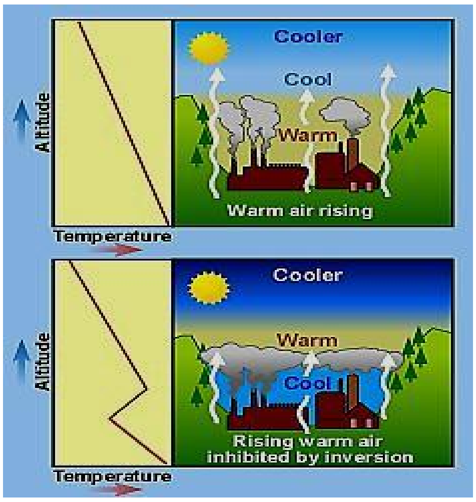


Figure 103 Temperature inversion- EPA-USA

Pollutants

As discussed in Chapter 2, the burning of fossil fuels in a boiler generates several types of pollutants that must be reduced and kept under control to avoid harmful effects to the environment and people living close to plants. Emissions from the stack are the most important and potentially dangerous because they leave the plant boundaries and affect the environment and human health (50).

The main polluting emissions that may result from combustion of fossil fuels in industrial boilers include, but are not limited to, the following:

- carbon dioxide
- nitrogen oxides
- sulphur oxides
- particulate matter
- volatile organic compounds
- carbon monoxide
- heavy metals
- dioxins and furans
- mercury

For industrial boilers, only CO_2, NO_x, SO_x, and particulate matter are normally regulated by local emission standards and controlled by public agencies. Emissions of dioxins, furans, and mercury are a new issue for regulatory bodies, and, as a consequence, are often neglected by boiler manufacturers. Regulations for these types of pollutants mostly focus on incinerators for urban and medical waste whose emissions are much higher than boilers. However, boiler operators and managers need to understand the characteristics of the different types of pollutants that can be generated from combustion of fuels in boilers, and their effects on the environment and human health. This knowledge will help ensure environmentally sound boiler operation and maintenance.

The next sections discuss the most important compounds emitted from boilers, highlighting their effects on the environment.

Carbon dioxide (CO_2)

Emissions of CO_2 from combustion of fossil fuels in industrial boilers cannot be avoided because CO_2 is always produced from combustion. CO_2 is a result of the combustion process, where carbon contained in the fuel reacts with air. For example, combustion of natural gas (methane, CH_4) gives:

$$CH_4 + 2\,O_2 \rightarrow CO_2 + 2\,H_2O + \text{energy}$$

CO_2 is formed during combustion in the combustion chamber, and emitted from the stack together with other combustion gases. CO_2 has harmful effects on the environment, causing the so-called "greenhouse effect": a process by which thermal radiation from a planetary surface is absorbed by atmospheric greenhouse gases, and re-radiated in all directions. Since part of this re-radiation is back towards the surface, energy is transferred to the surface and the lower atmosphere. As a result, the average surface temperature is higher than it would be if direct heating by solar radiation were the only warming mechanism. (51) The carbon cycle is shown in Figure 104 and the greenhouse effect in Figure 105.

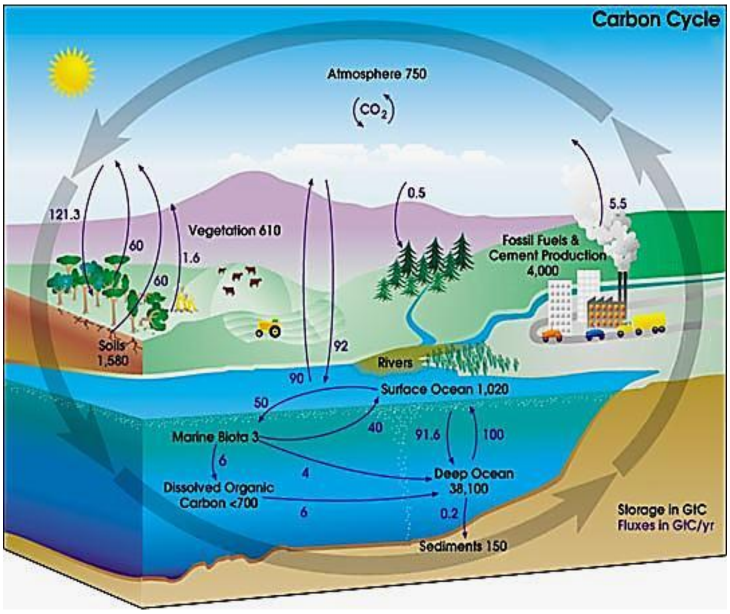


Figure 104 Carbon cycle (US EPA) (126)

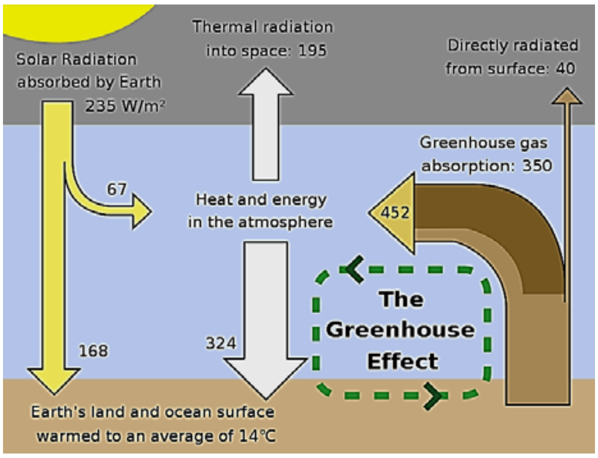


Figure 105 Greenhouse Effect (Wikipedia) (51)

A new technology, carbon capture and sequestration (CCS), is being applied to reduce the emissions from large boilers to the atmosphere. It consists of carbon capture and storage, where CO_2 is removed from flue gases (e.g., power stations) before being stored in underground reservoirs. Terrestrial and geological sequestration of CO_2emissions from a coal-fired plant is illustrated in Figure 106.

CO_2 emissions can be calculated as:

$$q_{CO2} = c_f / h_f \;\; C_{CO2}/C_m$$

where:

q_{CO2} = specific CO_2 emission (CO_2/kWh)

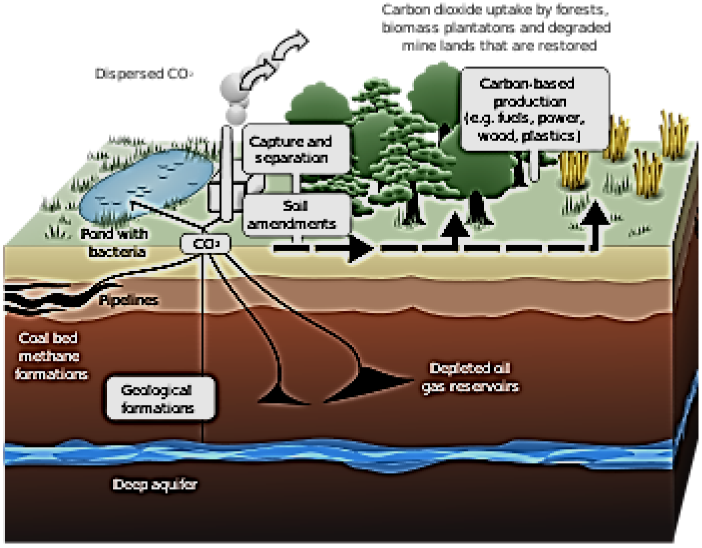


Figure 106 Schematic of carbon sequestration from a large coal power plant (Wikipedia) (232)

c_f = specific carbon content in the fuel (kg_C/kg_{fuel})

h_f = specific energy content (kWh/kg_{fuel})

C_m = specific mass carbon (kg/mol carbon)

C_{CO2} = specific mass carbon dioxide (kg/mol CO_2)

Emissions of CO_2 in combustion of some common fuels are shown in Table 17. (52) But it is important to note that heat loss (of 55% to 75%) in power generation is not reflected in these numbers.

Table 17 Carbon dioxide emissions

Fuel	**Specific Carbon Content** *(kg_C/kg_{fuel})*	**Specific Energy Content** *(kWh/kg_{fuel})*	**Specific CO_2 Emission** *(kg_{CO2}/kg_{fuel})*	**Specific CO_2Emission** *(kg_{CO2}/kWh)*
Coal (bituminous/anthracite)	**0.75**	**7.5**	**2.3**	**0.37**
Gasoline	**0.9**	**12.5**	**3.3**	**0.27**
Light Oil	**0.7**	**11.7**	**2.6**	**0.26**
Diesel	**0.86**	**11.8**	**3.2**	**0.24**
LPG - Liquefied Petroleum Gas	**0.82**	**12.3**	**3.0**	**0.24**
Natural Gas, Methane	**0.75**	**12**	**2.8**	**0.23**
Crude Oil				**0.26**
Kerosene				**0.26**
Wood *				**0.39**
Lignite				**0.36**
Bioenergy	**0**	**-**		**0**

* Commonly viewed as a biofuel

Nitrogen Oxides (NO_x)

NO_x gases, mainly nitric oxide and nitrogen oxide, are produced from the reaction of nitrogen and oxygen gases in the air during combustion, especially at high temperatures. NO_x gases are formed whenever combustion occurs. Typical reactions are:

$$N_2 + O_2 \rightarrow 2\ NO$$
$$N_2 + 2\ O_2 \rightarrow 2\ NO_2$$

NO_x is responsible for reactions resulting in the production of ozone and acid rain. Ozone and acid rain can damage monuments, affect the growth of forests and the biodiversity of lakes, reduce visibility, and cause health problems. A schematic of acid rain is shown in Figure 107, with the cumulative effects of NO_x, volatile organic compounds (VOC), and SO_x depicted.

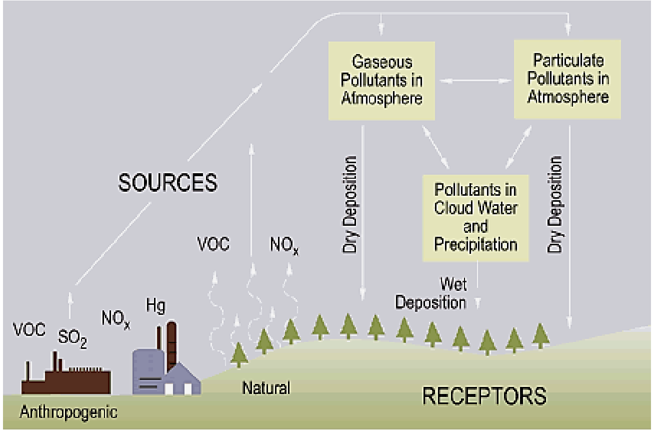


Figure 107 Acid rain (127)

NO_x emissions must be kept to a minimum in boilers. The contributions of different NO_x sources to total NO_x levels vary by country and metropolitan area. In general, in a metropolitan area, the contribution of mobile sources to the total NO_x level ranges from 60% to 80%. A significant portion of NO_x can also be attributed to residential, commercial, and industrial sources, which include industrial boilers. In industrial boilers, NO_x is primarily formed in two ways: thermal NO_x and fuel NO_x.

Thermal NO_x refers to NO_x formed through high temperature oxidation of nitrogen found in combustion air. Nitrogen (N_2) is inert gas at low temperatures, but, at high temperatures, it dissociates in atomic nitrogen (N), which is very reactive with oxygen and forms NO_x. It is produced by oils containing significant amounts of nitrogen and accounts for about 50% of NO_x production during combustion of fuels. The production of NOx is lower in natural gas combustion than that of oils. NO_x emissions from boilers are influenced by many factors, of which flame temperature and the amount of nitrogen in the fuel are the most significant. Other factors include excess air level and combustion air temperature. The more excess air that is inputted into the boiler, the more nitrogen there is, and the greater the amount of NO_x that is emitted.

Fuel NO_x refers to nitrogen present in the fuel matrix. Solid fuels, such as coal, may have nitrogen content ranging from 0.5% to 2%. Most NO_x control technologies for industrial boilers, in the range of 10 tons per hour (t/h) to 30 t/h steam production, reduce thermal NO_x and have little effect on fuel NO_x. Fuel NO_x is most economically reduced in industrial boilers by switching to cleaner fuels (fuels containing less nitrogen).

NO_x emissions

NO_x emissions from burning common fuels are indicated in Table 18. (53)

Table 18 NO_x emissions

Fuel type	Emissions of NO_x * (*g/kg fuel*)

Oil	3.0
Kerosene	3.0
Coal	4.5
Propane	2.3
Gasoline	27 ***
Hydrogen	0 **
Natural Gas	1.0
Wood, Birch 20% moisture content	0.7

***Catalytic systems common on most modern vehicles reduce NO_x.

*Note that emissions vary widely depending on application temperatures and air/fuel ratios. In general, higher combustion temperatures and higher air/fuel ratios increase NO_x emissions.
**Zero emission for hydrogen is a theoretical value. In practice, hydrogen burned in air produces more NO_x than natural gas due to the high flame speed.

Characteristics of nitrogen oxides that impact the effectiveness of specific air pollution control devices include the following: (54)

- NO_x can be reduced by injecting ammonia or urea at the proper temperature with or without a catalyst.
- NO_x can be chemically reduced by reburning using natural gas.

The quantity of NO_x formed during combustion depends on the quantity of nitrogen and oxygen available, temperature, level of mixing, and time for reaction. Management of these parameters can form the basis of control strategies involving process control and burner design (low NO_x burners and flue gas recirculation).

Sulphur Oxides (SO_x)

Sulphur dioxide (also sulfur dioxide, SO_2) is a poisonous gas released by volcanoes and in various industrial processes. Since coal and petroleum often contain sulphur compounds, their combustion generates sulphur dioxide unless the sulphur compounds are removed before burning the fuel. When flue gas has too much oxygen, the SO_2 further oxidizes into sulphur trioxide (SO_3). Further oxidation of SO_2, usually in the presence of a catalyst such as NO_2, forms sulphuric acid (H_2SO_4,) and thus acid rain. (55)

Airborne sulphuric acid has been found in fog, smog, acid rain, and snow. Sulphuric acid has also been found in lakes, rivers, and soil. The acid is extremely corrosive and harmful to the environment. See Figure 107 on acid rain). The typical reaction is:

$$2\ SO_2 + 2\ H_2O + O_2 \rightarrow 2\ H_2SO_4$$

The level of SO_x emitted depends on the sulphur content of the fuel. Most sulphur is emitted as SO_2 (90% to 95%). The SO_3 content is around 3%, with the remainder emitted as sulphate particulate. As most countries have imposed stringent environmental regulations on SO_2 emissions, SO_2 is now being removed from flue gases by a variety of methods, of which the most common are: (56)

- wet scrubbing using a slurry of alkaline sorbent, usually limestone or lime, or seawater;
- spray-dry scrubbing using similar sorbent slurries;
- set sulphuric acid process recovering sulphur in the form of commercial quality sulphuric acid;
- SNOX flue gas desulphurization, which removes sulphur dioxide, nitrogen oxides, and particulates from flue gases; and
- dry sorbent injection systems.

For a typical coal-fired power station, flue gas desulphurization (FGD) will remove 95% or more of the SO_2. For small industrial boilers, installation and operation of FGD devices can be challenging because of the high costs and complexity of operation. Cleaning fuel before using it can be a valid alternative.

- Characteristics of sulphur dioxide that impact the effectiveness of specific air pollution control devices include the following: (54)Sulphur can sometimes be removed from fuel prior to combustion. This may be a cost-effective way to reduce SO_2 formation.
- SO_2 is chemically reactive. Therefore, control techniques that reduce pollutant levels via chemical reaction (such as wet acid gas scrubbers and spray dryer absorbers) are appropriate. SO_2 can also be removed by fluidized limestone bed combustion.
- Formation of SO_2 occurs early in the primary flame and will occur even in fuel-rich flames. As a result, combustion control techniques are not applicable for reducing SO_2 emissions.
- Formation of SO_3 is found to occur only in fuel-rich mixtures and can be influenced by control of combustion conditions.

Particulate matter (PM)

Particulates – also known as particulate matter, suspended particulate matter (SPM), fine particles, and soot – are tiny subdivisions of solid matter suspended in a gas or liquid. Sources of particulate matter can be man-made or natural.

Particulate matter can be formed as the result of three processes:

- materials handling or processing (e.g., crushing or grinding ores, loading bulk materials, sanding of wood, abrasive cleaning sandblasting);
- emission of particles of noncombustible ash or incompletely burned materials during combustion; and
- gas conversion reactions or condensation in the atmosphere.

Some particulates occur naturally, originating from volcanoes, dust storms, forest and grassland fires, living vegetation, and sea spray. Human activities, such as the burning of fossil fuels in vehicles, power plants, and various industrial processes, also generate significant amounts of particulates. Fossil fuel combustion in industrial boilers generates particulate matter. In particular, coal and biomass generate high amounts of particulate matter depending on their composition (biomass) or ash content (coal). The ash content in some coals can reach up to 50%, resulting in high volumes of particulate matter.

The effects of inhaling particulate matter have been widely studied in humans and animals, and include asthma, lung cancer, cardiovascular issues, birth defects, and premature death. The size of the particle is a main determinant of where it will come to rest in the respiratory tract when inhaled. Because of their small size, particles on the order of ~10 micrometres or less (PM_{10}) can penetrate the deepest part of the lungs such as the bronchioles or alveoli. (57) The large number of deaths and other health problems associated with particulate pollution were first demonstrated in the early 1970s, and have been reproduced many times since. PM pollution is estimated to cause 22,000 to 52,000 deaths per year in the United States (from 2000), and 200,000 deaths per year in Europe. (57)

PM emissions from combustion sources consist of many different types of compounds, including nitrates, sulphates, carbons, oxides, and any uncombusted elements in the fuel. PM emissions are primarily dependent on the type and grade of fuel fired in the boiler. Generally, PM levels from natural gas are significantly lower than those of oils. Distillate oils result in much lower particulate emissions than residual oils. Coal and biomass combustion result in higher PM emissions, due to higher ash content/formation.

When burning heavy oils, particulate levels mainly depend on four fuel constituents: sulphur, ash, carbon residue, and asphaltenes. These constituents exist in fuel oils, particularly residual oils, and have a major effect on particulate emissions. Particulate emissions for an oil can be estimated if the fuel constituent levels are known.

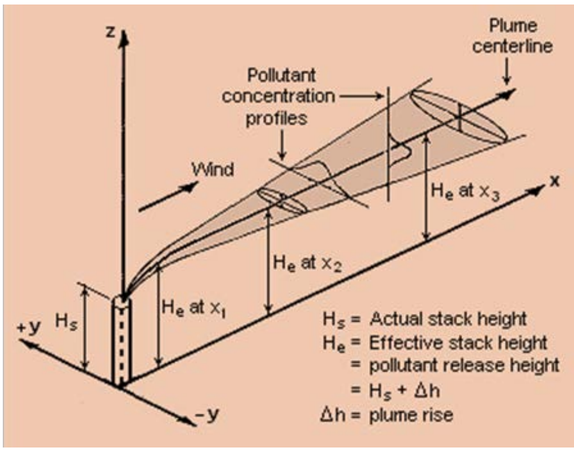


Figure 108 Pollutants plume diffusion from stack (Wikipedia) (128)

The dispersion of particulate matter in the environment mainly depends on particle dimensions (heavier particles deposit first on soil), stack height (high stacks help the diffusion of the PM in the environment), and environmental conditions (e.g., wind direction, atmospheric pressure, etc.). A model that can be used to calculate PM diffusion from a stack and deposition to soil is shown in Figure 108**Error! Reference source not found.**

PM characteristics that impact the effectiveness of specific air pollution control devices include the following: (54)

- particle size and size distribution
- particle shape
- particle density
- stickiness
- corrosivity
- condensation temperature
- reactivity, and
- toxicity.

Industrial boilers commonly use the following dust pollution control devices (see Chapter 4 for more detail): (58)

- *Mechanical collectors*: include dust cyclones and multicyclones.
- *Electrostatic precipitators*: particulate collection devices that remove particles from a flowing gas (such as air), using the force of an induced electrostatic charge. These highly efficient filtration devices minimally impede the flow of gases through the device, and can easily remove fine particulate matter such as dust and smoke from the air stream.

- *Baghouses*: consist of a blower, dust filter, filter-cleaning system, and dust receptacle or dust removal system (distinguished from air cleaners, which use disposable filters to remove the dust). They are designed to handle heavy dust loads.
- *Particulate scrubbers/wet scrubbers*: include a variety of devices that use pollutants from a furnace flue gas or from other gas streams. The polluted gas stream is brought into contact with the scrubbing liquid, by spraying it with the liquid, by forcing it through a pool of liquid, or by some other contact method, so as to remove the pollutants.

The most effective method of avoiding particulate emissions in industrial boilers is to use clean fuels. The emission levels of particulate matter can be lowered by switching from a residual to a distillate oil, or from a distillate oil to a natural gas. Additionally, through proper burner set-up, adjustment, and maintenance, particulate emissions can be minimized, but not to the extent accomplished by switching fuels.

Volatile organic compounds (VOCs)/hydrocarbons (hc)

VOCs contain combinations of carbon, hydrogen, and sometimes oxygen. VOCs vaporize easily once emitted into the air, and are of concern because of their role in ground level ozone formation. In relation to boiler performance, they are often referred to as hydrocarbons and generally are divided into two categories: methane and non-methane.

Formation of VOCs in industrial boilers primarily results from poor or incomplete combustion due to improper burner set-up and adjustment. To control VOC emissions from industrial boilers, no auxiliary equipment is needed; properly maintaining the burner/boiler package will keep VOC emissions at a minimum. An improperly maintained boiler/burner package can result in VOC levels over 100 times the normal levels. Proper maintenance includes maintaining:

- air/fuel ratio at the manufacturer's specified setting
- proper air and fuel pressures at the burner, and
- atomizing air pressure on oil burners at the correct levels.

Characteristics of VOCs that impact the effectiveness of specific air pollution control devices include the following: (54)

- Most VOCs are absorbable and may be collected by concentration on the surface of a liquid or solid.
- VOCs are combustible and may be oxidized by thermal or catalytic incineration.

A variety of techniques can be used to reduce VOC emissions including using material containing an inherently low quantity of VOCs and redesigning processes to reduce the quantities that are lost as fugitive emissions. When these techniques are not applicable or sufficient, the following add-on control systems can be used:

- thermal oxidation
- catalytic oxidation
- adsorption
- condensation and refrigeration
- biological oxidation

Carbon monoxide (CO)

During combustion of any carbonaceous fuel, CO can be formed as the result of two mechanisms:

- *Incomplete combustion*: The burning of carbonaceous fuels is a complex chemical process. CO formed as the first step in the combustion process is then converted to CO_2 by combustion with oxygen at temperatures greater than 627°C (1160 °F). When less than the stoichiometric amount of oxygen is present, CO is the final product of the reaction.
- *High-temperature dissociation of CO_2*: The bond energy for CO_2 is moderately low. At high temperatures, CO_2 easily dissociates to form CO and oxygen (O_2)

At elevated temperatures, an increase in oxygen concentration tends to decrease CO levels not only by allowing for complete combustion, but also because reaction rates increase with temperature, thus increasing the chance for collision between CO and O_2 molecules.

Characteristics of carbon monoxide that impact the effectiveness of specific air pollution control devices include the following:

- The quantity of oxygen available, temperature, level of mixing, and the time for reaction all affect the quantity of CO formed during combustion. Management of these parameters can form the basis of control strategies involving process control and burner design.
- CO is combustible and can be oxidized to CO_2.

Dioxins and furans

Dioxins and dioxin-like compounds (59) (60) are by-products of various industrial processes, and are commonly regarded as highly toxic environmental pollutants and persistent organic pollutants (POPs), including:

- *Polychlorinated dibenzo-p-dioxins (PCDDs)*: Technically, PCDDs (or simply, but inaccurately called, dioxins) are derivatives of dibenzo-*p*-dioxin. Of the 75 PCDDs, 7 of them are specifically toxic.
- *Polychlorinated dibenzofurans (PCDFs)*: Technically, PCDFs (or simply furans) are derivatives of dibenzofuran. Of the 135 congeners (derivatives differing only in the number and location of chlorine atoms), 10 of them have "dioxin-like" properties, although strictly speaking are not dioxins.
- *Polychlorinated biphenyls (PCBs)*: Although PCBs are also not dioxins, 12 of them have "dioxin-like" properties. Under certain conditions, PCBs may form more toxic dibenzofurans through partial oxidation.
- *Dioxin proper*: This simple compound is the basic chemical unit of the more complex dioxins. It is not persistent and has no PCCD- like toxicity.

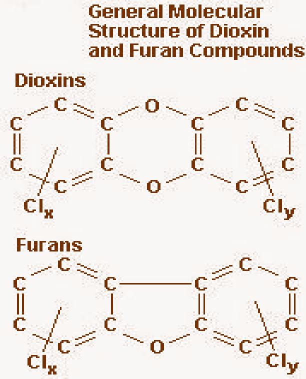


Figure 109 Molecular structure of dioxins and furans

Because dioxins refer to such a broad class of compounds that vary widely in toxicity, the concept of toxic equivalence (TEQ) has been developed to facilitate risk assessment and regulatory control. Toxic equivalence factors (TEFs) exist for 7 congeners of dioxins, 10 furans, and 12 PCBs. The reference congener is the most toxic dioxin, 2,3,7,8-tetrachlorodibenzo-*p*-dioxin (TCDD), which per definition has a TEF of 1.

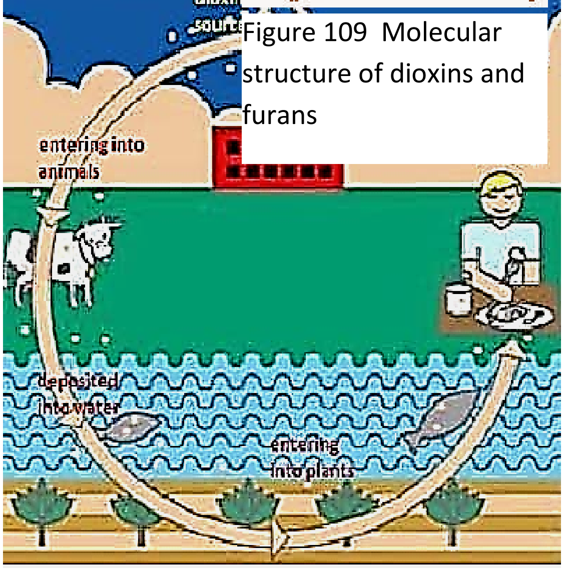


Figure 110 Exposure to dioxins (Greener Hill) (204)

In this discussion, the term “dioxins” refers to both PCDDs and PCDFs (dioxins and furans; see Figure 109 for their general molecular structure). The two words will be used without distinction. Dioxins are considered highly toxic to humans and animals. They can cause reproductive and developmental problems, damage the immune system, interfere with hormones, and also cause cancer. The dioxin chain of the transmission to humans is shown in Figure 110. The effects of dioxins on the environment are shown in Figure 112. (61)

Ingestion of dioxins has genetic and tumoural effects on the human body. The mechanism by which dioxins (TCDD) act on human cells is illustrated in Figure 111. Dioxins tend to accumulate in human fat tissue, and even very small quantities, less than 1 nanogram (1 nanogram = 10^{-9} grams), can be harmful.

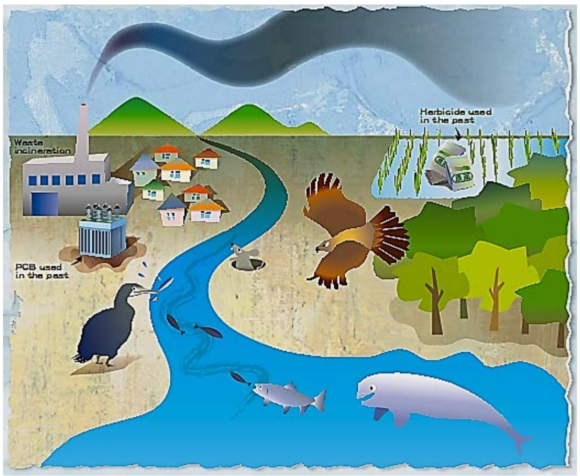


Figure 112 Effects of dioxins on the environment (Ministry of the environment-Japan) (61)

In 1995, the Governing Council of the United Nations Environment Programme (UNEP) called for global action to be taken on POPs, which were defined as "chemical substances that persist in the environment, bio-accumulate through the food web, and pose a risk of causing adverse effects to human health and the environment." (62) Negotiations were completed on 23 May 2001 in Stockholm, and the Stockholm Convention entered into force on 17 May 2004 with ratification by an initial 128 parties and 151 signatories. Co-signatories agreed to outlaw 9 of the 12 worst chemicals offenders, known as the “dirty dozen”, limit the use of DDT to malaria control, and curtail inadvertent production of dioxins and furans. UNIDO is the acting agency for the implementation of the Stockholm Convention. The list of dangerous chemical substances is periodically updated by the Conference of Parties to the Convention.

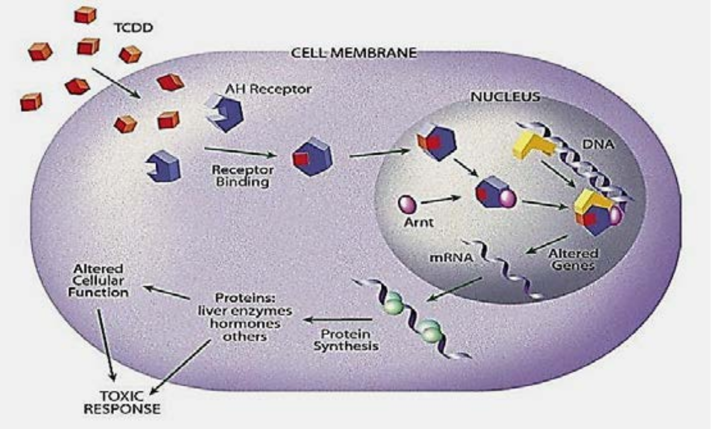


Figure 111 Biochemical mechanism of dioxin-initiated toxic response (129)

PCDD/PCDF formation in boilers

PCDDs and PCDFs are formed as unintentional by-products in certain manufacturing and disposal processes and activities, and may also be introduced into processes as contaminants in raw materials. PCDD/PCDF formation routes can be divided into two broad categories: formation in thermal processes, and formation in industrial-chemical processes. This section focuses on PCDD/PCDF formation in thermal processes.

PCDD/PCDF are formed in trace quantities in combustion processes when carbon, oxygen, hydrogen, and chlorine are present between 200 °C and 650 °C. Formation occurs via two primary mechanisms (see ANNEX 14 for more details):

- *De novo synthesis*: PCDDs and PCDFs are formed from non-extractable carbon structures that are basically dissimilar to the final product (PCDD/PCDF). Dioxins are first formed in the combustion process, and then destroyed by the high temperatures of combustion gases. When combustion gases cool down to between 300 °C and 400 °C after leaving the combustion chamber, dioxins are again (”de novo”) formed.

- *Precursor formation/reaction:* PCDDs and PCDFs are formed via aryl structures, derived from either incomplete aromatic oxidation or cyclization of hydrocarbon fragments.

Effects of fuel type on PCDD/PCDF emissions

Fossil fuels – coal, oil, and gas – are used, either individually or in combination with energy containing fuels from other processes, for steam generation in boilers. The type of fuel used depends on fuel availability and process economics.

Light fuel oil and natural gas

Always fired in specially designed burners, light fuel oil and natural gas are high-calorific, clean-burning fuels that leave little ash. Thus, in general, they are unlikely to generate large amounts of PCDD/PCDF. Increased gas use for power generation (as a replacement fuel for coal and oil) will result in reduction of PCDD/PCDF from the generation sector.

Heavy fuel oil

Heavy fuel oil is combusted for both steam generation and power generation purposes, and is usually burnt in specially designed burners incorporated in the boiler walls. Heavy fuel oil that is free from contaminants generally results in low levels of organic emissions.

Coal

Efficient coal combustion in large coal-fired power plants results in very low levels of emissions. Coal use in less-efficient sectors could be a significant source of local emissions. UNECE (1998) recommends the improvement of energy efficiency and energy conservation for utility and industrial boilers of over 50 MWe as an emissions reduction strategy due to lowered fuel requirements. However, it is acknowledged that while techniques for the reduction of particles, SO_x and NO_x, may result in the reduction or removal of PCDD/PCDF (and presumably PCB and HCB), the removal efficiencies will be variable. Chlorine removal from fossil fuel feeds is not currently seen as a cost-effective measure for PCDD/PCDF reduction.

Lignite

Lignite-fired power plants are typically operated close to mining regions. Due to the significantly lower calorific value of lignite compared to coal, it is mainly transported via belt conveyors from the storage area of the mine to the power station. Pulverized lignite-fired combustion and fluidized bed combustion are appropriate techniques for power generation from lignite. Due to lower combustion temperatures, pulverized lignite-fired boilers can achieve current NO_x emission standards by primary measures. Therefore, they typically do not use selective catalytic reduction.

PCDD/PCDF emissions from lignite-fired power plants have been reported in the range of 0.0002 ng I-TEQ/Nm^3 to 0.04 ng I-TEQ/Nm^3 (nanograms of toxic equivalent of PCCD/PCDF per normal cubic metre).

Dioxin releases from industrial boilers

Utility and industrial boilers are facilities designed to burn fuel to heat water or to produce steam for use in electricity generation or in industrial processes. The volumetric concentrations of chemicals listed in Annex C of the Stockholm Convention in the emissions from fossil fuel-fired boilers are generally very low. However, the total mass emissions from the boiler sector may be significant because of the scale of fossil fuel combustion, in terms of both tonnage and distribution, for electricity generation and heat or steam production (63).

Emission levels associated with best available techniques can be significantly lower than 0.1 ngTEQ/Nm^3 . TEQs are used to report the toxicity-weighted masses of mixtures of dioxins. This method of dioxin reporting is more meaningful than simply reporting the total number of grams of a mixture of various toxic compounds. The number of grams (TEQ) of a dioxin mixture is calculated by multiplying the mass of each compound in the mixture by its TEF, and then totalling them.

PCB and HCB emissions

Polychlorinated biphenyl (PCB) and hexachlorobenzene (HCB) emissions may arise from the use of recovered oils and other waste-derived fuels. Coal combustion is the third-largest global source of HCB emissions (Bailey, 2001).

PCBs have been used as coolants and lubricants in transformers, capacitors, and other electrical equipment because they do not burn easily and are good insulators. Among other things, products that may contain PCB include old fluorescent lighting fixtures and electrical devices containing PCB capacitors.

HCB has been widely used as a pesticide to protect the seeds of onions, and sorghum, wheat and other grains, against fungus. It has also been used to make fireworks, ammunition, and synthetic rubber, and as a solvent in the production of pesticide. Similar emission control strategies to those used for minimizing PCDD/PCDF emissions can be used for PCB and HCB emissions.

Mercury emissions

A heavy, silvery d-block chemical element, mercury (Hg, atomic number of 80) is the only metal that is liquid at standard conditions for temperature and pressure. It is also known as quicksilver. Due to the adverse health effects of mercury exposure, industrial and commercial uses are regulated in many countries. The World Health Organization (WHO), the U.S. Occupational & Safety Health Administration (OSHA), and the U.S. National Institute for Occupational Safety and Health (NIOSH) all treat mercury as an occupational hazard, and have established specific occupational exposure limits. Environmental releases and disposal of mercury are regulated in the United States primarily by the Environmental Protection Agency (EPA). (64) Case control studies have shown effects such as tremors, impaired cognitive skills, and sleep disturbance in workers with chronic exposure to mercury vapour even at low concentrations. (65)

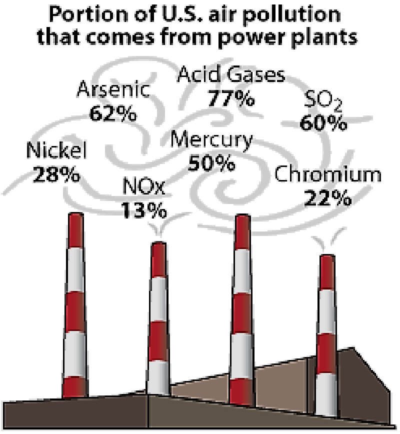


Figure 113 Emissions of pollutants from U.S. power plants (64)

Mercury is a trace component of all fossil fuels, including natural gas, gas condensates, crude oil, coal, tar sands, and other bitumen. The use of fossil hydrocarbons as fuels provides the main opportunity for releasing emissions of the mercury they contain into the atmospheric environment, but other avenues also exist in production, transportation, and processing systems. (66) Mercury can be emitted by boilers if the fuel used contains this compound. Studies carried out by the EPA have shown that power plants are currently the dominant emitters of mercury (50%), acid gases (over 75%), and many toxic metals (20% to 60 %) in the United States (see Figure 113). (64)

The amount of mercury emitted in the United States has been estimated by sector: (67)

Utility: 02. t/y (ton/year)Non-utility: 5.7 t/y to 7.7 t/y
Residentials: 2.8 t/y to 3.2 t/y

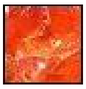
Widely available control technologies that can reduce mercury and other air toxics, include: (64)

- selective catalytic reduction with flue gas desulphurization)
- activated carbon injection, and
- activated carbon injection with fabric filter or electrostatic precipitators.

Other heavy metals releases

Other heavy metals that can be found in flue gas and ash after combustion are chromium, nickel, copper, zinc, arsenic, and selenium. Uranium and radioactive isotopes can also be found in the coal matrix, depending on the mine of origin. In very small amounts, many of these metals are necessary to support life; however, in larger amounts, they become toxic. They may build up in biological systems and become a significant health hazard. (68)

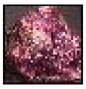
A brief description of technical and regulatory information for some toxic metals is provided below. (68)



Arsenic: Common sources of exposure to higher-than-average levels of arsenic include near or in hazardous waste sites and areas with high levels naturally occurring in soil, rocks, and water. Exposure to high levels of arsenic can cause death.

Beryllium: Elemental beryllium has a wide variety of applications. Occupational exposure most often occurs in mining, extraction, and in the processing of alloy metals containing beryllium. Beryllium can cause sensitization, and lung and skin disease in a significant percentage of exposed workers.

Cadmium: Cadmium is an extremely toxic metal commonly found in industrial workplaces, particularly where ore is being processed or smelted. Several deaths from acute exposure have occurred among welders who have unsuspectingly welded on cadmium-containing alloys or with silver solders.



Hexavalent-Chromium: Calcium chromate, chromium trioxide, lead chromate, strontium chromate, and zinc chromate are known human carcinogens. An increase in the incidence of lung cancer has been observed among workers in industries that produce chromate and manufacture pigments containing chromate.

Lead: Occupational exposure to lead is one of the most prevalent overexposures. Industries with high potential exposures include construction work, most smelter operations, radiator repair shops, and firing ranges.

In boilers, heavy metals are present both in bottom and fly ash, and in the flue gas at the stack exit. The control technologies for stack emissions are the same as for mercury:

- selective catalytic reduction with flue gas desulphurization
- activated carbon injection
- activated carbon injection with fabric filter or electrostatic precipitators

Ozone (O_3)

Ozone, a colourless gas, is the major component of smog. Except for very low levels of emissions from a limited number of processes, ozone is not emitted directly into the air. Instead, it is formed in the atmosphere in the presence of sunlight through complex chemical reactions between precursor emissions of VOC and NO_x. These reactions are accelerated by sunlight and increased temperatures and, therefore, peak ozone levels typically occur during the warmer times of the year. Ozone is not emitted from boilers.

CHAPTER 4 – AIR POLLUTION CONTROL DEVICES

SUMMARY

This Chapter deals with air pollution control technologies available on the market to reduce the amount of pollutants released from boilers. Several of the devices illustrated are mostly implemented in large utility boilers, and are not yet suitable for small boilers due to system complexity and capital and operating costs. They are introduced and discussed here as part of a general framework encompassing all available types of pollution abatement devices, their performance and costs, and how the emission of pollutants can be kept under control. Rising public concern about the environment and effects of pollutants on human health will lead to more and more stringent emission limits in the coming years. This will result in a greater need for extended use of pollution control devices in the heat sector, where small, simple boilers currently prevail over larger and more sophisticated ones. Therefore, boiler operators and managers need to be informed about the available technologies to reduce the pollutants emitted (as described in Chapter 3).

The Chapter begins by reviewing the performance, and advantages and disadvantages of various pollution control devices, with special emphasis placed on the most common pollutants: particulate matter, SO_x, and NO_x. The effects of each pollution control system on the efficiency, maintenance, and capital and operating costs of boilers are also discussed. Measurement and analysis of the various pollutants is briefly introduced, along with emission limits. Since every country sets up and implements its own regulations and limits, only the most advanced regulations are mentioned. A detailed description of all administrative mechanisms is out of scope for the Guide.

Since combustion of fossil fuels and biomass in industrial boilers produces several polluting compounds (as described in Chapter 3), pollution control techniques are used, either within the boiler combustion chamber or between the boiler and stack, to reduce the amount of dangerous material and compounds before their release to the environment.

Industrial boiler owners and operators use two approaches, often simultaneously, to reduce pollution and improve boiler performance:

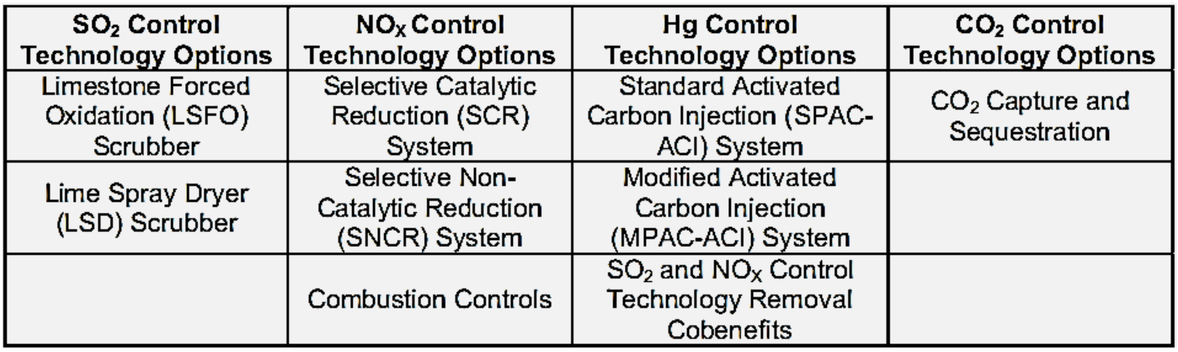
- clean fuels and hi-tech boilers
- air pollution control devices

Although many types of pollution abatement technologies are available for boilers, some are used in large boilers only — particularly for sulphur oxides (SO_x), nitrogen oxides (NO_x), and mercury (Hg) control, and carbon dioxide (CO_2) capture — because of their cost and complexity. Pollutant abatement devices can be broadly classified as devices for gaseous pollutants, and for particulate matter control.

Table 19 summarizes the most adopted emission control techniques for gaseous compounds. (69)

As already mentioned, most of these technologies are currently only used in large utility boilers. Since implementation for industrial boilers will occur over the next decade due to the stricter limits on pollutant release that governments are enforcing, these technologies are briefly discussed in this Chapter.

Table 19 Most adopted emission control techniques



SO_2 Control Technology Options	NO_X Control Technology Options	Hg Control Technology Options	CO_2 Control Technology Options
Limestone Forced Oxidation (LSFO) Scrubber	Selective Catalytic Reduction (SCR) System	Standard Activated Carbon Injection (SPAC-ACI) System	CO_2 Capture and Sequestration
Lime Spray Dryer (LSD) Scrubber	Selective Non-Catalytic Reduction (SNCR) System	Modified Activated Carbon Injection (MPAC-ACI) System	
	Combustion Controls	SO_2 and NO_X Control Technology Removal Cobenefits	

Particulate control devices, which reduce the amount of ash and unburned particles to the stack, are commonly used in small industrial boilers and large utility boilers. The most adopted particulate control devices, which will be discussed in depth, include:

- Dry scrubbers
- electrostatic precipitators, and)
- fabric filters (baghouse).

State-of-the-art CO_2 capture and storage technology is not discussed here because it is specifically designed for large power plants and is very challenging. Only a few pilot plants are currently in operation around the world. Although application of mercury abatement technology is at an early stage, it is briefly discussed because it is already available for industrial boilers, and some countries are currently enforcing regulations for mercury control.

Control efficiency

Control efficiency (CE) is a measure of emission reduction efficiency and can be used to measure the performance of various air pollution control devices (APCD). It is a percentage value representing the amount of emissions that are controlled by a control device, process change, or reformulation. (54) Control efficiency is calculated as:

$$\textit{Control Efficiency} = \frac{\textit{Uncontrolled Emission Rate} - \textit{Controlled Emission Rate}}{\textit{Uncontrolled Emission Rate}} \times 100$$

For example, in fabric filters, which are used to reduce particulate matter (PM) emissions, if the actual (measured) concentration of PM in the inlet stream to the fabric filter and the expected concentration of PM in the outlet stream are known, the CE equation may be used to back calculate the control efficiency. Generally, fabric filters are designed to reduce overall PM emissions to below an expected concentration when the inlet concentrations are within a specified range.

The design specifications for a fabric filter may state that the expected outlet emissions are 0.01 grains (1 gram = 15.43 grains) of PM per dry standard cubic foot of stack gas (0.01 gr/dscf) when the inlet emissions are between 5 gr/dscf and 20 gr/dscf. This means that the outlet emission rate remains relatively "constant" even though the inlet concentration varies; and, as the inlet emissions decrease, the overall control efficiency is decreased. Therefore, controlled emissions are calculated using the dust loading in the flue gas and the exhaust flow rate.

Example (54)

This example shows how to estimate PM emissions from a fabric filter when the exit gas flow rate and dust concentration are known.

$$E_{PM} = Q \times C$$

where:

Q = exit gas flow rate (dscf/min) = 50,000 dscf/min (dry standard cubic foot = 0.028 m^3)

C = PM concentration (gr/dscf) at exit = 0,01 gr/dscf

$$\begin{aligned} E_{PM} &= Q \times C \\ &= 50{,}000\ (\text{dscf/min}) \times 0.01\ (\text{gr/dscf}) \\ &= 500\ (\text{gr/min}) = 7865\ \text{grams/min} \end{aligned}$$

Note that in this example inlet concentration and control efficiency data are not needed.

The manufacturer provides the nominal efficiency of an APCD, but some facilities do not always operate devices at their maximum level of efficiency. Although APCDs should be designed to accommodate reasonable process variation and some deterioration, some types of control devices vary in efficiency based on process equipment operating rates, fuel quality, and age. It is therefore important to know how effectively an APCD works.

Questions that should be asked, or information that should be obtained, include the following: (54)

- How old is the control device? Some devices are affected by age and their control efficiencies deteriorate over time if not properly maintained. In the case of an electrostatic precipitator, for example, the collection efficiency declines due to corrosion, warpage, and the accumulation of non-removable dust on surfaces.
- Is the control device properly maintained? Most devices require routine maintenance and some devices may require intensive maintenance. For example, the bags (filters) in a fabric filter should be cleaned when they are blinded by a permanently entrained cake of particulate matter. Bags can also develop rips if not replaced frequently enough. The fields in an electrostatic precipitator must be maintained to operate at a specific voltage. If a device is not properly maintained, the control efficiency will be reduced.
- Is the device operated under conditions necessary for maximum efficiency and are these conditions monitored? A fabric filter may be designed to operate at a specific pressure drop to attain maximum efficiency and the pressure should be monitored. A thermal incinerator must operate at a particular temperature and residence time, and these parameters should also be monitored. Wet scrubbers must have the scrubbing liquor available at all times in proper amounts. When a device is not operated properly, the control efficiency will be reduced.
- What is the throughput to the control device relative to its design capacity? If a device is operated above its design capacity, the control efficiency may be reduced. For example, if too much gas is forced through a wet scrubber, channelling of gas can result and the control efficiency is reduced.

Particulate matter control

Four categories of particulate control techniques for industrial boilers can be identified:

- dry scrubbers (cyclones and multicyclones)
- wet scrubbers
- electrostatic precipitators
- fabric filters

Dry scrubbers

Cyclones

Cyclonic separation is a method of removing particulates from an air, gas, or liquid stream, without the use of filters, through vortex separation. Rotational effects and gravity are used to separate mixtures of solids and fluids. This method can also be used to separate fine droplets of liquid from a gaseous stream.

A high-speed rotating (air) flow is established within a cylindrical or conical container called a cyclone (see Figure 114). Air flows in a helical pattern, beginning at the top (wide end) of the cyclone and ending at the bottom (narrow) end before exiting the cyclone in a straight stream through the centre of the cyclone and out the top. Larger (denser) particles in the rotating stream have too much inertia to follow the tight curve of the stream; they strike the outside wall, and then fall to the bottom of the cyclone where they can be removed. In a conical system, as the rotating flow moves towards the narrow end of the cyclone, the rotational radius of the stream is reduced, thus separating smaller and smaller particles. (70)

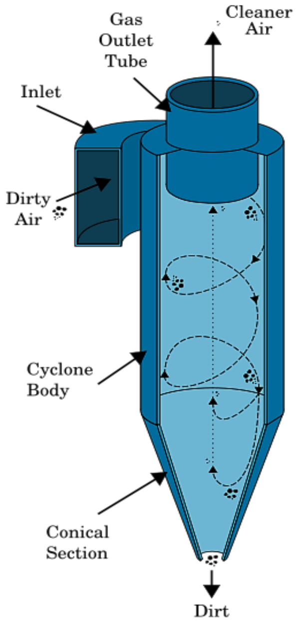


Figure 114 Cyclone separator(Wikipedia) (70)

Key advantages of cyclones include:

- low investment cost
- low operating cost, and
- reliability.

Key disadvantages of cyclones include:

- low collection efficiency particularly with small particles, and
- clogging problems.

Multicyclones

Multicyclones (71) (72) are dust collectors made up of various cyclones in parallel. They are designed to handle heavy flows without the cyclone units assuming prohibitive dimensions. Multicyclones consist of a certain number (sometimes high) of small diameter collection units, arranged in parallel according to widely differing technical and design solutions (Figure 115).

The use of small diameter units allows for high settling efficiencies because the efficiency increases as the diameter of the unit decreases, when all other conditions remain the same.

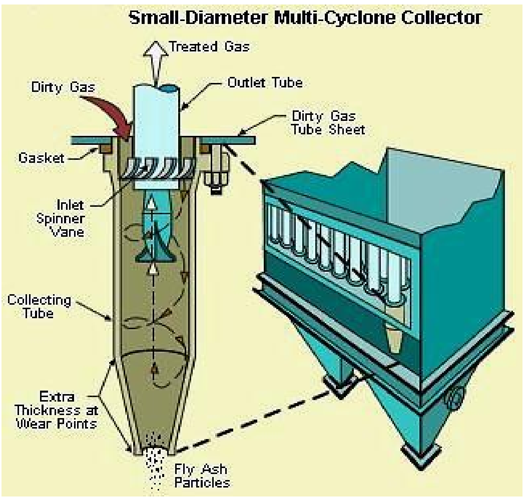


Figure 115 Multicyclone (US EPA) (72)

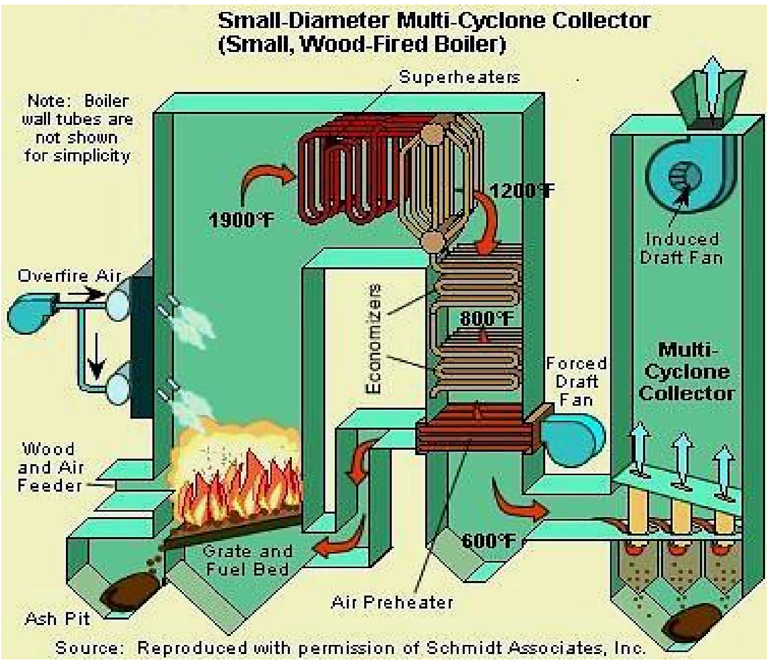
The limitations in this case are that dust concentrations in the air are too high, which could create problems of plugging; and higher installations costs as compared with normal cyclones owing to manufacturing difficulties. This discourages its use as a pre-cleaner but only as single dust collectors. In this case, the field of application is considerably restricted, and is limited almost exclusively to problems collecting non-abrasive particles present in not too high concentration, with specific gravity over 300 kg/m3 and not too fine particles (over 10 micron).

Key advantages include:

- low pressure drop (approximately 80 millimetres (mm) H_2O)
- no maintenance costs
- very low operating costs, and
- average cost of the equipment.

There are also some disadvantages:

- Plugging of the dust outlet tube and clogging from particles that accumulate on the fan blades can affect performance.
- Abrasion of large particles can lead to leaks or rough areas on the surface of the cylinder that can cause local turbulence, reducing the effectiveness of the vortex in removing particles.
- The efficiency can be decreased by hopper recirculation, which occurs when uneven pressure drops across the system, resulting in reversed flow of the exhaust stream in some areas of the multicyclone.



Source: Reproduced with permission of Schmidt Associates, Inc.

Figure 116 Multicyclone application (US EPA) (72)

A typical application of a conventional multicyclone collector is shown in Figure 116. In this example, the multicyclone is located after a small, wood-fired boiler and is used as a pre-collector for the fabric filter. The waste from a mechanical dust collector is dry particulate matter. To decrease the problems associated with handling fine dust, the collected particulate matter can be wetted in a pug mill into a clay-like consistency, or pelletized before it is recycled or landfilled. (54)

Wet scrubbers

Wet scrubbers (72) control PM and acid gases, with some control of organics. They are applied as a post-process technique to: (54)

- scrub particulates from incinerator exhausts
- control particulate and gaseous emissions simultaneously
- control acid gases
- control sticky emissions that would otherwise plug filter-type collectors

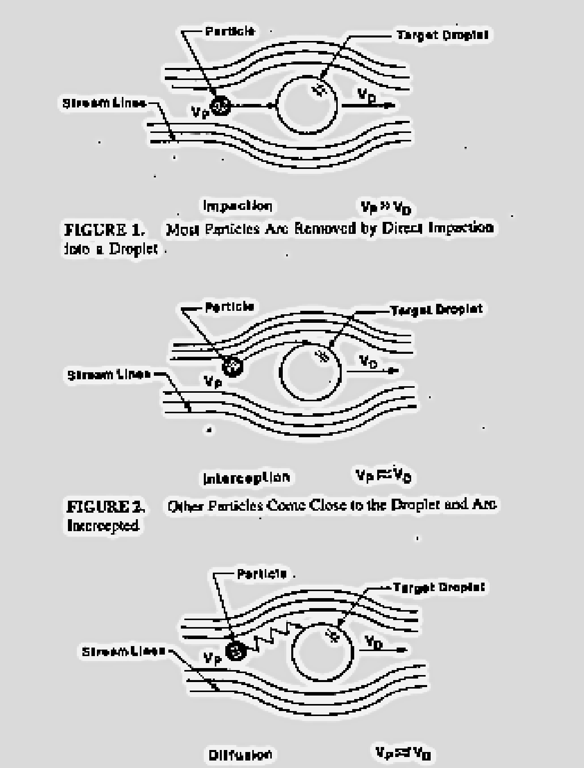


Figure 117 Schematic of wet scrubber removal of Particles (US EPA from AWMA 1992) (54)

- recover soluble dusts and powders, and
- control metallic powders such as aluminium dust that tend to explode if handled dry.

How wet scrubbers work

Particles are captured by liquid droplets through three mechanisms (54) (see Figure 117):

- *Impaction:* of the particle directly into a target droplet
- *Interception:* of the particle by the target droplet as the particle comes near the droplet
- *Diffusion:* of the particle through the gas surrounding the target droplet until the particle is close enough to be captured

Wet scrubbers remove particles from gas by capturing the particles in liquid droplets (usually water), and separating the droplets from the gas stream. They are configured to create a closely packed dispersion of fine droplets to act as targets for particle capture. The goal is to cause the tiny pollutant particle to be lodged inside the collecting droplet, and then to remove the larger droplet from the gas stream. In general, the smaller the target droplet is, the smaller the size of particulate that can be captured; and the more densely the droplets are packed, the greater the probability of capture.

Categories of wet scrubbers

Major categories (not exhaustive or listed in order of efficiency) of wet scrubbers include:

- Venturi scrubbers
- impingement and sieve plates
- spray towers
- Cyclonic spray
- mechanically aided
- condensation growth
- packed beds
- ejector
- mobile bed
- catenary grid
- froth tower
- oriented fibre pad, and
- wetted mist eliminators.

This section discusses Venturi scrubbers, impingement plate scrubbers, spray towers and cyclonic spray scrubbers.

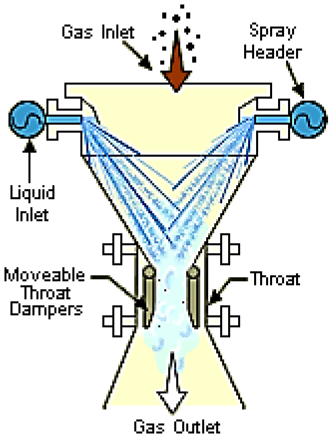


Figure 120 Adjustable throat Venturi scrubber (US EPA) (72)

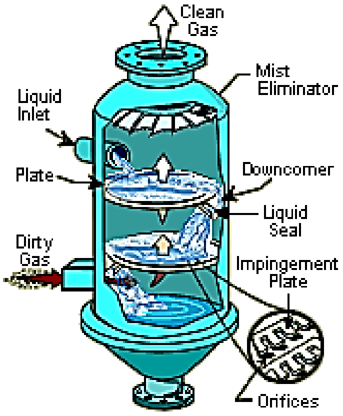


Figure 120 Impingement plate Scrubber (US EPA) (72)

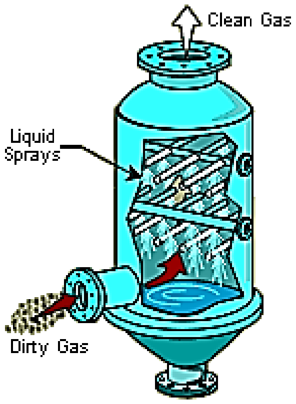


Figure 120 Spray tower Scrubber (US EPA) (72)

Venturi scrubbers

Particulate matter, which accelerates as it enters the Venturi throat, is driven into the slow moving, large water droplets that are introduced near the high velocity point at the inlet of the throat. The adjustable dampers are used to adjust the open cross-sectional area and thereby affect the speed of the particles entrained in the inlet gas stream. A typical Venturi throat is shown in Figure 120.

Impingement plate scrubbers

These scrubbers usually have one to three horizontal plates, each of which has a large number of small holes. The gas stream accelerating through the holes atomizes some water droplets in the water layer above the plate. Particles impact on these water droplets. A typical impingement plate scrubber is shown in Figure 120.

Spray tower scrubbers

This is the simplest type of particulate wet scrubber in commercial service. Sets of spray nozzles located near the top of the scrubber vessel generate water droplets that impact with particles in the gas stream as the gas stream moves upwards. A typical spray tower scrubber is shown in Figure 121.

Cyclonic spray scrubbers (66)

Cyclonic spray scrubbers use features of both the dry cyclone and the spray chamber to remove pollutants from gas streams. Generally, the inlet gas enters the chamber tangentially, swirls through the chamber in a corkscrew motion, and exits. At the same time, liquid is sprayed inside the chamber. As the gas swirls around the chamber, pollutants are removed when they impact on liquid droplets, are thrown to the walls, and washed back down and out.

Cyclonic scrubbers are generally low- to medium-energy devices, with pressure drops of 4 cm to 25 cm (1.5 in. to 10 in.) of water. Commercially available designs include the irrigated cyclone scrubber and the cyclonic spray scrubber (see Figure 121).

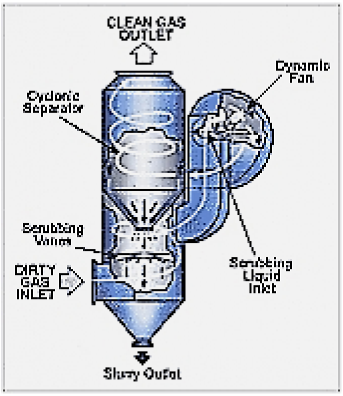


Figure 121 Cyclonic scrubber (Courtesy of ASPA Engineering) (195)

In the irrigated cyclone the inlet gas enters near the top of the scrubber into the water sprays. The gas is forced to swirl downward, then change directions, and return upward in a tighter spiral. The liquid droplets produced capture the pollutants, are eventually thrown to the side walls, and carried out of the collector. The "cleaned" gas leaves through the top of the chamber.

The cyclonic spray scrubber forces the inlet gas up through the chamber from a bottom tangential entry. Liquid sprayed from nozzles on a centre post (manifold) is directed toward the chamber walls and through the swirling gas. As in the irrigated cyclone, liquid captures the pollutant, is forced to the walls, and washes out. The "cleaned" gas continues upward, exiting through the straightening vanes at the top of the chamber).

Cyclonic spray scrubbers are more efficient than spray towers, but not as efficient as Venturi scrubbers, in removing particulates from the inlet gas stream. Particulates larger than 5 micrometres are generally collected by impaction with 90% efficiency.

Collection efficiency of wet scrubbers

All of the particulate wet scrubbers in commercial use depend on inertial impaction. However, the velocities of the particle-laden gas stream and the liquid targets vary substantially. Accordingly, there are substantial differences in the ability of particulate wet scrubbers to collect particles of less than approximately 5 micrometres. This is illustrated in Figure 122. If a significant portion of the particulate matter mass is composed of particles of less than 5 micrometres, care is needed to select the type of scrubber that is effective in this size range.

It should be noted that some types of wet scrubbers have limited capability to remove particles in less than 0.3-micrometres. Methods of particle collection for this very small size range take advantage of these particles' tendencies to diffuse slowly due to their interactions with gas molecules (Brownian diffusion). In other words, these particles are so small that their movement is influenced by collisions with individual molecules in the gas stream.

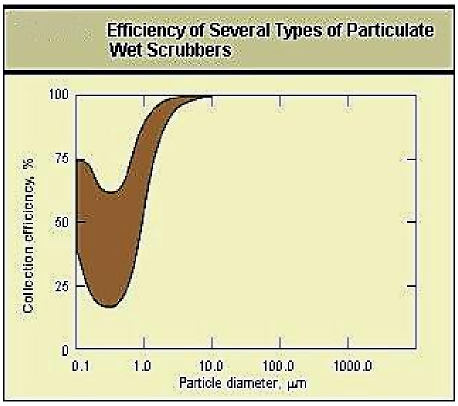


Figure 122 Wet scrubber particle collection efficiency (72)

Advantages and disadvantages of wet scrubbers (72)

Many types of particulate wet scrubbers can provide high efficiency control of particulate matter. One of their main advantages is the ability to simultaneously collect particulate matter and gaseous pollutants. Also, wet scrubbers can often be used on sources that have potentially explosive gases or particulate matter. They are compact and can often be retrofitted into existing plants with very limited space.

One of their main disadvantages is that they require make-up water to replace the water vaporized into the gas stream and lost to purge liquid and sludge removed from the scrubber system. Wet scrubbers generate a waste slurry that can present a wastewater treatment problem. The chemical and physical routine of the particulate matter being collected determines the ultimate disposal method of the slurry. If a scrubber is used to remove organic vapours, it is important that the vapours are released during the wastewater treatment process.

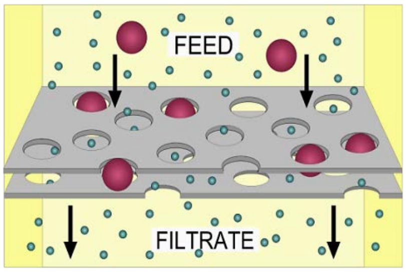


Figure 123 Mechanism Filtration Wikipedia) (42)

Other issues of concern include the following:

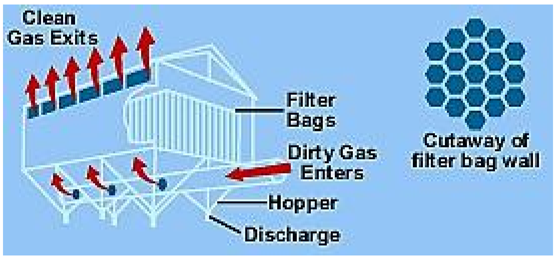
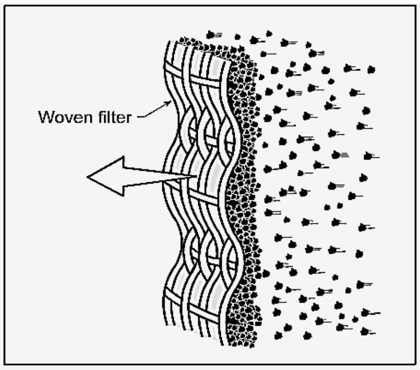


Figure 124 Fabric filter components (US-EPA) (94)

- Droplet entrainment in the flue gas can increase the opacity of the plume.
- Wet systems cause more corrosion problems than dry systems.
- Solids can build up at the wet-dry interface.

Fabric filters

Fabric filters, also referred to as baghouses, are used to control emissions of particulate matter and are capable of achieving the highest particulate removal efficiencies of all particulate control devices. Unlike other control devices, their efficiency does not decline when smaller particles are involved. However, fabric filters are generally designed to reduce overall PM emissions to below an expected concentration when the inlet concentrations are within a specified range. The expected outlet concentration remains relatively "constant" even though the inlet concentration varies within the specified range. (54)



Fig

Fabric filters are used to de-dust gaseous streams. In particular, in the power and heat sectors, they capture the particulate matter (ash and incombustibles) from the combustion flue gas before its exit to the stack, thus avoiding pollution to the environment.

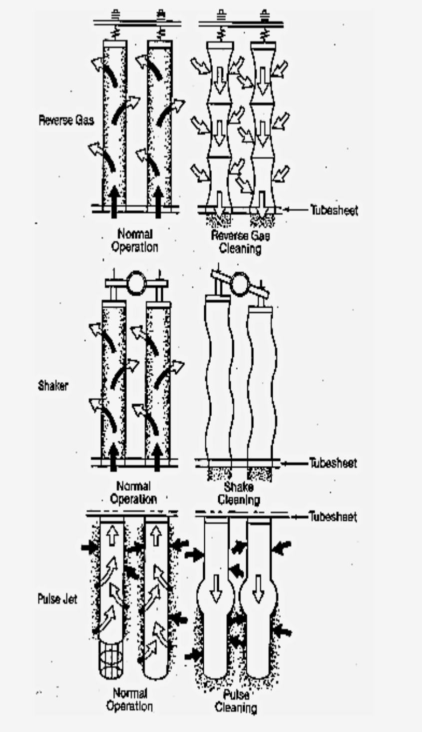


Figure 126 Fabric filter types (EPA From Babcock & Wilcox 1992) (54)

Fabric filters are one of the oldest means of controlling aerosol particles. Since 1950 they have been used widely as air cleaning devices in asphalt plants, cement manufacturing, carbon black plants, glass furnaces and a variety of ferrous and nonferrous foundry operations. (73) Electrostatic precipitators were by far the preferred control devices for particulates in the electric power industry. More and more stringent emissions regulations and limits, however, have increased the demand for fabric filter devices, which can guarantee more efficient capture of particulate matter.

How fabric filters work

A fabric filter system consists of several filtering elements ("bags"), a bag cleaning system, and dust hoppers contained in a main shell structure. Fabric filters remove dust from a gas stream by passing the stream through a porous fabric. The fabric does some of the filtering, but plays a more important role by acting as a support medium for the layer of dust that quickly accumulates on it. The dust layer ("cake") is responsible for the highly efficient filtering of small particles, but also increases the resistance to gas flow. The filter is normally installed before the induced draught fan, after the air heater, to maintain the gas duct at negative pressure.

Bags are made of special treated fabric, which lets the flue gas pass through but traps the particulates. The formation of a "cake" that sticks to the fabric amplifies its filtering performance (also referred to as "sieving"). (74)

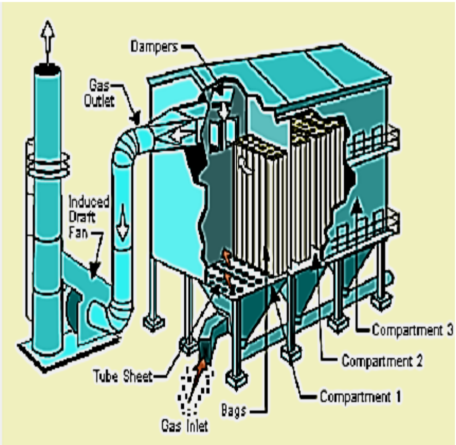


Figure 127 Reverse air fabric filter (US EPA) (72)

The main particle collection mechanisms of fabric filters are as follows: (54)

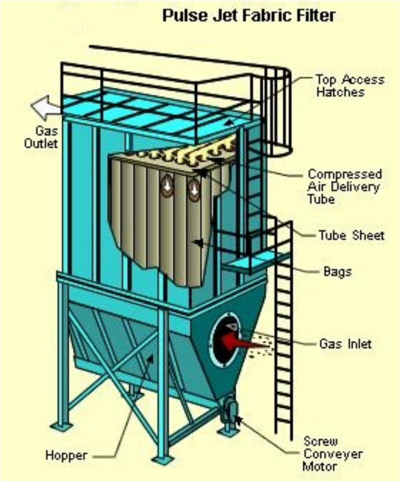


Figure 128 Pulse jet fabric filter (72)

- *Inertial impaction:* occurs as the flue gas stream flows through the fabric. As the gas stream approaches the fabric fibres, it accelerates and changes direction to pass around the fibre. Inertia maintains the forward motion of the particles, and they impact onto the surface of the fabric filter.
- *Collection by diffusion:* occurs as a result of both fluid motion and the Brownian (random) motion of particles. Diffusional effects are most significant for particles less than 1 micron in diameter.
- *Interception or sieving:* occurs when a particle comes within one particle radius of an obstacle.

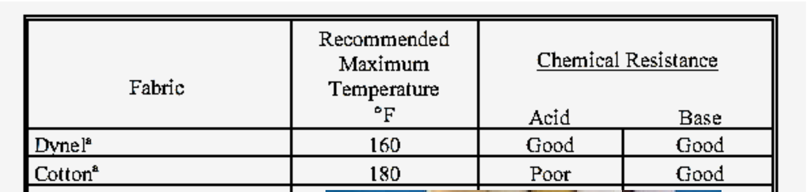
Bag filters can be made of woven or nonwoven materials (e.g., polyester, polypropylene, etc.). Fabric selection (considering both material and type of weave) is important because the fabric must be matched properly with both the gas stream characteristics and the type of particulate. Commonly used fabrics have very different abilities with respect to operating temperatures and chemical content of the gas stream. Some types of industrial fabrics used in fabric filters are shown in Figure 130. A bag life of three to five years is common.

Different types of fabric filters are available on the market according to fabric type and technology used to clean the bags. Some common fabric filter configurations are shown in Figure 126 Figure 127, Figure 127 and Figure 128:

- *Reverse air baghouses*: operate by directing the dirty flue gas inside the bags so that dust is collected on the bags' inside surfaces. The bags are periodically cleaned by reversing the flow of air. This causes the dust cake to fall from the bags to a hopper below. In some configurations, the bags are shaken during the reversed air flow.
- *Shaker baghouses:* are similar to reverse air units in that cleaning occurs on the inside surface of the bags. Unlike reverse air units, a mechanical motion is used to shake the bags and dislodge the accumulated dust cake.
- *Pulse jet baghouses:* a high-pressure air jet (6-7 bar) is periodically injected into the internal part of the bag. The bag blows and the particulate deposited on the fabric wall falls down to the ash hopper. The bags represent more than 20% of the cost of the device (Figure 128

Removal of the dust from the fabric is a crucial factor in the performance of a fabric filter. If the dust cake is not adequately removed, the pressure drop across the system increases to an excessive level. If too much cake is removed, excessive dust leakage occurs while the new cake develops.

Frequent inspection and maintenance of the bags and other components ensure control of emissions from fabric filters. Holes in bags cause jets of dirty gas that



Fabric	Recommended Maximum Temperature °F	Chemical Resistance Acid	Chemical Resistance Base
Dynel[a]	160	Good	Good
Cotton[a]	180	Poor	Good
Nylon[a]			l
Polypropylene[a]			nt
Dacron[a]			
Nomex®a			l
Teflon®a			nt
Fiberglass			l
P84 (polyimide)[b]			l
Ryton (polypropylene sulfide[b]			l
Expanded PTFE[c]			nt

[a] Cooper, C.D., and F.C. Alley. 1994.

Figure 129 Fabrics used for

Figure 130 Bag filters

rapidly destroy surrounding bags by abrasion. Dust sensors at the compartment outlet may sense this problem during operation or during bag cleaning. Dust falls on top of the tube sheet when a bag leaks during operation. In a pulse jet collector, this may be noticed as a sudden increase on an opacity meter beyond the fabric filter outlet when the cleaning air pulse suspends dust already on the tube sheet floor. The compartment with filter damage can be determined in this case. If bags are leaking, prompt inspection of the bags and replacement of the damaged filters are required. A delay causes excess emissions and additional bags to fail.

Advantages and disadvantages of fabric filters

Advantages of fabric filters include:

- low investment costs
- modularity
- small dimensions
- high efficiency with any type of particulate, and
- efficiency independent from sulphur content in flue gases.

Disadvantages of fabric filters include:

- high maintenance costs
- problems with moisture in flue gas
- deterioration at high temperatures, and
- high-pressure losses, which require more induced draught fan power.

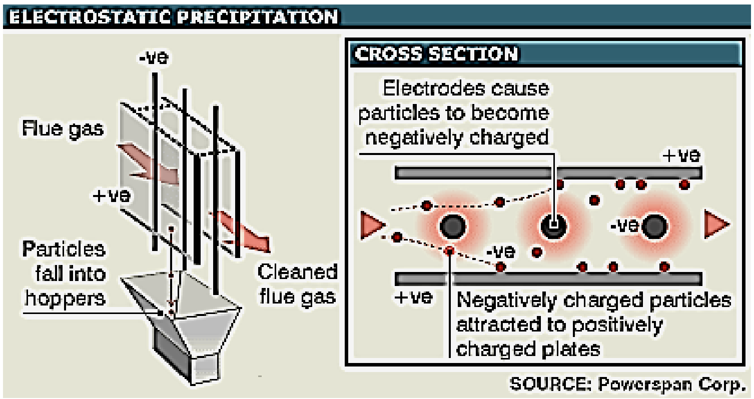
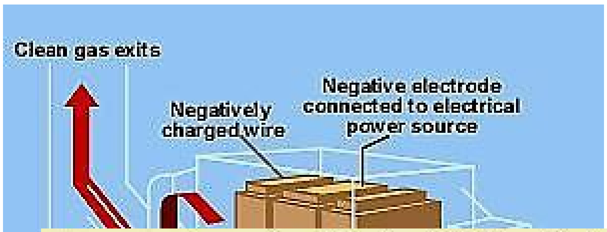


Figure 131 ESP-Working principle (BBC News) (194)

Electrostatic precipitators

An electrostatic precipitator (ESP), or electrostatic air cleaner, is a particulate collection device that removes particles from a flowing gas (such as air) using the force of an induced electrostatic charge. ESPs are highly efficient filtration devices that minimally impede the flow of gases through the device, and can easily remove fine particulate matter such as dust and smoke from the air stream. (58) In contrast to wet scrubbers, which apply energy directly to the flowing fluid medium, an ESP applies energy only to the particulate matter being collected; therefore, it is very efficient in its consumption of energy (in the form of electricity).



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How ESPs work

The working principle of an ESP is shown in Figure 131. The electric field uses high voltage (10,000 V to 20,000 V). In this condition, couples of ion-electrons are formed within the flue gas. Ions are attracted by the negative electrode; at the same time, electrons are attracted by the positive electrode (captation electrode), but are also captured by electro-negative molecules such as SO_x and oxygen. These negative ions tend to be adsorbed by particulate matter. This is called the “corona effect”. Particulate matter, which normally has a neutral charge and is not influenced by electric fields, assumes a negative electric charge and is attracted by the

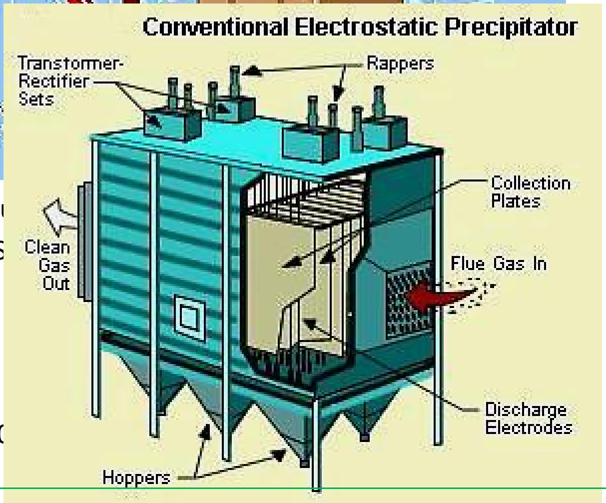


Figure 133 ESP (US EPA) (72)

positive electrode (captation) where it loses its charge and falls down along the electrode's walls (see Figure 132 and Figure 133).

Precipitator performance is very sensitive due to two particulate properties: (64)

- *Resistivity*: If particle resistivity is too high, the particles do not lose their charge and hide the electric field effect. If resistivity is too low, the particles can rapidly lose their charge and pass through the electric fields with no capture, and go to the stack.
- *Particle size distribution*: The particle size affects the amount of electric charge and influences the filtering performance.

ESPs are excellent control devices for many industrial particulate emissions, including smoke from electricity-generating utilities (coal and oil fired.) These devices treat gas volumes from several hundred thousand cubic feet to 2.5 million cubic feet (70,000 m^3/s) in the largest coal-fired boiler applications.

For a coal-fired boiler, collection is usually performed downstream of the air preheater at about 160 °C (320 °F), which provides optimal resistivity of the coal-ash particles. For some difficult applications with low-sulphur fuel, hot-end units have been built, which operate above 371 °C (700 °F). (75)

There are three common configurations for ESPs: (54)

- *Plate-wire precipitators*: The most common configuration, plate-wire ESPs feature a chamber consisting of a series of discharge wire electrodes that are equally spaced along the centre line between adjacent collection plates. Dirty gas flows into this chamber, and charged particles are collected on the plates as dust. Plate-wire ESPs can handle large volumes of gas and are used in coal-fired boilers, cement kilns, solid waste incinerators, paper mill recovery boilers, petroleum refining catalytic cracking units, sinter plants, basic oxygen furnaces, open hearth furnaces, electric arc furnaces, coke oven batteries, and glass furnaces.
- *Rigid discharge electrode (RDE) units*: Currently the most popular configuration, RDE units have electrodes suspended from high-voltage frames located in the area above the gas passages. The discharge electrodes are centred in the gas passages. In a common form of this design, sharp-pointed needles attached to a rigid structure are used as high-voltage electrodes instead of the electrodes hanging between plates of a plate-wire ESP. RDE units are typically used in the pulp and paper, ferrous and non-ferrous metals, petrochemical, cement, and waste-to-energy industries, as well as in electric power generating plants.
- *Wet precipitators*: These plate-wire, flat-plate, or tubular ESPs operate with water flow applied intermittently or continuously to wash the collected particles into a sump for disposal. The advantage of this configuration it is that it eliminates problems with re-entrainment. Disadvantages include increased complexity of the wash system, and increased difficulty and cost of disposing of the collected slurry.

Advantages and disadvantages of ESPs

Key advantages include the following (76):

- good efficiency for different particulate sizes including small concentrations
- work with flue gases with high moisture content
- work within a large temperature range

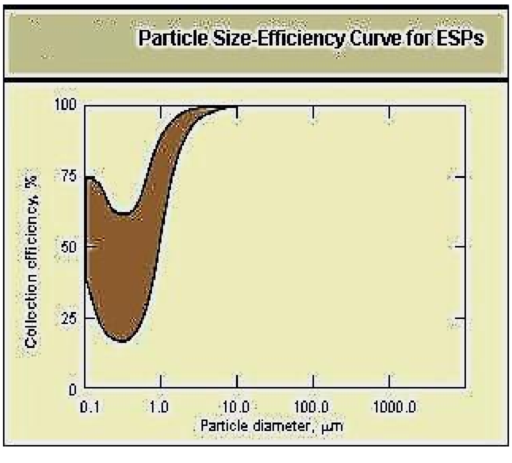


Figure 134 ESP particle collection efficiency (72)

Key disadvantages include the following:

- high investment costs
- efficiency depends on ash resistivity
- voluminous dimensions
- sensitivity to sulphur content (sulphur lowers resistivity)

Collection efficiency of ESPs

The typical particle size-collection efficiency curve for a properly sized and operated ESP is shown in Figure 134. The efficiency is usually at a minimum in the range of 0.1 micrometres to 0.5 micrometres. The shape of the efficiency curve is the combined effect of two particle electrical charging mechanisms, neither of which is highly effective in this particle size range. Although this decrease in efficiency occurs in the same particle size range as for particulate wet scrubbers, the cause of the decrease is entirely different.

The main issues affecting the control efficiency of an ESP are its design and proper maintenance. (54) The design of an ESP for a particular application is based on characteristics of the particulate matter that affect its ability to be collected and the gas volume flow rate. The ability of the particulate matter to be collected is affected by the particle migration velocity. The particle migration velocity is the rate at which the particle moves along the electric field lines toward the walls, where they are collected. Particle migration velocity is based on the estimated particle charge, mass of particles in the gas stream, and particle diameter and shape (size). These estimations are not always exactly correct because the particulate actually consists of particles of a wide range of sizes. Collection efficiency decreases as the particle diameter becomes smaller, down to about 0.5 microns (when Brownian motion effects cause movement toward the collection surfaces). Therefore, the collection efficiency of PM_{10} and $PM_{2.5}$ is much lower than for total PM.

The particle migration velocity is used to determine the specific collecting area (SCA) required to achieve the desired collection efficiency. The SCA is the ratio of the collecting surface area to the gas volume flow rate and is usually expressed in units of square feet of collection area per thousand actual cubic feet per minute of gas flow (ft^2/kacfm).

The design total collecting area (size of the ESP) is determined by multiplying the SCA by the gas volume flow rate. ESPs are usually designed with more theoretical total collecting area than is required to achieve a guaranteed control efficiency. This minimizes the possibility of not meeting the guarantee because of changes in PM or flue gas characteristics. Thus, if flue gas parameters and particulate matter characteristics are not considered when designing the ESP, the control efficiency will not be at the desired level.

The electrical fields must be properly maintained for the ESP to achieve the desired control efficiency. Each electrical field in an ESP is composed of bus sections. If electrical power is lost to a bus due to grounding or other reasons, the bus will be out of service. Bus sections out of service directly in line between fields will reduce the control efficiency because some of the particles miss multiple active fields. To account for this, the number of bus sections per field in industrial ESPs has increased over the last couple of decades.

Simply operating the ESP reduces the control efficiency over time. Non-removable dust build-up on discharge and collecting surfaces inhibits current flow and particle charge, resulting in fewer particles collected. Warping of components shortens the distance from discharge to ground, and corrosion creates sharp edges that cause arcing. Both of these conditions reduce the discharge voltage and charge build-up on the particles, reducing the collection ability of the particles.

Small and mini ESPs

Small and mini ESPs have been developed for special applications. (77) Small ESPs (**Error! Reference source not found.**) have been developed for boiler capacities from 1.0 MW to 2.5 MW. They can work on a flue gas flow range from 4,800 m³/h to 10,000 m³/h (≈ 2,825 cu. ft./min to 5,886 cu. ft./min), with gas temperatures of up to 420 °C (788 °F).

Mini ESPs (**Error! Reference source not found.**) have been developed for small boiler plants with capacities of up to 1 MW with biomass gasification. They can work with gas volumes of between 900 m³/h and 4,800 m³/h (≈ 530 cu. ft./min and 2,825 cu. ft./min), and with gas temperatures of up to 300 °C (572 °F).

Wet ESPs

A wet electrostatic precipitator (WESP or wet ESP (75)) operates with saturated air streams (100% relative humidity). WESPs (**Error! Reference source not found.**) are commonly used to remove liquid droplets such as sulphuric acid mist from industrial process gas streams, and when the gases have a high moisture content or contain combustible particulate or particles that are sticky in nature. Another positive effect is the additional bonding of toxic elements like hydrochloric acid (HCl), sulphur dioxide (SO_2), NaCl (sodium chloride) and hydrofluoric acid (HF). (77)

Wet ESPs can perform as follows:

- *Volume flow rates*: 1,000 m3/h to 500,000 m3/h (≈ 588.6 cu ft/min to 294,300 cu ft/min)
- *Temperatures*: up to 75 °C (≈ 167 °F)

For higher temperatures, an additional cooling zone can be provided.

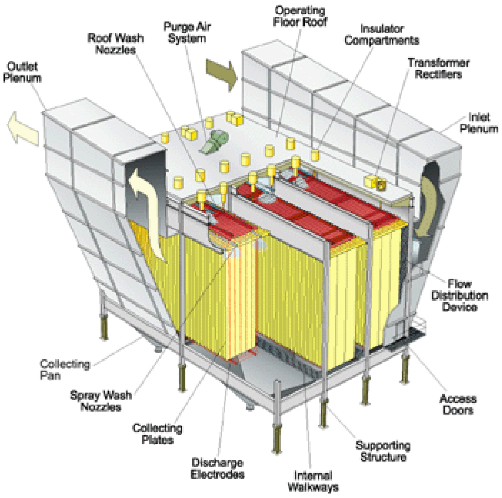


Figure 135 Wet ESP (Courtesy of B&W) **(255)**

The preferred and most modern type of WESP is a downflow tubular design. This design allows the collected moisture and particulate to form a slurry that helps to keep the collection surfaces clean. (69)

In a wet ESP, (77) the process gas vertically enters the ESP from below and is spread in a uniform flow profile across the entire filter cross-section by means of a gas distribution system. The particles/aerosols/water droplets are electrically charged by the application of high voltage (78V to 135kV) between the spray electrodes and the honeycomb collecting electrodes. On their way through the electric field, the charged particles are transported by electric field strength to the honeycomb collecting electrodes, where they agglomerate with the existing dust particles and are subsequently flushed off by a periodically working purging system. The dust-water-mixture automatically flows into the filter sump located below the gas intake. The purified gas leaves the filter through the gas outlet hood located at the filter head. The gas is distributed from bottom to top

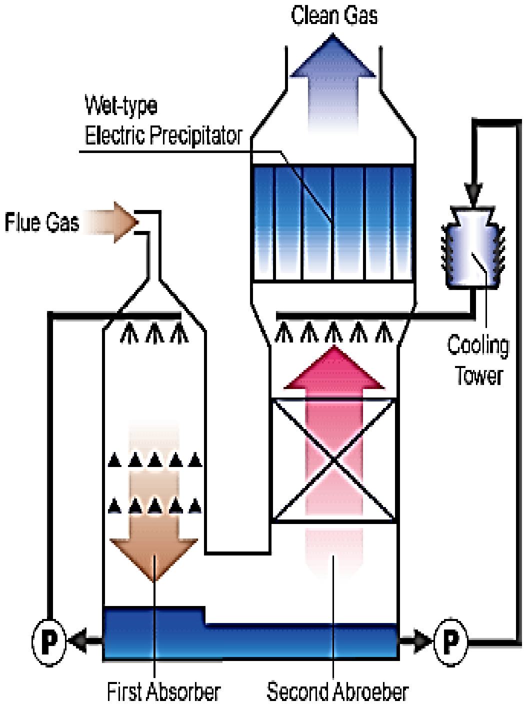


Figure 136 DeSO$_x$ coupled with wet ESP (Courtesy of Toyo Engineering-Japan) (78) through the honeycomb collecting electrodes (honeycomb clusters). The honeycomb shape results in a very large collection surface on a small base area.

Wet ESPs can be used for high sulphur fuels. When these fuels are combusted, high-concentration SO_2 gas develops proportionally along with sulphuric acid mist, which causes bluish smoke. The sulphuric acid mist cannot be removed with an ordinary desulphurization process. By treating the desulphurized flue gas with wet ESPs, 90% to 99% of the sulphuric acid mist can be collected and removed efficiently Figure 136). (78) . Plate style and upflow design wet ESPs are very unreliable and should not be used in applications where particulate is sticky in nature. (75)

Example (54)

Consider a coal-fired boiler that operates as follows:

Throughput: 1,764 MMBtu/hr (about 500 MW)
Operating hours: 8,500 hr/y
Permitted emissions: 0.03 lb particulate/MMBtu (13.6 gr/10^3 MJ; MJ = megajoules)
Control device: Electrostatic precipitator
Assumed control efficiency: 99%

If this process and its associated control equipment operated exactly as designed for the entire 8,500 hr/y, the expected emissions would be:

Expected annual particulate emissions = 1,764 MMBtu/hr x 8,500 hr/y x 0.03 lb Particulate/MMBtu = ~450,000 lb/y = ~225 tons/y

However, low voltage or other malfunctions might cause the ESP to occasionally operate at 95% efficiency rather than 99% efficiency. During such events, the emission rate would be 0.12 lb particulate/MMBtu (four times the "normal" emission rate of 0.03 lb particulate/MMBtu). If these anomalous conditions occurred during 5% of the total operating hours (i.e., 425 of the 8,500 hr per year) for the plant, annual particulate emissions would be:

Actual annual particulate emissions = 1,764 MMBtu/hr x (8,500 hr/y x 95%) x 0.03 lb/MMBtu + 1,764 MMBTU/hr x (8,500 hr/y x 5%) x 0.12 lb/MMBtu = 517,293 = 258 tpy

Thus, in this example, a 4% reduction in ESP efficiency for 5% of the operating time would increase actual annual particulate emissions by 33 tpy (20%) over the permitted amount.

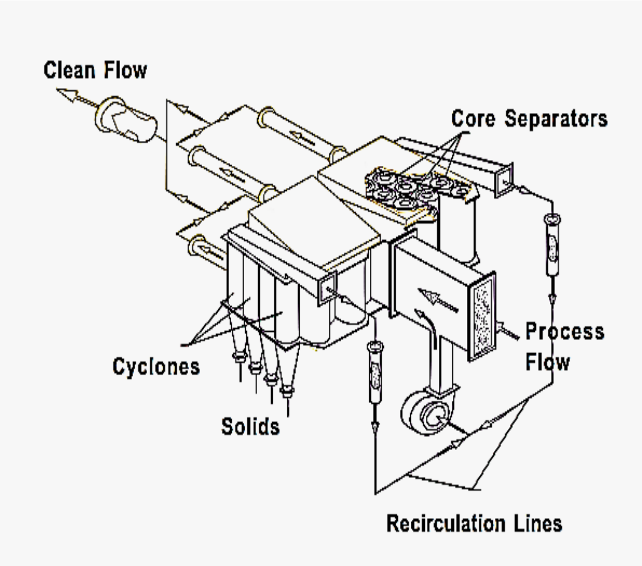


Figure 137 LSR Technologies' Core System Separator

Core separators

Core separators are mechanical dust-collecting devices that remove micron- and submicron-sized particles from gas streams. Historically, mechanical collectors have been ineffective in removing particles with diameters of less than 10 microns. A core separator system includes two conventional components: a cyclone collector for extracting solids and a fan for flow recirculation. A complete system is actually a multitude of cylindrical units, each with a single inlet for the stream to be treated and two outlets. One outlet is for the clean gas stream and the other contains a highly concentrated recirculation stream. The dust-laden recirculation stream is fed to a cyclone and returned again by means of the fan. The core separator component cleans the inlet stream and detains dust particles in the system. Because its efficiency is very high, most particles do not leave the system. They recirculate until collected by the cyclone.

Two factors govern the performance of core separators: high separation efficiency of the separator component, and the interaction between individual components. To achieve high separation efficiency, a proper bleed-flow ratio (i.e., ratio of the recirculation flow to the total flow) is required. By controlling bleed flow, the tangential and radial velocities are controlled independently to maintain them in the desirable range. A schematic of a core separator is shown in Figure 137. (79)

Comparing PM control devices

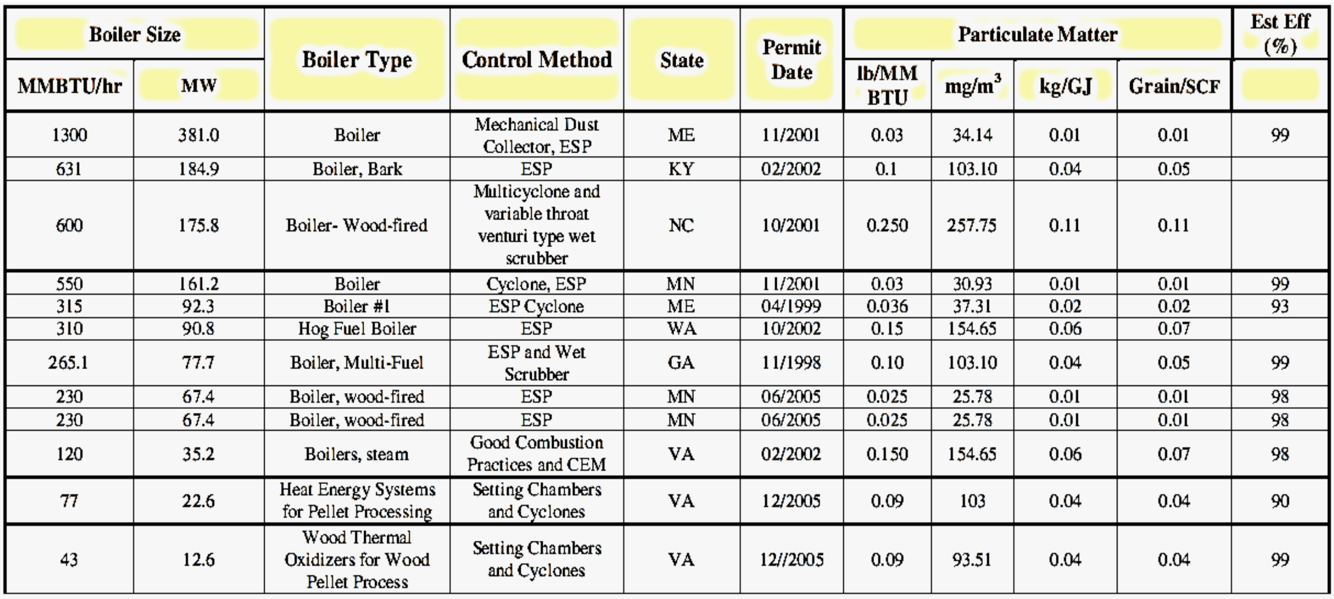
The performance of dust collectors is sensitive to many factors such as fuel characteristics, amount of dust in the flue gas, dust size distribution, flue gas temperature, flue gas moisture content, quality of maintenance service, etc. Keeping this in mind, Table 20 shows a broad classification of the performance of various technologies that are currently available. This can be used as a first step in selecting the best PM abatement devices for a given boiler.

Table 20 Comparison of PM control devices

Type of PM control device	PM removal efficiency (%)
High efficiency cyclone	**30–40**
Multicyclone	**40-50**
Venturi scrubber	**90-95**
ESP	**95-99**
Fabric filter	**95-99**

Table 21 shows the performance of boilers using different types of dust abatement devices in different working

Table 21 Performance of various PM abatement devices (EPA BACT DATA, 2008)

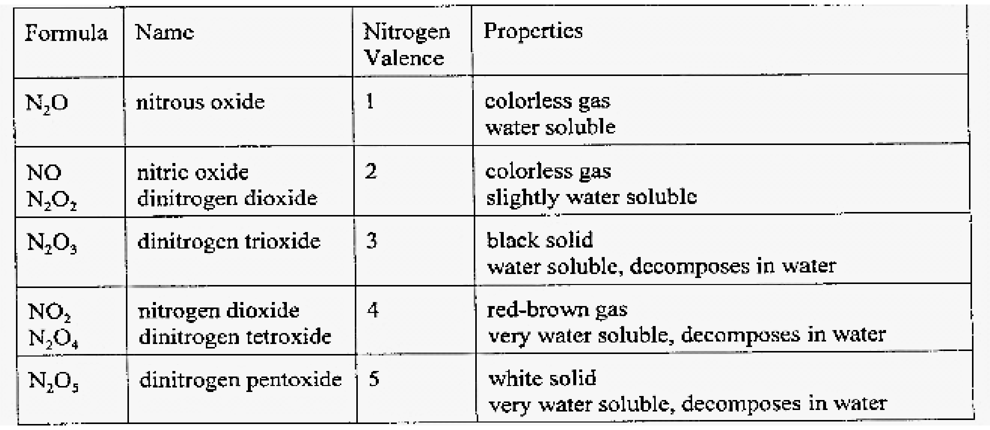


Boiler Size		Boiler Type	Control Method	State	Permit Date	Particulate Matter				Est Eff (%)
MMBTU/hr	MW					lb/MM BTU	mg/m^3	kg/GJ	Grain/SCF	
1300	381.0	Boiler	Mechanical Dust Collector, ESP	ME	11/2001	0.03	34.14	0.01	0.01	99
631	184.9	Boiler, Bark	ESP	KY	02/2002	0.1	103.10	0.04	0.05	
600	175.8	Boiler- Wood-fired	Multicyclone and variable throat venturi type wet scrubber	NC	10/2001	0.250	257.75	0.11	0.11	
550	161.2	Boiler	Cyclone, ESP	MN	11/2001	0.03	30.93	0.01	0.01	99
315	92.3	Boiler #1	ESP Cyclone	ME	04/1999	0.036	37.31	0.02	0.02	93
310	90.8	Hog Fuel Boiler	ESP	WA	10/2002	0.15	154.65	0.06	0.07	
265.1	77.7	Boiler, Multi-Fuel	ESP and Wet Scrubber	GA	11/1998	0.10	103.10	0.04	0.05	99
230	67.4	Boiler, wood-fired	ESP	MN	06/2005	0.025	25.78	0.01	0.01	98
230	67.4	Boiler, wood-fired	ESP	MN	06/2005	0.025	25.78	0.01	0.01	98
120	35.2	Boilers, steam	Good Combustion Practices and CEM	VA	02/2002	0.150	154.65	0.06	0.07	98
77	22.6	Heat Energy Systems for Pellet Processing	Setting Chambers and Cyclones	VA	12/2005	0.09	103	0.04	0.04	90
43	12.6	Wood Thermal Oxidizers for Wood Pellet Process	Setting Chambers and Cyclones	VA	12//2005	0.09	93.51	0.04	0.04	99

conditions for wood-burning systems. The boiler size is given in MMBtu per hour and in MW. PM emissions are shown in several units of measurement: pounds per million Btu, milligrams per kilogram, kilograms per gigajoule (1 GJ =10^9 joules), grains per standard cubic feet (1 grain = 64.798 milligrams). For comparison purposes, the best unit of measure is the energy unit produced by the boiler: kg/GJ or MMBtu/lb. According to the Table, ESPs alone, or together with cyclones, have the best PM reduction rates.

NO_X control technologies

Nitrogen oxides are formed during combustion of fuel in the presence of air. At elevated temperatures, nitrogen from the air and the fuel reacts with oxygen to form nitrogen oxides. Approximately 90% to 95% of the nitrogen oxides generated in combustion processes are in the form of nitric oxide (NO). Once in the atmosphere, the NO undergoes a variety of photochemical and thermal reactions to form NO_2. Accordingly, the total mass emissions of nitrogen oxides from the unit are usually expressed in the form of NO_2.

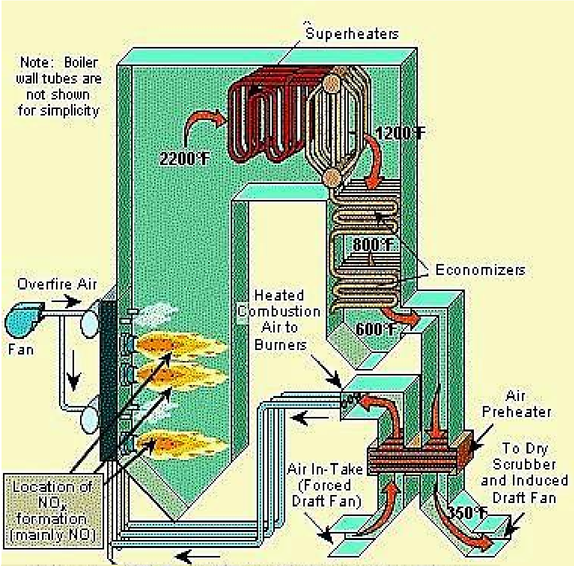


Formula	Name	Nitrogen Valence	Properties
N_2O	nitrous oxide	1	colorless gas water soluble
NO N_2O_2	nitric oxide dinitrogen dioxide	2	colorless gas slightly water soluble
N_2O_3	dinitrogen trioxide	3	black solid water soluble, decomposes in water
NO_2 N_2O_4	nitrogen dioxide dinitrogen tetroxide	4	red-brown gas very water soluble, decomposes in water
N_2O_5	dinitrogen pentoxide	5	white solid very water soluble, decomposes in water

The different types of NO_x that can be formed are shown in Table 22. (80)

Table 22 Types of NO_x

The complex sets of reactions responsible for nitrogen oxide generation are very sensitive to high oxygen concentrations and high gas temperatures in the combustion zone. Nitrogen oxide emissions are highest during high boiler or incinerator loads because the highest gas temperatures occur under these conditions. (72) The formation of NO_x is shown in Figure 138. (72)



EPA)

NO_x controls can be classified into:

- combustion controls, and
- post-combustion controls.

Combustion controls reduce NO_x emissions during the combustion process by regulating flame characteristics such as temperature and fuel-air mixing. Post-combustion controls

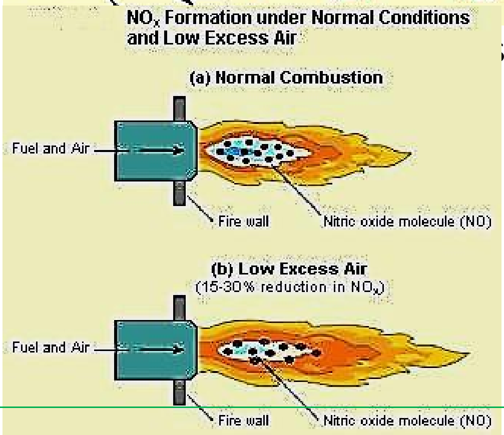


Figure 139 NO_x Formation (US EPA) (72) operate downstream of the combustion process and remove NO_x emissions from the flue gas. Each method results in a different degree of NO_x control. For example, when firing natural gas, low excess air firing typically reduces NO_x by 10%, flue gas recirculation by 75%, and selective catalytic reduction by 90%. (50)

Combustion controls

Combustion control techniques are frequently used on industrial boilers requiring NO_x controls because they are simpler and less expensive than post-combustion controls. Several options are available.

Low excess air firing

Excess air is a very important parameter for controlling the combustion performance of a boiler. Normally, fuels are fired with excess air to ensure complete combustion and avoid formation of carbon oxide, a potentially dangerous compound that can lead to boiler explosion. As already mentioned, high excess air levels may result in increased NO_x formation because the excess nitrogen and oxygen in the combustion air entering the flame will react to form thermal NO_x. To reduce excess air, the oxygen content at the burner is controlled and trimmed. Low excess air levels not only result in low NO_x generation, but also have a positive effect on boiler efficiency (Figure 139).

Water/steam injection

Injection of water or steam into the burner can reduce NO_x levels by more than 50% by lowering the flame temperature and thus the chemical reactions that generate NO_x. Higher reduction rates of up to 80% can be achieved for natural gas. The addition of water/steam results in boiler efficiency loss because the latent heat of vaporization of water (the heat that is needed to evaporate the injected water) is lost. Losses can reach up to 10%, depending on the amount of injected water.

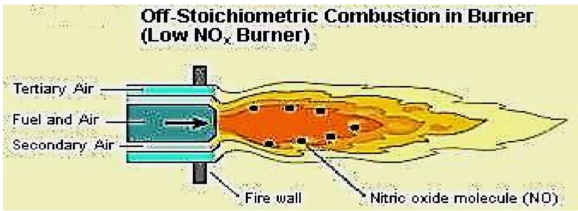


Figure 140 Low NO_x Burner (US EPA) (72)

Staged combustion

Staged combustion (81) involves changing the air and fuel flow patterns to reduce the peak flame temperature and oxygen concentrations. Enlarging the flame results in lower flame temperatures and lower thermal NO_x formation, which, in turn, result in lower overall NO_x emissions. The technology can be applied to most boiler types and sizes. Staged combustion can be achieved by modifying the burner design. These new types of burners are called low NO_x burners (LNB) (see Figure 140). Burner modifications can affect the overall performance of the burner itself and boiler operation.

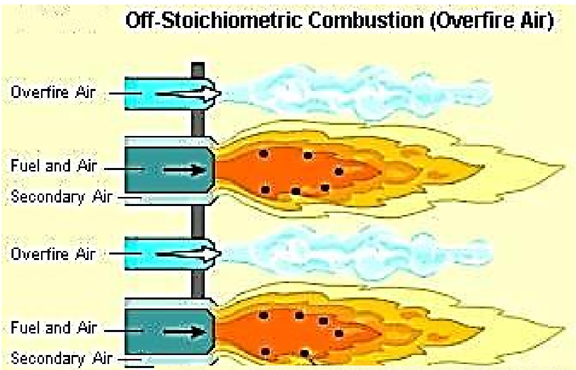


Figure 141 Pe
abatement d

Over fired air (OFA)

Over fired air is another system that introduces combustion air separately, over the floor of the burners, from special holes.

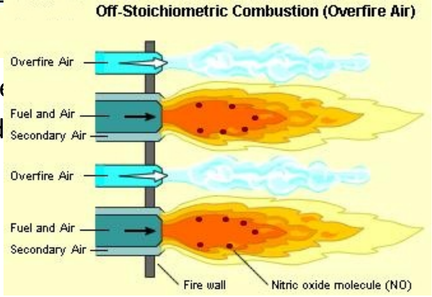


Figure 142 Over fire combustion

Flue gas recirculation (FGR)

Flue gas recirculation involves the return of combustion gases to the burner area of the boiler. The slightly cooled combustion gas from the boiler exit is mixed back with the burner flame to reduce the peak flame temperatures, thereby suppressing NO_x formation. This approach requires a separate recirculation fan and duct system. There are two types of FGR:

- *External flue gas recirculation*: uses an external fan to recirculate the flue gases back into the flame. An external duct routes the exhaust gases back from the stack to the burner. A valve controls the recirculation rate, based on boiler input.
- *Induced flue gas recirculation*: uses the combustion air fan to recirculate the flue gases back into the flame. A portion of the flue gases are routed by duct work or internally to the combustion air fan, where they are pre-mixed with the combustion air and introduced into the flame through the burner. New designs of induced FGR that use an integral FGR design are becoming popular because of their uncomplicated design and reliability.

Theoretically, there is no limit to the amount of NO_x reduction with FGR; practically, there is a physical, feasible limit. The limit of NO_x reduction varies for different fuels: it is about 80% for natural gas and 20% to 25% for standard fuel oils.

Fuel reburning

Fuel reburning (see Figure 143) involves the operation of a boiler's main burners at very low excess air (fuel-rich conditions). Between 10% and 20% of the total fuel is injected into the boiler through a series of ports. This creates fuel-rich conditions across the entire combustion chamber. The partially oxidized compounds formed in the burner and reburn fuel injection area, which is located in the middle region of the boiler, are then oxidized completely in the upper region of the boiler. A series of over fire air ports are used in this upper region to provide all of the air needed for complete combustion. Water/steam injection is often used in conjunction with other NO_x control methods such as burner modifications or flue gas recirculation.

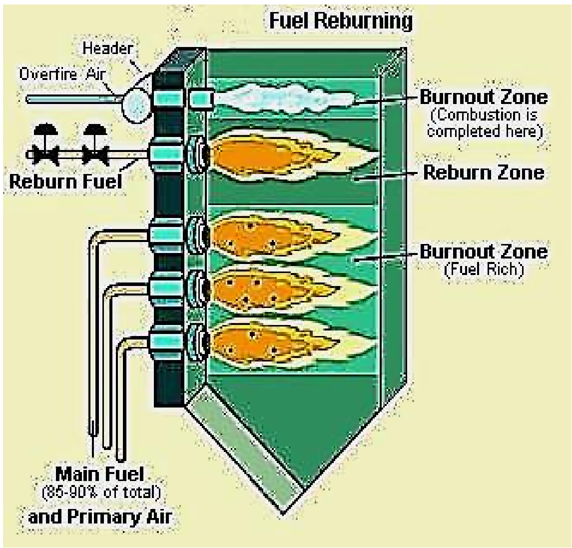


Figure 143 Fuel Reburning (US EPA) (72)

Post-combustion controls

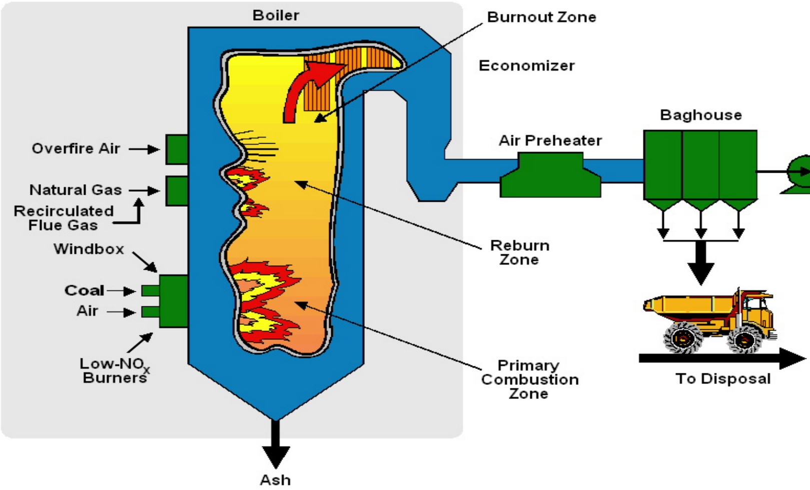


Figure 144 Combustion NOx control technologies (NETL DOE) (82)

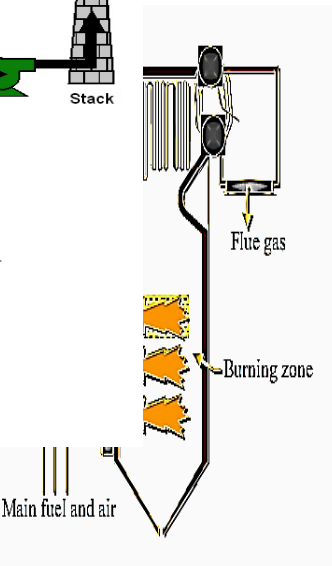


Figure 145 Selective Non - Catalytic Reduction (US EPA)

The current trend for low NO_x technologies is to design the boiler and low NO_x equipment as a package. This allows the NO_x control technology to be specifically tailored to the boiler's furnace design features, such as shape, volume, and heat release, thus addressing and minimizing the adverse effects on boiler operating parameters (e.g., turndown, capacity, efficiency, and CO levels). (50) Combustion NO_x control technologies for a large boiler are shown in **Figure** 144. (82)

Post-combustion technologies address NOx emissions after formation, and tend to be more expensive than combustion control techniques. They are generally are not used on boilers with inputs of less than 30 MW (100 MMBtu/hr). Post-combustion control methods include selective non-catalytic reduction and selective catalytic reduction.

Selective non-catalytic reduction (SNCR)

Selective non-catalytic reduction involves the injection of a NO_x-reducing agent, such as ammonia or urea, into the boiler exhaust gases at a temperature of approximately 1400 °F to 1600 °F. The ammonia or urea breaks down the NO_x in the exhaust gases into water and atmospheric nitrogen. SNCR reduces NO_x by up to 70%. A simplified diagram of the technology is shown in Figure 145, and a more comprehensive diagram for a large boiler is shown in Figure 146.

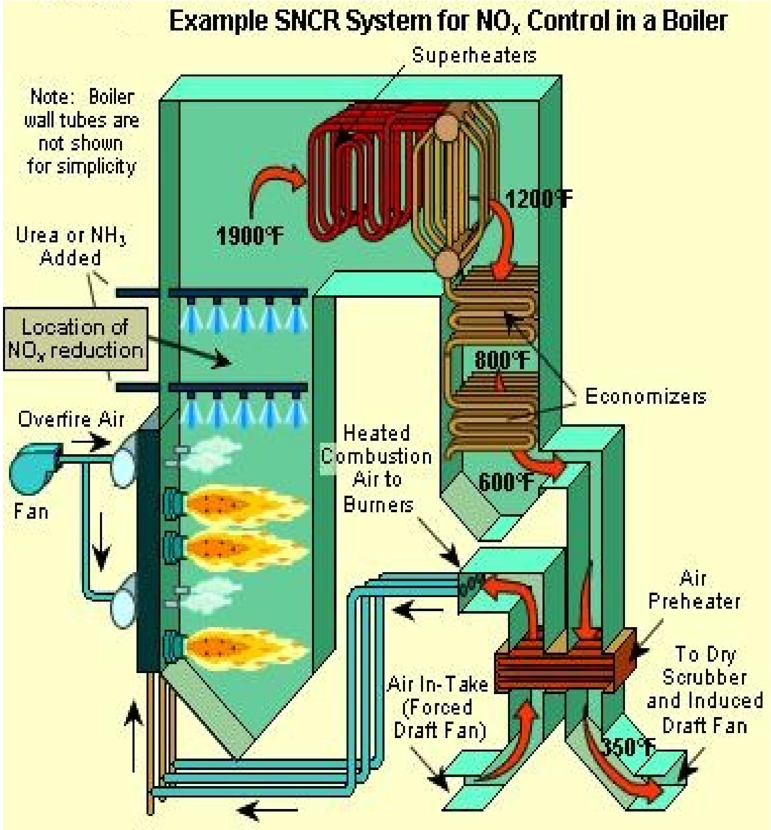


Figure 146 SNCR System (US EPA) (72)

Selective catalytic reduction (SCR)

Selective catalytic reduction (see Figure 147) involves the injection of ammonia into the boiler exhaust gases in the

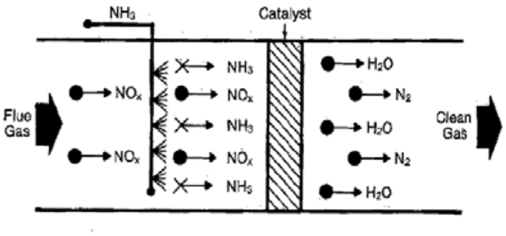


Figure 147-Selective Catalytic Reaction (SCR) –US EPA from B&W **(163)**

presence of a catalyst. The catalyst allows the ammonia to reduce NO_x levels at lower exhaust temperatures than SCNR. Unlike SCNR, where the exhaust gases must be approximately 750 °C to 900 °C (1400 °F to 1600 °F), SCR can be used when exhaust gases are between 250 °C and 650 °C (500 °F- and 1200°F), depending on the catalyst used. SCR can result in NO_x reductions of up to 90%. However, it is costly to use and can rarely be justified on boilers with inputs of less than 30 MW –(100 MMBtu/hr).

SO_x control technologies

The combustion of fuels containing sulphur (primarily oils and coals) results in pollutants occurring in the form of SO_2 (sulphur dioxide) and SO_3 (sulphur trioxide), together referred to as SO_x (sulphur oxides) (72). Sulphuric acid is also produced. The chemical reactions involved are:

$SO_2 + ½ O_2 = SO_3$

$SO_3 + H_2O = H_2SO_4$

The level of SO_x emitted depends directly on the sulphur content of the fuel, and not on boiler size or burner design. Typically, about 95% of the sulphur in the fuel is emitted as SO_2, 1% to 5% as SO_3, and 1% to 3% as sulphate particulate. Sulphate particulate is not considered part of the total SO_x emissions. A diagram of SO_2, SO_3 and H_2SO_4 (sulphuric acid) formation is shown in Figure 148.

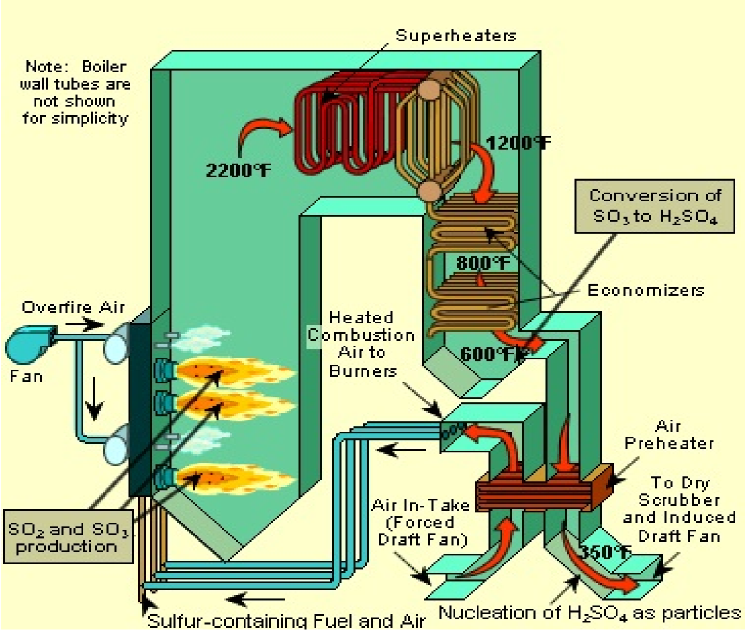


Figure 148 Location of sulphur dioxides in a boiler (US EPA) (72)

Sulphur dioxide flue gas treatment techniques

Sulphur can be present in residual oils, depending on raw oil origin and composition, and in coal, depending on its place of origin. Many types of gas desulphurization systems currently exist, while new technologies are also being tested. Most of these systems are implemented in large power boilers and are not suitable for small boilers because of prohibitive costs (30).

Two approaches to characterizing post-combustion control techniques are effective in reducing SO_2 emissions.

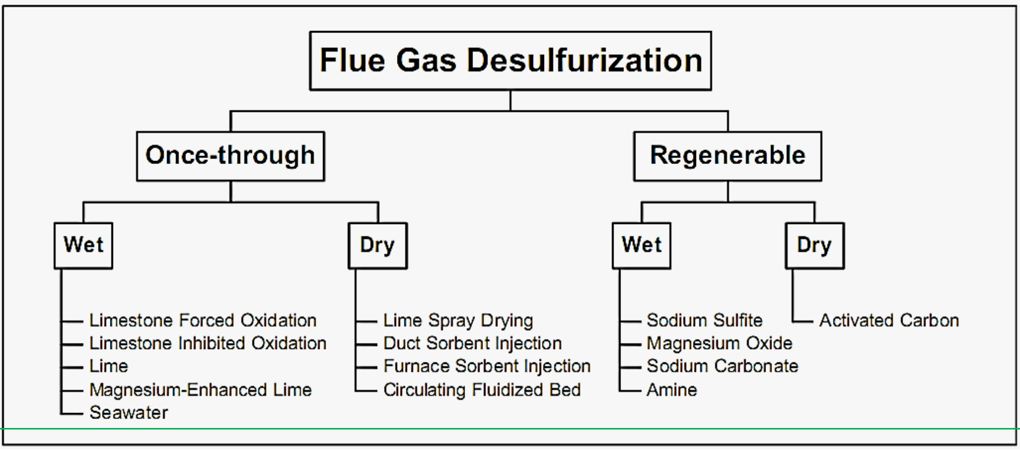


Figure 149 SO_2 removal technologies (US EPA) (83)

One approach involves categorizing the various flue gas desulphurization (FGD) techniques into non-regenerable (throwaway) and regenerable (recovery once through) processes. Non-regenerable and regenerable refer to the by-products, not the reagent. In a non-regenerable process, sulphur-bearing waste products that are derived from flue gas processing are stored or treated prior to disposal. Regenerable processes recover the SO_2 in some commercially useful form such as elemental sulphur or sulphuric acid. This classification is shown in Figure 149. (83)

The second approach is to categorize the FGD process as wet or dry. A wet process saturates the flue gas with water vapour whereas a dry process does not. Although the various FGD techniques are distinctively different in their implementation, they all involve chemical reactions that transform gaseous SO_2 into a liquid or solid sulphur-bearing compound. Flue gas scrubbers that effectively reduce SO_2 emissions are often described as complex chemical plants. (30) Because of complexity and high costs, their application is more suitable for large utility boilers than for industrial boilers.

Non-regenerable processes

Three widely used non-regenerable (once through) FGD techniques are lime or limestone wet scrubbing, the double-alkali (or dual-alkali) process, or lime dry scrubbing (30). Depending on the technique, the required desulphurization equipment is located either upstream or downstream from the PM collection system.

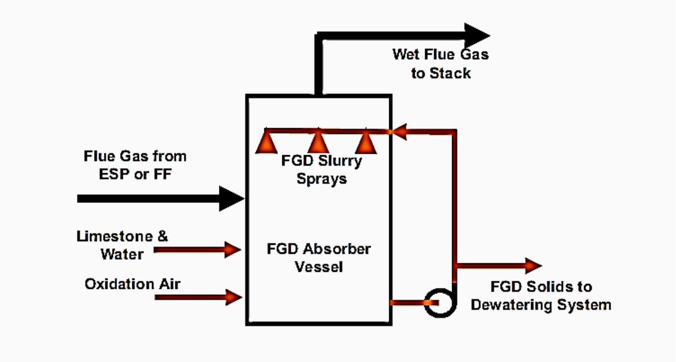


Figure 150 Wet FGD Process Schematic

Lime or limestone wet scrubbing process

Lime or limestone wet scrubbing is a very common FGD technique. In these systems, flue gas is contacted with an aqueous slurry of either lime or limestone in a countercurrent absorber, or scrubber, which is located after the PM collection system. Inside the scrubber, the lime (CaO) or limestone, which is predominantly calcium carbonate ($CaCO_3$), reacts with SO_2 to form calcium salts. To sustain this reaction, fresh slurry must be continuously introduced as the calcium salts are removed for processing and disposal. Several wet FGD systems are in commercial use with SO_2 removal efficiencies as high as 98%.

Most lime-FGDs discharge wastewaters that are either slurry of waters, dissolved solids, and/or suspended solids laden with heavy metals and salts; however, in most European countries the sludge water is classified as hazardous.

Double-alkali process

In the double-alkali (or dual-alkali) process, lime or limestone is consumed, and wet calcium salts, consisting primarily of calcium sulphite and calcium sulphate, are produced as waste. Unlike the lime or limestone wet scrubbing process, SO_2 absorption and waste production are performed as separate operations in the double-alkali process. Absorption is accomplished by circulating a soluble alkali such as sodium carbonate $NaCO_3$, sodium hydroxide (NaOH), or sodium sulphite (Na_2SO_3) through a scrubber. Effluent from the scrubber, which contains sodium-sulphur compounds, is

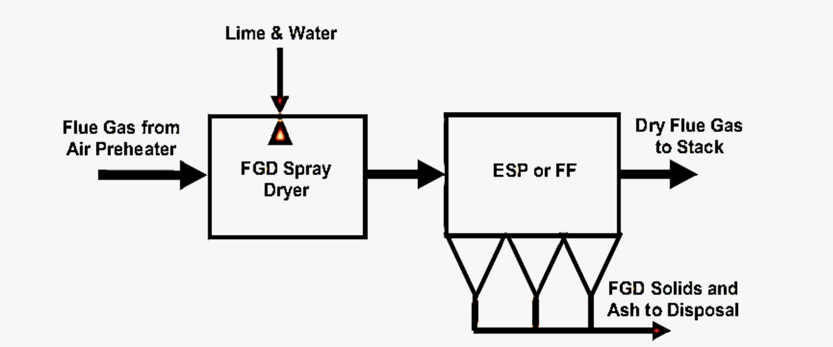


Figure 151 Dry FGD Process schematic –

then mixed with lime or limestone to produce a calcium-sulphur waste product. Sodium that is lost as a result of entrainment in the waste can sometimes complicate the disposal process because sodium sulphate contributes to surface and groundwater contamination. This process, which is located downstream from the PM collection system, results in excellent SO_2 removal efficiency.

The use of dual-alkali systems on utility boilers is attractive because of their ability to remove SO_2 efficiently and reduce scaling problems. Non-generable sodium FGD systems have been used mostly on industrial boilers. These systems use a sodium scrubbing liquor that absorbs SO_2 emissions efficiently, but they produce liquid wastes that can cause waste disposal problems. FGD systems used on utility boilers generate large quantities of liquid wastes. (84)

Lime dry scrubbing

Lime dry scrubbing is a relatively simple SO_2 removal technique. Located upstream from the PM collection system, lime dry scrubbing involves spraying a highly atomized slurry or aqueous solution of an alkaline reagent into the hot flue gas to absorb the SO_2. The predominant reagent used in dry scrubbers is slaked (hydrated) lime, but solutions of soda ash and its related compounds are sometimes used. Crystallized reaction products as well as fly ash from the boiler are collected in the PM collection system and then processed as waste.

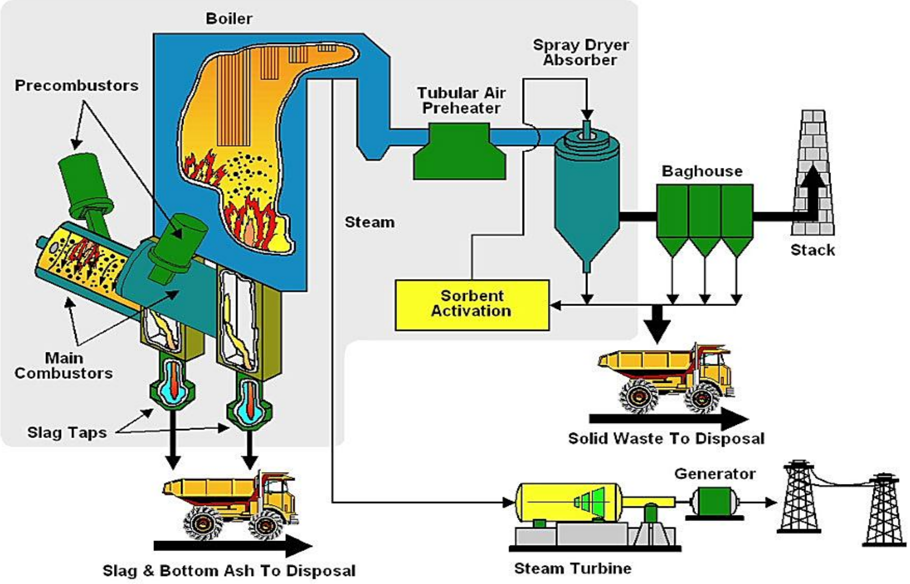


Figure 152 Spray dryer FGD with advanced combustors (NETL DOE)

Wet scrubbers are generally selected for high-sulphur fuels. Dry scrubbers, which are not as effective as wet scrubbers for high-sulphur fuels, are generally selected for low-sulphur fuels. Use of lime dry scrubbers on large utility boilers is limited because of the high cost of the reagent, but their use on industrial boilers is more attractive because they are easier to implement than wet scrubbers. Lime dry scrubbing is sometimes referred to as spray absorption, spray drying, or semi-wet scrubbing.

Regenerable processes

Regenerable FGD processes (30) typically involve an expensive and complex system for producing marketable sulphur or sulphuric acid instead of valueless sulphur-bearing waste. Although SO_2 removal efficiency is generally greater than 90%, application of regenerable FGD is limited. The processes are generally energy intensive and involve hazardous and potentially toxic gases that are not routinely associated with boiler operations. New technologies involve advanced combustors and spray driers, and injection of

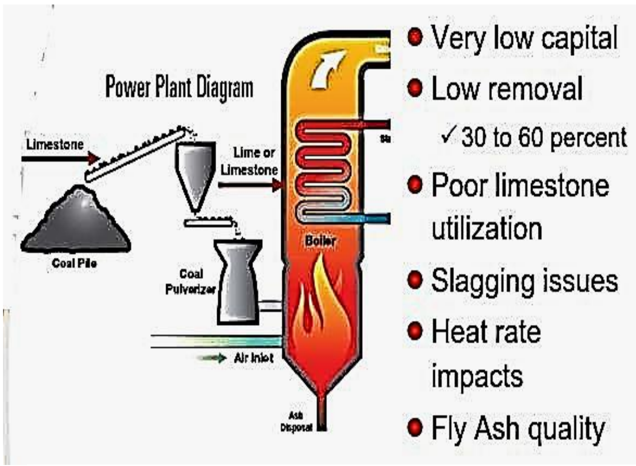


Figure 153 Dry sorbent injection- URS (85)

sorbents with sulphur capture for retrofitting existing power plants, as shown in Figure 153.

FGD technologies for small boilers

Using low-sulphur fuels is the most cost-effective method of reducing SO_x in industrial boilers. Because SO_x emissions primarily depend on the sulphur content of the fuel, burning fuels containing a minimal amount of sulphur (distillate oil) can achieve SO_x reductions, without the need to install and maintain expensive equipment. This solution also affects the cost of steam because cleaner fuels are more expensive than high-sulphur fuels.

The most suitable technologies for relatively small industrial boilers (100 MWe to 300 MWe) include: (85)

- High SO_x removal:
    - conventional dry FGD systems
        - lime
    - circulating dry scrubbers
        - lime
    - wet FGD systems
- Moderate removal:
    - furnace injection
        - lime or limestone
    - dry sorbent injection (see Figure 153)
        - trona or other sodium salts
        - high surface area hydrated lime

New technologies are now available for smaller boilers including Lextran's 3 in 1 SO_x, NO_x and mercury control, which is available for boilers of 5 MW capacity and above. (86) The absorption is realized by reacting SO_x, NO_x, and mercury pollutants with the Lextran catalyst, an organic substance in emulsion form, in a wet scrubber process. After facilitating the initial oxidation, the Lextran catalyst is released and recycled back into the process, leaving the pollutants in chemical form and amenable to becoming commercially beneficial by-products (fertilizers) with further neutralization by ammonia, potassium hydroxide (KOH), or other basic reagents to control the type of by-product see (Figure 154). (86)

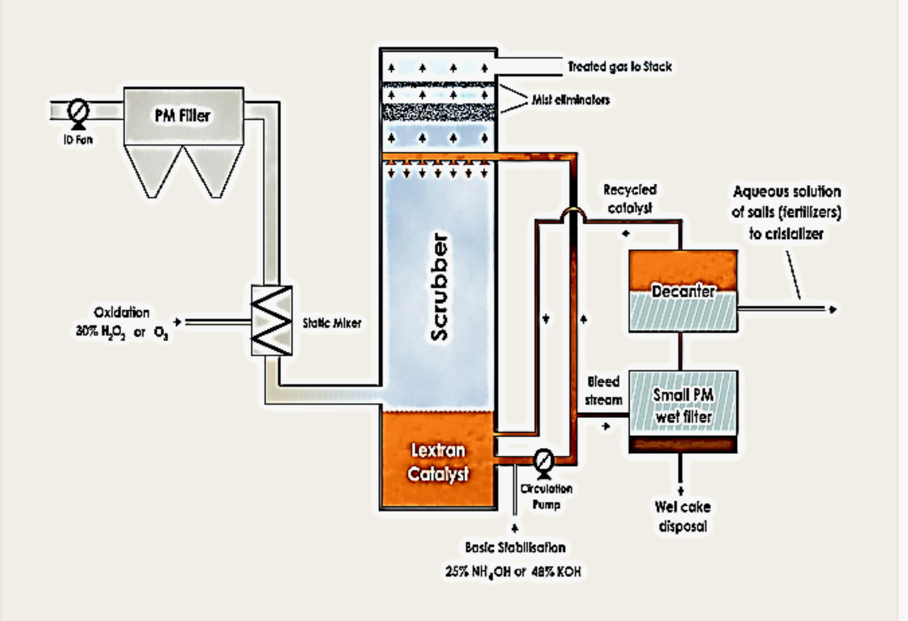
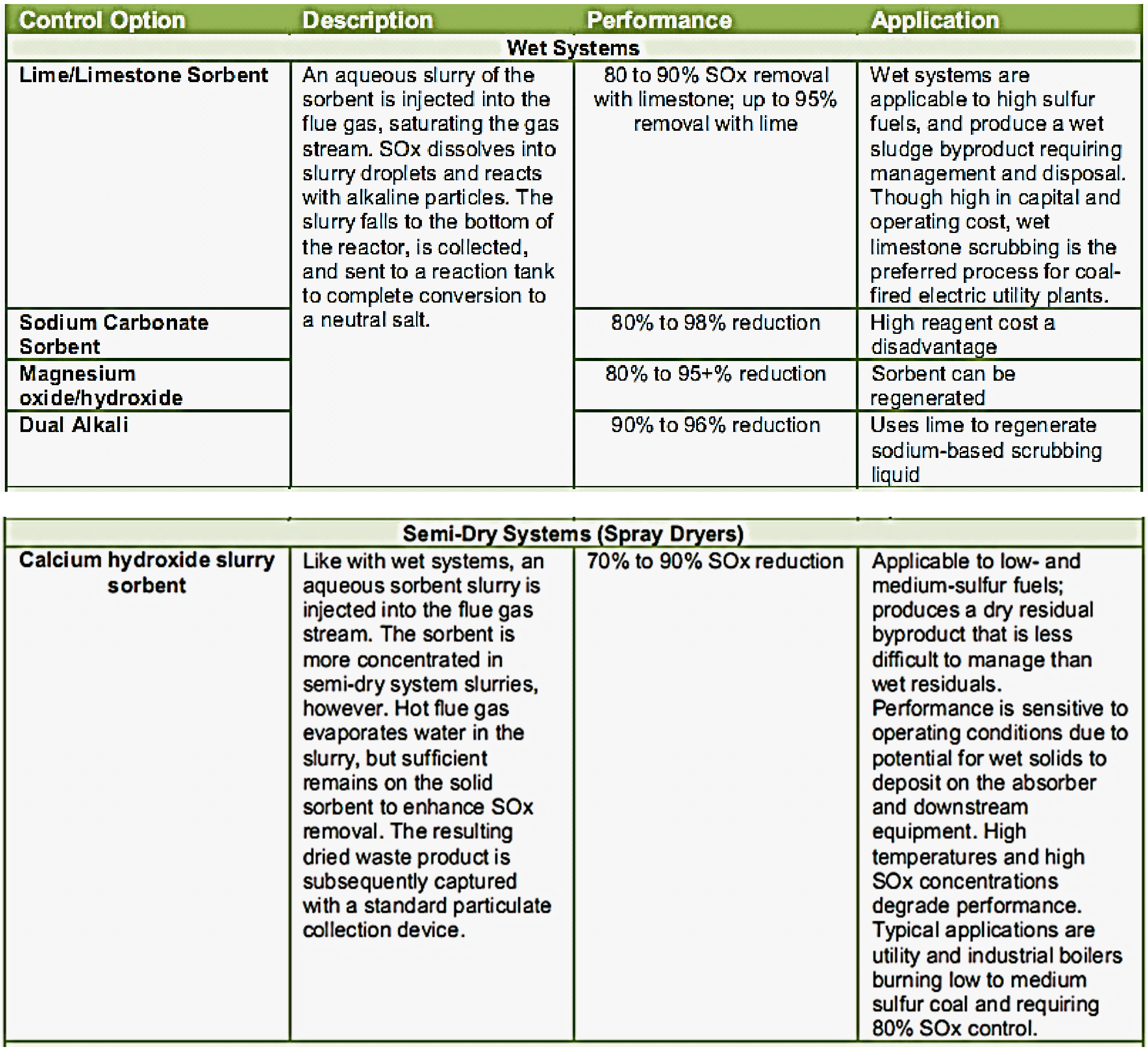


Figure 154 Lextran's NO_x, SO_x and Mercury removal technology (86)

Summary of FGD technologies

The performance and application of various SO_x control technologies are shown in Table 23.

Table 23 Performance and application of FGD technologies (138)



Control Option	Description	Performance	Application
Wet Systems			
Lime/Limestone Sorbent	An aqueous slurry of the sorbent is injected into the flue gas, saturating the gas stream. SOx dissolves into slurry droplets and reacts with alkaline particles. The slurry falls to the bottom of the reactor, is collected, and sent to a reaction tank to complete conversion to a neutral salt.	80 to 90% SOx removal with limestone; up to 95% removal with lime	Wet systems are applicable to high sulfur fuels, and produce a wet sludge byproduct requiring management and disposal. Though high in capital and operating cost, wet limestone scrubbing is the preferred process for coal-fired electric utility plants.
Sodium Carbonate Sorbent		80% to 98% reduction	High reagent cost a disadvantage
Magnesium oxide/hydroxide		80% to 95+% reduction	Sorbent can be regenerated
Dual Alkali		90% to 96% reduction	Uses lime to regenerate sodium-based scrubbing liquid
Semi-Dry Systems (Spray Dryers)			
Calcium hydroxide slurry sorbent	Like with wet systems, an aqueous sorbent slurry is injected into the flue gas stream. The sorbent is more concentrated in semi-dry system slurries, however. Hot flue gas evaporates water in the slurry, but sufficient remains on the solid sorbent to enhance SOx removal. The resulting dried waste product is subsequently captured with a standard particulate collection device.	70% to 90% SOx reduction	Applicable to low- and medium-sulfur fuels; produces a dry residual byproduct that is less difficult to manage than wet residuals. Performance is sensitive to operating conditions due to potential for wet solids to deposit on the absorber and downstream equipment. High temperatures and high SOx concentrations degrade performance. Typical applications are utility and industrial boilers burning low to medium sulfur coal and requiring 80% SOx control.

Dioxin and furan control

The generation of dioxins and furans was discussed in Chapter 3. Combustion studies indicate that both dioxin and furan compounds are destroyed when the gas temperatures exceed approximately 750 °C (1400 °F). In fact, oxidation of these compounds is completed at lower temperatures than some other forms of partially oxidized compounds, as shown in **Figure** 155. These temperatures usually exist in the combustion zones of incinerators and fossil fuel-fired boilers.

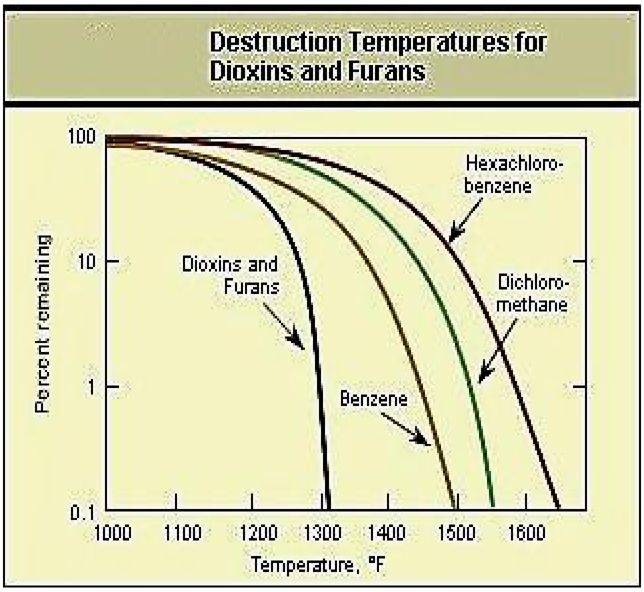
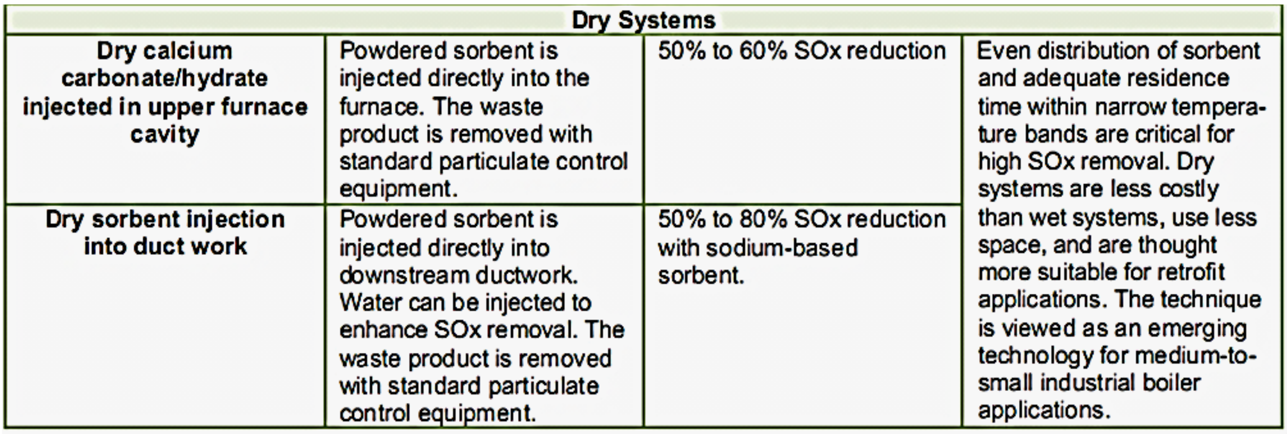


Figure 155 Destruction temperatures for dioxins and furans

The formation mechanisms decrease to negligible rates when the gas stream temperature goes below 200 °C (400 °F). Accordingly, ensuring that the gas stream is sufficiently cooled prior to the air pollution control system can eliminate this formation mechanism. Cooling is accomplished in the heat recovery equipment (economizers and air preheaters) or in the incinerator waste heat boilers. Some dioxins can be re-formed, however, as a result of the “de novo” formation mechanism in the economizer and de-dusting devices area. Polychlorinated dibenzo-p-dioxins (PCDDs) and polychlorinated dibenzofurans (PCDFs) can be destroyed when incinerated at sufficient temperatures with adequate residence time and mixing in the combustion zone. Good combustion practices are needed to limit the generation of dioxins during the combustion process in industrial boilers. Fast temperature quench after the combustion zone is necessary to prevent re-formation of PCDD/PCDF in the post-combustion zone.

Table 24 Dry systems



Dry Systems			
Dry calcium carbonate/hydrate injected in upper furnace cavity	Powdered sorbent is injected directly into the furnace. The waste product is removed with standard particulate control equipment.	50% to 60% SOx reduction	Even distribution of sorbent and adequate residence time within narrow temperature bands are critical for high SOx removal. Dry systems are less costly than wet systems, use less space, and are thought more suitable for retrofit applications. The technique is viewed as an emerging technology for medium-to-small industrial boiler applications.
Dry sorbent injection into duct work	Powdered sorbent is injected directly into downstream ductwork. Water can be injected to enhance SOx removal. The waste product is removed with standard particulate control equipment.	50% to 80% SOx reduction with sodium-based sorbent.	

Variables known to affect the formation of PCDD/PCDF in thermal processes include: [87]

- *Technology:* PCDD/PCDF formation can occur either in poor combustion or in poorly managed post-combustion chambers and air pollution control devices. Combustion techniques vary from very simple and very poor, such as open burning, to very complex and greatly improved, such as incineration using best available techniques.

- *Temperature*: PCDD/PCDF formation in the post-combustion zone or air pollution control devices has been reported to range between 200 °C and 650 °C; the range of greatest formation is generally agreed to be 200 °C to 450 °C, with a maximum of about 300 °C.
- *Metals:* Copper, iron, zinc, aluminium, chromium, and manganese are known to catalyse PCDD/PCDF formation.
- *Sulphur and nitrogen*: Sulphur- and nitrogen-containing chemicals inhibit the formation of PCDD/PCDF but may give rise to other by-products/
- *Chlorine:* Chlorine must be present in organic, inorganic or elemental form. Its presence in fly ash, or in elemental form in the gas phase, may be especially important.

Emissions of persistent organic pollutants (POPs) from boilers

Figure 156 shows potential locations for PCDD/PCDF formation in a large utility boiler. These locations are also relevant for large industrial boilers. Data are still being collected and analysed to better understand dioxin generation mechanisms in small boilers. Since small steam boilers are more compact, separating the various formation mechanisms along the flue gas pathway is more difficult. The dioxins emitted from a steam boiler are also called UP-POPs (unintentionally-produced POPs) because their production is not part of the production process but happens accidentally, as a result of combustion mechanisms and the presence of undesirable compounds in the fuel matrix.

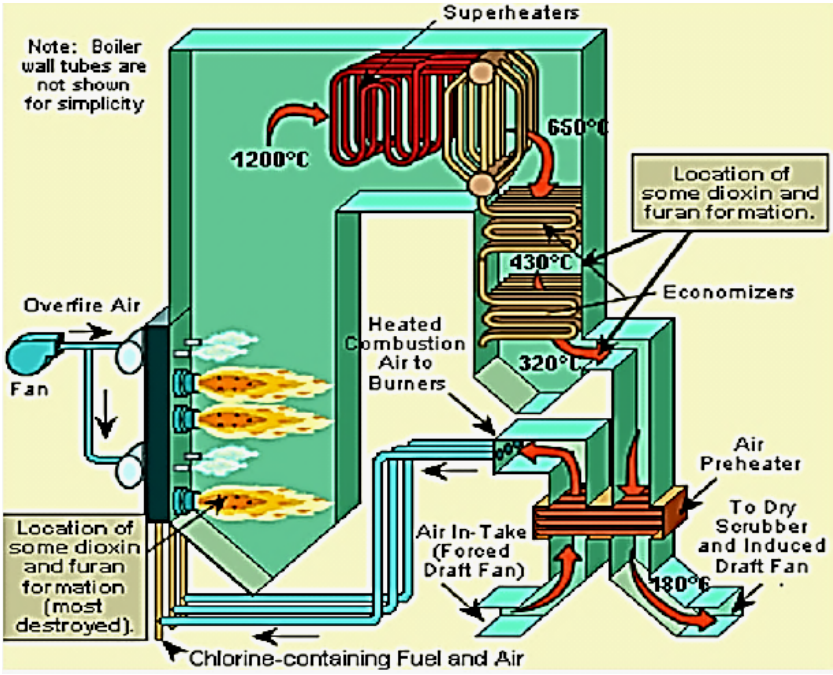


Figure 156 Dioxin formation mechanism in a large boiler (63)

The formation of dioxins can also occur in the dust abatement filters (e.g., ESPs) or bag filters positioned between the air heater and the stack.

The following operating parameters have been identified for air pollution control devices, which result in lower PCDD/PCDF emissions:

- low temperature at the particulate control device inlet
- minimization of gas or particle residence time in the 200 °C to400 °C temperature window
- uniform high combustor temperature
- good mixing with sufficient air
- minimization of entrained, unburned particulate matter
- feed rate uniformity

Other measures that can be taken to decrease the formation and release of dioxins and other chemicals listed in Annex C of the Stockholm Convention include:

- maintenance of efficient combustion conditions within the boiler and ensuring sufficient time is available to allow complete combustion to occur;
- undertaking measures to ensure fuel is not contaminated with Polychlorinated biphenyl (PCB), hexachlorobenzene (HCB) or chlorine, and is low in other components known to act as catalysts in the formation of PCDD and PCDF;
- use of appropriate gas-cleaning methods to lower emissions that may contain entrained pollutants; and
- appropriate strategies for disposal, storage or ongoing use of collected ash.

Measurement of the low levels of PCDDs, PCDFs, polychlorinated biphenyls (PCBs) and hexachlorobenzene (HCB) from combustion of fossil fuels in boilers is technically challenging and costly compared with measurement of criteria pollutants such as sulphur dioxide, nitrogen oxides, and particulates. Although direct measurement of persistent organic pollutants from individual facilities is encouraged to improve the knowledge base of emissions of these toxic components, it is acknowledged that, in some circumstances, this may not be possible except for those operating large and technically advanced facilities. In an efficient combustion process the levels of pollutants may be up to several orders of magnitude below prevailing standards. As a result, although PCDD, PCDF, PCB and HCB may possibly be present, they may be below the detection limits of currently available analytical methods.

Figure 157 shows a diagram of dioxin emissions from industrial boilers.

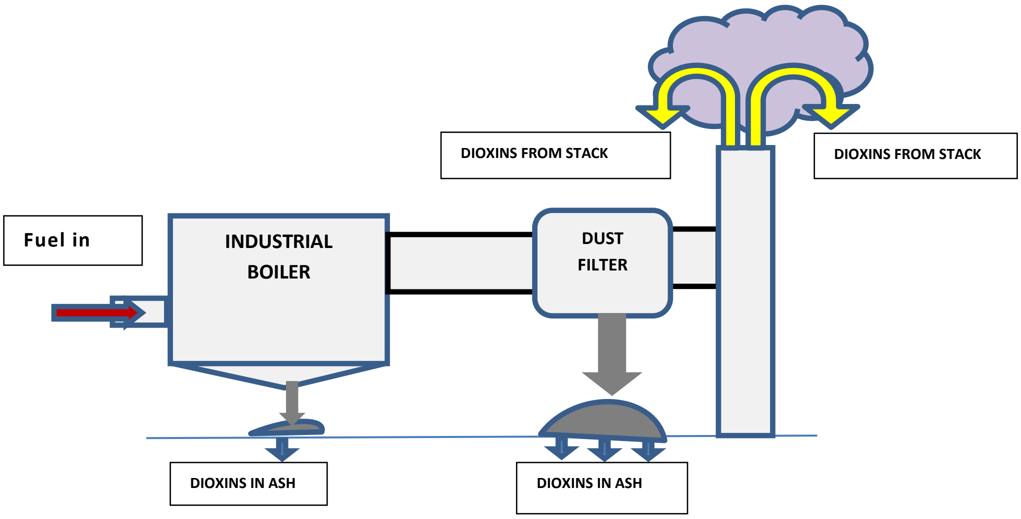


Figure 157 Dioxin emissions from industrial boilers

Dioxins are released to:

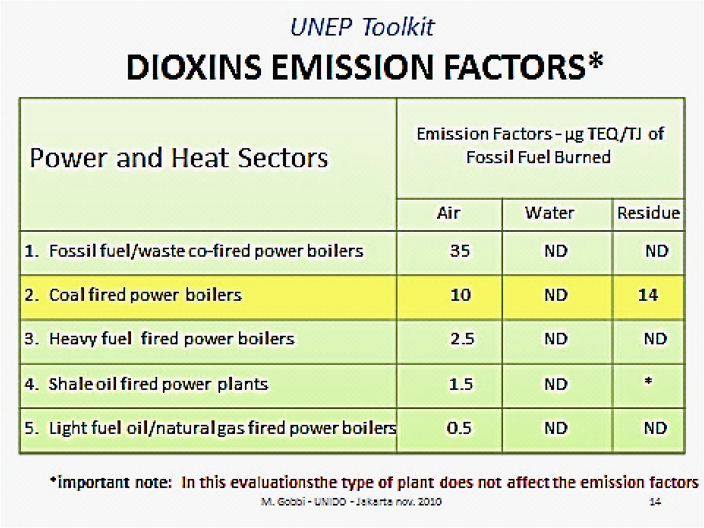
- air through the stack;
- residue through the ash collected at the bottom of the furnace ash bin and, mainly, at the dust filter fly ash collection system;
- water through the water discharge (blowdown); and
- land by leachate of dioxin-contaminated materials (if appropriate disposal has not been implemented).

The most harmful releases are those to air, as they disperse into the environment and cannot be confined. Although dioxins are emitted in very small quantities (micrograms per terajoule), even very small amounts can be harmful to the environment and human health. Moreover, dioxins are very stable compounds and, once generated, do not degrade and accumulate in the environment. Even if the accumulation effect is slow, dioxins can reach high concentrations over many years. Future generations, therefore, can be affected by accumulation of dioxins generated in the past.

Dioxin emission factors

The United Nations Environment Programme (UNEP (87)) has carried out a survey based on the available dioxin release data from boilers (mainly large power boilers). As an alternative to direct measurement, UNEP has identified emission factors (EF) for each source of industrial dioxins. Dioxin emission factors (I-TEQ) for the power and heat sector are given in Table 25 for three media: air, water, and residue, (87) which helps estimate the releases of dioxins from a boiler by referring to its fuel consumption, avoiding more expensive and complicated measurements. It can therefore be used for preliminary release assessment of dioxins.

Table 25 Dioxin emission factors for the power and heat sector (UNEP)



UNEP Toolkit

DIOXINS EMISSION FACTORS*

Power and Heat Sectors	Emission Factors - µg TEQ/TJ of Fossil Fuel Burned		
	Air	Water	Residue
1. Fossil fuel/waste co-fired power boilers	35	ND	ND
2. Coal fired power boilers	10	ND	14
3. Heavy fuel fired power boilers	2.5	ND	ND
4. Shale oil fired power plants	1.5	ND	*
5. Light fuel oil/natural gas fired power boilers	0.5	ND	ND

*important note: In this evaluationsthe type of plant does not affect the emission factors

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The EF is strictly linked to the energy content of the fuel, as expressed in µg-TEQ micrograms (toxic equivalent per terajoule) of energy input to the boiler (1 terajoule = 10^9 joule). It is also linked to the type of fuel burned. This is because the effect of the fuel prevails over other effects, and the data available at the time of preparation of the UNEP document did not allow for more detailed analysis of the effects of plant type and age on emissions. The Table does not take into account the effect of emission abatement devices. There is no differentiation between boilers equipped with APCD and those without, though the effect of APCD on dioxin emissions to air can be relevant.

The emission factors for biomass burning are given in Table 26. (87)

Table 26 Emission factors for biomass burning (UNEP)

	Emission Factors - µg TEQ/TJ of Biomass Burned		
	Air	**Water**	**Residue**
Mixed biomass-fired power boilers	**500**	**ND**	**ND**
Clean wood-fired power boilers	**50**	**ND**	**15**

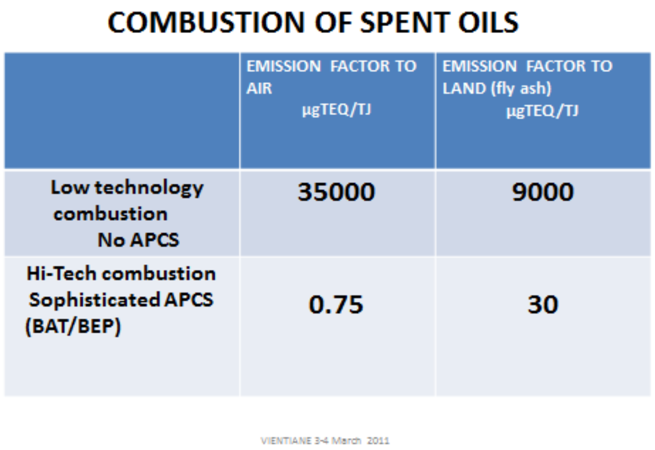
The emission factors for diesel engines, often used as generators or for combined production of heat and electricity, are given in Table 27. (87)

Table 27 Emission factors for diesel engines (UNEP)

	Emission Factors – µg TEQ/t of Diesel				
	Air	**Water**	**Land**	**Product**	**Residue**
Diesel engines	**0.1**	**NA**	**NA**	**NA**	**ND**

Although the use of spent oil (from car and truck exhaust oils, and restaurant and fast food) in standard boilers is discouraged in many countries, it is common in developing countries. UNEP has also developed emission factors for spent oil (see Table 28). (87)

Table 28 Emission factors for spent oil (UNEP)



COMBUSTION OF SPENT OILS

	EMISSION FACTOR TO AIR µgTEQ/TJ	EMISSION FACTOR TO LAND (fly ash) µgTEQ/TJ
Low technology combustion No APCS	**35000**	**9000**
Hi-Tech combustion Sophisticated APCS (BAT/BEP)	**0.75**	**30**

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By using the above emission factor tables, it is possible to evaluate the emissions of dioxins from a boiler and identify the potential outcomes of implementing measures to reduce the release of dioxins , e.g., boiler retrofit, new boiler purchase, fuel switching. Care should be taken, however, because if the boiler is not equipped with APCD, the dioxins contained in the fly ash (the ash that is carried out together with flue gases) will not be collected.

The dioxins referred to as residue in the tables will be released from the stack. For example, the EF for coal boilers are as follows:

EF to air: 10 µg TEQ/TJ

EF to residue: 14 µg TEQ/TJ

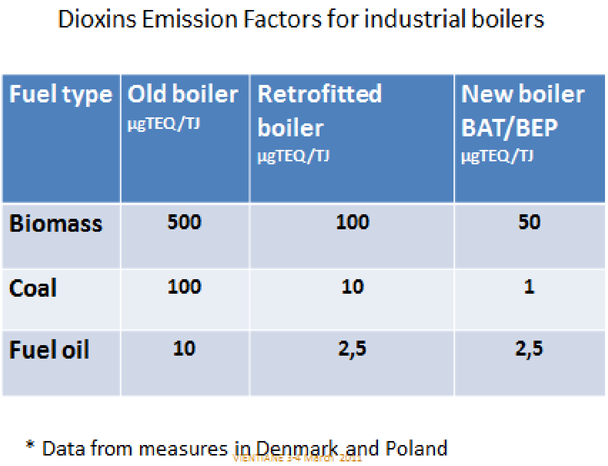
If the coal boiler has no filters, however, the EF will be:

EF to air: 24 µg TEQ/TJ

EF to residue: 0 µg TEQ/TJ

The emission factor tables must be used with care for small industrial boilers because they are based on large boilers equipped with sophisticated dust abatement devices, able to recover most of the fly ash carried out by flue gases. UNEP, therefore, also developed emission factors for small industrial boilers (see Table 29) to better represent their performance, particularly with respect to age and the possible solutions for modifying or replacing them. The Table is based on the limited data available in the literature for small industrial boilers. Old boilers emit more dioxins than new boilers because of the effect of wear and the technology on releases. This difference can be relevant for biomass and coal boilers.

Table 29 Emission factors for small industrial boilers (UNEP)



Dioxins Emission Factors for industrial boilers

Fuel type	Old boiler µgTEQ/TJ	Retrofitted boiler µgTEQ/TJ	New boiler BAT/BEP µgTEQ/TJ
Biomass	500	100	50
Coal	100	10	1
Fuel oil	10	2,5	2,5

* Data from measures in Denmark and Poland

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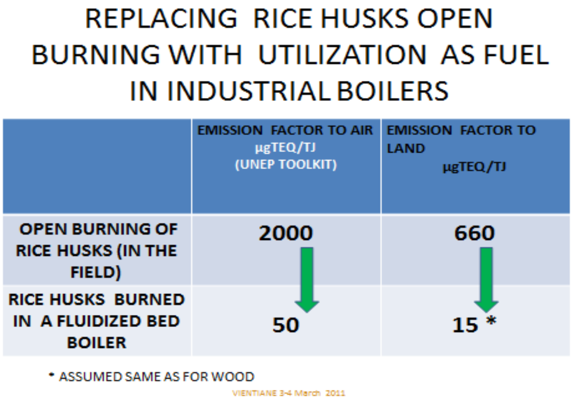
Switching from a dirty fuel to a cleaner one can have additional effects. Table 30 shows the difference between open burning of rice husks (a common agricultural practice) and burning them in a boiler. Since the dioxin EF for open burning of rice husks is much higher than the EF for burning them in boilers, using rice husks as fuel for boilers is not only economically attractive, but also greatly reduces emissions of dioxin to the environment.

Table 30 Emission factors for rice husk open burning versus in industrial boilers (UNEP)



REPLACING RICE HUSKS OPEN BURNING WITH UTILIZATION AS FUEL IN INDUSTRIAL BOILERS

	EMISSION FACTOR TO AIR µgTEQ/TJ (UNEP TOOLKIT)	EMISSION FACTOR TO LAND µgTEQ/TJ
OPEN BURNING OF RICE HUSKS (IN THE FIELD)	2000	660
RICE HUSKS BURNED IN A FLUIDIZED BED BOILER	50	15 *

* ASSUMED SAME AS FOR WOOD

VIENTIANE 3-4 March 2011

Example

To calculate dioxin releases to air from an industrial boiler, total releases over a year will be estimated since the emission levels are very low.

An old coal industrial boiler produces 8 t/h steam, and burns about 1.6 t/h of coal (lignite) with a heating value of 4000 kcal/h. The operating hours are 7000 h/year. To estimate the dioxin emissions, it is necessary to first calculate the total energy produced by burning coal.

Annual coal consumption: 1.6 t/h x 7000 h = 11,200 tons/year = 11,200 x 10^{3} kg
Coal heating value: 4000 kcal/kg = 16.72 MJ/kg = 16.71 x 10^{-6} TJ/kg (1 TJ = 10^{6} MJ)
Total energy consumed in one year: 11,200 x 10^{3} kg x 16.71 x10^{-6} TJ/kg = 187.15 TJ
Emission factor for an old industrial boiler: assumed as 100 µgTEQ/TJ (see the EF tables above)

The total amount of dioxins released by the boiler is:

$$\text{Total dioxins}_{\text{year}} = \text{EF} \times \text{Energy/year}$$

$$\text{Total dioxins}_{\text{year}} = 100\ \mu\text{gTEQ/TJ} \times 187.15\ \text{TJ} = 167100 \times 10^{-6}\ \mu\text{gTEQ} = 0.167\ \text{g/year}$$

Thus, the amount of total dioxins emitted from a coal-fired industrial boiler is 0.167 g/year

Mercury control and removal

The U.S. Environmental Protection Agency (EPA) has identified mercury as one of the toxic substances of greatest concern among the air toxic pollutants emitted by power plants. The type of fuel burned is significant for mercury emissions. The specific chemical form of mercury – known as the speciation – has a strong impact on its removal from flue gas by boiler air pollution control equipment. Mercury may be present as elemental mercury vapour (Hg^{0}), as a vapour of an oxidized mercury species (Hg^{2+}), or as particulate-bound mercury (Hg_{p}). (88)

The removal of mercury from flue gas is affected by the following factors: (89)

- *Coal type*: Halogen (chlorine, bromine, other) and sulphur content
- *Flue gas composition*: HCl, SO_{x}, incombustibles
- *Emission control equipment*: bag filters, electrostatic precipitators

Mercury may also be captured as a co-benefit of PM or SO_2 controls. NO_x controls can enhance the capture that is achieved in PM and SO_2 controls. (90) The six major areas of intervention for flue gas mercury removal are shown in Figure 158.

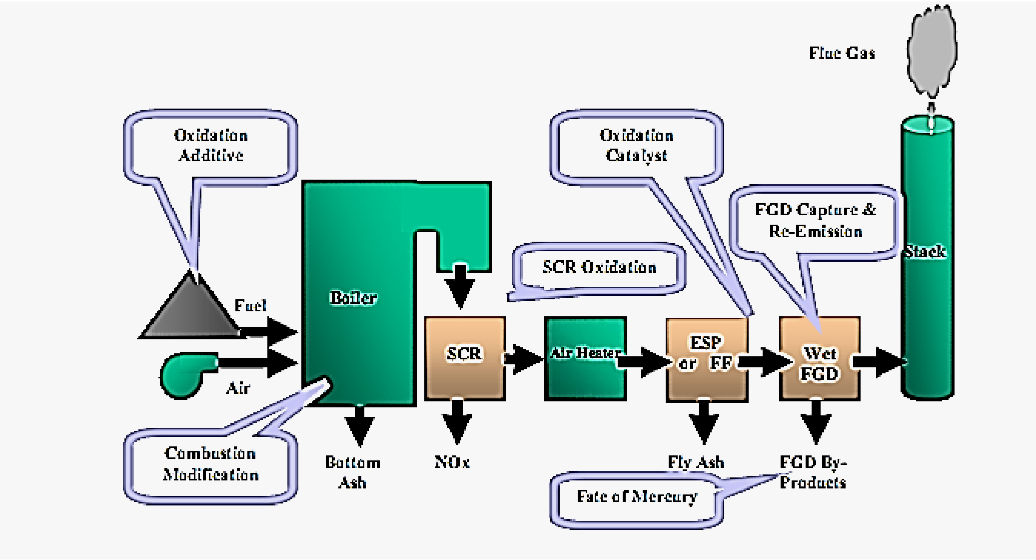


Figure 158 Major areas of intervention for Mercury removal(NETL DOE)

Control of mercury emissions from coal-fired boilers is currently achieved via existing controls used to remove PM, SO_2, and NO_X. This includes capture of particulate-bound mercury in PM control equipment and soluble mercury compounds in wet FGD systems. (88)

Mercury removal systems are mostly focused on large power plants. New systems to improve mercury capture include the following: (88)

- *Fuel blending*: Blending of small amounts of bituminous coal with sub-bituminous or lignite coal may provide some benefit to capture of mercury by existing equipment.
- *Addition of oxidizing chemicals*: The addition of chlorine to the fuel or injection into the flue gas is another approach that is being tested for enhancing intrinsic capture of mercury.
- *Increasing unburned carbon in fly ash*: Carbon in the fly ash has been shown to be an important factor in mercury capture by PM control equipment.
- *Mercury-specific catalysts***:** Enhancing capture by wet FGD processes is possible if Hg0 can be oxidized to Hg2+. Research efforts are underway to evaluate catalysts that are installed upstream of the wet FGD or injection of oxidizing chemicals upstream of the FGD.

Mercury control by sorbent injection

Unlike the technologies described earlier, where mercury removal was achieved as a co-benefit of removal of other pollutants, mercury control via injection of sorbent materials into the gas stream of coal-fired boilers is under development. Injection of dry sorbents (e.g., powdered activated carbon) has been used for control of mercury emissions from waste combustors and tested at numerous utility units in the United States. The mercury attaches to the carbon particles and is removed in a traditional particle control device (see Figure 159). However, sorbent injection experience on waste combustors may not be directly transferable to coal-fired electric utility boilers. (88)

Wet scrubbers are only effective for removal of soluble mercury species, such as Hg2+. Mercury vapour in its elemental form, Hg0, is insoluble in the scrubber slurry and not removed. Therefore, an additional process of Hg0 conversion, usually by adding halogens to the flue gas, is required to complete mercury capture. The type of coal burned and the presence of a selective catalytic reduction unit both affect the ratio of elemental to oxidized mercury in the flue gas, and thus the degree to which the mercury is removed. (91)

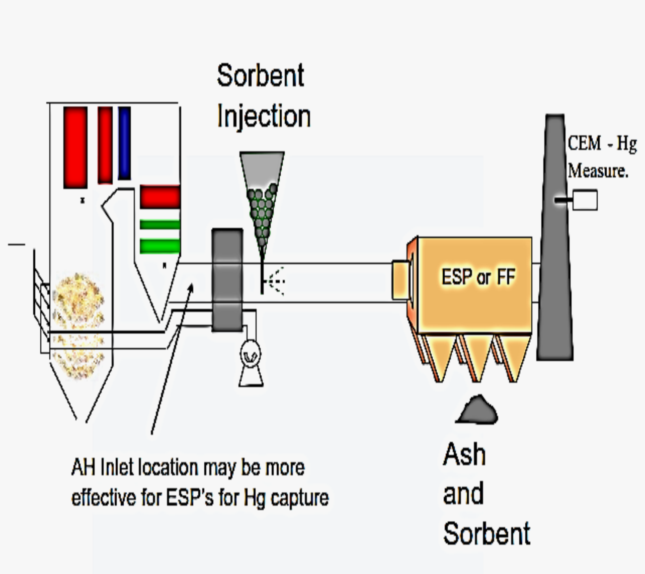


Figure 159 Mercury removal-sorbent injection (ADA Environmental Solutions) (139)

The most promising technologies for removing mercury from industrial boilers are: (92)

- powered activated carbon (PAC), the most thoroughly tested and commercially available of all the technologies to date, and proven to successfully remove up to 90% of mercury in many configurations;
- co-benefits with other scrubbing technologies;
- switching to fluidized bed boilers, which have demonstrated very low emissions;
- fixed bed activated carbon applications; and
- catalytic removal.

Multiple control devices

Multiple control devices may be used in combination to control one or many pollutants. For example, mechanical collectors are often used with fabric filters to control PM emissions: the mechanical collector collects large particles, and the fabric filter collects smaller particles. SCR is often used with fabric filters to control NO_x and PM emissions: the devices are arranged in a series, or tandem, relative to the flue gas stream. The specific types of devices used and the order in which they are arranged are dependent on the process, gas stream, and pollutant characteristics. The overall control efficiency for multiple devices is likely to be around the efficiency of the last device in the series.

Effects of APCD adoption on emissions and costs

The amount of pollutant released depends on the efficiency of the APCDs used: the lower the pollutant capture rate of the devices, the more pollutants released to the environment. The use of best available techniques (BAT; see Chapter 6), which guarantee higher pollutant removal rates, helps keep boiler emissions at the lowest possible values. The implementation of best environmental practices (BEP; also discussed in Chapter 6) also helps reduce the releases of pollutants to the environment. These include maintenance of APCDs. For example, an ESP can only operate for a limited period at lower than nominal efficiency as a consequence of poor maintenance. In this case, the amount of PM emitted to the air would be higher than under normal operating conditions.

Effects of APCD efficiency on emissions

Consider a hypothetical ESP that operates under 97.5% efficiency during a minor malfunction. Table 31 shows the emission increases that would occur if the device operated under malfunction conditions from 1% to 10% of the time, and if the ESP was otherwise expected to operate at design efficiencies between 98% and 99.5%. Small decreases in the control percentage can result in large percentage increases in actual emissions if the design efficiency is high (54).

Baseline: ESP with 99% dust removal efficiency assumed as BAT. If other, less efficient, non-BAT devices are used, additional dust will be emitted to air as shown in Table 31. A device with 80% efficiency, instead of 99%, will release 225 tons (baseline) + 54 tons/year more= 279 tons/year.

Table 31 Effect of reduced ESP efficiency on PM emissions

ESP design efficiency %	PM emissions tons/year	Incremental PM emissions tons/year
99	**258**	**Baseline (225 tons)**
95	**243**	**+15**

90	**230**	**+28**
85	**217**	**+41**
80	**204**	**+54**

If the ESP is not well operated and maintained, it will progressively lose its efficiency and experience malfunctions, during which the emissions of PM will be higher (see Table 32). For example, if the control device design efficiency is 99.5%, and operates under malfunction conditions (e.g., at 97.5% efficiency) for 5% of the operating time), the malfunction would add 20% to the expected annual emissions, which, in this case, are 225 ton/year of PM. In the case of 10% time malfunction, PM emissions would rise by about 40%. (54) This effect is less evident if the nominal efficiency of the devices is lower.

Table 32 Percentage increase of emissions of an ESP during malfunction (54)

Design Efficiency	**Percentage Downtime**									
	1%	**2%**	**3%**	**4%**	**5%**	**6%**	**7%**	**8%**	**9%**	**10%**
99.5%	4.0%	8.0%	12.0%	16.0%	20.0%	24.0%	28.0%	32.0%	36.0%	40.0%
99.0%	1.5%	3.0%	4.5%	6.0%	7.5%	9.0%	10.5%	12.0%	13.5%	15.0%
98.5%	0.7%	1.3%	2.0%	2.7%	3.3%	4.0%	4.7%	5.3%	6.0%	6.7%
98.0%	0.3%	0.5%	0.8%	1.0%	1.3%	1.5%	1.8%	2.0%	2.3%	2.5%

Effect of NO_x abatement devices

Choosing a low NO_x technology can have adverse effects on boiler performance. It can limit the turndown ratio (the capacity of the boiler to change from high load to low load), and reduce the boiler capacity (derating), as it will produce less steam for the same fuel in input, due to the different burner flame shaping. The effect of lowering the flame temperature for lower NO_x production can also reduce boiler efficiency because the heat transfer rate from gases to tube walls is reduced.

Changes in excess air ratio can also affect boiler performance. As already mentioned, the optimum excess air for a boiler ranges between 10% and 20% (2% to 4% O_2), according to the type of fuel used. Since NO_x controls often require higher excess air levels, this can result in increased stack losses, reduced boiler efficiency, and high levels of carbon monoxide under stoichiometric conditions.

Air pollution control costs

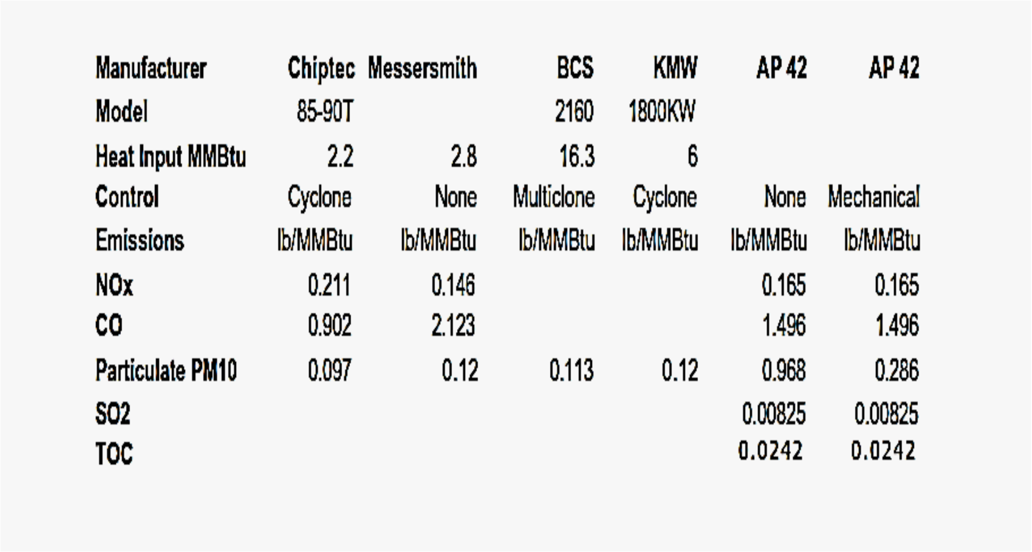
The addition of an APCD on an existing boiler results in additional costs, not only for the purchase of the device, but also for annual operating and maintenance expenses. APCD costs vary with performance, amount of flue gas to be treated, type of flue gas, type of boiler, and location. Surveying costs of air pollution control technologies is therefore challenging and cannot accurately reflect actual costs for specific markets and locations.

Comparison of particulate control technologies

This section compares costs of various particulate control technologies, based on a 2001 U.S. study of relatively small wood boilers. Although the findings are not recent, (93) they can be used to compare different technologies. Actual costs, however, would need to be verified on the basis of real needs in terms of efficiency and compliance to local emission standards and market availability.

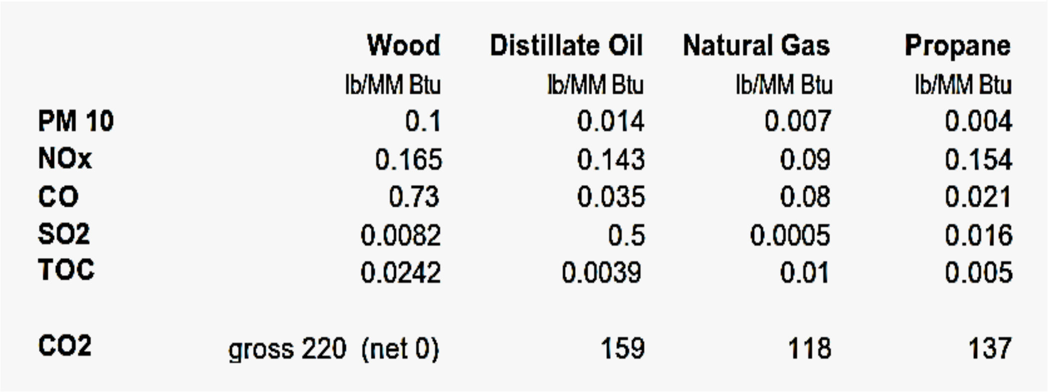
The study focused on wood-fired boilers in the size range of approximately 3 MMBtu to 10 MMBtu (1 MWth to 3 MWth). The analysis is generic in that it is applicable to any manufacturer or type of wood-fired boiler of this size for any location. It could also apply to biomass boilers in general. Table 33 summarizes the typical emissions of different U.S. manufacturers, adopting different pollution control technologies.

Table 33 Emission rates for small wood-fired boilers-Source: Resource System Group inc. (93)



Manufacturer	Chiptec	Messersmith	BCS	KMW	AP 42	AP 42
Model	85-90T		2160	1800KW		
Heat Input MMBtu	2.2	2.8	16.3	6		
Control	Cyclone	None	Multiclone	Cyclone	None	Mechanical
Emissions	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu
NOx	0.211	0.146			0.165	0.165
CO	0.902	2.123			1.496	1.496
Particulate PM10	0.097	0.12	0.113	0.12	0.968	0.286
SO2					0.00825	0.00825
TOC					0.0242	0.0242

Table 34 Comparison of boiler emissions (Resource System Group Inc.) (93)

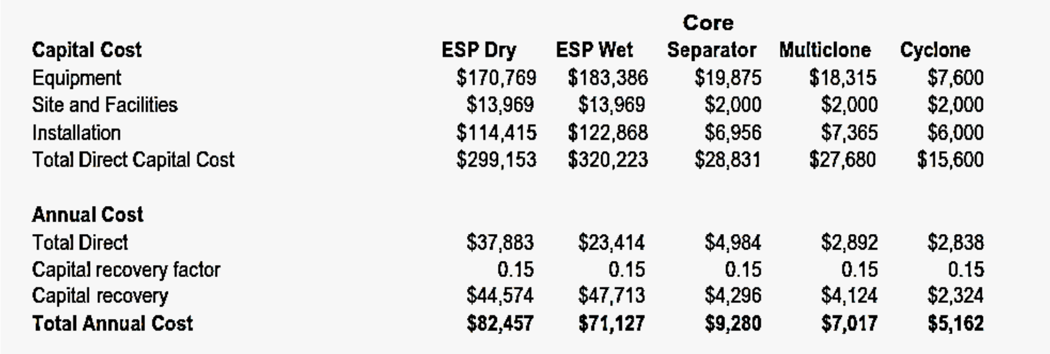


	Wood	Distillate Oil	Natural Gas	Propane
	lb/MM Btu	lb/MM Btu	lb/MM Btu	lb/MM Btu
PM 10	0.1	0.014	0.007	0.004
NOx	0.165	0.143	0.09	0.154
CO	0.73	0.035	0.08	0.021
SO2	0.0082	0.5	0.0005	0.016
TOC	0.0242	0.0039	0.01	0.005
CO2	gross 220 (net 0)	159	118	137

A comparison of the emissions of the most common pollutants from different fuels is given in Table 34.

The costs of pollution control for a 7.5 MMBtu (2 MWth) boiler, assuming an annual capacity factor of 75% and an emission rate (ER) of 0.71 lb/MMBtu (0.4 grams/MJ), are shown in Table 35. It is evident from the Table that cyclones and multicyclones are much cheaper than other technologies. The annual cost of a dry ESP is 15 times that of a cyclone. A core separator mechanical dust collector, a special device developed by the U.S. EPA, has been included in the evaluation.

Table 35 Particulate control System Costs Analysis (Resource System Group inc.) (93)



Capital Cost	**ESP Dry**	**ESP Wet**	**Core Separator**	**Multiclone**	**Cyclone**
Equipment	$170,769	$183,386	$19,875	$18,315	$7,600
Site and Facilities	$13,969	$13,969	$2,000	$2,000	$2,000
Installation	$114,415	$122,868	$6,956	$7,365	$6,000
Total Direct Capital Cost	$299,153	$320,223	$28,831	$27,680	$15,600
Annual Cost					
Total Direct	$37,883	$23,414	$4,984	$2,892	$2,838
Capital recovery factor	0.15	0.15	0.15	0.15	0.15
Capital recovery	$44,574	$47,713	$4,296	$4,124	$2,324
Total Annual Cost	**$82,457**	**$71,127**	**$9,280**	**$7,017**	**$5,162**

Sampling and analysis of particulate and gaseous pollutants

This section discusses some of the basic methodologies available for sampling and analysing pollutants from a boiler (94). This information is helpful in evaluating and selecting the type and quality of sampling devices to monitor emissions to the environment.

Particulate monitoring

Particulate monitoring is usually accomplished with manual measurements and subsequent laboratory analysis. A particulate matter measurement uses gravimetric principles. Gravimetric analysis refers to the quantitative chemical analysis of weighing a sample, usually of a separated and dried precipitate. In this method, a filter-based high-volume sampler (a vacuum- type device that draws air through a filter or absorbing substrate) retains atmospheric pollutants for future laboratory weighing and chemical analysis. Particles are trapped or collected on filters, and the filters are weighed to determine the volume of the pollutant. The weight of the filter with collected pollutants minus the weight of a clean filter gives the amount of particulate matter in a given volume of air.

Chemical analysis can be done by:

- atomic absorption spectrometry (AAS)
- atomic fluorescence spectrometry (AFS)
- inductively couple plasma (ICP) spectroscopy, and
- X-ray fluorescence (XRF) spectroscopy.

AAS, which has been used to determine single elements in analytical samples, is a sensitive means for the quantitative determination of more than 60 metals or metalloid elements (see Figure 160). This technique measures energy changes in the atomic state of the analyte. An analyte is a substance whose chemical composition is to be determined by chemical analysis. For example, AAS is used to measure lead in particulate monitoring. After lead particles are collected by gravimetric methods in a Teflon (polytetrafluoroethylene, PTFE) filter, lead is acid-extracted from the filter. The aqueous sample is vaporized and dissociates into its elements in the gaseous state. The element being measured, in this case lead, is aspirated into a flame or injected into a graphite furnace and atomized. A hollow cathode or electrodeless discharge lamp for the element being determined provides a source of that metal's particular absorption wavelength. The atoms in the unionized or "ground" state absorb energy, become excited, and advance to a higher energy level. A detector measures the amount of light absorbed by the element, hence the number of atoms in the ground state in the flame or furnace. The data output from the spectrometer can be recorded on a strip chart recorder or processed by computer. Determination of metal concentrations is performed from prepared calibration curves or read directly from the instrument.

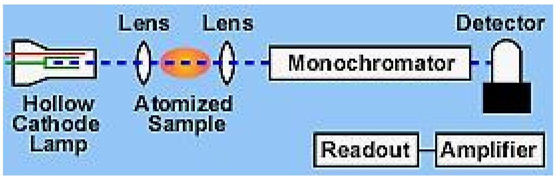


Figure 160 Atomic Absorption Spectrometry (US EPA) (94)

Gas monitoring

Gaseous pollutant monitoring can be accomplished using various measurement principles. As an example, sulphur dioxide monitoring can be accomplished with dynamic samplers for average concentrations over a 24-hour period and with static samplers for longer periods, e.g., 30 days. Some of the most common techniques to analyse gaseous pollutants include spectrophotometry, chemiluminescence, gas chromatography-flame ionization detector (GC-FID), gas chromatography-mass spectrometry (GC-MS), and Fourier transform infrared spectroscopy (FTIR).

With all sampling and analysis procedures, the end result is quantitative data. The validity of the data depends on the accuracy and precision of the methods used in generating the data. Accuracy is the extent to which measurements represent their corresponding actual values, and precision is a measurement of the variability observed upon duplicate collection or repeated analysis. To ensure the validity of data, various quality control measures are employed for each reference method. The primary quality control measure is calibration. Calibration checks the accuracy of a measurement by establishing the relationship between the output of a measurement process and a known input. Each of the reference methods has precise calibration procedures that must be followed to ensure accurate results.

Methods of measuring and analysing air pollutants are summarized in Table 36. (94)

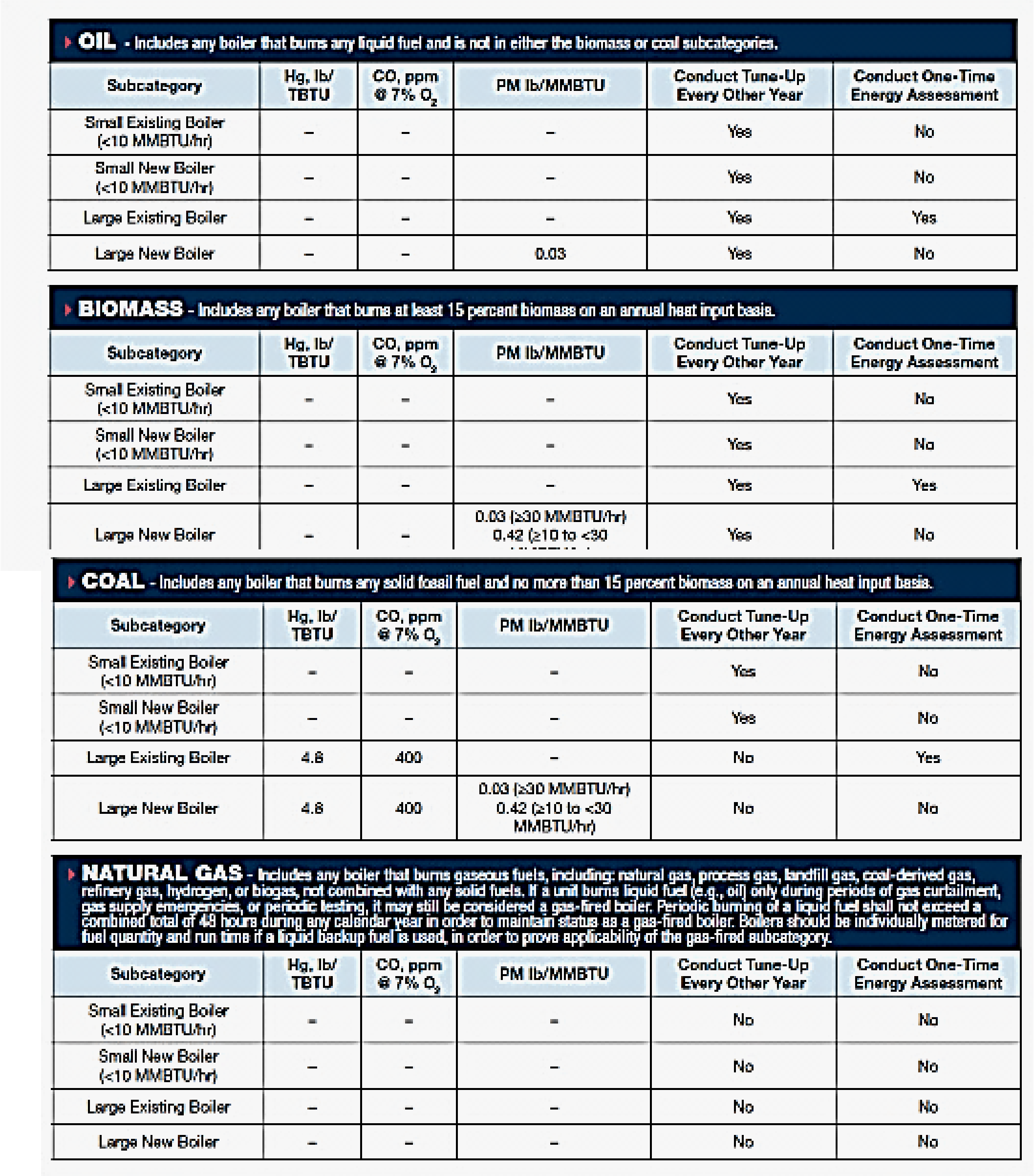
Table 36 Methods of measuring and analySing air pollutants

Methods of Measuring and Analysing Air Pollutants		
Method	**Variable Measured**	**Principle**
Gravimetric	PM_{10}, $PM_{2.5}$	Particles are trapped or collected on filters, and the filters are weighed to determine the volume of the pollutant.
Atomic absorption spectrometry (AAS)	More than 60 metals or metalloid elements (e.g., Pb, Hg, Zn)	Energy changes in the atomic state of the analyte are measured. Emitted radiation is a function of atoms present in the sample.
Spectrophotometry	SO_2, O_3	The amount of light that a sample absorbs is measured. The amount of light absorbed indicates the amount of analyte present in the sample.
Chemiluminescence	NO_2, O_3	This method is based upon the emission spectrum of an excited species that is formed in the course of a chemical reaction.
Gas chromatography (GC) - flame ionization detector (FID)	VOC	FIDs respond in proportion to the number of carbon atoms in gas sample.
Gas chromatography-mass spectrometry (GC-MS)	VOC	Mass spectrometers use the difference in the mass-to-charge ratio (m/z) of ionized atoms or molecules to separate them from each other.
Fourier transform infrared spectroscopy (FTIR)	CO, VOC, CH_4	The sample absorbs infrared radiation, and the difference in absorption is measured.

Boiler emission limits

Since emission standards and regulations vary widely by country and are periodically updated, it is difficult to present and discuss emission limits in detail. As an example of improved regulation of boiler emission limits, Table 37 lists the U.S. EPA's recent emission limits (95) by fuel used and boiler size.

Table 37 EPA emission limits (Cleaver Brooks) (95)



OIL - Includes any boiler that burns any liquid fuel and is not in either the biomass or coal subcategories.

Subcategory	Hg, lb/ TBTU	CO, ppm @ 7% O_2	PM lb/MMBTU	Conduct Tune-Up Every Other Year	Conduct One-Time Energy Assessment
Small Existing Boiler (<10 MMBTU/hr)	–	–	–	Yes	No
Small New Boiler (<10 MMBTU/hr)	–	–	–	Yes	No
Large Existing Boiler	–	–	–	Yes	Yes
Large New Boiler	–	–	0.03	Yes	No

BIOMASS - Includes any boiler that burns at least 15 percent biomass on an annual heat input basis.

Subcategory	Hg, lb/ TBTU	CO, ppm @ 7% O_2	PM lb/MMBTU	Conduct Tune-Up Every Other Year	Conduct One-Time Energy Assessment
Small Existing Boiler (<10 MMBTU/hr)	–	–	–	Yes	No
Small New Boiler (<10 MMBTU/hr)	–	–	–	Yes	No
Large Existing Boiler	–	–	–	Yes	Yes
Large New Boiler	–	–	0.03 (≥30 MMBTU/hr) 0.42 (≥10 to <30	Yes	No

COAL - Includes any boiler that burns any solid fossil fuel and no more than 15 percent biomass on an annual heat input basis.

Subcategory	Hg, lb/ TBTU	CO, ppm @ 7% O_2	PM lb/MMBTU	Conduct Tune-Up Every Other Year	Conduct One-Time Energy Assessment
Small Existing Boiler (<10 MMBTU/hr)	–	–	–	Yes	No
Small New Boiler (<10 MMBTU/hr)	–	–	–	Yes	No
Large Existing Boiler	4.8	400	–	No	Yes
Large New Boiler	4.8	400	0.03 (≥30 MMBTU/hr) 0.42 (≥10 to <30 MMBTU/hr)	No	No

NATURAL GAS - Includes any boiler that burns gaseous fuels, including: natural gas, process gas, landfill gas, coal-derived gas, refinery gas, hydrogen, or biogas, not combined with any solid fuels. If a unit burns liquid fuel (e.g., oil) only during periods of gas curtailment, gas supply emergencies, or periodic testing, it may still be considered a gas-fired boiler. Periodic burning of a liquid fuel shall not exceed a combined total of 48 hours during any calendar year in order to maintain status as a gas-fired boiler. Boilers should be individually metered for fuel quantity and run time if a liquid backup fuel is used, in order to prove applicability of the gas-fired subcategory.

Subcategory	Hg, lb/ TBTU	CO, ppm @ 7% O_2	PM lb/MMBTU	Conduct Tune-Up Every Other Year	Conduct One-Time Energy Assessment
Small Existing Boiler (<10 MMBTU/hr)	–	–	–	No	No
Small New Boiler (<10 MMBTU/hr)	–	–	–	No	No
Large Existing Boiler	–	–	–	No	No
Large New Boiler	–	–	–	No	No

KEY ▲**Fuel Subcategory:** If you are not sure which fuel subcategory applies to your boiler, use the Fuel Subcategory Calculation Tool at http://cleaverbrooks.com/Reference-Center/EPA-Compliance/Step-2/Step-2.aspx to
conduct an annual heat input fuel calculation.

▲**Boiler Size:** Boiler size is expressed in terms of rated design heat input capacity and is measured in million British thermal units per hour, or MMBTU/hr. A boiler is considered "small" if its input is <10 MMBTU/hr.

▲**New vs. Existing:** A boiler is considered "New" by EPA standards if you contracted to purchase it or have it rebuilt after June 4, 2010.

For more information about Area Source Rule Requirements, including boiler classification, visit the Cleaver-Brooks website at http://cleaverbrooks.com/Reference-Center/EPA-Compliance/Index.aspx or call your local Cleaver-Brooks representative at http://cleaverbrooks.com/Find-a-Rep/Index.aspx.

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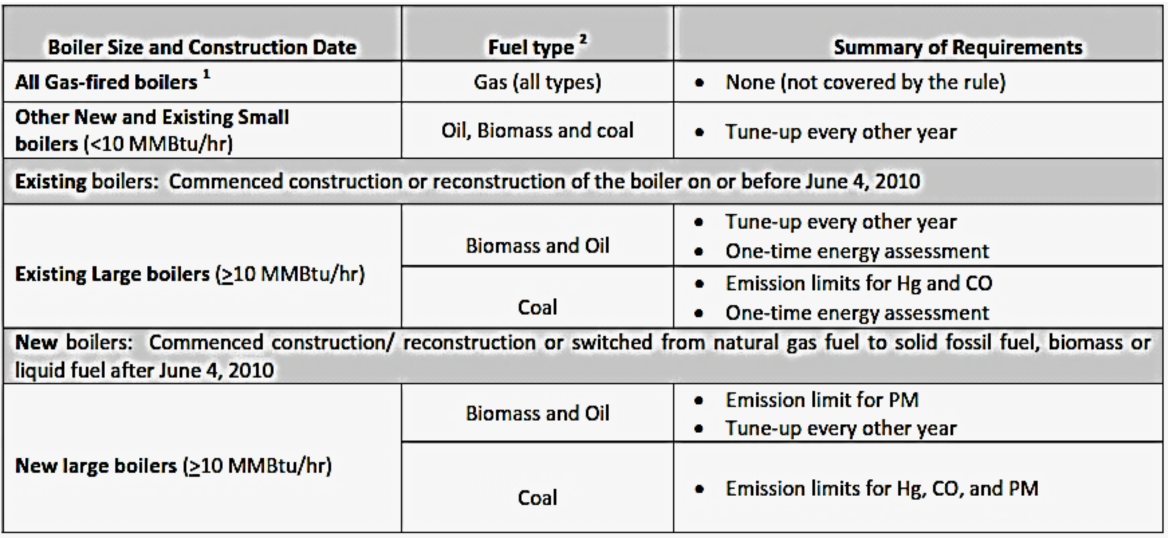
EPA rules have established "work practices requirements", summarized in Table 38, which can be considered as equivalent to implementation of best environmental practices (BEP) for boilers (discussed in Chapter 6). These rules confirm that periodic tune-ups of boilers are a good practice to reduce emissions. (96)

Table 38 EPA requirements for boilers (Cleaver Brooks) (96)

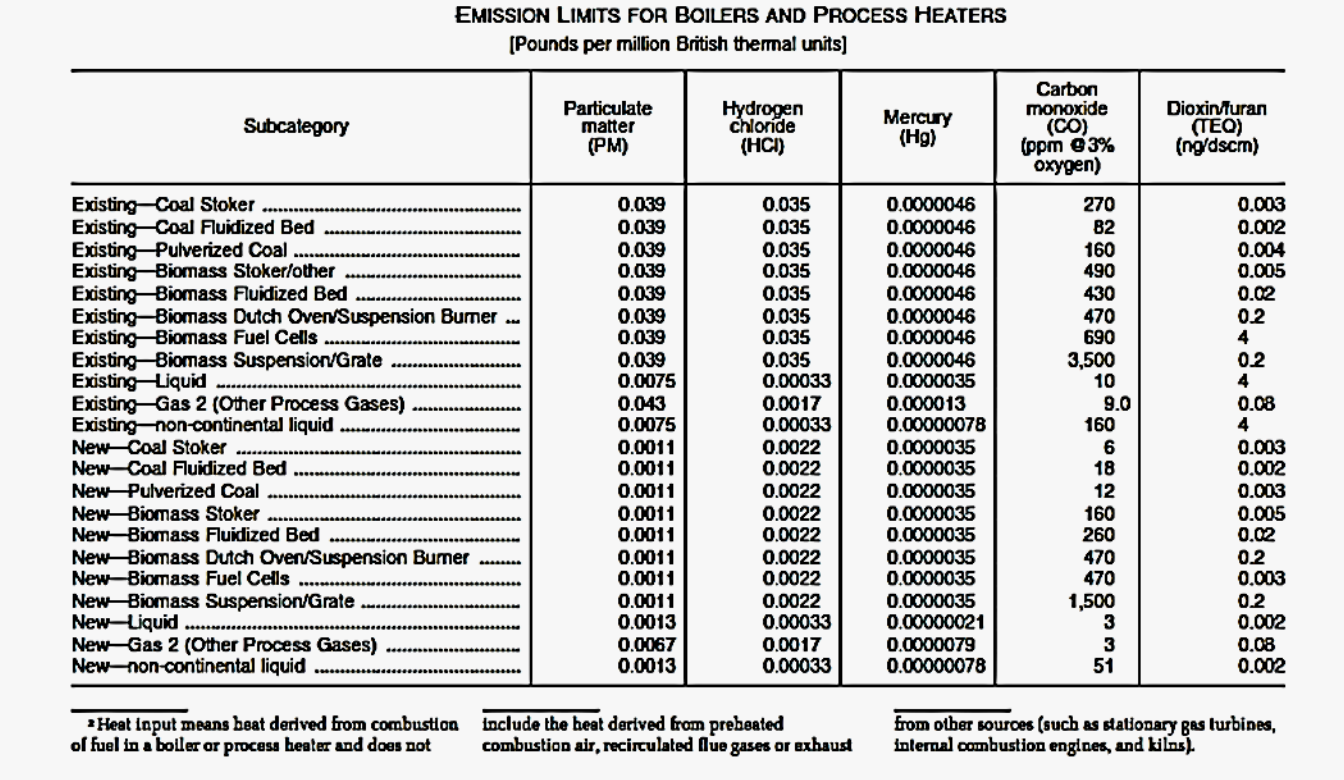


Boiler Size and Construction Date	Fuel type [2]	Summary of Requirements
All Gas-fired boilers [1]	Gas (all types)	• None (not covered by the rule)
Other New and Existing Small boilers (<10 MMBtu/hr)	Oil, Biomass and coal	• Tune-up every other year
Existing boilers: Commenced construction or reconstruction of the boiler on or before June 4, 2010		
Existing Large boilers (≥10 MMBtu/hr)	Biomass and Oil	• Tune-up every other year • One-time energy assessment
	Coal	• Emission limits for Hg and CO • One-time energy assessment
New boilers: Commenced construction/ reconstruction or switched from natural gas fuel to solid fossil fuel, biomass or liquid fuel after June 4, 2010		
New large boilers (≥10 MMBtu/hr)	Biomass and Oil	• Emission limit for PM • Tune-up every other year
	Coal	• Emission limits for Hg, CO, and PM

f

In March 2011, EPA released the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. (97) The standards include a table on limits for pollutant releases such as PM, CO, HCl, mercury and dioxins (see Table 39):

Table 39 Emission limits for industrial boilers US EPA



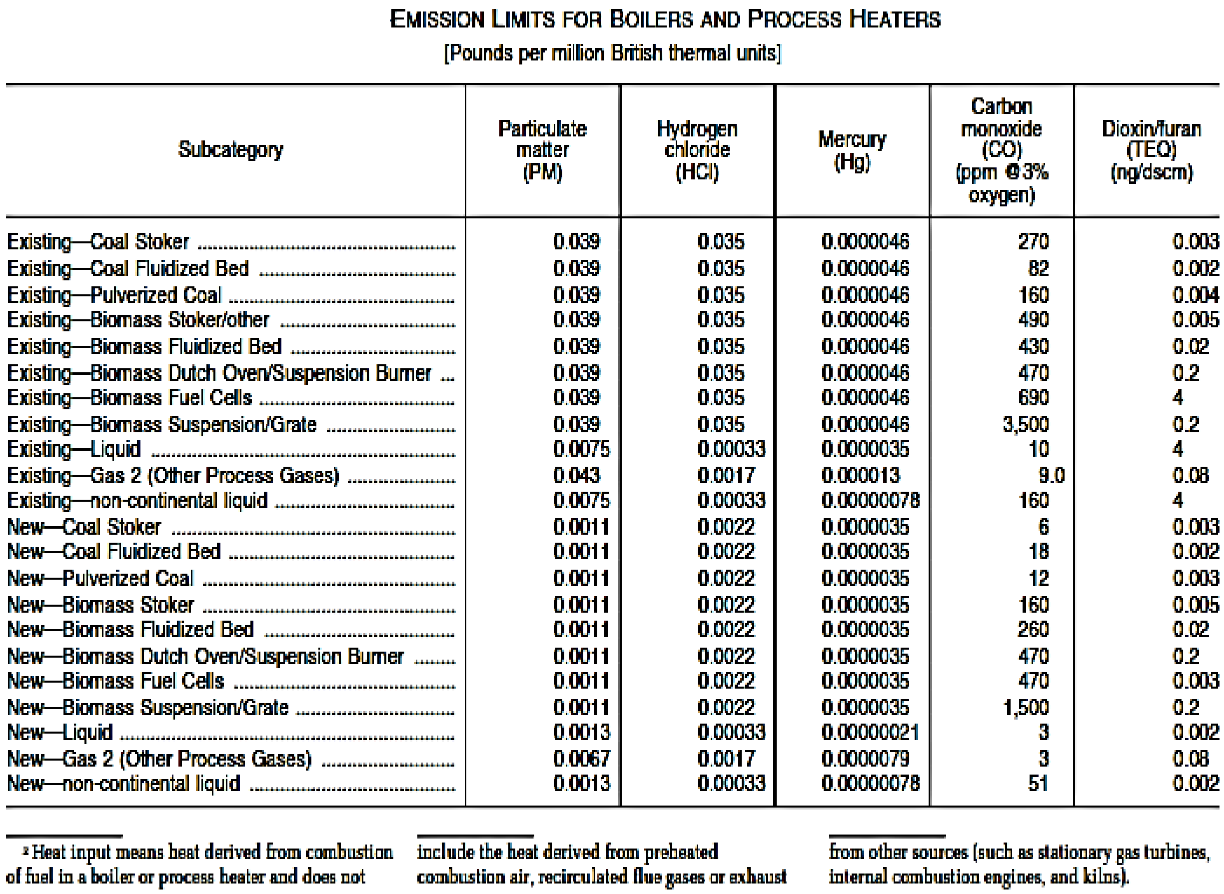
EMISSION LIMITS FOR BOILERS AND PROCESS HEATERS
[Pounds per million British thermal units]

Subcategory	Particulate matter (PM)	Hydrogen chloride (HCl)	Mercury (Hg)	Carbon monoxide (CO) (ppm @3% oxygen)	Dioxin/furan (TEQ) (ng/dscm)
Existing—Coal Stoker	0.039	0.035	0.0000046	270	0.003
Existing—Coal Fluidized Bed	0.039	0.035	0.0000046	82	0.002
Existing—Pulverized Coal	0.039	0.035	0.0000046	160	0.004
Existing—Biomass Stoker/other	0.039	0.035	0.0000046	490	0.005
Existing—Biomass Fluidized Bed	0.039	0.035	0.0000046	430	0.02
Existing—Biomass Dutch Oven/Suspension Burner	0.039	0.035	0.0000046	470	0.2
Existing—Biomass Fuel Cells	0.039	0.035	0.0000046	690	4
Existing—Biomass Suspension/Grate	0.039	0.035	0.0000046	3,500	0.2
Existing—Liquid	0.0075	0.00033	0.0000035	10	4
Existing—Gas 2 (Other Process Gases)	0.043	0.0017	0.000013	9.0	0.08
Existing—non-continental liquid	0.0075	0.00033	0.00000078	160	4
New—Coal Stoker	0.0011	0.0022	0.0000035	6	0.003
New—Coal Fluidized Bed	0.0011	0.0022	0.0000035	18	0.002
New—Pulverized Coal	0.0011	0.0022	0.0000035	12	0.003
New—Biomass Stoker	0.0011	0.0022	0.0000035	160	0.005
New—Biomass Fluidized Bed	0.0011	0.0022	0.0000035	260	0.02
New—Biomass Dutch Oven/Suspension Burner	0.0011	0.0022	0.0000035	470	0.2
New—Biomass Fuel Cells	0.0011	0.0022	0.0000035	470	0.003
New—Biomass Suspension/Grate	0.0011	0.0022	0.0000035	1,500	0.2
New—Liquid	0.0013	0.00033	0.00000021	3	0.002
New—Gas 2 (Other Process Gases)	0.0067	0.0017	0.0000079	3	0.08
New—non-continental liquid	0.0013	0.00033	0.00000078	51	0.002

[a] Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

- Boilers are classified into two main categories, Existing and New, each of which is divided by type of fuel used: 1-Coal. 2-Biomass, 3-Liquid, 4-Gas, 5-Non continental liquid.
- Coal boilers are also classified by type: 1-Stoker, 2- Fluidized bed, 3- Pulverized coal.
- Biomass boilers are also classified by type: 1-Stoker, 2-Fluidized bed, 3-Dutch oven/Suspension burner, 4-Fuel cells, 5-Suspension grate.

The classifications used take into account the intrinsic limits of each type of boiler, e.g., coal fluidized bed boilers have more stringent limits for dioxins and CO than stoker boilers because this technology normally guarantees lower emissions than stoker boilers. EPA's proposed limits thus try to take into account both type of fuel and technology.



EMISSION LIMITS FOR BOILERS AND PROCESS HEATERS

[Pounds per million British thermal units]

Subcategory	Particulate matter (PM)	Hydrogen chloride (HCl)	Mercury (Hg)	Carbon monoxide (CO) (ppm @3% oxygen)	Dioxin/furan (TEQ) (ng/dscm)
Existing—Coal Stoker	0.039	0.035	0.0000046	270	0.003
Existing—Coal Fluidized Bed	0.039	0.035	0.0000046	82	0.002
Existing—Pulverized Coal	0.039	0.035	0.0000046	160	0.004
Existing—Biomass Stoker/other	0.039	0.035	0.0000046	490	0.005
Existing—Biomass Fluidized Bed	0.039	0.035	0.0000046	430	0.02
Existing—Biomass Dutch Oven/Suspension Burner	0.039	0.035	0.0000046	470	0.2
Existing—Biomass Fuel Cells	0.039	0.035	0.0000046	690	4
Existing—Biomass Suspension/Grate	0.039	0.035	0.0000046	3,500	0.2
Existing—Liquid	0.0075	0.00033	0.0000035	10	4
Existing—Gas 2 (Other Process Gases)	0.043	0.0017	0.000013	9.0	0.08
Existing—non-continental liquid	0.0075	0.00033	0.00000078	160	4
New—Coal Stoker	0.0011	0.0022	0.0000035	6	0.003
New—Coal Fluidized Bed	0.0011	0.0022	0.0000035	18	0.002
New—Pulverized Coal	0.0011	0.0022	0.0000035	12	0.003
New—Biomass Stoker	0.0011	0.0022	0.0000035	160	0.005
New—Biomass Fluidized Bed	0.0011	0.0022	0.0000035	260	0.02
New—Biomass Dutch Oven/Suspension Burner	0.0011	0.0022	0.0000035	470	0.2
New—Biomass Fuel Cells	0.0011	0.0022	0.0000035	470	0.003
New—Biomass Suspension/Grate	0.0011	0.0022	0.0000035	1,500	0.2
New—Liquid	0.0013	0.00033	0.00000021	3	0.002
New—Gas 2 (Other Process Gases)	0.0067	0.0017	0.0000079	3	0.08
New—non-continental liquid	0.0013	0.00033	0.00000078	51	0.002

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[2] Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat derived from preheated combustion air, recirculated flue gases or exhaust from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

CHAPTER 5 – BOILER EFFICIENCY

SUMMARY

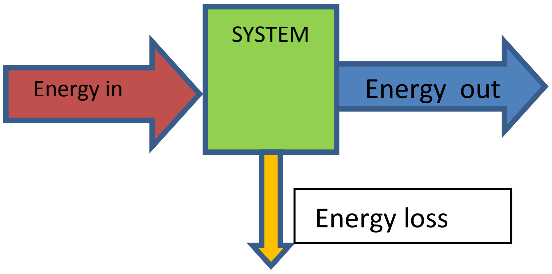
This Chapter deals with efficiency, which is one of the most critical parameters for the economically and environmentally sound operation of boilers. Improving efficiency means less fuel consumed and fewer pollutants emitted.

The Chapter discusses how to use different types of efficiency to determine the most suitable boiler operation. Since boiler operators need to know how to measure and improve the efficiency of a boiler, direct and indirect methods for measuring efficiency are illustrated. The Chapter also examines the main factors that affect efficiency including stack losses — the losses from the hot flue gases leaving the stack. Operators often keep high excess air values to optimize combustion, but this can result in loss of efficiency and increased fuel consumption. Other factors that affect efficiency are feedwater temperature, intermittent operation, and fouling of heat transfer surfaces.

Steam production is basically an energy conversion process in which fuel energy is converted into steam energy. Since boilers are the most energy-intensive components of a steam system, they should be the focus of energy management. Several factors are key ingredients in boiler performance. Typically, the energy exiting the boiler with the flue gas is the most significant loss associated with boiler operation. This loss is directly linked to the temperature of the flue gas and the amount of excess air supplied to the combustion process. Other combustion factors also impact this portion of the energy conversion process. Boiler blowdown (a periodic bleeding of steam from the boiler) is essential for the continued operation of any steam boiler, but is also a loss to the boiler operation. To a large extent, this loss can be managed and reduced. Heat transfer losses from the boiler shell are also an area of potential heat loss management.

Definition of boiler efficiency

The concept of efficiency is very important for understanding how sound management of boilers can reduce their emissions. Generally, efficiency is an expression of the amount of desired output from a component compared to the input required. In a system where there is energy in input, energy in output, and some energy lost, the efficiency can be expressed as:



$$EFFICIENCY = \frac{Energy\ out}{Energy\ in}$$

$$EFFICIENCY = \frac{Energy\ out}{Energy\ in}$$

$$\text{EFFICIENCY} = \frac{\text{Energy in} - \text{Energy loss}}{\text{Energy in}}$$

The energy out from the system is the difference between the energy in and the energy losses, according to the following equation:

$$Energy\ out\ =\ Energy\ in - energy\ loss$$

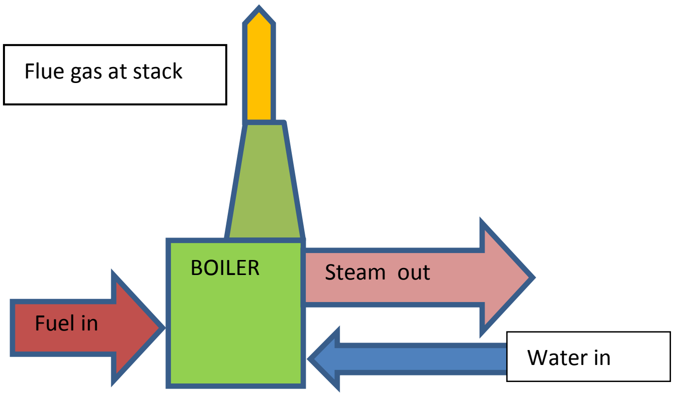
Efficiency is expressed by non-dimensional values, and is very often indicated as a percentage:

Efficiency = 0, 75 or

Efficiency = 75%

To avoid mistakes, the values used to calculate efficiency components, *energy in* and *energy out*, must be expressed using the same energy unit of measure (MJ, kcal, MBtu, etc.). Normally energy input is expressed in kilograms per hour (kg/h) of fuel and energy output is expressed in kg/h of steam, but efficiency cannot be measured by simply dividing the two values, even if they are apparently expressed in the same unit. The two values must be first converted into energy (MJ, kWh, Btu etc.) using the same energy units. Therefore, to calculate efficiency, kg/h of fuel and kg/h of steam must be converted into kilowatt hours (kWh), megajoules (MJ), or British thermal units (Btu).

In an industrial boiler, where the energy input is the fuel, and the energy output is the steam, efficiency can be expressed as:



Efficiency can be calculated as:

$$EFFICIENCY = \frac{Steam\ out}{Fuel\ in}$$

$$EFFICIENCY = \frac{Energy\ sSteam\ out - Energy\ water\ in}{Energy\ fFuel\ in}$$

The energy input (fuel in) is related to the energy content (fuel heating value). Each fuel has its own heating value, which can be expressed as kcal/kg, MJ/kg, or Btu/lb (see Chapter 2). The heating value multiplied by the fuel mass flow gives the amount of energy input to the boiler for the given unit of time (hours, in this case):

$$\text{Energy input} = \text{Fuel hHeating vValue x Ffuel mass flow}$$

$$\text{Fuel mass flow} = kg/h$$

$$\text{Fuel heating value} = MJ/kg$$

$$\text{Energy input} = MJ/kg \text{ x } kg/h \text{ x } 1h = MJ$$

The energy output is related to the intrinsic energy of the steam produced — the enthalpy (see Chapter 1 on *REVIEW OF BASIC CONCEPTS*). It mainly depends on the steam temperature and pressure, and the steam/water ratio for saturated steam. The enthalpy of the steam, measured in MJ/kg (or MBtu/lb), can be extracted from the enthalpy tables (see ANNEXES 2 and 3) according to steam characteristics (pressure and temperature). The enthalpy of steam multiplied by the fuel mass flow gives the amount of energy input to the boiler for the given time (hours, in this case):

$$\text{Energy out} = \text{Steam specific eEnthalpy x Steam mass flow}$$

$$\text{Steam mass flow} = kg/h$$

$$\text{Steam specific enthalpy} = MJ/kg$$

$$\text{Energy out} = MJ/kg \text{ x } kg/h \text{ x } h = MJ$$

Example

A boiler consumes 104 litres of fuel oil per hour and produces 1100 kg/h of steam at 3 bar and 134 °C (100% saturated steam). To calculate boiler efficiency, the fuel heating value and steam enthalpy are needed:

For fuel oil, the heating value can be assumed as 40 MJ/kg.

For steam, by using the steam tables, at pressure of 3 bar, the specific enthalpy of the steam is 2724,66 kjoule per kilogram (kJ/kg).

The units of measure for calculations are MJ and kg; thus both fuel and steam must be expressed as MJ/kg.

As fuel mass flow is given in litres, litres must be converted to kg by using the fuel density (or specific gravity). For fuel oil, a density of 0.8 kg/litre can be assumed.

The energy input is then:Energy input = 104 litres x 0,8 kg/litre x 40 MJ/kg = 3328 MJ/kg (assuming that the enthalpy of feedwater is negligible)

Energy output = 1100 kg/h x 2724,66 kJ/kg= 2997126 kJ/kg = 2997,13 MJ/kg

$$EFFICIENCY = \frac{Energy\ out = \ 2997\frac{MJ}{kg}}{Energy\ in = 3328\ MJkg} = 0.9 = 90\%$$

This means that 90% of energy of the fuel is used, while 10% is lost. Although most of the losses are found in the hot flue gases leaving the stack, other losses also exist, and will be discussed in detail in the next sections. Care must be taken because the term “boiler efficiency” is used in several instances to describe energy conversion processes associated with the boiler. The above definition of efficiency can be regarded as global boiler efficiency.

Types of boiler efficiency

The two most important ways of expressing boiler efficiency are combustion efficiency and thermal efficiency.

Combustion efficiency

Combustion efficiency indicates a burner’s ability to burn fuel measured by unburned fuel and excess air in the exhaust. The burner must ensure complete combustion of the fuel, by appropriate mixing with combustion air. If some of the fuel is not burned, it can be found at the stack, together with other compounds (e.g., ashes, pollutants). The more unburned particles detected at the stack, the lower the combustion efficiency (and, consequently, the global efficiency). Combustion efficiency is often calculated on the basis of flue gas analysis, by measuring the combustion products (carbon dioxide, $CO_{2,}$; nitrogen oxides, NO_x; carbon monoxide, CO) to determine combustion completeness.

Thermal efficiency

Thermal efficiency, or heat exchange efficiency, indicates the effectiveness of the heat exchangers in transferring heat from the hot gases generated by the combustion process to the water or steam in the boiler. The heat is transferred to the water (and steam) by radiation and convection. If the hot gases do not transfer all of their heat to the water to transform it into steam, some heat will be lost at the stack. The higher the temperature of the flue gases is at the stack, the lower the combustion efficiency.

The overall efficiency of the boiler can be calculated by multiplying the single efficiencies:

$$Boiler\ efficiency = Combustion\ efficiency \times Thermal\ efficiency$$

As efficiency is normally indicated by using the symbol η, the equation becomes:

$\eta_{boiler} = \eta_{fcombustion} \times \eta_{thermal}$

Efficiency is strictly linked to fuel consumption and the amount of emissions from the stack. The following principle is always valid:

The more efficient the boiler is, the lower the fuel consumption.

Example

If $\eta_{combustion}$ is 0.98 and $\eta_{thermal}$ is 0.92, boiler efficiency is:

η_{boiler} =0.98 x 0.92 = 0.90 = 90%

If, for some reason (e.g., delayed maintenance), the heat exchange surfaces become dirty and do not ensure good heat transmission, the boiler efficiency is reduced. Assuming a reduction in thermal efficiency from 0.92 to 0.85 (from 92% to 85%), the result is higher fuel consumption, which can be calculated as follows:

New boiler efficiency: 0.98 x 0.85 = 0.83 = 83%
New fuel consumption: to generate the same amount of steam, 2997,13 MJ/kg, the amount of heat needed will be: 2997,13 MJ/kg/0.83 = 3611 MJ/kg, instead of 3328 MJ/kg

The difference in fuel consumption can be calculated as follows:

Difference in fuel consumption (Δf fuel consumption): (3611 MJ/kg - 3328MJ/kg) / 40 MJ/kg (fuel oil heating value) = 7 kg/h

The fuel consumption will therefore be increased by 7 kg/h.

Assuming that the boiler runs 12 hours/day and 330 days/year, the increase in the annual fuel bill can be calculated. Assuming a fuel cost of about 600 USD/ton (0,6 USD/kg), the increase in the fuel bill will be:

Annual fuel bill increase = $\Delta f_{\text{fuel consumption)}}$ x daily working hours x 330 working days x fuel price

= 7 kg/h x 12 hour/day x 330 days/year x 0.6 USD/kg = 16 632 USD/year

The price of a 1 t/h capacity fuel oil boiler in the market varies greatly, according to its characteristics and local market rules, but usually ranges between 50,000 USD and 100,00 USD. The increase in fuel consumption in the above example can therefore represent from 15% to 30% of boiler capital investment.

Ways to calculate efficiency

Effect of efficiency on emissions

It is possible to calculate the effect of decreased efficiency on emissions. If we assume 1.5 tons of CO_2 per 1 ton of burned fuel oil, the increase in CO_2 emissions as a result of the increase in fuel consumption is as follows:

Boiler fuel consumption: 104 litres/h x 0.8 kg/litre = 83.2 kg/h
Boiler annual fuel consumption: 83.2 kg/h x 12 h x 330 days = 330 t/year
Boiler CO_2 emissions: 330 t/year x 1.5 $\text{tons}_{CO2}/\text{ton}_{fuel}$ = 495 tons CO_2/year

If the boiler is not properly maintained, the CO_2 emissions will increase as follows:

Increase in fuel consumption: 7 kg/h x 12 hour/day x 330 days/year = 27720 kg/year= 27.72 t/y
Increase in CO_2 emissions: 27.72 t/y x 1.5 $\text{tons}_{CO2}/\text{ton}_{fuel}$ = 41.58 tons CO_2/year

The boiler will emit an additional 41,58 t/y of CO_2.

Efficiency as boiler heat rate

The efficiency of a boiler is often given by using the boiler heat rate: the amount of fuel needed to generate a unit of product (e.g., a ton of steam or a kWh of electricity). The boiler heat rate can be expressed in kcal/kWh for electricity production, or in kcal/kg for steam production. The reference for calculating boiler efficiency is the unit of conversion between kcal and kWh: 1 kWh = 860 kcal.

Example

If a boiler uses 0,25 kg of fuel (fuel heating value = 10,000 kcal/kg) to produce 1 kWh of electricity, this means that it needs 0,25 kg x 10,000 kcal/kg = 2500 kcal to produce 1 kWh instead of the theoretical 860 kcal (which corresponds to 100% efficiency). Therefore, the efficiency can be calculated as:

$$EFFICIENCY = \frac{860}{2500} = 0,34 = 34\%$$

In this example, 860 kcal, which gives a reference for 100% energy conversion, is the link between boiler heat rate and boiler efficiency. Different units of measure give the same outcome.

Efficiency as boiler evaporation rate

The boiler evaporation rate can also be used to calculate boiler efficiency. The evaporation rate can be defined as the amount of steam produced per unit of fuel burned e.g., an evaporation rate of 5 means that 1 kg of fuel produces 5 kg of steam. The evaporation rate varies according to the actual efficiency of a boiler.

Example

Using the example above, the evaporation rate of a boiler that consumes 104 litres/h of fuel oil and produces 1100 kg/h of steam is calculated as follows (litres must be converted into kg to have homogeneous unit of measure).

Assuming a density of 0.8 kg/litre, the mass flow, expressed in kg, is 104 x 0.8 = 83.2 kg/h.

The evaporation rate is:

Evaporation rate = 1100 kg/h of steam/104 litre x 0,8 kg/litre = 13.2 kg of steam per kg of fuel

If the efficiency decreases from 90% to 83%, the fuel consumption (see example above) will increase by 7 kg/h to produce the same quantity of steam. The fuel consumption will then be 83.2 + 7 = 90.2. The evaporation rate is then:

Evaporation rate = 1100 kg/h/ 90.2 kg/h = 12.2 kg of steam per kg of fuel

This means that less steam is produced for the same quantity of fuel injected in the burner.

In summary, boiler efficiency is expressed as a non-dimensional number or a percentage (η), and heat rate and evaporation rate are directly related to efficiency. In boilers that generate both electricity and steam, the efficiency calculations are more complicated (see ANNEX 17).

Boiler efficiency is reduced by:

- energy losses in the flue gas during operation, either by unburned fuel because of excess fuel, or heating more air than necessary because of excess air; and

- radiation and convection loss from the exterior surface of the boiler during constant or intermittent operation.

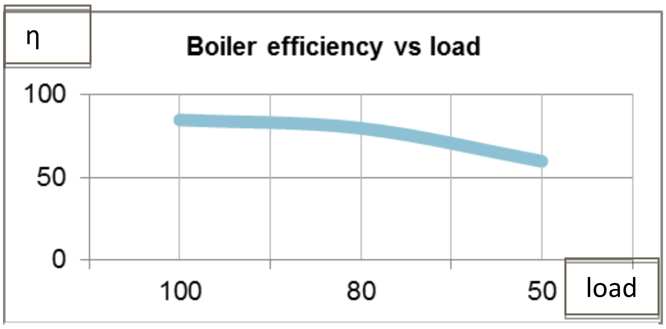


Figure 161 Boiler efficiency versus load

As efficiency varies with load, the performance of a boiler is better given by an efficiency versus load curve (a typical curve is shown in Figure 161. The lower the load is (x axis), the lower the efficiency, and, consequently, the higher the specific consumption (fuel used per unit of steam produced). Intermittent operation (e.g., turning on/off the boiler twice a day) results in lower efficiency.

Boiler efficiency calculations

Efficiency is an important parameter to consider when purchasing a boiler. The manufacturer must normally guarantee the boiler's efficiency because it affects the fuel consumption (and operating costs) during the boiler's lifetime. There are various ways to calculate efficiency, depending on its use.

To estimate the performance of a steam boiler operating in a production process, three main types of efficiency (whose names may vary in scientific and technical literature) can be examined:

- nominal efficiency
- test efficiency
- average efficiency (e.g., daily, weekly, annual)

The nominal efficiency of a boiler is the efficiency at nominal capacity (100% load), which usually corresponds to the value of capacity that can be read on the boiler plate and on the manufacturer's technical specifications. As illustrated above, the efficiency varies with load.

Test efficiency is boiler efficiency measured during post-commissioning tests, to check its compliance with the guaranteed efficiency. If the boiler is not properly assembled on site, the measured efficiency will not match the guaranteed value, resulting in increased fuel consumption (and increased operating costs). It is therefore important to test the actual efficiency of the boiler after final assembly at the customer's site.

Average efficiency is the average value of boiler (or plant) efficiency measured over a given period of time (e.g., day, week, month, year). This indicates how good the management of the steam generation system has been in that period, and boiler performance at various loads. For example, if a boiler has high efficiency at nominal load but low efficiency at reduced load, and it is operated most of the time at reduced load, the average efficiency will be unsatisfactory. Average efficiency is calculated by dividing the total energy produced (steam production in the case of industrial boilers) over the given period (e.g., one year) by the total fuel consumption in the same period:

$$\frac{total\ energy\ production}{total\ fuel\ consumptions} = \eta_{av}$$

Average efficiency is very important for evaluating and optimizing boiler performance, and calculating the amount of pollutants released to the environment. It should be used by plant managers to summarize, compare and analyse the performance of the steam production plant over time, and to identify ways to improve efficiency and reduce operating and maintenance costs. The example below shows how average efficiency can be used to estimate the effects of changes in efficiency on fuel bills.

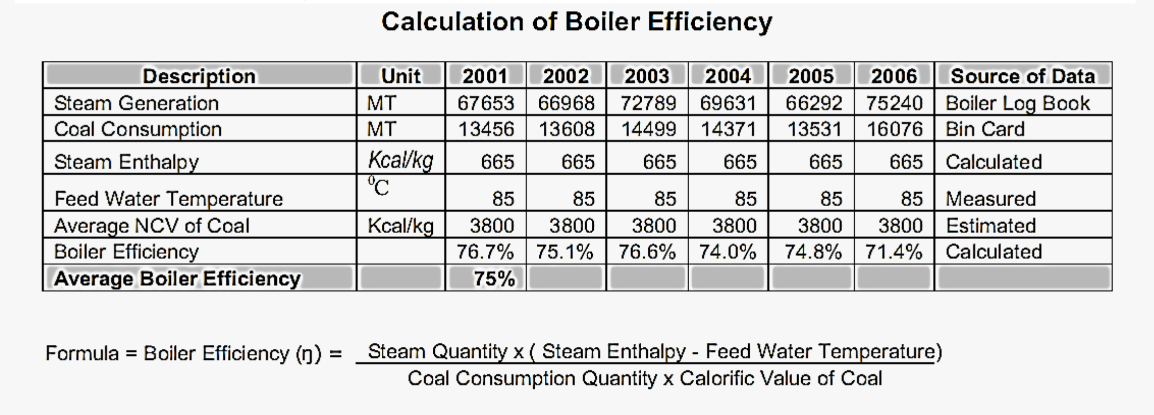
Example

Table 40 uses average efficiency to analyse the steam production system performance of a factory. (98) It lists the amount of steam produced per year for 2001-2006, fuel (coal) consumption, average steam specific enthalpy, feedwater temperature, average heating value of the coal (NCV: net calorific value), and boiler efficiency.

The coal heating value, steam enthalpy and feedwater temperature were kept steady over the six-year period. The steam generation production increased from 67653 Mt/y (metric tons) to 75240 Mt/y, and the fuel consumption increased from 13456 t/y to 16076 t/y. The table shows that boiler efficiency was reduced from 76.7% in 2001 to 71.4% in 2006.

To find out the effect of efficiency reduction on fuel consumption, the effect of the steam production increase must be separated from that of efficiency reduction. This can be done by calculating the heat rate of the boiler (ratio of steam produced to fuel consumed), which shows how much fuel is needed to produce a unit (t/h) of steam.

Table 40 Boiler efficiency variations (UNFCC) (98)



Calculation of Boiler Efficiency

Description	Unit	2001	2002	2003	2004	2005	2006	Source of Data
Steam Generation	MT	67653	66968	72789	69631	66292	75240	Boiler Log Book
Coal Consumption	MT	13456	13608	14499	14371	13531	16076	Bin Card
Steam Enthalpy	*Kcal/kg*	665	665	665	665	665	665	Calculated
Feed Water Temperature	^{0}C	85	85	85	85	85	85	Measured
Average NCV of Coal	Kcal/kg	3800	3800	3800	3800	3800	3800	Estimated
Boiler Efficiency		76.7%	75.1%	76.6%	74.0%	74.8%	71.4%	Calculated
Average Boiler Efficiency		**75%**						

$$\text{Formula} = \text{Boiler Efficiency } (\eta) = \frac{\text{Steam Quantity x (Steam Enthalpy - Feed Water Temperature)}}{\text{Coal Consumption Quantity x Calorific Value of Coal}}$$

a) Boiler heat rate 2001 = $(13456\ \mathrm{Mt/y\ coal})/(67653\ \mathrm{Mt/y\ steam}) = 0{,}1988$ tons of coal/tons of steam

b) Boiler heat rate 2006 = $(16076\ \mathrm{Mt/y\ coal})/(75240\ \mathrm{Mt/y\ steam}) = 0{,}2136$ tons of coal/tons of steam

The difference between the two heat rates that can be ascribed to the efficiency variation alone is therefore:

Δ heat rate = 0.2136 – 0.1988 = 0.014 tons of coal per ton of steam

The effect of efficiency reduction on fuel consumption is:

$\Delta_{\text{consumption}}75240\text{t}_{\text{steam}}/\text{y}$ x 0.014 tons of coal/tons of steam = 1053 tons of coal per year

As a result of the reduction in efficiency, the boiler consumes 1053 additional tons of coal per year.

Assuming a coal price of 100 USD/t, the effect of the increased fuel bill is:

Fuel additional expenses = 1053 t/y x 100 USD/t = 105,300 USD/y

Assuming that the boiler works 7000 hours/year, the capacity of the boiler can be calculated back as follows:

$$\text{Estimated boiler capacity} = \frac{annual\ steam\ production}{boiler\ working\ \frac{hours}{year}} = \frac{75240\,\frac{t}{y}\,steam}{7000\,\frac{h}{y}} = 10.7\,\frac{t}{h}$$

Assuming a price of between 300,000 USD and 500,000 USD for a 10 t/h coal boiler, the economic effect of 5% efficiency reduction (more than 100,000 additional operating costs per year) ranges between 20% and 30% of boiler cost. This confirms the importance of maintaining the highest efficiency levels.

Efficiency and boiler auxiliaries

Caution should be used when comparing efficiency values for different boilers. Efficiency must refer to the same working conditions (nominal capacity) and the same set of auxiliary systems because a plant's overall efficiency varies by the number and power absorption of its auxiliaries.

The total plant efficiency is calculated as follows:

$\eta_{plant} = \eta_{boiler} \times \eta_{auxiliaries}$

When the boiler runs at a reduced load, the efficiency is normally lower and the consumption (heat rate) is higher.

Effect of intermittent operation

The energy loss due to radiation and convection will increase with intermittent operation and reduced combustion time.(99) Figure 162 shows that the more shutdowns there are, the lower the average efficiency.

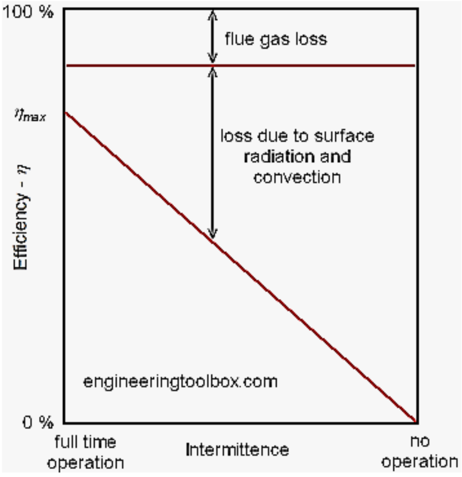


Figure 162 Effect of intermittent operation (Engineering Toolbox) (99)

Multiple boiler systems

If more than one boiler is operating in the boiler house, the average efficiency is affected by how each of the boilers is operated. The most common situation is a steam production plant equipped with two boilers, with one normally in operation and one normally in standby. In the event of failure, the standby boiler will start running, and the front boiler will be stopped for repairs. In this case, the average efficiency is calculated by taking into account the period in which the standby boiler operated.

If there are more than two boilers, the average efficiency can be calculated for each boiler by dividing the steam it produced by the fuel it burned. This allows selection of the most efficient boiler for the longest operational period, saving fuel and money. More complex situations, such as boilers with different tasks (e.g., base load boilers and peak load boilers), must be analysed case by case to identify the operating conditions that lead to the maximum average efficiency and minimum fuel consumption.

Effect of boiler sizing

Many boiler plants experience substantial seasonal variations in demand, e.g., food industry production often depends on availability of seasonal agricultural products. If one boiler only provides steam/heat to the process, the efficiency at which it converts fuel energy into steam or hot water drops sharply at low load. It can drop to about 40% of maximum capacity rating (MCR). It therefore makes sense to select boiler sizes to match seasonal demand: for example, a small boiler operating at close to full load in periods of low demand, with one or two larger boilers sized to handle peak loads. Investment costs would be higher, but the boilers would operate more efficiently and the final steam cost would be lower. Reductions in emissions would also be substantial. Again, each situation must be analysed on a case-by-case basis.

Energy efficiency drift

The performance of an operating boiler declines over time, due to poor combustion, heat transfer surface fouling, deterioration of fuel and water quality, and poor operation and maintenance. Efficiency testing helps determine the extent to which boiler efficiency drifts away from optimum efficiency. Any observed abnormal deviations could therefore be investigated to pinpoint the problem area for necessary corrective action. Hence, it is necessary to find out the current level of efficiency for performance evaluation, which is a prerequisite for energy conservation action in industry.

Efficiency measurements

International standards have been developed to measure efficiency, of which the ASME (American Society of Engineers) Boiler and Pressure Vessel Code is one of the most widely used. Although normally used to test the guaranteed efficiency values during the commissioning tests, it can also be used to verify how far the boiler is from the optimal conditions.

ASME Standard PTC-4-1 Power Test Code for Steam Generating Units can be used to test the efficiency of steam boilers. It includes the direct method and the indirect method. In general, the direct method is relatively easy to implement and does not need many measurements. However, it does not provide information on where energy is lost. In contrast, the indirect method requires more measurements, but does indicate where energy is lost.

Direct method

This is also known as the "input-output method" because it only needs information on the useful output (steam) and the heat input (i.e., fuel) to evaluate the efficiency. The efficiency can be evaluated by using the following formula:

$$\boxed{EFFICIENCY = \frac{Energy\ out}{Energy\ in}}$$

As explained above, the energy input is the fuel mass flow to the burner, which can be calculated as follows:

$$Energy\ input\ = fuel\ heating\ value\ \times fuel\ mass\ flow\ rate$$

The energy output is the enthalpy difference between feedwater and steam:

$$Energy\ output = Steam\ flow\ rate\ (steam\ enthalpy - feed\ water\ enthalpy)$$

The measurements required to use these equations must be made during a period of steady operation in which the boiler has been producing a constant steam flow for

FiguFigure 163 Water

bommeter

approximately 1 hour. During the data gathering period, the water level in the boiler's steam drum should be constant. Additional measurements required are steam temperature and pressure exiting the boiler, and feedwater pressure and temperature. These steam and feedwater properties provide the information required to determine the enthalpy content of the water entering and the steam exiting the boiler.

For small oil and gas boilers with no condensate recovery, the measurements are relatively easy to obtain. The steam flow rate in this case is the same as the water flow rate. A water meter on the water feeding pipeline provides the data on the steam flow rate (see Figure 163). A meter on the fuel oil pipeline (or a scale for solid fuels) provides the data on the fuel flow rate. Temperature measurements are also needed at the water feeding line, the steam line exit from the boiler, and the fuel line before the burner. Temperature can be measured with thermometers. Depending on the steam working conditions (pressure and temperature), special thermometers may be necessary.

To measure the energy input to the boiler, the fuel calorific value is needed. The data provided by the fuel supplier can be used or a calorimeter bomb to obtain more precise measurements. This is a simple device, very common in chemical labs, which measures the heat (energy) produced by burning one unit of fuel (see Figure 164).

Figure 165 Calorimeter Bomb-Wikipedia (253)

The energy (enthalpy) input to the boiler is related to the temperature of the fuel and to its heating value. It can be calculated as follows:

$$\text{Enthalpy input (MJ/ kg/h} = \text{flow rate}_{fuel} \text{ x enthalpy}_{fuel} + \text{flow}_{rate\ fuel} \text{ x fuel heating value)}$$

It can be written as:

$$\text{Enthalpy input (MJ/ kg/h} = \text{flow rate}_{fuel} \text{ x (enthalpy}_{fuel} + \text{heating value}_{fuel}\text{)}$$

The enthalpy of feedwater should also be added if relevant.

The energy output can be calculated by using the steam enthalpy. Assuming that the steam is saturated, the enthalpy can be obtained by consulting the steam tables (see ANNEXES 2 and 3). The energy (enthalpy) output is therefore:

$$\text{Energy (enthalpy) out} = \text{flow rate x (enthalpy}_{\text{steam out}} - \text{enthalpy}_{\text{water in}}\text{)}$$

The efficiency of the boiler is then calculated as follows:

$$(flow\ rate\ steam\ x\ (\ enthalpy\ steam\ -\ enthalpy\ feed\ water)\ ))/(flow\ rate\ fuel\ x\ (enthalpy\ fuel\ +$$
$$= \text{Boiler efficiency}$$

Measurement of energy input

The measurement of heat input requires information on the calorific value of the fuel and its flow rate in terms of mass or volume, according to the nature of the fuel: (100)

- *Gaseous fuels:* A gas meter of the approved type can be used and the measured volume should be corrected for temperature and pressure. A sample of gas can be collected for calorific value determination, but it is usually acceptable to use the calorific value declared by the gas suppliers.
- *Liquid fuels*: Heavy fuel oil is very viscous, and this property varies sharply with temperature. The meter, which is usually installed on the combustion appliance, should be regarded as a rough

indicator only. For test purposes, a meter calibrated for the particular oil to be used and over a realistic range of temperature should be installed. Even better is the use of an accurately calibrated day tank.

Solid fuels: The accurate measurement of the flow of coal or other solid fuel is very difficult. In large facilities, automatic mass flow measurement systems are used on travelling tapes that deliver the coal to the mills (pulverized coal burners). The mass flow is determined by measuring the velocity of the travelling tape and the mass of the coal passing through a fixed geometry gate. Other sophisticated systems based on radiations are also available (Figure 167).

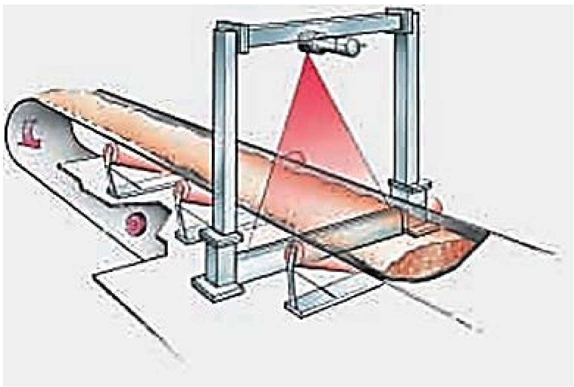


Figure 166 Gamma rays coal mass flowmeter (Berthold Technologies-Germany) (153)

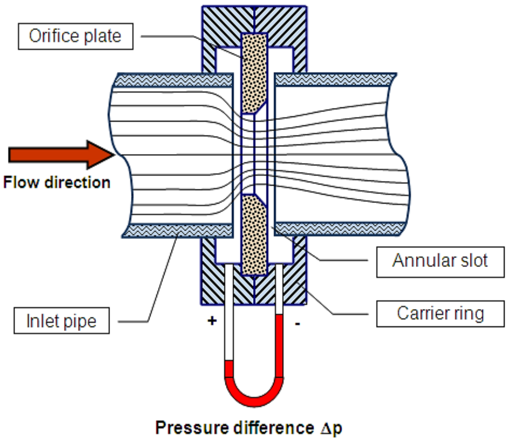


Figure 167 Orifice plate flowmeter

Measurements of energy output

Several methods can be used to measure heat output. For steam boilers, an installed steam meter can be used to measure flow rate. Several types of flowmeters are available on the market, and differ in the methodology used to measure the steam flow, including the following:

- orifice plate flowmeters (see Figure 166)
- turbine flowmeters (including shunt or bypass types)
- variable area flowmeters
- spring loaded variable area flowmeters
- direct in-line variable area (DIVA) flowmeter
- pitot tubes
- vortex shedding flowmeters

To measure the fuel heating value (calorific value), a calorimeter bomb must be used and samples taken to an equipped lab for testing.

For small boilers, the alternative is to measure the feedwater flow rate. This can be done by putting a water meter in the water feeding line to the boiler for steam systems with no condensate recovery (open cycles). For condensate recovery systems, the water meter should be positioned immediately before the boiler water inlet.

To calculate the efficiency of the boiler, both gross calorific value (GVC) and lower (net) calorific value (LCV) can be used, depending on the international standards used or the agreement with the boiler supplier. As the heat used to evaporate the water content in the fuel is normally not recovered in industrial boilers, using LCV produces more realistic outcomes. GCV is mostly used in the United States, and LCV in Europe.

Example

<u>Type of boiler: Coal-fired boiler</u>

Heat output data

Quantity of steam generated (output): 8 t/h

Steam pressure/temperature: 10 kg/cm^2 (g)/ 180 °C

Enthalpy of steam (dry & saturated) at 10 kg/cm^2(g) pressure: 665 kcal/kg

Feedwater temperature: 85 °C

Enthalpy of feedwater: 85 kcal/kg

Heat input data

Quantity of coal consumed (input): 1.6 t/h

Coal heating value: 4000 kcal/kg

<u>Calculation</u>

Boiler efficiency (η) = ((Q x(H -h))/(q x GCV)) x100

Where **Q** = Quantity of steam generated per hour (kg/hr)

q = Quantity of fuel used per hour (kg/hr)

LCV = Lower (net) calorific value of the fuel (kcal/kg)

H = Enthalpy of steam (kcal/kg)

H = Enthalpy of feedwater (kcal/kg)

$$Boiler\ efficiency = \frac{8\frac{t}{h} \times 1000\ kg\ \times \frac{(665-85)kcal}{kg}}{1{,}6\frac{t}{h} \times 1000\ kg\ \times 4000\frac{kcal}{kg}}$$

Indirect method

As mentioned earlier, the indirect method measure requires undertaking more measurements than the direct method, but it provides valuable information on where the energy is lost in the boiler. Assuming a theoretical boiler efficiency of 100, the actual efficiency is calculated by subtracting the heat losses fraction from 100:

Efficiency = 100 – Heat losses

The various heat losses occurring in the boiler are shown in Figure 168. The indirect method implies the calculation of all energy losses to calculate the energy output, according to the following formula:

ENERGY OUT = ENERGY IN - ENERGY LOSSES

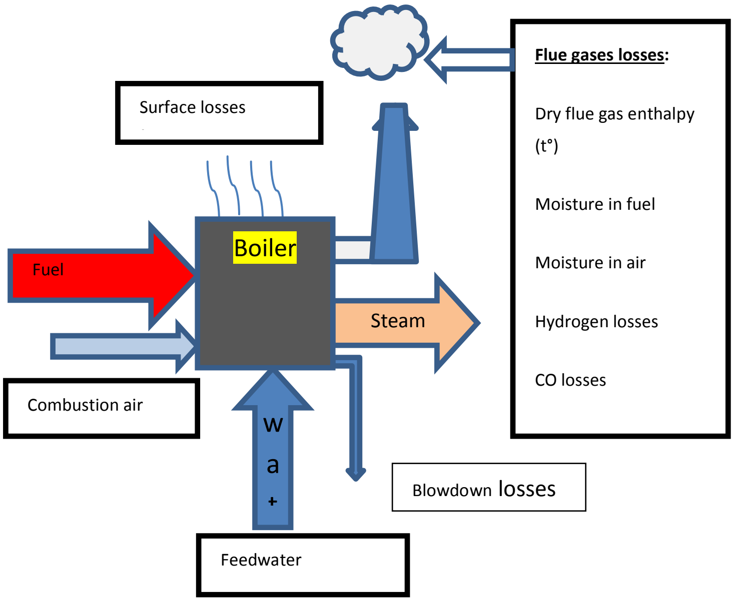
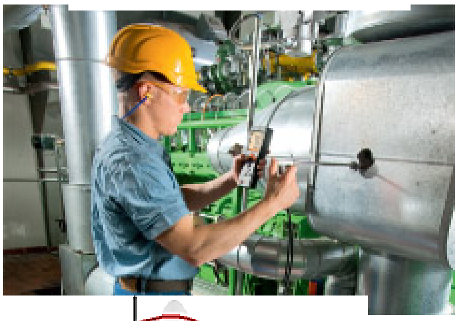


Figure 168 Efficiency measurement - heat losses

For large, sophisticated boilers, calculating the energy losses that occur in the boiler and auxiliary systems can be complicated. For small boilers, however, energy loss can be estimated by calculating the main energy loss from the flue gases exiting the stack. Sophisticated flue gas analysers, which are currently available on the market at a reasonable cost, can be used to calculate boiler efficiency. Instruments range from inexpensive, small hand-held devices to large, permanently installed units that can produce lab-quality results continuously. The type of gas analyser used depends on the type of gases to be monitored and whether requirements call for analysis on a spot basis or continuous monitoring. One of the most common flue gas analyser, the TESTO 350, is shown in Figure 169

Figure 169 TESTO 350 Analyzer

Gas analysers measure the by-products of the fuel combustion process. For fossil fuels, the components of interest from an environmental perspective are NO_x, CO_2, CO and sulphur dioxide (SO_2), if any. Flue gas analysis is performed by inserting a probe into the flue gas duct before the air heater (if present), and before the induced draught fan and stack. It is important that air leakages are not present along the flue gas duct during the analysis, so as not to distort the measurement outcomes. It is also necessary to take the temperature of combustion air (normally ambient temperature). Measurement values are either provided in part per million (ppm) or percentage (%), depending on the analyser type and size.



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Modern flue gas analysers are able to calculate boiler efficiency as a result of flue gas analysis, by using the indirect methodology and internal algorithms to calculate the heat loss at the stack. Oxygen

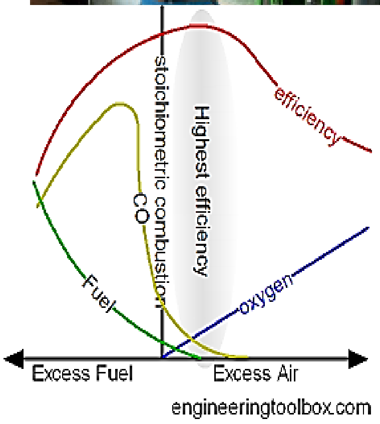


Figure 171 Relationship between efficiency and excess air (Engineering Toolbox) [(168)]

and/or CO_2 measurements, along with the air temperature, are needed to calculate boiler efficiency. The measurements are based on the relationships between CO_2, CO and oxygen content and efficiency (see Figure 171). The Figure shows the areas where efficiency is at its maximum. The highest efficiency area, however, does not coincide with stoichiometric combustion. This is because it is very difficult to obtain stoichiometric conditions (exact air-to-fuel ratio) throughout the entire combustion chamber, particularly in large boilers. There will always be areas with air-to-fuel ratios lower or higher than stoichiometric conditions. Low excess air levels ensure that the fuel has air for complete combustion, optimizing combustion efficiency.

Stack losses

Boiler stack loss (25) is typically the major loss component associated with boiler operation. Many factors are incorporated in the stack loss category, but the major contributors are the flue gas temperature and excess air amount. Rarely do these losses combine to be less than 8% of the total fuel energy input to the boiler, and generally they result in more than 15%.

Commonly, stack loss is converted into an expression of efficiency. Combustion efficiency is determined by the following equation:

$\eta_{combustion}$ *= 100% – stack loss (minor losses omitted)*

This equation is very similar to the indirect efficiency equation provided above. In fact, combustion efficiency represents the major components of indirect efficiency with shell losses, blowdown losses, and miscellaneous losses omitted. In this case, stack loss is the only loss considered in combustion efficiency, and is expressed as a percentage of total fuel input energy. In this Guide, stack loss is evaluated by using tables. ANNEX 16 provides stack loss tables for different fuels. (25)

Because stack losses can be massive and are generally the largest loss in magnitude, they require close management. The investigation of stack losses can be limited to two main categories: temperature effect and excess air effect.

Flue gas oxygen content

Steam generation efficiency centres on the energy transfer process in the boilers. The main factors affecting the efficiency of this energy transfer process are the temperature of the exiting flue gas and the flue gas oxygen content (25). These issues are related in many areas. Flue gas oxygen content can represent a significant loss to the steam system if the content is not maintained within the proper limits. The flue gas oxygen content, also indicated and measured as “excess air,” is very important for boiler operation. In the combustion process, fuel must come in contact with oxygen to allow the release of the chemical energy resident in the fuel. If the fuel does not react, it leaves the combustion area and the boiler. This is a loss to the system because the fuel energy, which was purchased, was not released, and it presents a safety and environmental hazard because combustion can occur in boiler areas not designed for combustion. The partial combustion of the fuel will form carbon monoxide, which is a toxic low-grade fuel. Reduced oxygen content can also result in the potential production of smoke or opacity due to poor combustion and the formation of particles from partial combustion of the fuel.

Since these conditions must be avoided, excess oxygen is supplied to the combustion zone to ensure that all of the fuel is combusted. However, this excess oxygen enters the boiler at ambient temperature, 21 °C (70° F) for example, and exits the boiler with the flue gas at an elevated temperature, 232 °C (450 °F) for example. Therefore, the fuel heats the extra air brought into the boiler from ambient temperature to flue gas temperature.

Further compounding the problem is the fact that the oxygen source is ambient air, which contains much more nitrogen than it does oxygen. The nitrogen does nothing for the combustion process except to extract energy and increase the loss. Management of this flue gas loss requires the excess oxygen to be maintained within an appropriate range, which depends on the fuel type and the method of monitoring and control.

Table 41 shows typical control limits for steam boilers. The table shows the amount of oxygen (O_2) in the flue gas as it exits the combustion chamber, which is also expressed as excess air. Excess air is the amount of air introduced to the combustion zone in comparison to the theoretical, stoichiometric amount required for complete combustion with no excess air. The excess air values in the table correspond to the flue gas oxygen content values.

Table 41 Flue gas oxygen content control parameters (EERE USA-Steam Survey Guide) (25)

	Automatic control flue gas O_2 content		**Positioning control flue gas O_2 content**		**Automatic control excess air**		**Positioning control excess air**	
	Minimum (%)	**Maximum (%)**	**Minimum (%)**	**Maximum (%)**	**Minimum (%)**	**Maximum (%)**	**Minimum (%)**	**Maximum (%)**
Natural gas	1.5	3.0	3.0	7.0	8.5	18.0	18.0	55.0
No. 2 fuel oil	2.0	3.0	3.0	7.0	11.0	18.0	18.0	55.0
No. 6 fuel oil	2.5	3.5	3.5	8.0	14.0	21.0	21.0	65.0
Pulverized coal	2.5	4.0	4.0	7.0	14.0	25.0	25.0	50.0
Stoker coal	3.5	5.0	5.0	8.0	20.0	32.0	32.0	65.0

The two main designations in the Table are automatic control and positioning control, which are types of excess air control on a boiler.

Positioning control is generally accomplished as part of an overall boiler control system without flue gas oxygen measurement. Typically, a pressure controller observing steam pressure is the main system controller. As the steam pressure decreases, the controller will increase fuel flow to increase boiler steam output. Combustion air flow will be increased in a pre-set manner in response to the fuel flow setting. Combustion air is not adjusted based on flue gas oxygen content. Periodically the relationship between the combustion air setting and the fuel flow is verified and adjusted through flue gas oxygen content evaluation. Non-automatic control is also accomplished through monitoring of the flue gas oxygen content and manually adjusting the quantity of combustion air. This type of operation is usually found on boilers with constant load.

Automatic control refers to any type of boiler control that continually monitors flue gas oxygen content and adjusts the combustion air flow to maintain required limits. Any type of control will result in a range of flue gas oxygen content. Most boilers operate with less excess oxygen requirement at higher loads than at lower loads, primarily because of the improved mixing and combustion parameters at higher loads.

As an example, consider a boiler that has a flue gas exit temperature of 293 °C (560 °F) and a combustion air inlet temperature of 21 °C (70° F). This produces a flue gas temperature difference of 490°F (560°F – 70°F). The flue gas oxygen content was measured to be 11.0%. Table 42 identifies the loss associated with the energy exiting the boiler with the flue gas, accounting for about 25.18%. (This table, and tables for other fuels, can be found in ANNEX 16.) If this loss can be reduced, by recovering energy to the steam, the operating cost of the boiler will decrease. Even without flue gas monitoring and control, the boiler should be capable of operating with a flue gas oxygen content ranging between 3.0% and 7.0%. If the oxygen content is reduced to an average of 5.0% and the flue gas exhaust temperature remains constant, the combustion loss will be reduced to 18.18%. In other words, boiler efficiency will improve by 7.0 percentage points (25.18% to 18.18%). The initial boiler efficiency was determined to be 72.2%.

Table 42 Stack loss of No. 2 fuel oil (%) -EERE USA-Steam Survey Guide (25)

Flue gas O_2 content (%)	**Flue gas temperature—combustion air temperature (°F)**														
	230	**250**	**270**	**290**	**310**	**330**	**350**	**370**	**390**	**410**	**430**	**450**	**470**	**490**	**510**
1.00	10.33	10.74	11.16	11.58	12.00	12.43	12.85	13.28	13.70	14.13	14.56	14.99	15.42	15.85	16.28
2.00	10.55	10.99	11.43	11.87	12.31	12.75	13.20	13.64	14.09	14.54	14.99	15.44	15.89	16.34	16.79
3.00	10.79	11.25	11.72	12.18	12.65	13.11	13.58	14.05	14.52	14.99	15.46	15.94	16.41	16.89	17.36
4.00	11.07	11.56	12.04	12.53	13.02	13.52	14.01	14.50	15.00	15.50	15.99	16.49	17.00	17.50	18.00
5.00	11.38	11.89	12.41	12.93	13.45	13.97	14.49	15.01	15.54	16.07	16.59	17.12	17.65	18.18	18.72
6.00	11.73	12.28	12.83	13.38	13.93	14.48	15.04	15.59	16.15	16.71	17.27	17.83	18.40	18.96	19.53
7.00	12.13	12.72	13.30	13.89	14.48	15.07	15.66	16.26	16.85	17.45	18.05	18.65	19.25	19.85	20.45
8.00	12.60	13.22	13.85	14.48	15.11	15.75	16.38	17.02	17.66	18.30	18.94	19.58	20.23	20.88	21.52
9.00	13.14	13.81	14.49	15.17	15.85	16.54	17.22	17.91	18.60	19.29	19.98	20.68	21.38	22.07	22.77
10.00	13.77	14.51	15.25	15.99	16.73	17.47	18.22	18.96	19.71	20.46	21.22	21.97	22.73	23.49	24.25
11.00	14.54	15.35	16.15	16.96	17.78	18.59	19.41	20.23	21.05	21.87	22.70	23.52	24.35	25.18	26.02
12.00	15.48	16.37	17.26	18.16	19.06	19.96	20.87	21.77	22.68	23.59	24.51	25.42	26.34	27.26	28.18

After tuning the boiler, efficiency would increase to 79.2%. This assumes that blowdown losses, shell losses, and other miscellaneous losses remain constant (approximately 2.6% of fuel energy input). An oxygen content of 5.0% was chosen because the boiler would be operating within the control range of flue gas oxygen content (3.0% to 7.0%). The approximate savings would be approximately 900,000 USD/year, and attainable with relatively minor investment. The revised boiler operating costs (fuel only) would be 9,245,000 USD/year.

The example boiler could be equipped with an automatic oxygen trim system to further reduce the stack loss. The oxygen trim system could control the flue gas oxygen content to 2.5%, and the combustion loss would decrease to 16.6% if the flue gas temperature remained constant. In other words, boiler efficiency would increase to 80.8%. The potential savings would be calculated as follows:

Savings = 9,245,000 USD/year (1 – 0.980) = 183,000 USD/year (24)

This significant savings would require investment in combustion control equipment. The economics of this project appear favourable, but further analysis would be required to determine the total project cost associated with the installation of the combustion control equipment.

The location of oxygen measurement is important, especially for boilers operating with negative pressure in, and downstream of, the combustion zone. Boilers operating with negative pressure will have some air leaking into the flue gas stream. This air has not passed through the combustion zone and, as a result, did not contribute to the combustion process. This can provide a false oxygen reading that results in poor combustion performance if the input air flow is reduced based on this erroneous measurement. Therefore, the oxygen sensor should be installed as close to the combustion zone as is practically possible to achieve acceptable sensor life and accurate measurement of oxygen content.

In this example, flue gas temperature was assumed to remain constant when excess air was reduced. Typically, flue gas temperature does not remain constant when the amount of excess air is adjusted. In general, flue gas temperature decreases as excess air is decreased. However, this is not a universal rule, and should be investigated on a case-by-case basis.

Flue gas combustibles

A secondary measurement for determining combustion performance is the concentration of combustible material remaining in the flue gas after the combustion zone. Poor or incomplete combustion can result even if the appropriate amount of oxygen is introduced to the combustion chamber (25).

Three main factors affect combustion:

- reaction time
- reaction temperature
- reactant mixture

For the combustion reaction to proceed to completion, fuel and oxygen must have enough time, be at the proper temperature, and be appropriately mixed. If any component is missing, the reaction will not proceed to completion. Babcock & Wilcox describes this as “the three T’s of combustion; Time, Temperature, and Turbulence.” The main chemical component arising from incomplete combustion is carbon monoxide. Periodic carbon monoxide (or combustibles) measurement can provide insight into the performance of the combustion zone.

A generally accepted limit is to have no more than 200 ppm combustibles in the flue gas. However, each boiler should be investigated to determine the base combustibles level. Any changes observed during periodic monitoring can then be interpreted as a problem in the combustion process. For example, a natural gas-fired boiler may have 15 ppm combustibles in the flue gas under normal operating conditions. If this concentration increased to 50 ppm (still well below the generally accepted limit), it would indicate a combustion problem.

Flammability limits

Not only must fuel and air be in the appropriate concentrations to obtain efficient combustion, they must also be within proper limits to establish a flame. For example, methane (natural gas essentially) must be mixed with at least 85% air (by volume) and no more than 95% air to burn. This indicates that the air fuel mixture will not burn if there is more than 100% excess air (10% oxygen in the combustion products). However, many boilers operate with more excess air than this. The explanation is that the full amount of extra air is not passing through the flame zone. Air is either entering as “tramp air” through a shell leak or the combustion air system, but it is not affecting the flame zone. Even though this air is not passing through the flame zone, it still affects boiler efficiency by absorbing energy from the fuel (25).

This discussion is relevant when deciding on the appropriate method to reduce stack loss. Typically, excess air loss is reduced by more precise control of the combustion air entering the flame zone. However, if a significant portion of the air passing through the boiler does not pass through the flame zone, then reducing flue gas oxygen content may result in substoichiometric conditions (oxygen starved) in the flame zone. This could cause an explosion or economic problems. Periodically measuring flue gas combustibles concentration in a boiler is essential when correcting flue gas oxygen content problems.

Flue gas temperature

An obvious loss associated with boiler operation occurs when the exhaust flue gas exits the boiler with an elevated temperature (25). A diagnostic measurement essential to boiler efficiency evaluation is the exhaust flue gas temperature. This measurement should be recorded at least daily and for boiler steam load and ambient conditions. The location of the sensing point is also critical. It should be as close as possible to the flue gas exit of the last point of heat exchange for the flue gas. In other words, if the boiler is equipped with a feedwater economizer, the temperature sensor should be located at the flue gas exit from the economizer. The idea is to obtain the true energy content of the flue gas stream in relation to the energy exchange processes within the boiler. An annual comparison should be made between current and previous flue gas temperatures with the boiler operating under similar steam loading and ambient conditions.

The flue gas exit temperature is affected by many factors, including:

- boiler load (steam production)
- boiler design
- combustion-side heat transfer surface fouling
- fireside heat transfer surface fouling
- flue gas bypassing heat transfer surfaces because of failed boiler components, and
- excess air (possibly).

The next sections describe how these factors usually affect flue gas temperature, and how they can be managed.

Boiler load

As the boiler load increases, the flue gas exit temperature generally increases too. This is primarily because the amount of heat transfer surface within the boiler is fixed, which allows less heat transfer per unit mass of combustion products as the load increases. Since elevated flue gas temperatures are indicative of elevated loss, it would appear that the boiler should be operated at low load to reduce stack losses. However, as the boiler load is diminished, the flue gas oxygen content must increase to maintain proper combustion. This serves to increase stack loss because of elevated excess air flow. Shell losses do not increase in magnitude as the boiler load increases, but they increase as a percentage of total fuel energy input. As a result, most typical boilers do not experience significant improvement in efficiency when the steam load is reduced.

Many boilers experience a greater non-proportional increase in flue gas temperature when the boiler is operated at a load greater than 100% of design. This can result in significant losses and is the main component leading to efficiency reduction for boilers operating at greater than 100% of full load.

In summary, boiler load generally affects flue gas exhaust temperature. Since this effect is essentially a design characteristic of the boiler, there is little that can be done to manage this. However, it is important to take this change into account when evaluating performance degradation. Flue gas temperatures should be recorded with respect to boiler load as well as ambient temperature.

Boiler design

The design of a boiler is key to overall steam generation efficiency. Heat transfer area and other design considerations are important factors in determining the amount of energy transferred from the flue gas. Obviously, additional heat transfer area will, in general, equip a boiler to operate more efficiently (i.e., reduce flue gas exhaust temperature), but at additional expense.

From a management standpoint, little can be done operationally to reduce the design component of stack loss once the boiler has been installed. Generally, improvements in this area require installing additional heat recovery equipment, such as a feedwater economizer or combustion air preheater, to extract energy from the flue gas. A feedwater economizer exchanges heat between the flue gas and feedwater prior to entering the boiler. A combustion air preheater exchanges heat between the flue gas and the combustion air entering the boiler.

Practical limits dictate the maximum amount of energy that can be extracted from the flue gas. These limits arise from corrosion issues and result in a minimum (practical) flue gas temperature that is significantly influenced by the corrosiveness of the flue gas. If the fuel contains sulphur, the sulphur content of the fuel is directly responsible for this limit. Sulphur itself is a fuel, which reacts with oxygen to form sulphur oxide (SO_2 or SO_3) (see Chapter 3). These chemicals react with water (H_2O) to form sulphuric acid (H_2SO_4), which can corrode many boiler components. Problems occur with this chemical when it condenses. Therefore, the flue gas must be maintained at a temperature greater than the dew point of sulphuric acid in the flue gas. Experience indicates that the corrosion rate can be reduced to safe limits if the temperature of the heat transfer surface is maintained above certain minimum values. These values correspond to the feedwater inlet temperature for economizers.

If the fuel does not contain sulphur, the dew point of water vapour is the temperature limit because of the potential carbonic acid corrosion. Carbonic acid (H_2CO_3) forms when carbon dioxide (CO_2) reacts with water.

Existing metallurgical technology allows the flue gas to be cooled below the dew point of these chemicals, and thus minimizes corrosion. This technology is not considered in this Guide, but should be investigated with equipment specialists.

Heat transfer surface fouling

A boiler is a large heat exchanger with a tremendous amount of heat transfer surface area. If the heat transfer surface becomes fouled, heat transfer will be reduced and efficiency will suffer. Fouling can occur on the water-steam side of the boiler as well as on the combustion flue gas side. The fouling mechanisms and management techniques vary by deposit type.

Waterside fouling most commonly results from dissolved chemicals in the feedwater, which precipitate on boiler heat transfer surfaces. These “dissolved solids” are much more soluble in liquid water than in steam. Therefore, these chemicals enter the boiler with the feedwater, but essentially do not leave the boiler with the steam; as a result, they concentrate in the boiler water. If not removed with blowdown, these chemicals concentrate until the saturation limit is reached at which point precipitation occurs. The most detrimental form of precipitation for heat transfer is a precipitant forming a layer of scale, which insulates the heat transfer surface.

Waterside fouling is best addressed by prevention. This is accomplished through make-up water treatment, condensate conditioning, chemical addition, and blowdown. Waterside fouling is generally a thin scale deposited at the boiler tube surface. Once the layer of scale has formed, two primary methods of removal are used: mechanical cleaning and chemical cleaning. Mechanical cleaning can involve water jet cleaning, which uses high-pressure water jets to scrub and dislodge the scale deposit. Brushes and other scrubbing devices are also used in this service. Chemical or acid cleaning acts to dissolve the deposit. All of these methods are obviously conducted while the boiler is out of service, and should be completed by trained, experienced personnel.

Waterside fouling can contribute to tube failures. Many of the deposits are accelerated by increased heat flux; therefore, the “hottest” section of tubes can tend to scale more rapidly. As the scale layer forms, the tube is insulated at the inside tube surface, which allows the external surface to increase in temperature. The tube strength decreases as the temperature increases, and tube failures can result. Under-deposit corrosion can also occur resulting in tube failures.

Fireside fouling is generally more prevalent in solid fuel boilers than fuel oil- or natural gas-fired boilers. Solid fuels contain some amount of ash that generally remains in solid form throughout the combustion and heat transfer processes. Ash will form into fine particles that can be carried with the flue gas. As the ash-laden flue gas contacts boiler heat transfer surfaces, the ash can attach to these surfaces. Similar to waterside scale deposits, fireside ash deposits insulate the heat transfer surfaces and result in reduced boiler efficiency in the form of increased flue gas temperature. Natural gas and light fuel oils carry essentially no ash load. Generally, No. 6 fuel oil (heavy fuel oil) has some component of ash, which provides fouling potential. Fireside fouling can also promote corrosion and result in tube failures.

Fireside fouling is reduced by periodic off-line and on-line cleaning. Sootblowing is generally an effective method for cleaning the combustion side of boilers that burn fuels with an ash component. It sprays a high-pressure steam jet onto the surface of the boiler tubes to dislodge the accumulated deposits while the boiler is in service. Compressed air is used on some boilers as the blowing medium. The flue gas exit temperature should be monitored before and after the sootblowing operation to indicate performance. Sootblowing is also conducted with acoustic horns, which vibrate the deposit from the tube surfaces.

Although sootblowers are critical for maintaining the cleanliness of the boiler tubes, they can be located anywhere in the boiler that is prone to fouling. To verify the effectiveness of the sootblowing operation, flue gas temperatures exiting the sootblower sections before and after the sootblowing event should be monitored. Thermometers should be calibrated to ensure proper monitoring. The flue gas temperature should decrease after sootblowing.

Failure of internal components

Boilers are designed with specific paths for the combustion gases to pass through. These paths are provided by internal baffles, which can fail. If a component fails, a significant loss can result. A failed internal component should obviously be repaired; however, the magnitude of the economic loss will dictate whether the boiler should be taken off-line immediately or repaired during a scheduled outage.

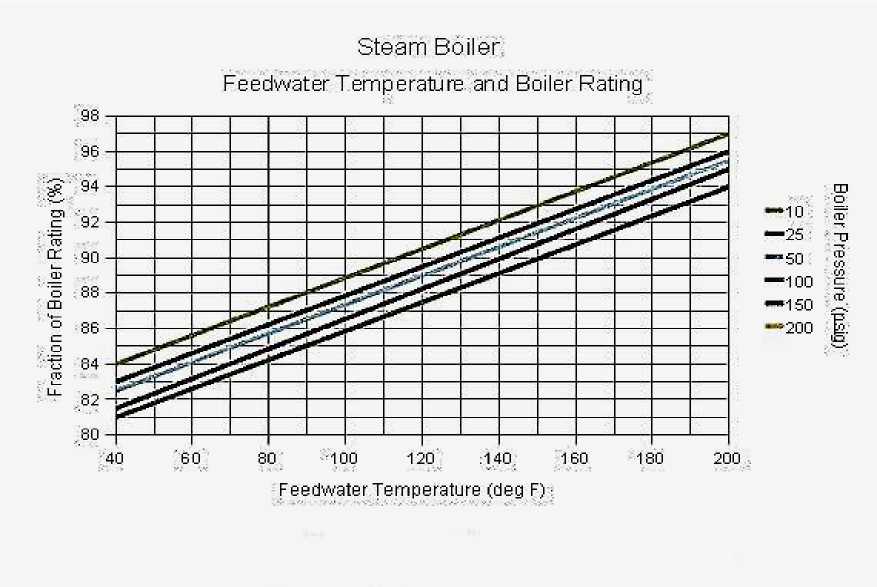


Figure 172 Effect of feedwater temperature on boiler rating (Engineering Toolbox)

Effect of feedwater temperature on boiler rating

The steam-generating boiler output is reduced with lower feedwater temperatures, as indicated in Figure 172. (102) The lower the feedwater temperature is, the lower the boiler rating. The rating decreases with increased operating pressure.

CHAPTER 6 – IMPLEMENTATION OF BEST AVAILABLE TECHNICHIQUES AND BEST ENVIRONMENTAL PRACTICES

SUMMARY

Knowledge of best available techniques (BAT) and best environmental practices (BEP) is essential for purchasing and operating boilers. The economics of steam production is affected by fuel type, boiler type, and number and quality of auxiliaries. Although it is commonly believed that buying a cheap boiler saves money, it can be easily demonstrated that cheap boilers are less efficient and less reliable, which ultimately results in increased annual costs and a higher cost for produced steam.

BAT and BEP can be implemented on many parts of a boiler and its auxiliaries. The Chapter provides examples and suggestions on how to improve boiler performance by implementing BAT/BEP. As discussed in Chapter 5, stack losses are one of the most critical points for boiler operation with the amount of excess air strongly affecting boiler performance. An example of how to optimize excess air is illustrated. Burner optimization, condensate recovery, blowdown recovery and optimization, water purity, and the most critical boiler components are also discussed to demonstrate the potential for improving boiler performance.

Factors affecting boiler selection

Supplying a steam production system for a production process includes:

- boiler and auxiliaries selection and purchase (affects capital and operating costs), and
- boiler operation and maintenance (affects operating costs).

Both are important for production process economics because, as the expected boiler lifetime is more than 20 years, a non-optimized boiler purchase will affect steam production costs and supply for a long time. Non-optimized operation will also have a negative effect on steam production costs and on the environment.

Boiler operation is related to the following:

- *Fuel costs and characteristics (solid, liquid or gaseous):* Fuel costs affect steam production, while fuel characteristics affect maintenance type and costs e.g., solid fuels need ash collection and disposal systems and normally require more personnel and expenses than gaseous fuels.
- *Number and sophistication of auxiliary systems:* The more auxiliary systems there are, the more demanding the maintenance service. Automated systems require fewer operation personnel than manual systems.
- *Steam needs:* Steady steam demand, and the resultant steady working conditions of the boiler, require fewer manoeuvers than, for instance, daily operation with load variations. Therefore, it may work with higher efficiencies and, consequently, is less expensive.
- *Pollutants emitted*: Compliance with emission limits may result in additional costs for steam production. All environmental aspects of boiler operation must be identified and carefully evaluated, in the context of trends in regulations and standards.

When selecting a new boiler, all parameters that can affect boiler economics and environmental impact should be carefully evaluated. The focus should be on the final cost of the steam produced, plant safety and reliability, and the amount of pollutants released.

Three main factors drive the financial aspects of boiler selection:

- *Investment payback period***:** Many factory managers give priority to the boiler price rather than to the investment payback period. This is often because financial resources are not available. However, it normally results in higher operating and maintenance costs, and increased final steam costs and emissions of pollutants. Selecting a Boiler and auxiliaries must therefore be based on the payback period or return on investment (ROI) rather than on market price.

- *Fuel type*: Fuel selection is of capital importance for steam production economics because it affects the investment payback. Operating costs strongly depend on fuel price. Fuel selection should be made *before* boiler selection in the decision-making process. Once the fuel is selected, it is easy to identify boilers that can burn that fuel. Fuel selection must be based on the following parameters:
    - *Fuel price to the factory (including transportation costs) and supplier reliability*: As already mentioned, fuel prices affect steam production costs. It is important to verify the existence of more than one supplier and/or agree on long-term supply contracts to avoid price variations.
    - *Fuel availability*: The fuel must be available all year long, with no constraints on production or supply. For instance, biomass may be available seasonally; an oil product has no seasonal constraints, but, under certain conditions, a factory may be dependent on a single supplier with consequent risk to fuel cost and availability.
    - *Fuel characteristics:* Since boiler performance is affected by fuel characteristics, it is important to fix the heating value and contaminants content in the fuel purchase specifications. Both values have a direct effect on boiler efficiency and pollutants emitted. Selection of auxiliaries also depends on fuel characteristics e.g., solid fuels need different auxiliaries than liquid and gaseous fuels.
    - *Fuel price trends*: Since a boiler, once purchased, will last for more than 20 years, fuel price trends should be examined to prevent unexpected price increases from negatively affecting the final cost of the steam produced. For example, it currently seems very likely that prices for oil products and gaseous fuels will increase in the next decades. Care should therefore be taken when selecting oil products or natural gas as the primary fuel for the boiler. Selecting a boiler capable of using two or more different fuels allows the ability to switch to the cheapest (or most available) fuel in case of market changes.
- *Pollutants released*: The amount of pollutants released from a boiler to the environment is directly linked to the type of fuel burned. As a general rule, the dirtier the fuel is, the higher the amount of pollutants released to the environment. The amount of pollutants released by the boiler indirectly affects boiler operation. More and stricter laws and regulations on pollutant emissions from industrial boilers are continuously being enforced all over the world because of increased global warming and other negative effects on the environment and human health, particularly in developing countries. Boiler owners must adopt cleaner fuels, more efficient air pollution control devices (APCD), and good operating and maintenance practices to comply with upcoming new rules, which will ultimately result in higher steam production costs.

Effect on the environment

The more pollutants a boiler emits, the greater the negative effects on the environment and human health. Selection of a cheaper boiler that emits more pollutants will very likely result in future problems and additional costs when it is cannot comply with new, stricter regulations on emissions. A more expensive, but more efficient, boiler equipped with APCDs will be better able to comply with upcoming emission limits and regulations.

Adopting best available techniques (BAT) and best environmental practices (BEP) for industrial boilers improves efficiency and results in compliance with emission limits. BAT is best implemented during the boiler design and construction phase when evaluating specific issues such as furnace temperature, heat recovery, combustion systems, and efficiency; or in retrofit analyses of older boilers. BEP is more relevant to proper boiler operation and maintenance focused on reducing releases of pollutants.

This Chapter discusses BAT and BEP for industrial boilers (though does not provide not an exhaustive list), with special emphasis on reduction of pollutants, particularly dioxins and carbon dioxide (CO_2). It demonstrates that, in many cases, it is possible to improve the economics of boiler operation while, at the same time, reducing the releases of pollutants. The adoption of BAT/BEP may result in advantages for the factory owner (lower fuel bills) and for the community (lower pollution). Investments can usually be recovered in a few years.

Best available techniques

BAT categories

BAT to achieve lower emission of pollutants for industrial boilers can be divided into two main categories:

- efficiency improvement/combustion optimization
- APCD installation

Efficiency improvement/combustion optimization

Improved boiler efficiency is achieved by several techniques that lead to lower fuel consumption per unit of steam produced. The improvement in boiler efficiency normally results in better boiler performance and lower emissions of pollutants. As a result of efficiency improvement, less fuel is burned in total, which reduces the fuel bill and emissions of pollutants, particularly CO_2. While efficiency improvement is a primary measure to reduce CO_2 emissions, a secondary measure is to switch to a fuel that produces less CO_2 (see Chapter 2). For instance, when burned, oil produces less CO_2 per unit of energy produced than coal.

Efficiency improvement has two beneficial effects on production and release of dioxins:

- As less fuel is burned, fewer dioxins are produced and released to the environment.
- Since efficiency improvement often results in optimized combustion conditions, the production of dioxins per unit of fuel burned in the combustion zone is lower.

APCD installation

Installation of APCD in between the boiler and the stack reduces emissions of polluting compounds (see Chapter 4), but has negative effects on efficiency and operating costs:

- Flue gas pressure losses are increased by the presence of pollution control equipment along the duct.
- The power absorption of boiler auxiliaries consequently increases (the draught fans need more power and the pollution control equipment needs additional power to function).
- Additional APCD auxiliaries, such as pumps, fans, electric fields, etc., require power.
- The plant needs more maintenance because of the presence of additional equipment.
- There are additional operating costs (e.g., cost of disposal of the ash collected by the pollution control device).

BAT to reduce dioxin releases

This section looks in detail at a key example of the effects of BAT adoption on boilers and their emissions: BAT to reduce dioxin releases. To reduce the emission of persistent organic pollutants (POPs) from fossil fuel-fired utility and industrial boilers, a variety of measures can be used to minimize the pathways for generation and release of such pollutants in boiler design and operation.

Fuel specification and monitoring

The unintentional introduction of contaminated fuels, which may promote the formation of POPs, must be reduced as much as possible. This is especially important when co-firing fossil fuels with other fuel types. Controls should be introduced to ensure that the fuels used are within the required specifications.

Combustion conditions

To achieve complete combustion of POPs contained in the fuel, special attention must be paid to the four cornerstones of high destruction efficiency:

- temperature
- time
- turbulence
- excess oxygen

Doing so will also ensure the destruction of precursors and reduce soot formation, and therefore provide fewer possible sites for solid catalysis in the cooling gas effluent. Table 43 illustrates the influence of combustion conditions on emission of pollutants from refuse-derived fuel, although the values shown are higher than might be expected from combustion using fossil fuels.

Table 43 Effect of combustion conditions on PCDD/PCFD emissions (ng/Rm³) (103)

Species	**Good combustion**	**Poor combustion**
PCDD (total)	70–230	200–600
PCDF (total)	220–600	700–1,300
$Cl_{3\text{-}6}$ benzenes*	4,000–6,000	7,000–16,000

*Includes all of the congeners of tri, tetra and penta, as well as the fully substituted hexa.

It is generally accepted that a temperature in excess of 900 ºC and a gas residence time of 2 seconds are sufficient to achieve complete oxidation of polychlorinated dibenzodioxins (PCDD), as long as the gas flow is sufficiently turbulent and excess O_2 is present. McKay (2002) suggests that a furnace temperature higher than 1000 ºC should be maintained to ensure that all POPs are oxidized.

Excess air and turbulent conditions in the furnace are also important factors. High degrees of turbulence avoid the formation of cold pockets where oxidation temperatures cannot be reached. High turbulence also leads to uniform distribution of oxygen to ensure total combustion, avoiding sub-stoichiometric zones, providing that air is in excess.

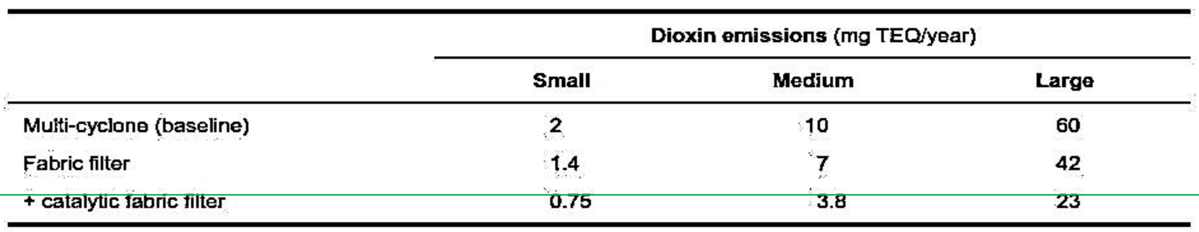
To assess the efficiency of combustion, real-time monitoring of carbon monoxide (CO) can be useful. High CO levels indicate incomplete combustion and conditions under which POPs may survive or be created.

When solid fuel is used, low-moisture pulverized fuels are preferred to crushed or lumpy fuels to maximize mixing and combustion conditions. Evaporation is an endothermic reaction and, when moisture is introduced into the furnace, the combustion temperature decreases. Introducing pulverized fuel allows, under good turbulent conditions, isothermal conditions throughout the entire furnace and optimum mixing with oxygen.

Air pollution control devices

Air pollution control devices can be installed to further control and limit emissions (see Chapter 4), although, in

Table 44 Coal-fired boilers: expected annual emissions for different levels of control



	Dioxin emissions (mg TEQ/year)		
	Small	**Medium**	**Large**
Multi-cyclone (baseline)	2	10	60
Fabric filter	1.4	7	42
+ catalytic fabric filter	0.75	3.8	23

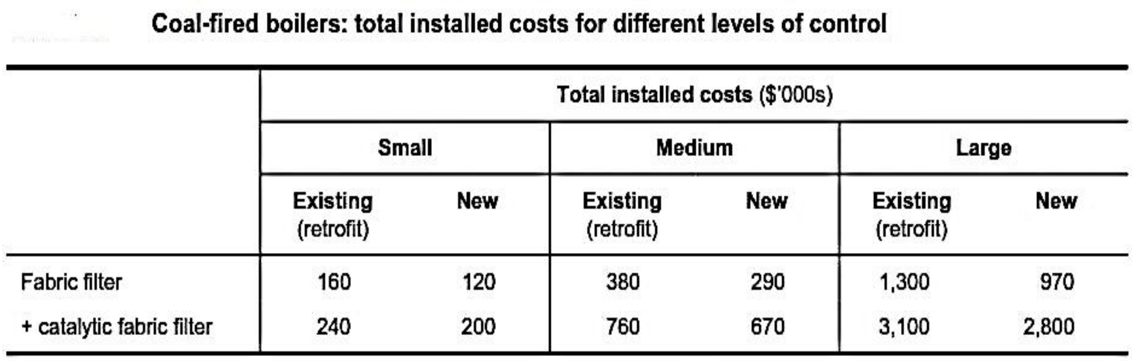
the case of fossil fuel-fired utilities and industrial boilers, they are considered as additional or secondary measures. As an exampleTable 45 provides data on the effects of dust filters on dioxin emissions, based on a report from New Zealand's Ministry of Environment. (104) The report shows different amounts of dioxin emissions at different control levels for small (around 1 MWth), medium (5 MWth) and large boilers (5 MWth). The report considered two levels of dioxin control that can be used for coal-fired boilers equipped with multicyclone filters: i) adding a fabric filter (or baghouse); ii) using a catalytic fabric filter, which involves replacing the filters in the baghouse with others impregnated with a catalyst. These figures are converted into µTEQ/TJ (7000 hours operation/year):

Table 45 Effect of various dust filters on dioxins capture

Filter type	Emission Factor µgTEQ/TJ
Multi-cyclone	**79**
Fabric filter	**56**
Fabric filter + catalytic	**30**

The associated capital and operating costs are shown in Table 46 and Table 47 (104).

Table 46 Coal-fired boilers: Installation costs

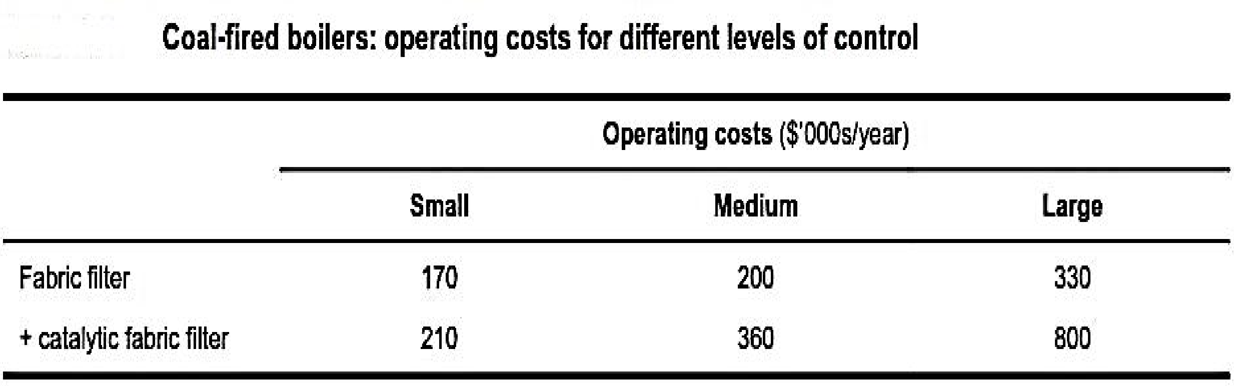


Coal-fired boilers: total installed costs for different levels of control

	Total installed costs ($'000s)					
	Small		Medium		Large	
	Existing (retrofit)	New	Existing (retrofit)	New	Existing (retrofit)	New
Fabric filter	160	120	380	290	1,300	970
+ catalytic fabric filter	240	200	760	670	3,100	2,800

According to the report, the installation of sophisticated filters can result in reductions ranging from 20% (bag filters) to 60% (bag filters + catalyst). Operating costs increase from 170,000 USD/year to 210,000 USD/year for small boilers and from 330,000 USD/year to 800,000 USD/year for large boilers. For small boilers assuming that the steam is produced at 10 bar, with an enthalpy of 2776 kjoule per kilogram (kJ/kg), and that the efficiency of the boiler is 85%, it is possible to estimate the incremental costs per kg of steam produced. The outcomes give high values for small boilers (more than 20 USD/ton of steam), and lower values for large boilers (about 1 USD/ton of steam). The cost effectiveness (i.e., how much a reduction of 1 unit of dioxin will cost by adding more sophisticated filters to a standard boiler equipped with standard (multicyclone) filters) is shown in Table 48 (104) The Table shows that reducing dioxin emissions by 1 mgTEQ/year would cost from 73,500 USD for medium boilers to 323,000 USD for small boilers.

TaTable 47 Coal-fired boilers: Operating costs



Coal-fired boilers: operating costs for different levels of control

	Operating costs ($'000s/year)		
	Small	Medium	Large
Fabric filter	170	200	330
+ catalytic fabric filter	210	360	800

Other considerations

It should be noted that the formation of PCDD, PCDF, PCB and HCB is complex; thus removing particles in the flue gases does not mean POPs will not be emitted. Although important, these cleaning techniques are not the only solution. As mentioned earlier, fuel quality and combustion control are the most important steps for minimizing POP emissions.

The capture of particles from the flue gases may produce an amount of contaminated dust waste, which should be handled with care as a possible POP-containing product. Generally, combustion products, such as fly ash and bottom ash from pulverized coal combustion, contain very low residual levels of POPs, with PCDD of less than 1 pg I-TEQ/g (Meij and Winkel 2001). Disposal methods are therefore likely to be dictated by prevention of release of other possible contaminants in the material rather than by any POPs that may be present.

For residues containing higher levels of contamination, several techniques are recommended for reduction of POPs before disposal. These include catalytic treatment at low temperatures and with reduced oxygen concentrations, extraction of the heavy metals and combustion to destroy organic matter, vitrification, and plasma technology (UNECE 1998). A summary of measures constituting best environmental practices and best available techniques is presented in Table 49

Table 49 BAT and BEP for reduction of dioxin releases (103)

Issue	Best environmental practices	Best available techniques	Environmental benefit

Fuel	Fuel sourcing Fuel monitoring Fuel specifications	Control fuel input to meet specifications by rejection, substitution, purification or blending	Minimization of persistent organic pollutants introduced into the combustion system
Combustion conditions	Design appropriate reactor for the specified fuel usage Monitor combustion conditions, particularly: • Temperature (> 900 °C) • Time (> 1 second) • Turbulence (high) • Oxygen (in excess) Operate and maintain to achieve designed conditions Develop specific conditions and operating procedures for co-firing, particularly during furnace start-up and shutdown	Automated or computerized combustion control system to maintain ideal combustion conditions Maximized oxidation by maintaining ideal fuel/oxygen mix	Destruction of compounds of persistent organic pollutants present in the fuel Minimization of formation of persistent organic pollutants during combustion
Collection	Operation and maintenance of existing air pollution control devices	Assess potential for environmental improvement by installation of air pollution control device Install air pollution control device when environmental benefits can be demonstrated	Minimize persistent organic pollutant content of gases
Waste disposal	Collect solid and liquid wastes from the combustion process and air pollution control device Handle and store appropriately to minimize environmental release	Assess potential for waste volume reduction and recycling Safe disposal	Minimize and control the release to the environment

Achievable performance levels

The available data suggest that for an effective boiler system using only coal, oil or gas as the fuel, an achievable performance level for volumetric emissions of PCDD/PCDF from fossil fuel-fired utility and industrial boilers is < 0.1 ng I-TEQ/Nm^3. Actual emissions are likely to be much lower than this amount. Table 50 shows the emission factors for PCDD/PCDF from controlled bituminous and sub-bituminous coal combustion, expressed in nanograms /kg.

Table 50 Emission factors for PCDD and PCDF (ng/kg) from bituminous and sub-bituminous coals (103)

Congener	Flue gas desulphurization spray dryer absorber and fabric filter	Electrostatic precipitator or fabric filter
2,3,7,8-TCDD	n.d.	0.0072
Total TCDD	0.197	0.046
Total PeCDD	0.353	0.022
Total HxCDD	1.50	0.014
Total HpCDD	5.00	0.042
Total OCDD	14.4	0.208
Total PCDD	**21.4**	**0.333**
2,3,7,8-TCDF	n.d.	0.026
Total TCDF	1.25	0.202
Total PeCDF	2.42	0.177
Total HxCDF	6.35	0.096

Congener	Flue gas desulphurization spray dryer absorber and fabric filter	Electrostatic precipitator or fabric filter
Total HpCDF	22.0	0.038
Total OCDF	68.5	0.033
Total PCDF	**101**	**0.545**
TOTAL PCDD/PCDF	**122**	**0.880**

Best environmental practices

Efficiency and steam generation costs

The implementation of BAT/BEP affects the economics of the boiler system and, consequently, factory production costs. Before discussing the effects of BAT/BEP implementation, it is useful to recall some key economic concepts related to how the cost of steam can be calculated. Two methodologies can be used: (105)

- *Detailed financial assessment*: requires detailed information on bank loan rates as well as costs using predictions for future inflation rates. Calculations are quite complicated, but can be carried out with the assistance of dedicated software tools.
- *Simplified analysis*: based on averaged interest rates and on basic assumptions for operating costs. This method is useful in comparisons of different options and preliminary evaluations of steam costs.

This section uses the second methodology because it is easy to implement, does not need special expertise or financial tools, and can help decision-makers narrow down the options to be analysed in more detail.

The calculation of steam cost will be limited to the boiler island only, excluding the steam distribution system and associated steam losses and condensate recovery, which are very dependent on the manufacturing process. For the sake of simplicity, the calculation will assume steam production at nominal rate and fixed pressure and temperature. Although load variations usually affect the cost of steam, this assumption can be used for boiler cost comparisons (selection of a new boiler or retrofitting of an old one) where the operating conditions are similar. A more exhaustive evaluation would take into account more technical and financial data, but would require more tools and time e.g., rate of return (ROR), return of investment (ROI). ANNEX 15 provides more information on these more complicated financial evaluations of investments.

In the simplified method for calculating the cost of steam produced by a boiler, the components may be divided into two main categories:

- *Fixed costs*: These costs occur even when the boiler is not operating, including:
    - depreciation of boiler and auxiliary equipment
    - bank loan interest rates, and
    - staff costs, assuming that the factory has to pay its personnel even when the boiler is not operating.
- *Variable costs*: These costs occur only when the boiler is operating, including:
    - fuel
    - repairs
    - maintenance materials and labour (Repairs and Maintenance: R+M)
    - power and consumables (for pumps, fans, etc.)

- raw water supply
- boiler feedwater treatment, and
- ash disposal costs (solid fuels).

Maintenance and operating costs can be also expressed as a percentage of the investment or as an annual fixed fee. This makes the comparisons even easier.

Depreciation of investment

The depreciation of the investment (boiler purchase) can be linked to the technical life of the boiler. Currently, boilers tend to last more than 20 years, but, for financial calculations, a lifetime of 20 years is usually acceptable. After 20 years, the residual value of the boiler is assumed to equal 0. The boiler could last for longer, providing extra revenues, but decommissioning costs should also be taken into account.

Assuming that a bank loan has been requested to pay for the boiler, and fixed annual instalments are paid to the bank (if the boiler is paid for with a variable interest loan, the calculations are different), the mortgage rate to be paid to the bank is expressed by the mortgage constant formula:

$$r = 1 - \frac{1}{(1+i)^n}$$

Where:

r = mortgage rate

i = interest rate

n = boiler lifetime

It is not necessary to use this formula because widely available online database and software tools provide the mortgage rate ***r*** amount to be used, for given capital, interest rate and period, for comparison calculations. The software tools for calculating house purchase mortgages can also be used for boiler calculations.

Example

For a loan at an interest rate of 6% and term of 20 years, the annual mortgage constant formula would be:
$r = [1-[1/(1.06)^{20}]]= 8.72\%$

If the investor borrows 100,000 USD then the annual payment would be:
Annual Payment = 100,000 X 0.0872 = 8,720 USD

Consider two purchasing options:

1. New efficient boiler
2. Old inefficient second-hand boiler

Assumptions:
Boiler capacity: 3 t/h 10 bar
Fuel: Heavy oil
Boiler price:
New boiler: 150,000 USD
Second-hand boiler: 30,000 USD

Boiler efficiency:
  New boiler: 85%
  Second-hand boiler: 70%
Fuel cost: 600 USD/ton
Interest rate: 6%
Mortgage annual payment: 8.72% of capital cost
Maintenance:
    New boiler: 5% of capital cost/year
    Second-hand boiler: 10% of capital cost/year

Based on these assumptions, the outcomes are shown in Table 51.

Table 51 Comparison between second hand and new boiler purchase

	Mortgage rate 20 years	Annual payment USD	Working hours per year	Total fuel consumption kg/year	Annual fuel bill USD	Fuel bill difference USD	Maintenance cost difference USD	Total annual difference USD
NEW BOILER	8.72%	13080	4000	979765	587859		4500	
OLD BOILER	8.72%	2616	4000	1189714	713829	125970		**111,006**

In one year, the fuel savings achieved by the more efficient, new boiler would cover the difference between the old and the new boiler. The investment payback period is therefore less than one year.

The maintenance costs are higher for the new boiler because they have been assumed to be a percentage of the capital cost; the new boiler will have additional and more sophisticated and equipment.

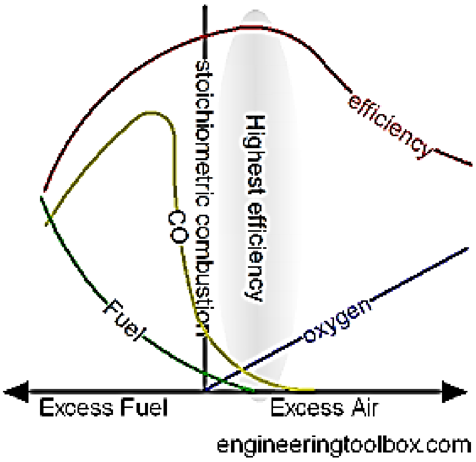


Figure 173 Relationship between efficiency and excess air (Engineering Toolbox) (168)

Efficiency and excess air levels

To ensure complete combustion of the fuel used, combustion chambers are supplied with excess air. Excess air increases the amount of oxygen and the probability of combustion of all fuel. When fuel and oxygen in the air are in perfect balance, combustion is said to be stoichiometric. The exact stoichiometric ratio between air and fuel is very difficult to achieve in the bulk combustion chamber because, for several reasons, the fuel/air mixture is not homogeneous everywhere; there will be areas with excess air and areas with low combustion air. As the latter can lead to CO formation and dangerous operating conditions (boiler explosion), a small amount of excess air is normally ensured during combustion of fuels (106).

Combustion efficiency will increase with increased excess air, until the heat loss in the excess air is greater than the heat provided by more efficient combustion. Boiler efficiency will decrease with increased excess air because as more air is added to combustion,

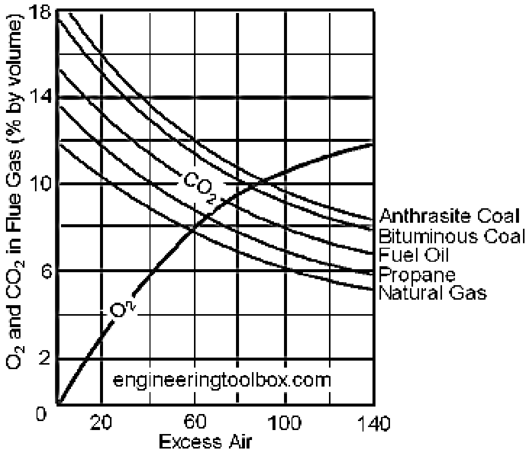


Figure 174 Relationship between excess air, fuels and combustion products - engineering Toolbox

more air will go to the stack and the greater the heat losses will be from the stack. Efficiency reaches its maximum for oxygen values slightly higher than stoichiometric conditions because of the non-homogeneous distribution of fuel and air within the combustion chamber. Figure 173 shows the relationship between efficiency and excess air.

Achieving the highest efficiency requires excess air of:

- 5% - 10% for natural gas
- 5% - 20% for fuel oil, and
- 15% - 60% for coal.

Excess air is often measured/given as excess oxygen. Keeping in mind that the amount of oxygen in the air is about 21% (ratio of 1:5), the conversion factor between excess air and excess oxygen is 5. This means that 15% excess air is equal to 15/5 = 3% excess oxygen; 60% excess air gives 60/5 = 12% excess oxygen.

The $CO_{2,}$ (a product of combustion) content in the flue gas is an important indication of combustion efficiency. Figure 174 shows the relationship between excess air and CO_2 in the flue gas.(107) The optimal CO_2 content after combustion is approximately 10% for natural gas and 13% for lighter oils.

As mentioned earlier, the temperature of the flue gas at the stack is important to achieve good efficiencies. The rule of thumb is that the higher the flue gas temperature at the stack, the lower the efficiency. This is because the heat (energy) lost at the stack is higher with higher temperatures. Normal combustion efficiencies for natural gas at different amounts of excess air and flue gas temperatures are indicated in Table 52 For the same stack temperature (200 °C), the higher the excess oxygen is, the lower the combustion efficiency. For the same excess oxygen (3%), the higher the stack temperature is, the lower the combustion efficiency.

Table 52 Relationship between efficiency and flue gas stack temperatures (Engineering Toolbox) (107)

Combustion Efficiency (%)						
Excess %		**Net Stack Temperature* (°*F*)**				
Air	**Oxygen**	**200**	**300**	**400**	**500**	**600**
9.5	**2.0**	**85.4**	**83.1**	**80.8**	**78.4**	**76.0**
15	**3.0**	**85.2**	**82.8**	**80.4**	**77.9**	**75.4**
28.1	**5.0**	**84.7**	**82.1**	**79.5**	**76.7**	**74.0**
44.9	**7.0**	**84.1**	**81.2**	**78.2**	**75.2**	**72.1**

81.6	**10.0**	**82.8**	**79.3**	**75.6**	**71.9**	**68.2**

* The "net stack temperature" is the difference between the temperature of the flue gas inside the chimney and the room temperature outside the burner.

Example (19)

A boiler operates for 8,000 hours per year and consumes 500,000 million British thermal units (Btu; MMBtu) of natural gas while producing 45,000 lb/hour of 150 pounds per square inch gauge (psig) steam. Stack gas measurements indicate an excess air level of 44.9% with a flue gas combustion air temperature of 400°F. Using the table above, the boiler combustion efficiency is 78.2% (E1). Tuning the boiler reduces excess air to 9.5% with a flue gas combustion air temperature of 300 °F. The boiler combustion efficiency increases to 83.1% (E2). Assuming a fuel cost of $8.00/MMBtu, the annual savings are:

Annual Savings = Fuel Consumption x (1–E1/E2) x Fuel Cost = 29,482 MMBtu/y x $8.00/MMBtu = 235,856 USD

Flue gas losses and stack temperatures

The relationships between the temperature difference between the flue gas and supply air, CO_2 concentration in the flue gas, and the efficiency loss in the flue gas, is shown in **Figure** 175. (107) The higher the net stack temperature is, the greater the heat losses in the flue gas e.g., a net stack T° of 100 °C at 15% CO_2 in the flue gas results in about 4% heat losses at the stack. If the net stack T° rises to 400 °C, the heat losses are about 16%. If the amount of excess air rises, the percentage of CO_2 in the flue gas decreases because the CO_2 produced will be diluted in more air. The Figure also shows that an increase of excess air (decrease of % of CO_2 in the flue gas) results in more flue gas losses e.g., at 200 °C stack exit T°, the flue gas losses decrease from 35% to about 8% when CO_2 increases from 3% to 15%.

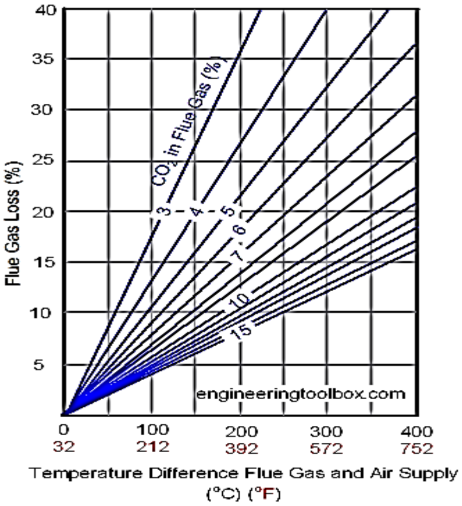


Figure 175 Effects of stack temperature on flue gas losses

Excess air is very often measured by the value of CO. Because CO forms when combustion takes place under stoichiometric conditions, the amount of CO indicates how much of the fuel has been burned under stoichiometric conditions (incomplete combustion).

Optimization of excess air

Optimizing excess air is the easiest way to substantially improve boiler efficiency. All that is required is some initiative on the part of the boiler operator and the appropriate instruments for monitoring excess air, incomplete combustion and

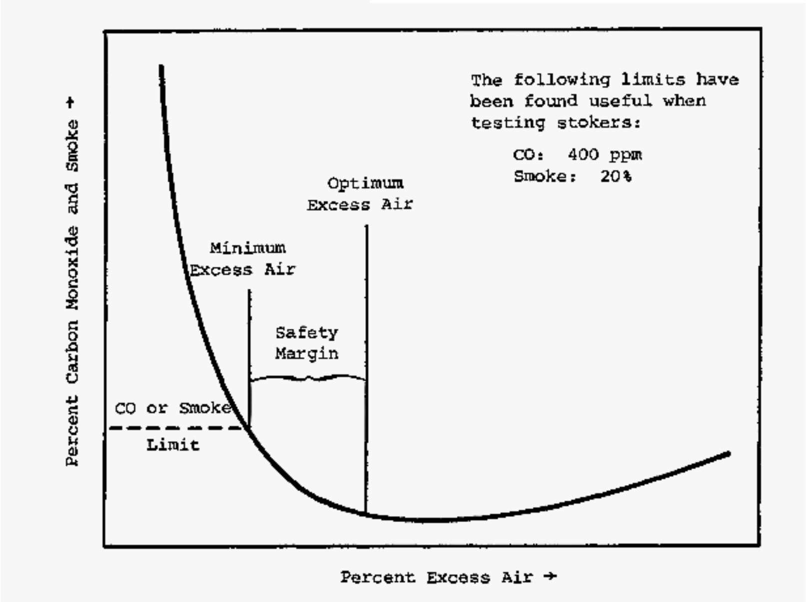


Figure 176 Excess air optimization (108)

stack temperatures. Careful observation and thoughtful action can increase efficiency by 1% to 4%.

Optimum excess air (108) is illustrated in Figure 176. When excess air is reduced in the combustion chamber, the gas stack heat loss drops until there is no longer enough oxygen for complete combustion. At this point, sometimes called the “smoke limit” or the “CO limit,” smoke and carbon monoxide rapidly increase. This is the minimum excess air level and the operating point of maximum efficiency for the boiler. However, operating the boiler at this point is flirting with disaster because the excess air will easily swing below the smoke and/or CO limit. Therefore, the operator must allow for a safety margin in the excess air level so that normal swings in the load do not produce undesirable firing conditions. The size of the margin is determined by trial and error, and depends on the stability of the load and the sophistication of the combustion controls. The safety margin typically ranges between 5% and 20% excess air (1% and 5% oxygen). The optimum excess air can be established at this point. However, it must be re-established at several different firing rates because more excess air is required at reduced loads than at full load.

Excess air measurement techniques

To tune the boiler for optimum excess air, three basic measurements are required:

- O_2 or CO_2 for determining operating excess air levels
- CO and visual observations for detecting the minimum excess air limit
- stack gas temperature for determining the stack heat loss

Excess air can be determined by using Figure 177 if either the percentage of O_2 or the percentage of CO_2 in the flue gas is known. Portable flue gas sampling devices can record these measurements at a relatively low cost.

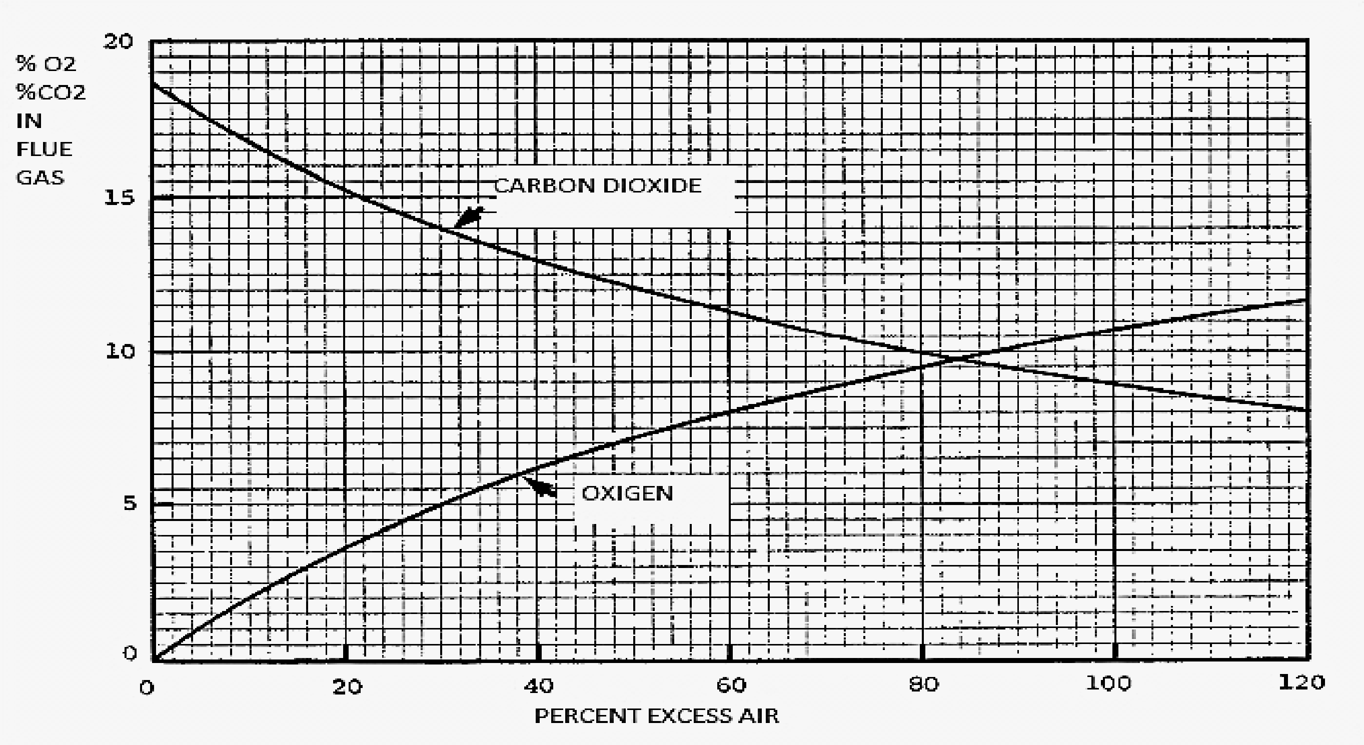


Figure 177 Oxygen and carbon dioxide in flue gas

Excess air values for different fuels are shown in ANNEX 18

Efficiency improvement procedures

1. Before determining the optimum oxygen operating level, the boiler should be inspected and maintenance tasks performed to ensure it is in good mechanical condition. The following steps should then be taken to minimize the flue gas oxygen: Bring the boiler to the test firing rate and put combustion control on manual. Make sure that safety interlocks are functioning properly.
2. After stabilizing flame conditions, take a complete set of readings (O_2 or CO_2, stack gas temperature, CO and/or opacity).
3. Increase the air flow to the furnace by about 1%, allowing time to stabilize. Then take another set of readings.
4. Reduce the air flow in small steps while observing stack and flame conditions. Allow the unit to stabilize following each change and record the data.
5. Continue to reduce the air flow until a minimum excess air condition is reached as indicated by smoke, a sudden rise in CO or other visible deterioration conditions.
6. Establish a safe margin in excess air above the minimum and reset the combustion controls to maintain this “optimum” level.
7. Develop a CO or smoke versus excess air characteristics curve similar to the figure above using the data obtained from this test.
8. Compare the minimum excess air value to the predicted value provided by the manufacturer. High excess air levels should be investigated.
9. Repeat steps 1-8 for each boiler load to be considered. Some compromise in optimum excess air settings may be necessary since control adjustments at one firing rate may affect conditions at other firing rates.
10. After these adjustments have been completed, verify the operation of these settings by observing normal load swings. If undesirable conditions are encountered, increase the safety margin.

The data obtained in steps 2 to 5 will look something like the data in Table 53.

Table 53 Excess air control adjustments

	%=O_2	**CO Ppm**	**Stack gas temperature ° F (°C)**
Step 2	8.9	105	472 (244)
Step 3	10.0	130	463 (239)
Step 4			
A	8.3	95	461 (238)
B	7.5	100	461 (238)
C	6.8	158	456 (235)
D	6.0	270	450 (232)
E	5.2	612	445 (229)
Step 5	4.8	1050	442 (228)
Step 6	6.6	180	455 (235)

In this example, the baseline or as-found = 2 was 8.9%. The air flow was first raised and then lowered in stages until the carbon dioxide exceeded 1000 ppm (parts per million). As the test proceeded, the carbon monoxide data were a function of O_2, as shown in Figure 178.

The carbon monoxide limit is taken to be 400 ppm. Therefore, the minimum flue gas oxygen operating level is 5.6%. If a 1% oxygen safety margin is selected, the optimum operating level is 6.2% O_2. Since this is reasonably close to the optimum operating level that was determined by testing, the boiler is operating at it should. Step 8 is now complete.

To find out by how much boiler efficiency was improved Figure 179 shows the relationship between stack temperature, stack heat loss and flue gas oxygen content.

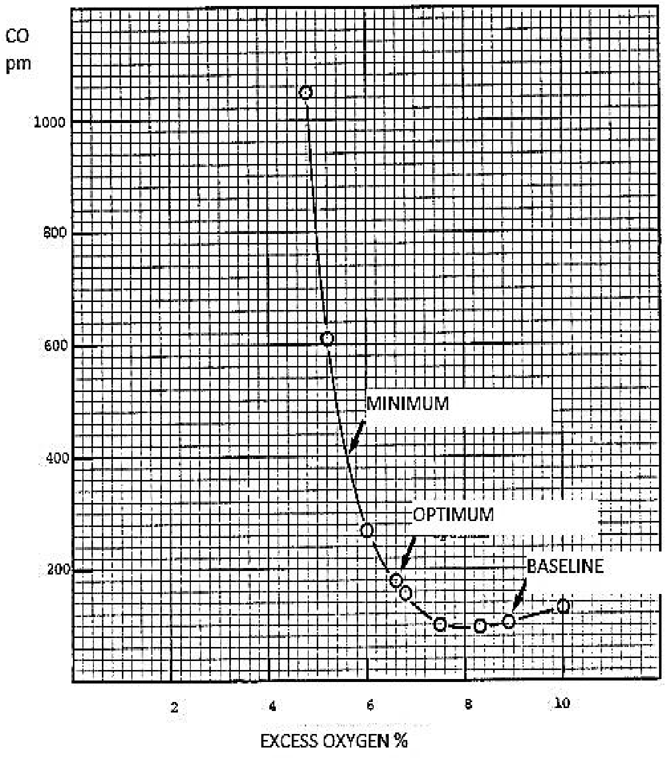


Figure 178 Excess oxygen versus carbon monoxide

The graph relates stack gas (O_2) and stack gas temperature to stack gas heat loss for a typical bituminous coal. It may be used for most coals to find approximate gas heat loss savings. The results are shown in Table 54.

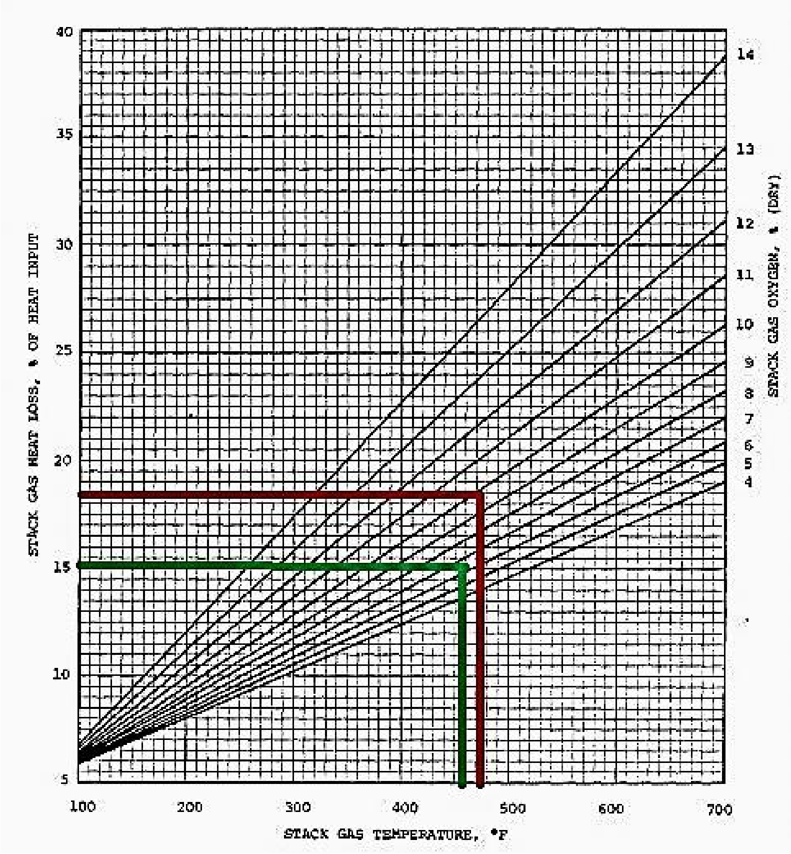


Figure 179 Efficiency improvement evaluation

Table 54 Efficiency gain from stack temperature and excess air reductions

	O_2%	Stack gas temperature °F	Stack gas heat loss (from the figure)
Baseline Test	**8.9**	**472**	**17.8%**
Optimum Test	**6.6**	**455**	**15.1%**
		EFFICIENCY GAIN	**2.7 %**

To calculate the fuel bill savings, if the baseline boiler efficiency is assumed to be 80%, 2.7% of the 80% is saved. The actual savings will be:

2.7% efficiency gain/80% boiler efficiency x 100 = 3.38% fuel savings

If the assumption is that the boiler consumes 3 t/h of coal, operates 7000 hours/year at full load, and the cost of coal is 100 USD/t, the annual savings will be:

Annual fuel consumption: 3 t/h x 7000 h/y = 21000 t/y

Annual fuel bill: 21000 t/y x 100 USD/t = 2,100,000 USD/y

Savings: 2,100,000 x 0.038 efficiency gain = 79800 USD/y

The reductions in CO_2 and dioxin releases (and sulphur oxide (SO_x) and nitrogen oxide (NO_x) releases) can be calculated. The following emission factors can be assumed:

CO_2 releases: 1.84 tons CO_2 per ton of coal

Dioxin releases: 10 μ TEQ/TJ

Coal heating value: 16 MJ/kg (megajoules/kilogram)

CO_2

Total CO_2 emissions in a year: 21000 t/y x 1.84 t_{CO2}/t_{coal} = 38640 tons

Avoided CO_2 emissions: 38640 x 0,038 efficiency gain = 1468 t_{CO2}/y

Dioxins

Since the emission factor is linked to the energy inputted to the boiler, the total coal energy burned is calculated as:

21000 t/y x 16 MJ/kg (16000 MJ/t) = 336 x 10^6 MJ/t = 336 TJ/y (1 TJ = 10^6 MJ)

Dioxin releases: 336 TJ/y x 10 μ TEQ/TJ = 3360 μ TEQ/y

Reduction in dioxin releases: 3360 μ TEQ/year x 0.038 efficiency gain = 128 μ TEQ/y

This is a case study only, and situations will differ case by case. However, in all cases, efforts to minimize excess air will result in cost savings and less pollution.

Flue gas analysers

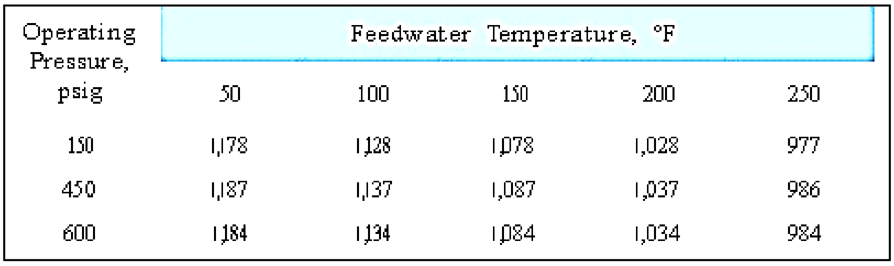
The percentage of oxygen in the flue gas can be measured by inexpensive gas-absorbing test kits. More expensive (500 USD to 1,000 USD) hand-held, computer-based analysers that display percentage of oxygen, stack gas temperature, and boiler efficiency are a good investment for any boiler system with annual fuel costs exceeding 50,000 USD. More sophisticated, but easy-to-use, hand-held gas analysers are also available for measuring the amount of pollutants emitted from a boiler.

Benchmarking of the fuel cost of steam generation

Benchmarking the fuel cost of steam generation, in USD per 1,000 pounds (USD/1,000 lb) or per ton (USD/t) of steam, is an effective way to assess the efficiency of the boiler's steam system (20). This cost is dependent upon fuel type, unit fuel cost, boiler efficiency, feedwater temperature, and steam pressure. The calculation provides a good first approximation of the cost of generating steam and serves as a tracking device to allow for boiler performance monitoring.

Table 55 shows the heat input required (in Btu) to produce 1 lb of saturated steam at different operating pressures and varying feedwater temperatures (given in psig and °F). Table 56 shows Bar, °C and MJ conversions.

Table 55 Heat required per unit of steam produced (BTU/lb steam) (19)



Operating Pressure, psig	Feedwater Temperature, °F				
	50	100	150	200	250
150	1,178	1,128	1,078	1,028	977
450	1,187	1,137	1,087	1,037	986
600	1,184	1,134	1,084	1,034	984

Table 56 Heat required per unit of steam produced (MJ/kg steam)

Operating Pressure (bar)	**Feedwater Temperature (°C)**				
	10	***38***	***66***	***93***	***121***
10	**2.76**	**2.64**	**2.53**	**2.41**	**2.29**
31	**2.78**	**2.67**	**2.55**	**2.43**	**2.31**
41	**2.78**	**2.66**	**2.54**	**2.42**	**2.31**

Higher feedwater temperatures result in less heat per unit of steam produced, which means the higher the water inlet temperature, the higher the system efficiency. The influence of steam pressure on efficiency is low. Table 55 and Table 56 have been calculated using steam tables (difference between the enthalpies of steam and feedwater; see ANNEXES 2 and 3). The average boiler efficiencies for different fuels are given in Table 57.

Table 57 Average combustion efficiencies for different fuels

Fuel Type	**Combustion Efficiency, %**
Natural Gas	**90**
Distillate/No. 2 Oil	**89**
Residual/No. 6 Oil	**88**
Coal	**86**

Example

A boiler fired with natural gas costing 8.00 USD/MMBtu produces 450-psig saturated steam and is supplied with 250 °F feedwater. Using values from the tables, the fuel cost of producing steam can be calculated as follows:

Heat required per unit of steam produced = 986 Btu/lb

Steam cost = 8.00×10^{-6} USD/Btu x 986 Btu/lb x 90% efficiency = 7×10^{-3} USD/lb = 7 USD/1000lb = 15.5 USD/ton (metric)

Boiler feedwater 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 feedwater used in the boiler. When feedwater enters the boiler, the elevated temperatures and pressures cause the components of water to behave differently. Most of the components in the feedwater 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. This section explains deposit control, followed by two major types of boiler water treatment: internal water treatment and external water treatment.

Deposit control

Deposits in boilers may result from hardness contamination of feedwater and corrosion products from the condensate and feedwater system. Hardness contamination of feedwater 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 boiler efficiency significantly. Different types of deposits affect boiler efficiency differently. Thus it may be useful to analyse the characteristics of deposits. The insulating effect of deposits causes the boiler metal temperature to rise and may lead to tube failure by overheating.

Two main groups of impurities cause deposits:

- *Hard salts of calcium and magnesium*: These “hardness salts” are the most important chemicals in water that influence the formation of deposits in boilers:
  - Alkaline: Calcium and magnesium bicarbonate dissolve in water to form an alkaline solution; 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 chemicals because the hardness can be removed by boiling.
  - Non-alkaline: Calcium and magnesium sulphates, chlorides, 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 that takes place within the boiler, or by chemical change to a less soluble compound.
- *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.

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 blowdown. This method is limited to boilers in which feedwater is low in hardness salts, low-pressure, high total dissolved solids (TDS) content in boiler water is tolerated, and only a small quantity of water is required to be treated. If these conditions are not met, then high rates of blowdown are required to dispose of 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.

External water treatment

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

- ion exchange
- deaeration (mechanical and chemical)
- reverse osmosis, and
- demineralization.

Before using any of these treatments, it is necessary to remove suspended solids and colour from the raw water because they may foul the resins used in the subsequent treatment sections. Methods of pretreatment 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 salts, and possibly non-hardness salts. Removal of only hardness salts is called “softening”, while total removal of salts from a solution is called “demineralization”.

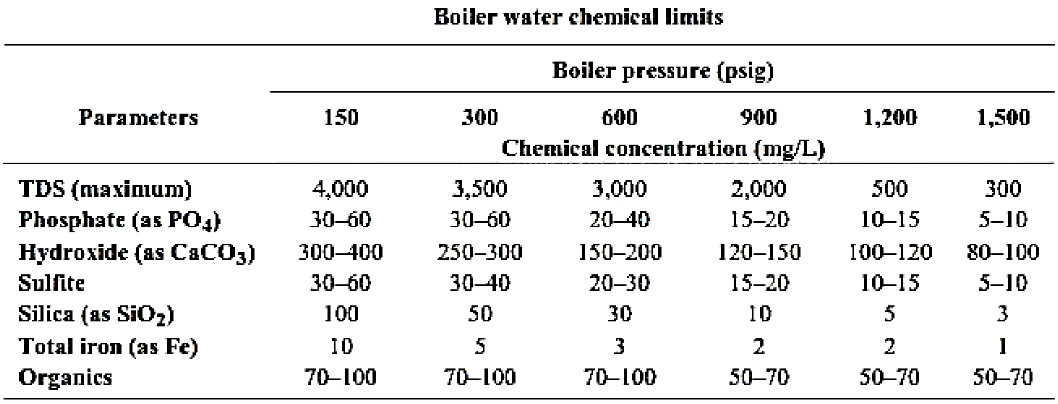
Ion-exchange process (softener plant)

In an 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 exchange”, in which calcium and magnesium ions are exchanged for sodium ions. After saturation, regeneration is done with sodium chloride. Since sodium salts are soluble, they 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, blowdown quantity, or 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.

Table 58 shows feedwater limits for boilers working at different pressures. (25) The rule of thumb is that the greater the pressure, the more stringent the limits.

Table 58 Boiler feedwater chemical limits of concentration



Boiler water chemical limits

Parameters	Boiler pressure (psig)					
	150	300	600	900	1,200	1,500
	Chemical concentration (mg/L)					
TDS (maximum)	4,000	3,500	3,000	2,000	500	300
Phosphate (as PO_4)	30–60	30–60	20–40	15–20	10–15	5–10
Hydroxide (as $CaCO_3$)	300–400	250–300	150–200	120–150	100–120	80–100
Sulfite	30–60	30–40	20–30	15–20	10–15	5–10
Silica (as SiO_2)	100	50	30	10	5	3
Total iron (as Fe)	10	5	3	2	2	1
Organics	70–100	70–100	70–100	50–70	50–70	50–70

Deaeration

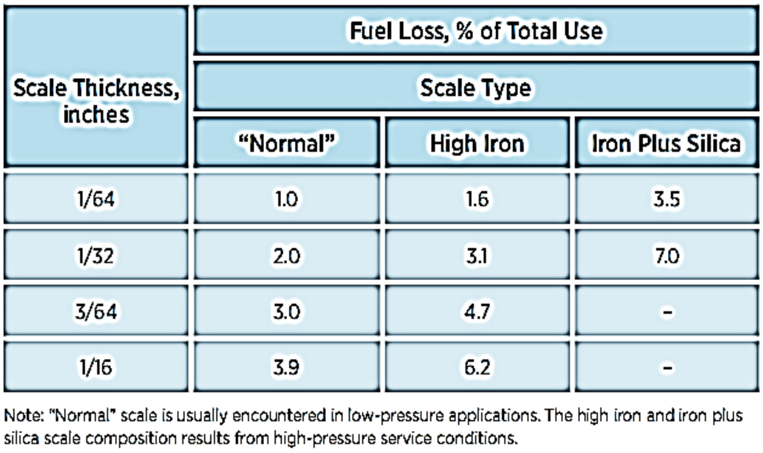
In deaeration, dissolved gases, such as oxygen and carbon dioxide, are expelled by preheating the feedwater before it enters the boiler. All natural waters contain dissolved gases in solution. Certain gases, such as CO_2 and O_2, greatly increase corrosion. When heated in boiler systems, CO_2 and O_2 are released as gases and combined water to form carbonic acid (H_2CO).

Removal of oxygen, carbon dioxide and other non-condensable gases from boiler feedwater 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. Deaeration can be done by mechanical deaeration, chemical deaeration, or both (see section on *Boiler control systems* in Chapter 1).

Clean boiler waterside heat transfer surfaces

Preventing the formation of scales can translate into substantial energy savings, even for small boilers (20). Scale deposits occur when calcium, magnesium, and silica, commonly found in most water supplies, react to form a continuous layer of material on the waterside of the boiler heat exchange tubes. Scale creates a problem because it typically possesses a thermal conductivity an order of magnitude less than the corresponding value for bare steel. Even thin layers of scale serve as an effective insulator and retard heat transfer. The result is

Table 59 Effect of scale on fuel consumption (22)



Scale Thickness, inches	Fuel Loss, % of Total Use		
	Scale Type		
	"Normal"	High Iron	Iron Plus Silica
1/64	1.0	1.6	3.5
1/32	2.0	3.1	7.0
3/64	3.0	4.7	-
1/16	3.9	6.2	-

Note: "Normal" scale is usually encountered in low-pressure applications. The high iron and iron plus silica scale composition results from high-pressure service conditions.

overheating of boiler tube metal, tube failures, and loss of energy efficiency. Table 59 shows the effect of different scale types on fuel consumption. The higher the scale is, the higher the fuel consumption; the worse the scale type is, the higher the fuel consumption.

Figure 180 shows that heat transfer can be impaired by deposits on the waterside of boiler tubes. Such deposits can reduce boiler efficiency substantially, and lead to serious mechanical and operating problems as well. Waterside deposits restrict the amount of heat transferred to the boiler water and, in watertube boilers, also restrict water circulation. The tube metal temperature rises as a result, which may increase both the rate of deposition and flue gas temperature. In extreme cases, the tubes fail from overheating. The Figure shows that scaling at tubes waterside can increase the temperature at the external side of the tubes from 600 °F (clean tubes) to 800 °F, and soot deposits can increase it from 600° F to 650 °F.

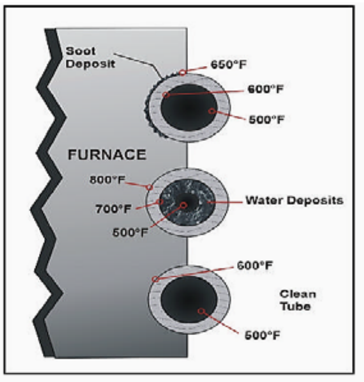


Figure 180 Effects of Deposits on Boiler Tube Heat Transfer (178)

Example

A boiler uses 450,000 MMBtu of fuel annually while operating for 8,000 hours at its rated capacity of 45,000 lb/hr of 150 psig steam (about 10 tons/hour and 10 bar pressure). If scale 1/32nd of an inch thick is allowed to form on the boiler tubes, and the scale is of "normal" composition, Table 59indicates a fuel loss of 2%.

The increase in operating costs, assuming energy is priced at 8.00 USD per million Btu (8.00 USD/MMBtu), is:

Annual Operating Cost Increase = 450,000 MMBtu/y x 8.00 USD/MMBtu x 0.02 = 72,000 USD

As far as emissions are concerned, assuming a CO_2 emission factor of 116 lb/MMBtu, the annual CO_2 increase is: 450,000 MMBtu x 116 lb/MMBtu x 0.02 = 1,044,000 lb/y = 469 tons CO_2/y

Energy-efficient burners

The purpose of the burner is to mix molecules of fuel with molecules of air. A boiler will run only as well as the burner performs. A poorly designed boiler with an efficient burner may perform better than a well-designed boiler with a poor burner. Burners are designed to maximize combustion efficiency while minimizing the release of emissions. A power burner mechanically mixes fuel and combustion air, and injects the mixture into the combustion chamber. All power burners essentially provide complete combustion while maintaining flame stabilization over a range of firing rates. Different burners, however, require different amounts of excess air and have different turndown ratios. The turndown ratio is the maximum inlet fuel or firing rate divided by the minimum firing rate (20).

An efficient natural gas burner requires only 2% to 3% excess oxygen, or 10% to 15% excess air in the flue gas, to burn fuel without forming excessive carbon monoxide. Most gas burners exhibit turndown ratios of 10:1 or 12:1 with little or no loss in combustion efficiency. Some burners offer turndowns of 20:1 on oil and up to 35:1 on gas. A higher turndown ratio reduces burner starts, provides better load control, saves wear and tear on the burner, reduces refractory wear, reduces purge-air requirements, and provides fuel savings.

Efficient burner technologies

An efficient burner provides the proper air-to-fuel mixture throughout the full range of firing rates, without constant adjustment. Many burners with complex linkage designs do not hold their air-to-fuel settings over time. Often, they are adjusted to provide high levels of excess air to compensate for inconsistencies in burner performance. An alternative to complex linkage designs, modern burners are increasingly using servomotors with parallel positioning to independently control the quantities of fuel and air delivered to the burner head. Controls without linkage allow for easy tune-ups and minor adjustments, while eliminating hysteresis, or lack of retraceability, and provide accurate point-to-point control. These controls provide consistent performance and repeatability as the burner adjusts to different firing rates.

Alternatives to electronic controls are burners with a single drive or jackshaft. Standard burners that make use of linkages to provide single-point or proportional control should be avoided. Linkage joints wear and rod-set screws can loosen, allowing slippage, suboptimal air-to-fuel ratios, and efficiency declines.

Applications

Purchasing a new energy-efficient burner is a good idea if the existing burner is cycling on and off rapidly. Rotary-cup oil burners that have been converted to use natural gas are often inefficient. Determining the potential energy saved by replacing an existing burner with an energy-efficient burner requires several steps:

1. Complete recommended burner-maintenance requirements and tune the boiler.
2. Conduct combustion-efficiency tests at full- and part-load firing rates.
3. Compare the measured efficiency values with the performance of the new burner. Most manufacturers will provide guaranteed excess levels of oxygen, carbon monoxide, and nitrous oxide.

Example

Even a small improvement in burner efficiency can provide significant savings. Consider a 50,000 lb/hr process boiler with a combustion efficiency of 79% (E1). The boiler annually consumes 500,000 MMBtu of natural gas. At a price of 8.00 USD/MMBtu, the annual fuel cost is 4 million USD. What are the savings from an energy-efficient burner that improves combustion efficiency by 1%, 2%, or 3%? (See Table 60.)

Cost Savings = Fuel Consumption x Fuel Price x (1 - E1/E2)

Table 60 Burner optimization-efficiency improvement

Burner Combustion Efficiency Improvement, %	Energy Savings MMBtu/y	Annual Dollar Savings USD
1%	6,250	50,000
2%	12,345	98,760
3%	18,290	146,320

If the installed cost is 75,000 USD for a new burner that provides an efficiency improvement of 2%, the simple payback on investment is as follows:

Simple Payback = 75,000 USD/98,760 USD/y = 0.76 year

Burner maintenance should be conducted at regular intervals. Wear on the firing head, diffuser, or igniter can result in air leakage or failure of the boiler to start. One burner distributor recommends maintenance four times per year, with the change of seasons. A change in weather results in a change in combustion.

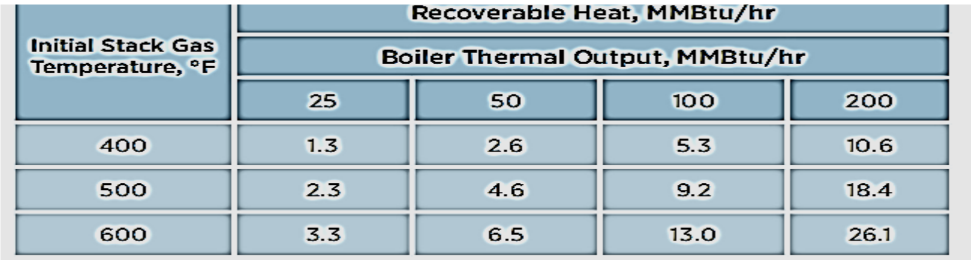
Appropriate fan selection

Fan selection is also important. Backward-curved fans provide more reliable air control than forward-curved fans. Radial-damper designs tend to provide more repeatable air control at lower firing rates than blade-type damper assemblies.

Feedwater economizers for waste heat recovery

A feedwater economizer reduces steam boiler fuel requirements by transferring heat from the flue gas to incoming feedwater (20). Boiler flue gases are often rejected to the stack at temperatures of more than 55 °C to 85 °C (100°F to 150°F) higher than the temperature of the generated steam. Generally, boiler efficiency can be increased by 1% for every 22 °C (40 °F) reduction in flue gas temperature. By recovering waste heat, an economizer can often reduce fuel requirements by 5% to 10%, and pay for itself in less than 2 years. Table 61 provides examples of the potential for heat recovery.

Table 61 Recoverable heat from flue Gases (22)



Initial Stack Gas Temperature, °F	Recoverable Heat, MMBtu/hr			
	Boiler Thermal Output, MMBtu/hr			
	25	50	100	200
400	1.3	2.6	5.3	10.6
500	2.3	4.6	9.2	18.4
600	3.3	6.5	13.0	26.1

Example

An 80% efficient boiler generates 45,000 lb/hr (20 t/h) of 150-psig (10 bar) steam by burning natural gas. Condensate is returned to the boiler and mixed with make-up water to yield 117 °F (47 °C) feedwater. The stack temperature is measured at 500 °F (260 °C). Determine the annual energy savings that will be achieved by installing an economizer given 8,400 hr/y of boiler operation at a fuel cost of 8.00 USD/MMBtu.

From the steam tables, the following enthalpy values are available:

For 150-psig saturated steam: 1,195.5 Btu/lb

For 117 °F (47 °C) feedwater: 84.97 Btu/lb

Boiler heat output = 45,000 lb/hr x (1,195.5 – 84.97) Btu/lb = 50 million Btu/hr

The recoverable heat corresponding to a stack temperature of 500 °F (260 °C) and a natural gas-fired boiler load of 50 MMBtu/hr is shown in Table 61 as 4.6 MMBtu/hr.

Annual Savings = (4.6 MMBtu/hr x 8.00 USD/MMBtu x 8,400 hr/y)/0.80 = 386,400 USD

Exhaust gas temperature limits

The lowest temperature to which flue gases can be cooled depends on the type of fuel used: 120 °C (250 °F) for natural gas, 150 °C (300 °F) for coal and low-sulphur content fuel oils, and 175 °C (350 °F) for high-sulphur fuel oils. These limits are set to prevent condensation and possible corrosion of the stack due to formation of sulphuric acid.

Condensing economizers, made of corrosion-resistant materials, can achieve lower stack exit temperatures and recover more energy (see section on *Installation of condensing economizers* below).

Applications

A feedwater economizer is appropriate when insufficient heat transfer surface exists within the boiler to remove combustion heat. Boilers that exceed 100 boiler horsepower, operating at pressures of 75 psig or above, and that are significantly loaded all year long, are excellent candidates for an economizer retrofit.

Combustion air heaters

For fuel-fired industrial heating processes, one of the most powerful ways to improve efficiency and productivity is to preheat the combustion air going to the burners (109). The source of this heat energy is the exhaust gas stream, which leaves the process at elevated temperatures. A heat exchanger, placed in the exhaust stack or ductwork, can extract a large portion of the thermal energy in the flue gases and transfer it to the incoming combustion air. Recycling heat this way will reduce the amount of the purchased fuel needed by the furnace.

Many processes produce dirty or corrosive exhaust gases that will plug or attack heat exchangers. Since some exchangers are more resistant to these conditions than others, all options must be investigated if the process is not a clean one. Preparation of a detailed analysis of the troublesome materials in your exhaust gas stream is necessary for discussions with potential vendors.

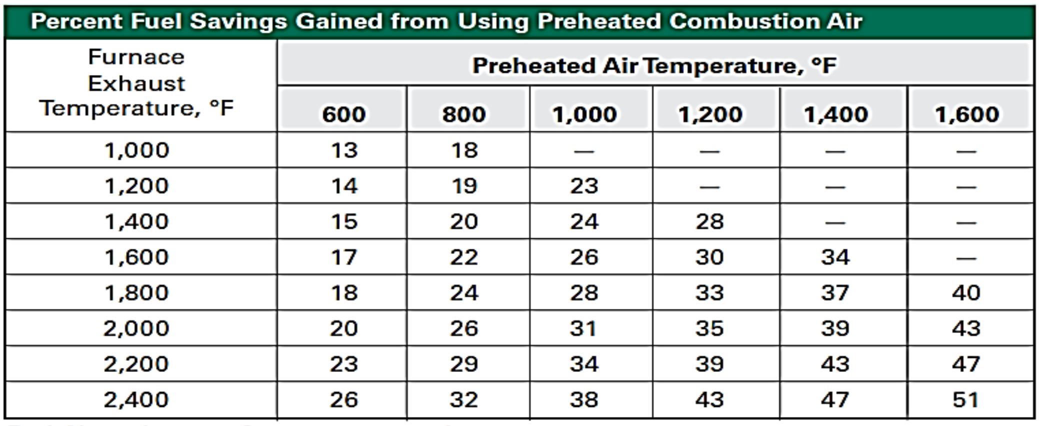
Fuel savings for different process temperatures can be found in Table 62, and used to estimate reductions in energy costs.

There are two types of air preheaters:

- *Recuperators*: These are gas-to-gas heat exchangers placed on the furnace stack. Internal tubes or plates transfer heat from the outgoing exhaust gas to the incoming combustion air while keeping the two streams from mixing. Recuperators are available in a wide variety of styles, flow capacities, and temperature ranges.
- *Regenerators*: These include two or more separate heat storage sections. Flue gases and combustion air take turns flowing through each regenerator, alternately heating the storage medium and then withdrawing heat from it.

For uninterrupted operation, at least two regenerators and their associated burners are required: one regenerator is needed to fire the furnace while the other is recharging.

Table 62 Fuel Savings (109)



Percent Fuel Savings Gained from Using Preheated Combustion Air

Furnace Exhaust Temperature, °F	Preheated Air Temperature, °F					
	600	800	1,000	1,200	1,400	1,600
1,000	13	18	—	—	—	—
1,200	14	19	23	—	—	—
1,400	15	20	24	28	—	—
1,600	17	22	26	30	34	—
1,800	18	24	28	33	37	40
2,000	20	26	31	35	39	43
2,200	23	29	34	39	43	47
2,400	26	32	38	43	47	51

Fuel: Natural gas at 10 percent excess air

Example

A furnace operates at 1600 °F for 8,000 hours per year at an average of 10 MMBtu/hr using ambient temperature combustion air. At 5 USD per MMBtu, annual energy cost is 800,000 USD. Use of preheated air at 800° F will result in 22 % fuel savings, or 176,000 USD annually. The preheated air system installation is estimated to cost between 200,000 USD and 250,000 USD with a payback period of 13.6 months to 17 months, or an annual return on investment of 70% to 88%.

To decide whether to purchase and install an air preheater on an existing boiler, it is helpful to calculate the payback period of the investment using the following formula:

$$\textbf{\textit{Payback period}} = \frac{investment\ cost}{fuel\ savings\ x\ operating\,\frac{hours}{year}\,x\ fuel\ cost}$$

Example

A furnace operates at 1600 °F (870°C) for 8,000 hours per year at an average of 10 MMBtu/hr, (about 10550 MJ/hour) using ambient temperature combustion air. The cost of fuel oil is assumed to be 600 USD/ton. The fuel oil heating value is 40 MJ/kg. The cost of a fuel energy unit is as follows:

$$\text{Cost of fuel energy unit} = \frac{\frac{\frac{600}{1000}\,USD\$}{kg}}{40\ x\,\frac{MJ}{kg}} = 0.015\ \text{USD/MJ}$$

The annual energy bill is: 10550 MJ/hour x 8000 hours x 0.015 USD/MJ = 1,266,000 \$/y

UsingTable 61, if the exhaust gases at 1600 °F (870 °C) are sent to an air preheater and exit at 800 °F (426 °C), the energy savings are 22%. The fuel bill savings are 1,266,000 x 20% = 253,000 USD/year.

The preheated air system installation is estimated to cost between 200,000 USD and 250,000 USD. According to the formula above, the payback period is:

$$\textbf{\textit{Payback period}} = \frac{250{,}000}{253{,}000} \cong 1$$

The investment will be recovered in about 1 year.

The fuel savings will be:

$$\textbf{\textit{Fuel savings}} = \frac{10550\,\frac{\text{MJ}}{\text{hour}}\ \text{x 8000 hours}}{40\,\frac{MJ}{kg}}\ \text{x}\ 22\%\ / = 2110\ \text{tons/y}$$

These savings will positively affect the emissions of pollutants.

For avoided pollution, the reduction in CO_2 and dioxin releases gained by installing an air heater on an existing boiler can be calculated. For fuel oil boilers, an emission factor of 3,08 tons CO_2 per ton of fuel burned can be assumed. As the boiler will save 2110 tons of fuel per year, the amount of CO_2 not released to the environment will be:

CO_2 not emitted = 2110 x 3.08 = 6500 tons CO_2

For dioxins, assuming an emission factor for fuel oil of 2.5 µgTEQ/TJ, the emissions avoided can be calculated as follows:

2110 t/y x 40 MJ/kg = 2110 t/y x 40000 MJ/t (0.04TJ/t) (1TJ = 10^{-6} MJ)

2110 t/y x 0.04 TJ/t x 2,5 µgTEQ/TJ = 211 µgTEQ/y

This example demonstrates that it is possible to simultaneously reduce the emissions of pollutants to the environment and improve plant economics.

Optimization of air-to-fuel ratio for burners

Fuel needs oxygen to burn. In fuel-fired systems, excess air is provided to ensure complete and safe combustion. However, too much excess air will reduce combustion efficiency by increasing heat losses carried away by the exhaust gases. (110) The solution is to:

- test the amount of excess oxygen and carbon monoxide in the exhaust gases using an electronic combustion (flue) gas analyser
- modify the air-to-fuel ratio to provide sufficient air for complete combustion but minimize the amount of excess air, and
- ensure that carbon monoxide levels in the exhaust gas do not reach excessive levels.

If carbon monoxide levels exceed 100 ppm, it could mean the boiler has insufficient air for complete combustion or has improper air/fuel mixing. Small boilers can be checked periodically with portable combustion analysers. Optimizing combustion efficiency can reduce fuel costs by 3% to 10%.

Excess air levels will be different for different firing rates and for different boilers. For natural gas boilers, high firing rates may require less than 2% excess oxygen (10% excess air), while low firing rates may require more than 6% excess oxygen to ensure complete combustion. Oil-fired systems will require more excess air than gas-fired systems. Colder supply air will result in an increased level of excess air because colder air is denser than warmer air.Figure 181 can be used to optimize the air-to-fuel ratio in the following example.

Example

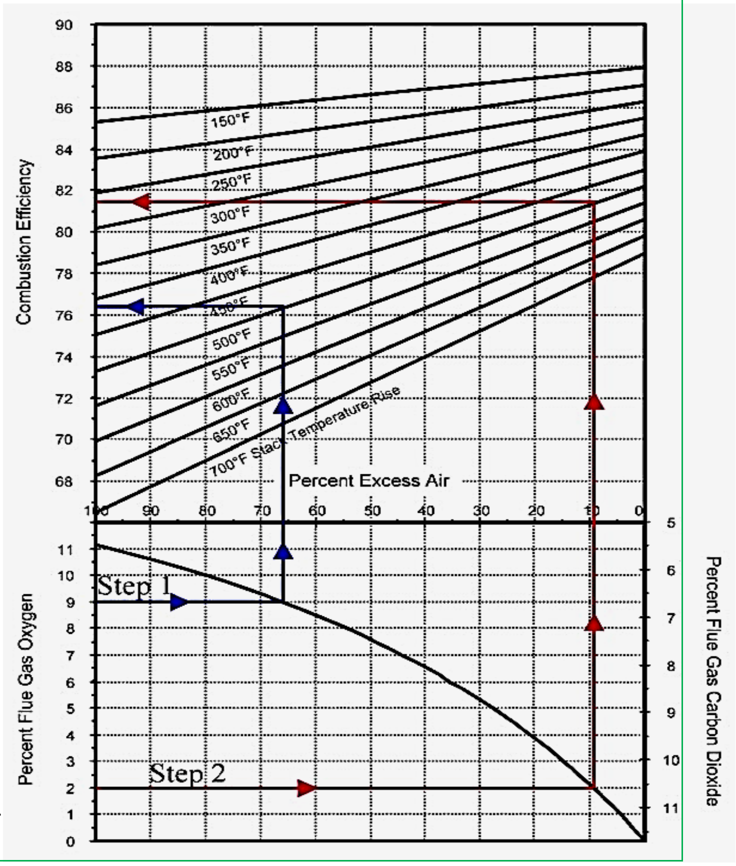


Figure 181 Excess air optimization (EERE USA)

Inspection and testing using a portable combustion analyser led to the observation that a boiler is currently operating at 9% oxygen (~65% excess air) in the exhaust gases. It is believed that the burner can be adjusted to operate at 2% oxygen (~10% excess air). The exhaust gases leaving the boiler are 570 °F. The air at the combustion inlet is 70 °F. Assuming the historical boiler fuel consumption (while operating at 9% excess oxygen) is 40,000 million Btu/y at 6.00 USD/million Btu, determining the potential energy and cost savings through improving the air-to-fuel ratio of the boiler (reducing excess air) is illustrated below.

Relevant data:

Existing level of oxygen in the exhaust gases is 9%.

Target level of oxygen in the exhaust gases is 2%.

Stack temperature rise is 500 °F (stack temperature: 570 °F; combustion air inlet temperature: 70 °F).

Using the Figure, Step 1, blue line, existing combustion efficiency is 76.5% (or 0.765).

Using the Figure, Step 2, working with excess air of 2%, the target combustion efficiency is 81.5% (or 0.815) (red line).

Historical boiler fuel consumption is 40,000 million Btu/y.

Marginal boiler fuel cost is 6.00 USD/million Btu.

Potential energy savings = [(0.815-0.765)/(0.815)] x (40,000 million Btu/y) = 2,454 million Btu/y

Potential energy cost reduction = (2,454 million Btu/y) x (6.00 USD/million Btu) = 14,724 USD/y

Installation of turbulators on two- and three-pass firetube boilers

The packaged firetube boiler is the most common boiler design used to provide heating or process steam in industrial and heavy commercial applications. Although firetube boilers are available in ratings up to 85,000 pounds of steam per hour (lb/hr; about 38 t/h), they are generally specified when the required steam pressure is under 150 psig and the boiler capacity is less than 25,000 lb/hr (about 11 t/h). Watertube boilers are designed for larger, high-pressure, and superheated steam applications (111).

In a firetube boiler, hot combustion gases pass through long, small-diameter tubes, where heat is transferred to water through the tube walls. Firetube boilers are categorized by the number of "passes," or the number of times that the hot combustion gases travel across the boiler heat exchange surfaces. For example, a two-pass boiler provides two opportunities for hot gases to transfer heat to the boiler water. Hot combustion gases enter the tubes in a turbulent flow regime, but, within a few feet, laminar flow begins and a boundary layer of cooler gas forms along the tube walls. This layer serves as a barrier, retarding heat transfer. Turbulators, which consist of small baffles, angular metal strips, spiral blades, or coiled wire, are inserted into the boiler tubes to break up the laminar boundary layer. This increases the turbulence of the hot combustion gases and the convective heat transfer to the tube surface. The result is improved boiler efficiency. Turbulators are usually installed on the last boiler pass.

Turbulator installers can also balance gas flow through the tubes by placing longer turbulators in the uppermost tubes. This practice increases the effectiveness of the available heat transfer surface by eliminating thermal stratification and balancing the gas flow through the fire tubes.

Applications

Turbulators can be a cost-effective way to reduce the stack temperature and increase the fuel-to-steam efficiency of single-pass horizontal return tubular (HRT) brick-set boilers and older two- and three-pass oil- and natural gas-fuelled firetube boilers. Turbulators are not recommended for four-pass boilers or coal-fired units. A four-pass unit provides four opportunities for heat transfer. It has a greater heat exchange surface area, lower stack temperature, higher fuel-to-steam efficiency, and lower annual fuel costs than a two- or three-pass boiler operating under identical conditions. New firetube boilers perform better than older two- and three-pass designs.

Condensate recovery

Steam can be produced by the boiler and either be directly used in the manufacturing process (e.g., in the food industry) or sent to a heat transfer device (heat exchanger) that transfers its heat to another fluid, and then reverts to the liquid phase (condensate) and goes back to the boiler. In both cases, steam losses can occur from steam traps and other devices that eliminate condensate from the steam pipelines (111).

An attractive method of improving a plant's energy efficiency is to increase the condensate return to the boiler. (20) Returning hot condensate to the boiler makes sense for several reasons. As more condensate is returned, less make-up water is required, saving fuel, make-up water, and chemical and treatment costs. Less condensate discharged into a sewer system reduces disposal costs. Return of high purity condensate also reduces energy losses due to boiler blowdown. Significant fuel savings occur as most returned condensate is relatively hot (130 °F to 225 °F), reducing the amount of cold make-up water (50 °F to 60 °F) that must be heated.

A simple calculation indicates that energy in the condensate can be more than 10% of the total steam energy content of a typical system. shows the heat remaining in the condensate at various condensate temperatures, for a steam system operating at 100 psig (7 bar) with make-up water at 55 °F (13 °C) Figure 182.

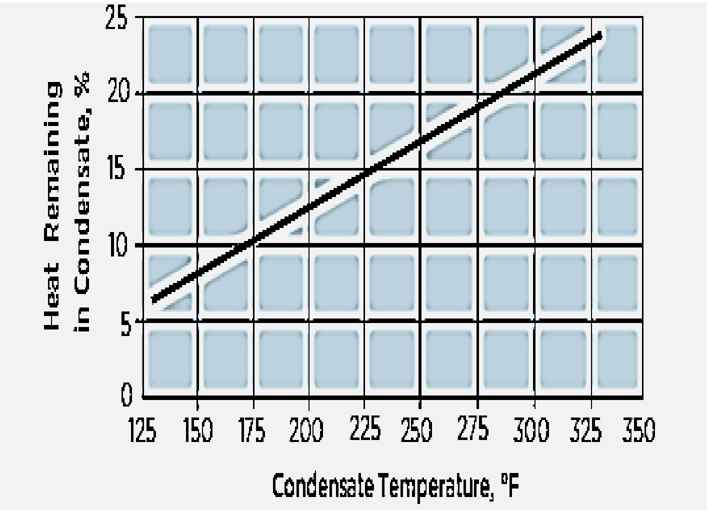
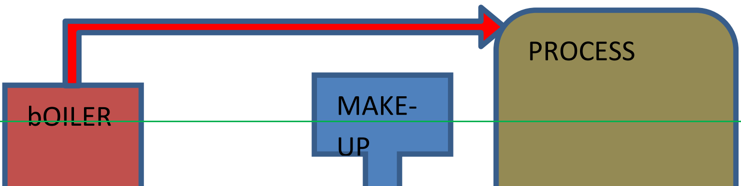


Figure 182 Heat remaining in condensate (22)

A simplified diagram of a condensate return system is shown in Figure 183.



Let:

h_c = enthalpy of condensate at 180 °F = 148 Btu/lb (346 kJ/kg)
h_m = enthalpy of make-up water at 55 °F = 23 Btu/lb (54 kJ/kg)
h_s = enthalpy of steam at 100 psig = 1,189 Btu/lb (2787 kJ/kg)
The percentage of heat remaining in condensate is:
$= (h_c – h_m)/(h_s – h_m) \times 100$
= (148 – 23)/(1,189 – 23) x 100 = 11.0%

Example

Consider a steam system that returns an additional 10,000 lb/hr of condensate at 180 °F after distribution modifications (4.5 tons/hour at 82 °C). Assume this system operates 8,000 hours annually with an average boiler efficiency of 80%, and make-up water temperature of 55 °F (13 °C).

The water and sewage costs for the plant are 0.002 USD per gallon (USD/gal; 0.5 USD/cubic metre); and the water treatment cost is 0.002 USD/gal (0.5 USD/cubic metre). The fuel cost is 8.00 USD/MMBtu (0,008 USD/MJ).

Assuming a 12% flash steam loss, (some condensate flashes off to steam again when saturated condensate is reduced to some lower pressure), calculate overall savings achievable by recuperating the flash steam losses.

Annual water, sewage, & chemicals savings

Steam loss: 12% of 10000 lb/hr = 1200 lb/hr
Savings by water recovery, assuming water density of 8.34 lb/gal
1200 lb/hr x (0.002 +0.002) USD/gal x 8000 h/y /8.34lb/gal = 4603 USD/y

Annual fuel savings

The fuel savings are given by calculating the energy saved by recovering the flash steam losses.
The enthalpy difference between condensate and make-up water is:
$\Delta h = C (h_c – h_m)$; where C is the heat capacity of make-up water, assumed as 1 Btu/lb °F
Δh = 1 x (180- 55) = 125 Btu/lb/hr
The fuel savings will be (assuming a boiler efficiency of 90%):
1200 lb/hr x 125 Btu/lb x 8×10^{-6} USD/Btu x 8000 h/y/0.9 = 10666 USD/y
Total annual savings: 10666 + 4603 = 15269 USD/y
In terms of pollution, the amount of CO_2 not emitted can be calculated.
Fuel savings:
Assuming natural gas with a heating value of 900 Btu/ft^3 (about 45MJ/kg), the fuel savings are:
125 Btu/lb/hr x 8000 h/y /900 Btu/ft^3 = 1111 ft^3/y
Assuming a CO_2 emission factor for natural gas of 0.12 lb CO_2/ft^3, the avoided CO_2 emissions are:
1111 ft^3/y x 0.12 lb CO_2/ft^3 = 133 lb/y = 60 kg/y CO_2

Blowdown recovery

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 feedwater, they will concentrate and may eventually reach a level where their solubility in the water is exceeded and they start 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 automatically replaced by feedwater — thus maintaining the optimum level of TDS in the boiler water and removing those solids that have fallen out of solution and tend to settle on the internal surfaces of the boiler. Blowdown is necessary to protect the surfaces of the heat exchanger in the boiler. However, blowdown can be a significant source of heat loss, if improperly carried out.

Conductivity measurement is used for monitoring overall TDS present in the boiler. The more solids that are present in the water, the higher the conductivity (and the lower the electrical resistance). A rise in conductivity indicates a rise in the "contamination" of the boiler water.

Intermittent and continuous blowdown

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

Intermittent blowdown

Intermittent blowdown is conducted by manually operating a valve fitted to a discharge pipe at the lowest point of the boiler shell to reduce parameters (e.g., TDS or conductivity, pH, silica and phosphates concentration) within prescribed limits so that steam quality is not likely to be affected. This type of blowdown 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 blowdown, a large diameter line is opened for a short period of time, with the time based on a general rule such as “once in a shift for 2 minutes”.

Since intermittent blowdown requires large short-term increases in the amount of feedwater put into the boiler larger feedwater pumps than for continuous blowdown may be needed. The TDS level will also 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. A substantial amount of heat energy is lost with intermittent blowdown.

Continuous blowdown

There is steady and constant dispatch of a small stream of concentrated boiler water, and replacement by steady and constant inflow of feedwater. This ensures constant TDS and steam purity at a given steam load. Once a blowdown valve is set for 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 preheating boiler feedwater. This type of blowdown is common in high-pressure boilers.

The residual blowdown that leaves the flash vessel still contains a good deal of heat energy, of which a significant proportion can also be recovered by introducing a heat exchanger to heat up cold make-up water. Complete blowdown heat recovery systems 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.

The quantity of blowdown 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% and the TDS in make-up water is 300 ppm, then the percentage blowdown is given as:
= 300 x 10 /3000 = 1%
If boiler steam capacity is 3 t/hr (3000 kg/hr), then the required blowdown rate is:
= 3000 x 1 /100 = 30 kg/hr

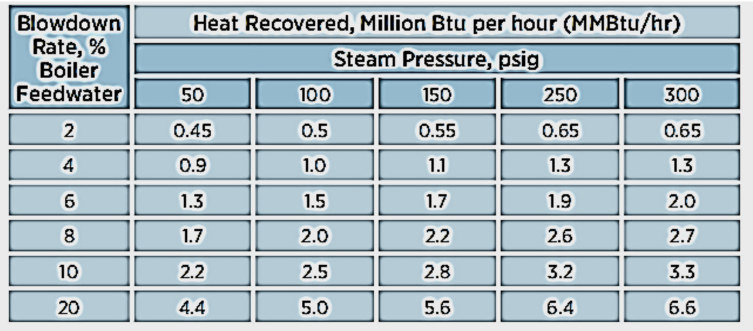
Benefits of blowdown control

Good boiler blowdown control can significantly reduce treatment and operating costs, including:

- lower pretreatment costs
- less make-up water consumption
- reduced maintenance downtime
- increased boiler life, and
- lower consumption of treatment chemicals.

Heat can be recovered from boiler blowdown by using a heat exchanger to preheat boiler make-up water. Any boiler with continuous blowdown exceeding 5% of the steam rate is a good candidate for the introduction of blowdown waste heat recovery. Larger energy savings occur with high-pressure boilers. Table 63 shows the potential for heat recovery from boiler blowdown.

Table 63 Recoverable heat from boiler blowdown (22)



Blowdown Rate, % Boiler Feedwater	Heat Recovered, Million Btu per hour (MMBtu/hr)				
	Steam Pressure, psig				
	50	100	150	250	300
2	0.45	0.5	0.55	0.65	0.65
4	0.9	1.0	1.1	1.3	1.3
6	1.3	1.5	1.7	1.9	2.0
8	1.7	2.0	2.2	2.6	2.7
10	2.2	2.5	2.8	3.2	3.3
20	4.4	5.0	5.6	6.4	6.6

Example

In a plant where the fuel cost is 8.00 USD/MMBtu (8 USD per 1000 MJ) and the boiler produces 50,000 lb/hr (22.5 t/h), a continuous blowdown rate of 3,200 lb/hr (1.44 t/h) is maintained to avoid the build-up of high concentrations of dissolved solids. What are the annual savings if a make-up water heat exchanger is installed that recovers 90% of the blowdown energy losses?

Assuming the boiler pressure at 150 psig (about 10 bar), the heat recovered is 3200/50000 = 6%.

The 80% efficient boiler produces 50,000 lb/hr of 150- psig steam. It operates for 8,000 hours per year. The blowdown ratio is:

Blowdown Ratio = 3,200/(3,200 + 50,000) = 6.0%

Using Table 63, the heat recoverable corresponding to a 6% blowdown ratio with a 150-psig boiler, operating pressure is 1.7 MMBtu/hr. Since the Table is based on a steam production rate of 100,000 lb/hr, the annual savings for this plant, assuming an efficiency of 90%, are as follows:

Annual Energy Savings = 1.7 MMBtu/h x (50,000 lb/hr/100,000 lb/hr) x 8000 hours/0.9 = 7555 MMBtu

Assuming the cost of fuel is 8 USD/MMBtu, the savings are: 7555 x 8 = 60440 USD/y.

In terms of pollution reduction, the avoided CO_2 emissions are, assuming a CO_2 emission factor of 116 lb/MMBtu: 116 x 7555 = 876380 lb = 394 tons CO_2/y

Automatic blowdown control systems

To reduce the levels of suspended and total dissolved solids in a boiler, water is periodically discharged or blown down. High dissolved solids concentrations can lead to foaming and carryover of boiler water into the steam. This could lead to water hammer, which may damage piping, steam traps, or process equipment. Surface blowdown, which removes dissolved solids that accumulate near the boiler liquid surface, is often a continuous process. Suspended and dissolved solids can also form sludge. Sludge must be removed because it reduces the heat transfer capabilities of the boiler, resulting in poor fuel-to-steam efficiency and possible pressure vessel damage. Sludge is removed by mud or bottom blowdown (20).

During the surface blowdown process, a controlled amount of boiler water containing high dissolved solids concentrations is discharged into the sewer. In addition to wasting water and chemicals, the blowdown process wastes heat energy because the blowdown liquid is at the same temperature as the steam produced — approximately 185 °C (366 °F) for 150-psig (about 10 bar) saturated steam — and blowdown heat recovery systems, if available, are not 100% efficient.

Waste heat may be recovered through the use of a blowdown heat exchanger or a flash tank in conjunction with a heat recovery system.

Advantages

With manual control of surface blowdown, there is no way to determine the concentration of dissolved solids in the boiler water, nor the optimal blowdown rate. Operators do not know when to blow down the boiler, or for how long. Likewise, using a fixed rate of blowdown does not take into account changes in make-up and feedwater conditions, or variations in steam demand or condensate return.

An automatic blowdown control system optimizes surface blowdown rates by regulating the volume of water discharged from the boiler in relation to the concentration of dissolved solids present. Automatic surface blowdown control systems maintain water chemistry within acceptable limits, while minimizing blowdown and reducing energy losses. Cost savings come from the significant reduction in the consumption, disposal, treatment, and heating of water.

How they work

With an automatic blowdown control system, high- or low-pressure probes are used to measure conductivity. These probes provide feedback to a blowdown controller that compares the measured conductivity with a set-point value, and then transmits an output signal that drives a modulating blowdown release valve. Conductivity is a measure of the electrical current carried by positive and negative ions when a voltage is applied across electrodes in a water sample. Conductivity increases when the dissolved ion concentrations increase.

The measured current is directly proportional to the specific conductivity of the fluid. Total dissolved solids, silica, chloride concentrations, and/or alkalinity contribute to conductivity measurements. These chemical species are reliable indicators of salts and other contaminants in the boiler water.

Applications

Boilers without a blowdown heat recovery system, and with high blowdown rates, offer the greatest energy savings potential. The optimum blowdown rate is determined by a number of factors, including boiler type, operating pressure, water treatment, and make-up water quality. Savings also depend upon the quantity of condensate returned to the boiler. With a low percentage of condensate return, more make-up water is required and additional blowdown must occur. Boiler blowdown rates often range from 1% to 8% of the feedwater flow rate, but they can be as high as 20% to maintain silica and alkalinity limits when the make-up water has a high solids content.

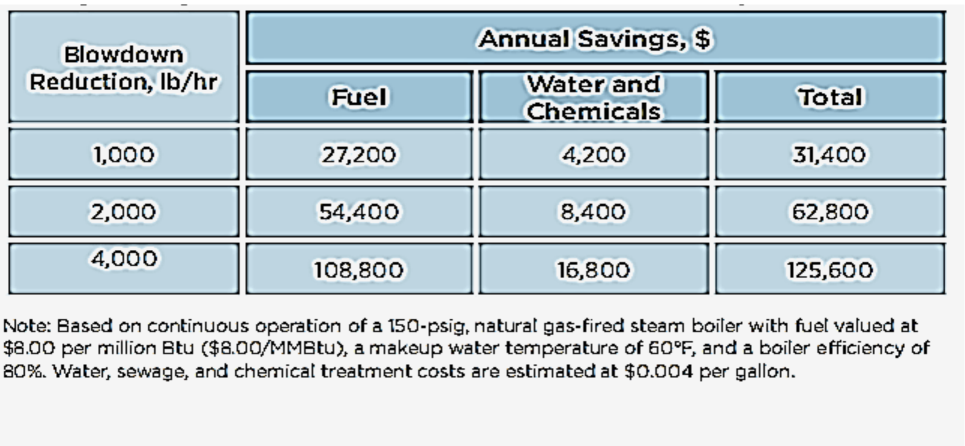
Price and performance

Example

For a 100,000 lb/hr steam boiler (45 tons/hr), decreasing the required blowdown rate from 8% to 6% of the feedwater flow rate will reduce make-up water requirements by approximately 2,300 lb/hr (0.9 t/h).

Annual energy, water, and chemicals savings due to blowdown rate reductions for a sample system are summarized inTable 63. In many cases, these savings can provide a 1 to 3 year simple payback on the investment in an automatic blowdown control system.

Table 64 Recoverable heat from automatic boiler blowdown (22)



Blowdown Reduction, lb/hr	Annual Savings, $		
	Fuel	Water and Chemicals	Total
1,000	27,200	4,200	31,400
2,000	54,400	8,400	62,800
4,000	108,800	16,800	125,600

Note: Based on continuous operation of a 150-psig, natural gas-fired steam boiler with fuel valued at $8.00 per million Btu ($8.00/MMBtu), a makeup water temperature of 60°F, and a boiler efficiency of 80%. Water, sewage, and chemical treatment costs are estimated at $0.004 per gallon.

Inspection and repair of steam traps

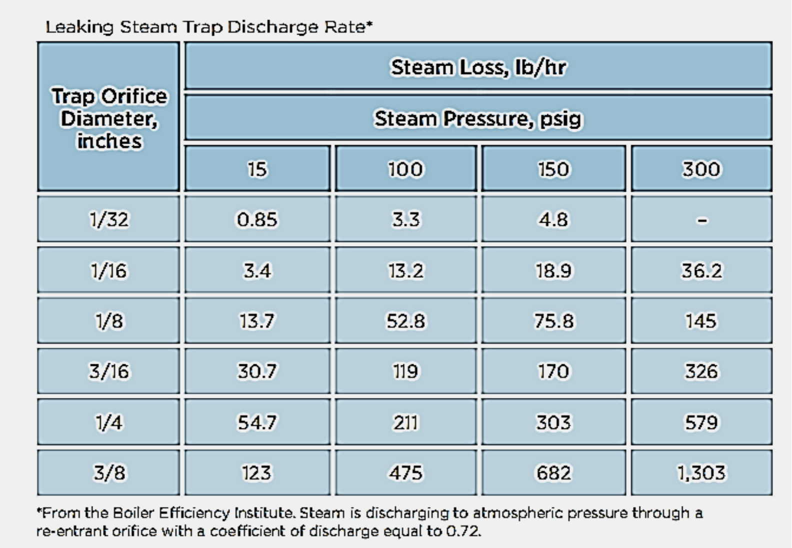
In steam systems that have not been maintained for 3 to 5 years, between 15% and 30% of the installed steam traps may have failed — thus allowing live steam to escape into the condensate return system. In systems with a regularly scheduled maintenance program, leaking traps should account for less than 5% of the trap population. If the steam distribution system includes more than 500 traps, a steam trap survey will probably reveal significant steam losses.

Example

In a plant where the value of steam is 10.00 USD/1,000 lb, an inspection program indicates that a trap on a 150-psig steam line is stuck open. The trap orifice is 1/8th inch in diameter. Table 65 shows the estimated steam loss as 75.8 lb/hr. After the failed trap is repaired, annual savings are:

Annual savings = 75.8 lb/hr x 8,760 hr/y x 10.00 USD/1,000 lb = 6,640 USD

Table 65 Leaking steam trap discharge rate (236)



Leaking Steam Trap Discharge Rate*

Trap Orifice Diameter, inches	Steam Loss, lb/hr			
	Steam Pressure, psig			
	15	100	150	300
1/32	0.85	3.3	4.8	-
1/16	3.4	13.2	18.9	36.2
1/8	13.7	52.8	75.8	145
3/16	30.7	119	170	326
1/4	54.7	211	303	579
3/8	123	475	682	1,303

*From the Boiler Efficiency Institute. Steam is discharging to atmospheric pressure through a re-entrant orifice with a coefficient of discharge equal to 0.72.

Prevention of duct air infiltrations

In small boilers with burners using combustion air at ambient pressure, it is important that there are no obstacles to the air feeding system. Thus, the boiler room must be vented, and window/door openings should not be obstructed. Boilers with forced- or induced-draught combustion, which use a fan to supply combustion air, require proper adjustment based on the volume of air that the fan can supply. If, after proper adjustment, covers are removed, inspection doors are kept open, or air can enter the boiler from openings other than those of design, extra air goes to the burner, resulting in a loss of efficiency.

During boiler operation, the following measures should be implemented to avoid loss of efficiency:

- Keep observation doors closed and probe ports plugged.
- Keep covers and other openings in place.
- Check the sealing integrity to avoid extra air being fed to the burner.

Clean heat transfer surfaces

Industrial process heating systems use various methods to transfer heat to the load. These include direct heat transfer from the flame or heated gases to the load, and indirect heat transfer from radiant tubes, muffles, or heat exchangers. Indirect heating systems that use fuel firing, steam, or hot liquids to supply heat are discussed in this section. In each case, clean heat transfer surfaces can improve system efficiency. Deposits of soot, scale or oxides, sludge, and slag on the heat transfer surfaces should be avoided (113).

Contamination from flue gas and heating medium

Problem areas from flue gas contamination include the following:

- *Soot:* black substance formed by combustion that adheres to heat transfer surfaces.
- *Scale or oxide:* formed when metals are oxidized in the presence of oxygen, water vapour, or other oxidizing gases.
- *Sludge*: residue from a liquid–solid mixture after the liquid evaporates.

- *Slag*: residue formed by oxidation at the surface of molten metals, which can also adhere to heat transfer surfaces.

These contaminants impede the efficient transfer of heat and reduce the efficiency of industrial heating systems. Contamination of heat transfer surfaces is typically the result of:

- low air-to-fuel ratios
- improper fuel preparation
- malfunctioning burners
- oxidation of heat transfer surfaces in high temperature applications
- corrosive gases or constituents in the heating medium
- stagnant or low-velocity areas in contact with heat transfer surfaces for hot liquid or gas heating systems, or
- special atmospheres (such as in heat treating furnaces) that can produce soot during the heating process.

As shown in Table 66 , a 1/32-inch thick layer of soot can reduce heat transfer by about 2.5%.

Table 66 Efficiency reductions caused by soot deposits (97)

Efficiency Reductions Caused by Soot Deposits*		
Soot Layer Thickness		
1/32 inch (0.8 mm)	1/16 inch (1.6 mm)	1/8 inch (3 mm)
2.5%	4.5%	8.5%

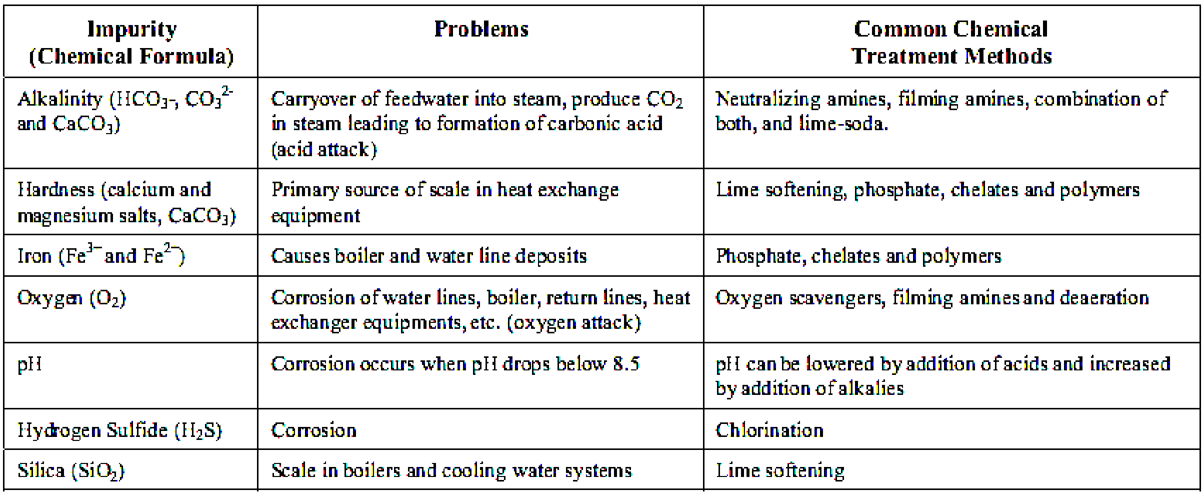
**Extracted from the Application Note – Energy Efficiency Operations and Maintenance Strategies for Industrial Gas Boilers, Pacific Gas and Electric Company, May 1997.*

Contamination from flue gas can also shorten equipment life and lead to unscheduled maintenance. The extent to which dirty heat transfer surfaces affect efficiency can be estimated from an increase in stack temperature relative to a “clean operation” or baseline condition. Efficiency is reduced by approximately 1% for every 40 °F increase in stack temperature.

Contamination from the water supply

Scale is formed from deposits of calcium, magnesium, or silica from the water supply. Problems occur when these minerals form a continuous layer of material on the water side of heat transfer surfaces; surfaces with scale deposits have much lower thermal conductivity than bare metal. Efficiency losses from scale deposits can range from 1% to 7%. Scale deposits can also lead to decreased heat transfer equipment life, especially because of corrosion. Most scale problems are caused by inadequate water treatment. Scale can be removed mechanically (by manual brushing) or with acid cleaning.

Table 67 Common impurities in water



Impurity (Chemical Formula)	Problems	Common Chemical Treatment Methods
Alkalinity (HCO_3-, CO_3^{2-} and $CaCO_3$)	Carryover of feedwater into steam, produce CO_2 in steam leading to formation of carbonic acid (acid attack)	Neutralizing amines, filming amines, combination of both, and lime-soda.
Hardness (calcium and magnesium salts, $CaCO_3$)	Primary source of scale in heat exchange equipment	Lime softening, phosphate, chelates and polymers
Iron (Fe^{3-} and Fe^{2-})	Causes boiler and water line deposits	Phosphate, chelates and polymers
Oxygen (O_2)	Corrosion of water lines, boiler, return lines, heat exchanger equipments, etc. (oxygen attack)	Oxygen scavengers, filming amines and deaeration
pH	Corrosion occurs when pH drops below 8.5	pH can be lowered by addition of acids and increased by addition of alkalies
Hydrogen Sulfide (H_2S)	Corrosion	Chlorination
Silica (SiO_2)	Scale in boilers and cooling water systems	Lime softening

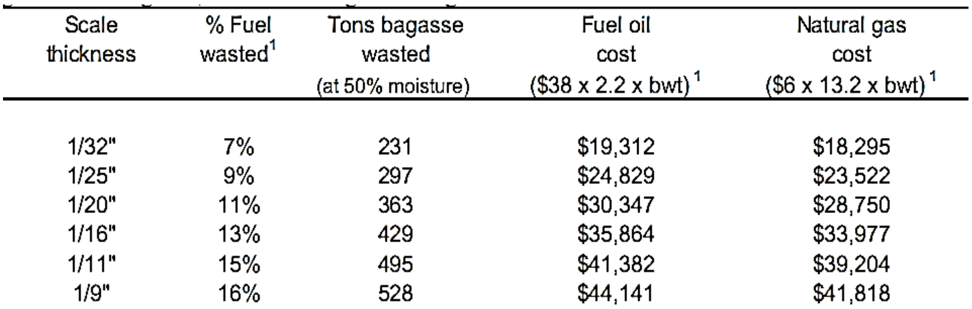
Table 67 summarizes the problems associated with the common impurities in water and related solutions. (114)

Example

The effect on the fuel bill due to scaling in a factory grinding 10,000 tons of cane per day is shown in Table 68, where bagasse used is 3,300 tons per day, 2.2 barrels fuel oil = 1 mt bagasse, 13,200 ft_3 natural gas = 1 mt bagasse, and bwt = bagasse weight.

Table 69 and Table 69 summarize the effects that dirty heat transfer surfaces can have on efficiency.

Table 68 Effects of scale thickness on efficiency



Scale thickness	% Fuel wasted[1]	Tons bagasse wasted (at 50% moisture)	Fuel oil cost ($38 x 2.2 x bwt)[1]	Natural gas cost ($6 x 13.2 x bwt)[1]
1/32"	7%	231	$19,312	$18,295
1/25"	9%	297	$24,829	$23,522
1/20"	11%	363	$30,347	$28,750
1/16"	13%	429	$35,864	$33,977
1/11"	15%	495	$41,382	$39,204
1/9"	16%	528	$44,141	$41,818

Table 69 Effect of dirty heat transfer surfaces on efficiency

	Reference	Efficiency loss
Soot deposits	**1/16 inch (0.16 cm)**	**4.5%**
Dirty heat transfer surfaces	**40°F (22 °C) increase T° at stack**	**1%**
Scale	**1/16 inch (0.16mm)**	**13%**

Installation of condensing economizers

The key to a successful waste heat recovery project is optimizing the use of the recovered energy. By installing a condensing economizer, companies can improve overall heat recovery and steam system efficiency by up to 10%. Many boiler applications can benefit from this additional heat recovery, such as district heating systems, wallboard production facilities, greenhouses, food processing plants, pulp and paper mills, textile plants, and hospitals. Condensing economizers require site-specific engineering and design, and a thorough understanding of the effect they will have on the existing steam system and water chemistry.

A conventional feedwater economizer reduces steam boiler fuel requirements by transferring heat from the flue gas to the boiler feedwater. For natural gas-fired boilers, the lowest temperature to which flue gas can be cooled is about 120 °C (250 °F) to prevent condensation and possible stack or stack liner corrosion.

The condensing economizer (25) improves waste heat recovery by cooling the flue gas below its dew point, which is about 57 °C (135 °F) for products of combustion of natural gas. The economizer reclaims both sensible heat from the flue gas and latent heat by condensing flue gas water vapour (see Table 70). All hydrocarbon fuels release significant quantities of water vapour as a combustion by-product. The equation below shows the reactants and combustion products for the stoichiometric combustion in air of methane (CH_4), the primary constituent of natural gas. When one molecule of methane is burned, it produces two molecules of water vapour. When moles are converted to pound/mole, we find that every pound of methane fuel combusted produces 2.25 lb of water vapour, which is about 12% of the total exhaust by weight.

$CH_4 + 2O_2 + 7.5N_2 \rightarrow CO_2 + 2H_2O + 7.5N_2$

Table 70 Effect of condensing economizer on efficiency

System	combustion efficiency (4% excess oxygen)	Stack gas temperature °F	Stack gas temperature °C
Boiler	78 to 83%	350 to 550	177 to 288
with feedwater economizer	84 to 86%	250 to 300	120 to 150
with feedwater and condensing economizer	92 to 95 %	75 to 150	25 to 65

Since the higher heating value of methane is 23,861 Btu/lb (55 MJ/kg), 41.9 lb of methane is required to provide 1 MMBtu of energy, resulting in 94.3 lb of high temperature water vapour. The latent heat of vaporization of water under atmospheric pressure is 970.3 Btu/lb. When 1 MMBtu of methane is combusted, 91,495 Btu of water vapour heat of evaporation (94.3 lb x 970.3 Btu/lb) is released up the boiler stack. This latent heat represents approximately 9% of the initial fuel energy content. The bulk of this latent heat can be recovered by cooling the exhaust gas below its dew point using a direct contact or indirect condensing economizer. It is possible to heat water to about 93 °C (200 °F) with an indirect economizer, or 60 °C (140 °F) with a direct contact economizer.

The available heat in a boiler’s exhaust gases is dependent upon the hydrogen content of the fuel, the fuel firing rate, the percentage of excess oxygen in the flue gases, and the stack gas temperature.

Example

Consider a natural gas-fired boiler that produces 100,000 lb/hr of 100-psig saturated steam. At 83% efficiency, the boiler firing rate is about 116 MMBtu/hr. At its full firing rate, the boiler consumes over 4,860 lb of natural gas each hour while exhausting 10,938 lb of high temperature water vapour each hour. The water vapour in the flue gas contains over 10.6 MMBtu/hr of latent heat. As shown in Table 71, the total heat actually available for recovery is strongly dependent upon the stack gas temperature at the condensing economizer outlet.

Example

Assume that an indirect contact condensing economizer is retrofitted onto this 100,000 lb/hr steam boiler to heat 50% of the make-up water from 55 °F to 200 °F, and flue gases are cooled to 100 °F. At these conditions, 12.75 MMBtu/hr of total energy is available in the exhaust, of which 7.55 MMBtu/hr will be recovered to heat make-up water in the condensing economizer. More energy could be recovered if additional heat sinks are available. Given 8,000 hours per year of boiler operation, and a fuel cost of 8.00 USD/MMBtu, the annual energy recovered is valued at:

Annual Savings = 7.55 MMBtu/hr x 8,000 hr/y x 8.00 USD/MMBtu/0.83 = 582,170 USD

Table 71 Available heat for recovery

Flue Gas Temperature Leaving Condensing Economizer	75˚F	100˚F	125˚F	150˚F
Sensible Heat	6.46	5.75	5.03	4.31
Latent Heat	9.51	7.00	2.01	0.0

Total Available	**15.97**	**12.75**	**7.04**	**4.31**

Note: This assumes an 83% fuel-to-steam efficiency, 4% excess oxygen, a stack temperature of 300 °F after feedwater economizer, a blowdown rate of 4%, and a boiler feedwater temperature of 260 °F. Make-up water temperature is 55 °F.

Example

A food processing plant installed an indirect contact condensing economizer on a 20,000-lb/hr boiler. The condensing economizer reduced the flue gas temperature from 300 °F to 120 °F, while capturing 2.0 MMBtu/hr of sensible and latent heat. Energy recovered by the condensing economizer heated make-up water reduced deaerator steam requirements from 5,000 lb/hr to 1,500 lb/hr.

BEP for boiler critical components

In general, the critical components are those whose failure will directly affect the reliability of the boiler. They can be prioritized by their impact on safety, reliability, and performance. Implementation of BEP on those components (or a good maintenance program) can help improve boiler performance. Critical pressure parts include the following (115):

- *Drums*: The steam drum is the single most expensive component in the boiler. Consequently, any maintenance program must address the steam drum, as well as any other drums, in the convection passes of the boiler. In general, problems in the drums are associated with corrosion. In some instances, where drums have rolled tubes, rolling may produce excessive stresses that can lead to damage in the ligament areas. Problems in the drums normally lead to indications that are seen on the surfaces-either inside diameter (ID) or outside diameter (OD).
- *Headers*: Boilers designed for temperatures above 482 ˚C (900 ˚F) can have superheater outlet headers that are subject to creep – the plastic deformation (strain) of the header from long-term exposure to temperature and stress. However, industrial boilers are more typically designed for temperatures lower than that. Lower temperature headers are subject to corrosion or possible erosion. Additionally, cycles of thermal expansion and mechanical loading may lead to fatigue damage
- *Tubing*: The majority of forced outages in all types of boilers are caused by tube failures. Failure mechanisms vary greatly from the long term to the short term. Superheater tubes operating at sufficient temperature can fail long term (over many years) due to normal life expenditure. However, most industrial boiler tubes do not have a finite life due to their temperature of operation under normal conditions. Tubes are more likely to fail because of abnormal deterioration such as water/steam-side deposition retarding heat transfer, flow obstructions, tube corrosion (ID and/or OD), fatigue, and tube erosion.
- *Piping:* For lower temperature systems, main steam piping is subject to the same damage as noted for the boiler headers. In addition, the piping supports may experience deterioration and become damaged from excessive or cyclical system loads. Feedwater piping may be prone to corrosion or flow assisted corrosion (FAC), depending upon the operating parameters of the feedwater system, the flow rates, and the piping geometry. This is also referred to as erosion-corrosion. If susceptible, the pipe may experience material loss from internal surfaces near bends, pumps, injection points, and flow transitions. Ingress of air into the system can lead to corrosion and pitting. Out-of-service corrosion can occur if the boiler is idle for long periods.
- *Deaerators*: Overlooked for many years in condition assessment and maintenance inspection programs, deaerators have been known to fail catastrophically in both industrial and utility plants. The damage mechanism is corrosion of shell welds, which occurs on the ID surfaces.

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ANNEXES

Sommario

ANNEX 1 UNITS OF MEASUREMENT

From Wikipedia, the free encyclopedia (1)

A unit of measurement is a definite magnitude of a physical quantity, defined and adopted by convention and/or by law, that is used as a standard for measurement of the same physical quantity.[1] Any other value of the physical quantity can be expressed as a simple multiple of the unit of measurement.

For example, length is a physical quantity. The metre is a unit of length that represents a definite predetermined length. When we say 10 metres (or 10 m), we actually mean 10 times the definite predetermined length called "metre".

The definition, agreement, and practical use of units of measurement have played a crucial role in human endeavor from early ages up to this day. Different systems of units used to be very common. Now there is a global standard, the International System of Units (SI), the modern form of the metric system.

In trade, weights and measures is often a subject of governmental regulation, to ensure fairness and transparency. The Bureau international des poids et mesures (BIPM) is tasked with ensuring worldwide uniformity of measurements and their traceability to the International System of Units (SI). Metrology is the science for developing nationally and internationally accepted units of weights and measures.

In physics and metrology, units are standards for measurement of physical quantities that need clear definitions to be useful. Reproducibility of experimental results is central to the scientific method. A standard system of units facilitates this. Scientific systems of units are a refinement of the concept of weights and measures developed long ago for commercial purposes.

Science, medicine, and engineering often use larger and smaller units of measurement than those used in everyday life and indicate them more precisely. The judicious selection of the units of measurement can aid researchers in problem solving (see, for example, dimensional analysis).

Systems of units

Traditional systems

Historically many of the systems of measurement which had been in use were to some extent based on the dimensions of the human body according to the proportions described by Marcus Vitruvius Pollio. As a result, units of measure could vary not only from location to location, but from person to person.

Metric systems

A number of metric systems of units have evolved since the adoption of the original metric system in France in 1791. The current international standard metric system is the International System of Units. An important feature of modern systems is standardization. Each unit has a universally recognized size.

Both the Imperial units and US customary units derive from earlier English units. Imperial units were mostly used in the British Commonwealth and the former British Empire. US customary units are still the main system of measurement used in the United States despite Congress having legally authorized metric measure on 28 July

1866.[3] Some steps towards US metrication have been made, particularly the redefinition of basic US units to derive exactly from SI units, so that in the US the inch is now defined as 0.0254 m (exactly), and the avoirdupois pound is now defined as 453.59237 g (exactly)[4]

Natural systems

While the above systems of units are based on arbitrary unit values, formalized as standards, some unit values occur naturally in science. Systems of units based on these are called natural units. Similar to natural units, atomic units (au) are a convenient system of units of measurement used in atomic physics.

Also a great number of unusual and non-standard units may be encountered. These may include the Solar mass, the Megaton (1,000,000 tons of TNT).

Conversion of units

Process

The process of conversion depends on the specific situation and the intended purpose. This may be governed by regulation, contract, Technical specifications or other published standards. Engineering judgment may include such factors as:

The precision and accuracy of measurement and the associated uncertainty of measurement

The statistical confidence interval or tolerance interval of the initial measurement

The number of significant figures of the measurement

The intended use of the measurement including the engineering tolerances

Some conversions from one system of units to another need to be exact, without increasing or decreasing the precision of the first measurement. This is sometimes called soft conversion. It does not involve changing the physical configuration of the item being measured.

By contrast, a hard conversion or an adaptive conversion may not be exactly equivalent. It changes the measurement to convenient and workable numbers and units in the new system. It sometimes involves a slightly different configuration, or size substitution, of the item. Nominal values are sometimes allowed and used.

Multiplication factors

Conversion between units in the metric system can be discerned by their prefixes (for example, 1 kilogram = 1000 grams, 1 milligram = 0.001 grams) and are thus not listed in this article. Exceptions are made if the unit is commonly known by another name (for example, 1 micron = 10−6 metre).

Table ordering

Within each table, the units are listed alphabetically, and the SI units (base or derived) are highlighted.

[edit]Tables of conversion factors

This article gives lists of conversion factors for each of a number of physical quantities, which are listed in the index. For each physical quantity, a number of different units (some only of historical interest) are shown and expressed in terms of the corresponding SI unit.

Lenght

Legend

Symbol	Definition
≡	exactly equal to
≈	approximately equal to
digits	indicates that *digits* repeat infinitely (e.g. 8.294369 corresponds to 8.294369369369369…)
(H)	of chiefly historical interest

Volume

Volume

Name of unit	Symbol	Definition	Relation to SI units
acre-foot	ac ft	≡ 1 ac x 1 ft = 43 560 ft^3	= 1 233.481 837 547 52 m^3
acre-inch		≡ 1 ac × 1 in	= 102.790 153 128 96 m^3
barrel (imperial)	bl (imp)	≡ 36 gal (imp)	= 0.163 659 24 m^3
barrel (petroleum)	bl; bbl	≡ 42 gal (US)	= 0.158 987 294 928 m^3

barrel (US dry)	bl (US)	≡ 105 qt (US) = 105/32 bu (US lvl)	= 0.115 628 198 985 075 m^3
barrel (US fluid)	fl bl (US)	≡ 31½ gal (US)	= 0.119 240 471 196 m^3
cubic foot	cu ft	≡ 1 ft × 1 ft × 1 ft	≡ 0.028 316 846 592 m^3
cubic inch	cu in	≡ 1 in × 1 in × 1 in	≡ 16.387 064×10^{-6} m^3
cubic metre (SI unit)	m^3	≡ 1 m × 1 m × 1 m	≡ 1 m^3
cubic mile	cu mi	≡ 1 mi × 1 mi × 1 mi	≡ 4 168 181 825.440 579 584 m^3
cubic yard	cu yd	≡ 27 cu ft	≡ 0.764 554 857 984 m^3
cup (breakfast)		≡ 10 fl oz (imp)	= 284.130 625×10^{-6} m^3
gallon (imperial)	gal (imp)	≡ 4.546 09 L	≡ 4.546 09×10^{-3} m^3
gallon (US dry)	gal (US)	≡ ⅛ bu (US lvl)	= 4.404 883 770 86×10^{-3} m^3
gallon (US fluid; Wine)	gal (US)	≡ 231 cu in	≡ 3.785 411 784×10^{-3} m^3
litre	L	≡ 1 dm^3 [17]	≡ 0.001 m^3
load		≡ 50 cu ft	= 1.415 842 3296 m^3
timber foot		≡ 1 cu ft	= 0.028 316 846 592 m^3
ton (displacement)		≡ 35 cu ft	= 0.991 089 630 72 m^3
ton (freight)		≡ 40 cu ft	= 1.132 673 863 68 m^3
ton (water)		≡ 28 bu (imp)	= 1.018 324 16 m^3

Mass

Notes:

- In this table, the unit *gee* is used to denote standard gravity in order to avoid confusion with the "g" symbol for grams.
- In physics, the pound of mass is sometimes written **lbm** to distinguish it from the pound-force (**lbf**). It should not be read as the mongrel unit "pound metre".

Mass

Name of unit	Symbol	Definition	Relation to SI units
electronvolt	eV	≡ 1 eV (energy unit) / c^2	= 1.7826×10^{-36} kg
grain	gr	≡ 1/7000 lb av	≡ 64.798 91 mg
kilogram	kg	≡ mass of the prototype near Paris (≈ mass of 1L of water)	≡ 1 kg (SI base unit)[8]
pound	lb	≡ slug·ft/s^2	= 0.45359237 kg
pound (avoirdupois)	lb av	≡ 0.453 592 37 kg = 7000 grains	≡ 0.453 592 37 kg

pound (metric)		≡ 500 g	= 500 g
pound (troy)	lb t	≡ 5 760 grains	= 0.373 241 7216 kg
quarter (imperial)		≡ 1/4 long cwt = 2 st = 28 lb av	= 12.700 586 36 kg
quarter (informal)		≡ ¼ short tn	= 226.796 185 kg
quarter, long (informal)		≡ ¼ long tn	= 254.011 7272 kg
quintal (metric)	q	≡ 100 kg	= 100 kg
ton, long	long tn or ton	≡ 2 240 lb	= 1 016.046 9088 kg
ton, short	sh tn	≡ 2 000 lb	= 907.184 74 kg
tonne (mts unit)	t	≡ 1 000 kg	= 1 000 kg

Density

Density

Name of unit	Symbol	Definition	Relation to SI units
gram per millilitre	g/mL	≡ g/mL	= 1,000 kg/m^3
kilogram per cubic metre (SI unit)	kg/m^3	≡ kg/m^3	= 1 kg/m^3
kilogram per litre	kg/L	≡ kg/L	= 1,000 kg/m^3
pound (avoirdupois) per cubic foot	lb/ft^3	≡ lb/ft^3	≈ 16.01846337 kg/m^3
pound (avoirdupois) per cubic inch	lb/in^3	≡ lb/in^3	≈ 2.767990471×10^4 kg/m^3
pound (avoirdupois) per gallon (imperial)	lb/gal	≡ lb/gal	≈ 99.77637266 kg/m^3
pound (avoirdupois) per gallon (US fluid)	lb/gal	≡ lb/gal	≈ 119.8264273 kg/m^3

Frequency

Frequency

Name of unit	Symbol	Definition	Relation to SI units
hertz (SI unit)	Hz	≡ Number of cycles per second	= 1 Hz = 1/s
revolutions per minute	rpm	≡ One unit rpm equals one rotation completed around a fixed axis in one minute of time.	≈ 0.104719755 rad/s

Speed or velocity

Speed

Name of unit	Symbol	Definition	Relation to SI units
foot per hour	fph	≡ 1 ft/h	≈ 8.466 667×10^{-5} m/s
foot per minute	fpm	≡ 1 ft/min	= 5.08×10^{-3} m/s
foot per second	fps	≡ 1 ft/s	= 3.048×10^{-1} m/s
inch per hour	iph	≡ 1 in/hr	≈ 7.05 556×10^{-6} m/s
inch per minute	ipm	≡ 1 in/min	≈ 4.23 333×10^{-4} m/s
inch per second	ips	≡ 1 in/s	= 2.54×10^{-2} m/s
kilometre per hour	km/h	≡ 1 km/h	= 1/3.6 m/s≈ 2.777 778×10^{-1} m/s
knot	kn, kt	≡ 1 NM/h = 1.852 km/h	≈ 0.514 444 m/s
knot (Admiralty)	kn	≡ 1 NM (Adm)/h = 1.853 184 km/h[citation needed]	= 0.514 773 m/s
metre per second (SI unit)	m/s	≡ 1 m/s	= 1 m/s
mile per hour	mph	≡ 1 mi/h	= 0.447 04 m/s
mile per minute	mpm	≡ 1 mi/min	= 26.8224 m/s
mile per second	mps	≡ 1 mi/s	= 1 609.344 m/s
speed of light in vacuum	*c*	≡ 299 792 458 m/s	= 299 792 458 m/s
speed of soundin air	*s*	Varies especially with temperature. About 1225 km/h (761 mph) in air at sea level to about 1062 km/h (660 mph) at jet altitudes.	≈ 340 to 295 m/s at aircraft altitudes

Flow (volume)

Flow

Name of unit	Symbol	Definition	Relation to SI units
cubic foot per minute	CFM[citation needed]	≡ 1 $\mathrm{ft^3/min}$	$= 4.719474432\times10^{-4}\ \mathrm{m^3/s}$
cubic foot per second	$\mathrm{ft^3/s}$	≡ 1 $\mathrm{ft^3/s}$	$= 0.028316846592\ \mathrm{m^3/s}$
cubic inch per minute	$\mathrm{in^3/min}$	≡ 1 $\mathrm{in^3/min}$	$= 2.7311773\times10^{-7}\ \mathrm{m^3/s}$
cubic inch per second	$\mathrm{in^3/s}$	≡ 1 $\mathrm{in^3/s}$	$= 1.6387064\times10^{-5}\ \mathrm{m^3/s}$
cubic metre per second (SI unit)	$\mathrm{m^3/s}$	≡ 1 $\mathrm{m^3/s}$	$= 1\ \mathrm{m^3/s}$
gallon (US fluid) per day	GPD[citation needed]	≡ 1 gal/d	$= 4.381263638\times10^{-8}\ \mathrm{m^3/s}$
gallon (US fluid) per hour	GPH[citation needed]	≡ 1 gal/h	$= 1.051503273\times10^{-6}\ \mathrm{m^3/s}$
gallon (US fluid) per minute	GPM[citation needed]	≡ 1 gal/min	$= 6.30901964\times10^{-5}\ \mathrm{m^3/s}$
litre per minute	LPM[citation needed]	≡ 1 L/min	$= 1.6\times10^{-5}\ \mathrm{m^3/s}$

Acceleration

Acceleration

Name of unit	Symbol	Definition	Relation to SI units
foot per hour per second	fph/s	≡ 1 ft/(h·s)	$\approx 8.466\,667\times10^{-5}\ \mathrm{m/s^2}$
foot per minute per second	fpm/s	≡ 1 ft/(min·s)	$= 5.08\times10^{-3}\ \mathrm{m/s^2}$
foot per second squared	$\mathrm{fps^2}$	≡ 1 $\mathrm{ft/s^2}$	$= 3.048\times10^{-1}\ \mathrm{m/s^2}$
gal; galileo	Gal	≡ 1 $\mathrm{cm/s^2}$	$= 10^{-2}\ \mathrm{m/s^2}$
inch per minute per second	ipm/s	≡ 1 in/(min·s)	$\approx 4.233\,333\times10^{-4}\ \mathrm{m/s^2}$
inch per second squared	$\mathrm{ips^2}$	≡ 1 $\mathrm{in/s^2}$	$= 2.54\times10^{-2}\ \mathrm{m/s^2}$
metre per second squared (SI unit)	$\mathrm{m/s^2}$	≡ 1 $\mathrm{m/s^2}$	$= 1\ \mathrm{m/s^2}$
standard gravity	*g*	≡ 9.806 65 $\mathrm{m/s^2}$	$= 9.806\,65\ \mathrm{m/s^2}$

Force

Force

Name of unit	Symbol	Definition	Relation to SI units
kilogram-force; kilopond; grave-force	kgf; kp; Gf	≡ g × 1 kg	= 9.806 65 N
newton (SI unit)	N	A force capable of giving a mass of one kg an acceleration of one metre per second, per second.[25]	= 1 N = 1 kg·m/s^2

Pressure or mechanical stress

Pressure

Name of unit	Symbol	Definition	Relation to SI units
atmosphere (standard)	atm		≡ 101 325 Pa [26]
atmosphere (technical)	at	≡ 1 kgf/cm^2	= 9.806 65×10^4 Pa [26]
bar	bar		≡ 10^5 Pa
centimetre of mercury	cmHg	≡ 13 595.1 kg/m^3 × 1 cm × g	≈ 1.333 22×10^3 Pa [26]
centimetre of water (4 °C)	cmH_2O	≈ 999.972 kg/m^3 × 1 cm × g	≈ 98.063 8 Pa [26]
foot of mercury (conventional)	ftHg	≡ 13 595.1 kg/m^3 × 1 ft × g	≈ 40.636 66×10^3 Pa [26]
foot of water (39.2 °F)	ftH_2O	≈ 999.972 kg/m^3 × 1 ft × g	≈ 2.988 98×10^3 Pa [26]
inch of mercury (conventional)	inHg	≡ 13 595.1 kg/m^3 × 1 in × g	≈ 3.386 389×10^3 Pa [26]
inch of water (39.2 °F)	inH_2O	≈ 999.972 kg/m^3 × 1 in × g	≈ 249.082 Pa [26]
kilogram-force per square millimetre	kgf/mm^2	≡ 1 kgf/mm^2	= 9.806 65×10^6 Pa [26]
millimetre of mercury	mmHg	≡ 13 595.1 kg/m^3 × 1 mm × g ≈ 1 torr	≈ 133.3224 Pa [26]
millimetre of water (3.98 °C)	mmH_2O	≈ 999.972 kg/m^3 × 1 mm × g = 0.999 972 kgf/m^2	= 9.806 38 Pa
pascal (SI unit)	Pa	≡ N/m^2 = kg/(m·s^2)	= 1 Pa [27]
pound per square foot	psf	≡ 1 lbf/ft^2	≈ 47.880 26 Pa [26]
pound per square inch	psi	≡ 1 lbf/in^2	≈ 6.894 757×10^3 Pa [26]

Energy

Energy

Name of unit	Symbol	Definition	Relation to SI units
barrel of oil equivalent	bboe	≈ 5.8×10^{6} $\mathrm{BTU}_{59\,°\mathrm{F}}$	≈ 6.12×10^{9} J
British thermal unit (ISO)	$\mathrm{BTU}_{\mathrm{ISO}}$	≡ 1.0545×10^{3} J	= 1.0545×10^{3} J
British thermal unit (International Table)	$\mathrm{BTU}_{\mathrm{IT}}$		= $1.055\,055\,852\,62\times10^{3}$ J
British thermal unit (mean)	$\mathrm{BTU}_{\mathrm{mean}}$		≈ $1.055\,87\times10^{3}$ J
British thermal unit (thermochemical)	$\mathrm{BTU}_{\mathrm{th}}$		≈ $1.054\,350\times10^{3}$ J
British thermal unit (39 °F)	$\mathrm{BTU}_{39\,°\mathrm{F}}$		≈ $1.059\,67\times10^{3}$ J
British thermal unit (59 °F)	$\mathrm{BTU}_{59\,°\mathrm{F}}$	≡ $1.054\,804\times10^{3}$ J	= $1.054\,804\times10^{3}$ J
British thermal unit (60 °F)	$\mathrm{BTU}_{60\,°\mathrm{F}}$		≈ $1.054\,68\times10^{3}$ J
British thermal unit (63 °F)	$\mathrm{BTU}_{63\,°\mathrm{F}}$		≈ 1.0546×10^{3} J
calorie (International Table)	$\mathrm{cal}_{\mathrm{IT}}$	≡ 4.1868 J	= 4.1868 J
calorie (mean)	$\mathrm{cal}_{\mathrm{mean}}$	$^{1}/_{100}$ of the energy required to warm one gram of air-free water from 0 °C to 100 °C @ 1 atm	≈ 4.190 02 J
calorie (thermochemical)	$\mathrm{cal}_{\mathrm{th}}$	≡ 4.184 J	= 4.184 J
calorie (3.98 °C)	$\mathrm{cal}_{3.98\,°\mathrm{C}}$		≈ 4.2045 J
calorie (15 °C)	$\mathrm{cal}_{15\,°\mathrm{C}}$	≡ 4.1855 J	= 4.1855 J
calorie (20 °C)	$\mathrm{cal}_{20\,°\mathrm{C}}$		≈ 4.1819 J
Celsius heat unit (International Table)	$\mathrm{CHU}_{\mathrm{IT}}$	≡ 1 $\mathrm{BTU}_{\mathrm{IT}}$ × 1 K/°R	= $1.899\,100\,534\,716\times10^{3}$ J
cubic centimetre of atmosphere; standard cubic centimetre	cc atm; scc	≡ 1 atm × 1 cm^{3}	= 0.101 325 J
cubic foot of atmosphere; standard cubic foot	cu ft atm; scf	≡ 1 atm × 1 ft^{3}	= $2.869\,204\,480\,9344\times10^{3}$ J
cubic foot of natural gas		≡ 1 000 $\mathrm{BTU}_{\mathrm{IT}}$	= $1.055\,055\,852\,62\times10^{6}$ J
cubic yard of atmosphere; standard cubic yard	cu yd atm; scy	≡ 1 atm × 1 yd^{3}	= $77.468\,520\,985\,2288\times10^{3}$ J
foot-pound force	ft lbf	≡ g × 1 lb × 1 ft	= 1.355 817 948 331 4004 J
gallon-atmosphere (imperial)	imp gal atm	≡ 1 atm × 1 gal (imp)	= 460.632 569 25 J

gallon-atmosphere (US)	US gal atm	≡ 1 atm × 1 gal (US)	= 383.556 849 0138 J
horsepower-hour	hp·h	≡ 1 hp × 1 h	= 2.684 519 537 696 172 792×10^6J
inch-pound force	in lbf	≡ *g* × 1 lb × 1 in	= 0.112 984 829 027 6167 J
joule (SI unit)	J	The work done when a force of one newton moves the point of its application a distance of one metre in the direction of the force.[25]	= 1 J = 1 m·N = 1 kg·m^2/s^2 = 1 C·V = 1 W·s
kilocalorie; large calorie	kcal; Cal	≡ 1 000 $\mathrm{cal}_{\mathrm{IT}}$	= 4.1868×10^3 J
kilowatt-hour; Board of Trade Unit	kW·h; B.O.T.U.	≡ 1 kW × 1 h	= 3.6×10^6 J
ton of coal equivalent	TCE	≡ 7 $\mathrm{Gcal}_{\mathrm{th}}$	= 29.3076×10^9 J
ton of oil equivalent	TOE	≡ 10 $\mathrm{Gcal}_{\mathrm{th}}$	= 41.868×10^9 J
ton of TNT	tTNT	≡ 1 $\mathrm{Gcal}_{\mathrm{th}}$	= 4.184×10^9 J

Power or heat flow rate

Power

Name of unit	Symbol	Definition	Relation to SI units
atmosphere-cubic centimetre per minute	atm ccm	≡ 1 atm × 1 cm^3/min	= 1.688 75×10^{-3} W
atmosphere-cubic centimetre per second	atm ccs	≡ 1 atm × 1 cm^3/s	= 0.101 325 W
atmosphere-cubic foot per hour	atm cfh	≡ 1 atm × 1 cu ft/h	= 0.797 001 244 704 W
atmosphere-cubic foot per minute	atm·cfm	≡ 1 atm × 1 cu ft/min	= 47.820 074 682 24 W
atmosphere-cubic foot per second	atm cfs	≡ 1 atm × 1 cu ft/s	= 2.869 204 480 9344×10^3 W
BTU (International Table) per hour	$\mathrm{BTU}_{\mathrm{IT}}$/h	≡ 1 $\mathrm{BTU}_{\mathrm{IT}}$/h	≈ 0.293 071 W
BTU (International Table) per minute	$\mathrm{BTU}_{\mathrm{IT}}$/min	≡ 1 $\mathrm{BTU}_{\mathrm{IT}}$/min	≈ 17.584 264 W
BTU (International Table) per second	$\mathrm{BTU}_{\mathrm{IT}}$/s	≡ 1 $\mathrm{BTU}_{\mathrm{IT}}$/s	= 1.055 055 852 62×10^3 W
calorie (International Table) per second	$\mathrm{cal}_{\mathrm{IT}}$/s	≡ 1 $\mathrm{cal}_{\mathrm{IT}}$/s	= 4.1868 W

erg per second	erg/s	≡ 1 erg/s	= 10^{-7} W
foot-pound-force per hour	ft lbf/h	≡ 1 ft lbf/h	≈ 3.766 161×10^{-4} W
foot-pound-force per minute	ft lbf/min	≡ 1 ft lbf/min	= 2.259 696 580 552 334×10^{-2} W
foot-pound-force per second	ft lbf/s	≡ 1 ft lbf/s	= 1.355 817 948 331 4004 W
horsepower (boiler)	bhp	≈ 34.5 lb/h × 970.3 BTU_{IT}/lb	≈ 9.810 657×10^{3} W
horsepower (European electrical)	hp	≡ 75 kp·m/s	= 736 W
horsepower (imperial electrical)	hp	≡ 746 W	= 746 W
horsepower (imperial mechanical)	hp	≡ 550 ft lbf/s	= 745.699 871 582 270 22 W
horsepower (metric)	hp	≡ 75 m kgf/s	= 735.498 75 W
watt (SI unit)	W	The power which in one second of time gives rise to one joule of energy.[25]	= 1 W = 1 J/s = 1 N·m/s = 1 kg·m^2/s^3

Temperature

Temperature

Name of unit	Symbol	Definition	Conversion to kelvin
degree Celsius	°C	°C ≡ K − 273.15	[K] ≡ [°C] + 273.15
degree Fahrenheit	°F	°F ≡ °C × 9/5 + 32	[K] ≡ ([°F] + 459.67) × 5/9
degree Newton	°N		[K] = [°N] × 100/33 + 273.15
degree Rankine	°R;	°R ≡ K × 9/5	[K] ≡ [°R] × 5/9
degree Réaumur	°Ré		[K] = [°Ré] × 5/4 + 273.15

kelvin (SI base unit)	K	≡ 1/273.16 of the thermodynamic temperature of the triple point of water.[8]	≡ 1 K

References
1. **Wikipedia.** http://en.wikipedia.org/wiki/Conversion_of_units. [Online] [Riportato: 02 04 2012.]

ANNEX 2- STEAM PROPERTIES (SI Units)

Properties of Saturated Steam - Pressure in Bar (1)

The Saturated Steam Table with properties as boiling point, specific volume, density, specific enthalpy, specific heat and latent heat of vaporization

The following tables give the relationship between temperature, absolute pressure, density, specific entalpy. Latent heat of vaporization and specific heat. The definition of the quantities are given below:

Absolute pressure
Boiling point
Density
Specific enthalpy
Latent heat of vaporization
Specific heat

The unit of measure are given according to the international system and in kcal/kg

Absolute pressure	Boiling point	Specific volume (steam)	Density (steam)	Specific enthalpy of liquid water (sensible heat)		Specific enthalpy of steam (total heat)		Latent heat of vaporization		Specific heat
(bar)	*(^oC)*	*(m^3/kg)*	*(kg/m^3)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg.K)*
0.02	17.51	67.006	0.015	73.45	17.54	2533.64	605.15	2460.19	587.61	1.8644
0.03	24.10	45.667	0.022	101.00	24.12	2545.64	608.02	2444.65	583.89	1.8694
0.04	28.98	34.802	0.029	121.41	29.00	2554.51	610.13	2433.10	581.14	1.8736
0.05	32.90	28.194	0.035	137.77	32.91	2561.59	611.83	2423.82	578.92	1.8774
0.06	36.18	23.741	0.042	151.50	36.19	2567.51	613.24	2416.01	577.05	1.8808
0.07	39.02	20.531	0.049	163.38	39.02	2572.62	614.46	2409.24	575.44	1.8840
0.08	41.53	18.105	0.055	173.87	41.53	2577.11	615.53	2403.25	574.01	1.8871
0.09	43.79	16.204	0.062	183.28	43.78	2581.14	616.49	2397.85	572.72	1.8899
0.1	45.83	14.675	0.068	191.84	45.82	2584.78	617.36	2392.94	571.54	1.8927
0.2	60.09	7.650	0.131	251.46	60.06	2609.86	623.35	2358.40	563.30	1.9156

Absolute pressure	Boiling point	Specific volume (steam)	Density (steam)	Specific enthalpy of liquid water (sensible heat)		Specific enthalpy of steam (total heat)		Latent heat of vaporization		Specific heat
(bar)	*(^oC)*	*(m^3/kg)*	*(kg/m^3)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg.K)*
0.3	69.13	5.229	0.191	289.31	69.10	2625.43	627.07	2336.13	557.97	1.9343
0.4	75.89	3.993	0.250	317.65	75.87	2636.88	629.81	2319.23	553.94	1.9506
0.5	81.35	3.240	0.309	340.57	81.34	2645.99	631.98	2305.42	550.64	1.9654
0.6	85.95	2.732	0.366	359.93	85.97	2653.57	633.79	2293.64	547.83	1.9790
0.7	89.96	2.365	0.423	376.77	89.99	2660.07	635.35	2283.30	545.36	1.9919
0.8	93.51	2.087	0.479	391.73	93.56	2665.77	636.71	2274.05	543.15	2.0040
0.9	96.71	1.869	0.535	405.21	96.78	2670.85	637.92	2265.65	541.14	2.0156
1	99.63	1.694	0.590	417.51	99.72	2675.43	639.02	2257.92	539.30	2.0267
1.1	102.32	1.549	0.645	428.84	102.43	2679.61	640.01	2250.76	537.59	2.0373
1.2	104.81	1.428	0.700	439.36	104.94	2683.44	640.93	2244.08	535.99	2.0476
1.3	107.13	1.325	0.755	449.19	107.29	2686.98	641.77	2237.79	534.49	2.0576
1.4	109.32	1.236	0.809	458.42	109.49	2690.28	642.56	2231.86	533.07	2.0673
1.5	111.37	1.159	0.863	467.13	111.57	2693.36	643.30	2226.23	531.73	2.0768
1.5	111.37	1.159	0.863	467.13	111.57	2693.36	643.30	2226.23	531.73	2.0768
1.6	113.32	1.091	0.916	475.38	113.54	2696.25	643.99	2220.87	530.45	2.0860
1.7	115.17	1.031	0.970	483.22	115.42	2698.97	644.64	2215.75	529.22	2.0950
1.8	116.93	0.977	1.023	490.70	117.20	2701.54	645.25	2210.84	528.05	2.1037

Absolute pressure	Boiling point	Specific volume (steam)	Density (steam)	Specific enthalpy of liquid water (sensible heat)		Specific enthalpy of steam (total heat)		Latent heat of vaporization		Specific heat
(bar)	*(^oC)*	*(m^3/kg)*	*(kg/m^3)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg.K)*
1.9	118.62	0.929	1.076	497.85	118.91	2703.98	645.83	2206.13	526.92	2.1124
2	120.23	0.885	1.129	504.71	120.55	2706.29	646.39	2201.59	525.84	2.1208
2.2	123.27	0.810	1.235	517.63	123.63	2710.60	647.42	2192.98	523.78	2.1372
2.4	126.09	0.746	1.340	529.64	126.50	2714.55	648.36	2184.91	521.86	2.1531
2.6	128.73	0.693	1.444	540.88	129.19	2718.17	649.22	2177.30	520.04	2.1685
2.8	131.20	0.646	1.548	551.45	131.71	2721.54	650.03	2170.08	518.32	2.1835
3	133.54	0.606	1.651	561.44	134.10	2724.66	650.77	2163.22	516.68	2.1981
3.5	138.87	0.524	1.908	584.28	139.55	2731.63	652.44	2147.35	512.89	2.2331
4	143.63	0.462	2.163	604.68	144.43	2737.63	653.87	2132.95	509.45	2.2664
4.5	147.92	0.414	2.417	623.17	148.84	2742.88	655.13	2119.71	506.29	2.2983
5	151.85	0.375	2.669	640.12	152.89	2747.54	656.24	2107.42	503.35	2.3289
5.5	155.47	0.342	2.920	655.81	156.64	2751.70	657.23	2095.90	500.60	2.3585
6	158.84	0.315	3.170	670.43	160.13	2755.46	658.13	2085.03	498.00	2.3873
6.5	161.99	0.292	3.419	684.14	163.40	2758.87	658.94	2074.73	495.54	2.4152
7	164.96	0.273	3.667	697.07	166.49	2761.98	659.69	2064.92	493.20	2.4424
7.5	167.76	0.255	3.915	709.30	169.41	2764.84	660.37	2055.53	490.96	2.4690
8	170.42	0.240	4.162	720.94	172.19	2767.46	661.00	2046.53	488.80	2.4951

Absolute pressure	Boiling point	Specific volume (steam)	Density (steam)	Specific enthalpy of liquid water (sensible heat)		Specific enthalpy of steam (total heat)		Latent heat of vaporization		Specific heat
(bar)	*(^{o}C)*	*(m^{3}/kg)*	*(kg/m^{3})*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg.K)*
8.5	172.94	0.227	4.409	732.03	174.84	2769.89	661.58	2037.86	486.73	2.5206
9	175.36	0.215	4.655	742.64	177.38	2772.13	662.11	2029.49	484.74	2.5456
9.5	177.67	0.204	4.901	752.82	179.81	2774.22	662.61	2021.40	482.80	2.5702
10	179.88	0.194	5.147	762.60	182.14	2776.16	663.07	2013.56	480.93	2.5944
11	184.06	0.177	5.638	781.11	186.57	2779.66	663.91	1998.55	477.35	2.6418
12	187.96	0.163	6.127	798.42	190.70	2782.73	664.64	1984.31	473.94	2.6878
13	191.60	0.151	6.617	814.68	194.58	2785.42	665.29	1970.73	470.70	2.7327
14	195.04	0.141	7.106	830.05	198.26	2787.79	665.85	1957.73	467.60	2.7767
15	198.28	0.132	7.596	844.64	201.74	2789.88	666.35	1945.24	464.61	2.8197
16	201.37	0.124	8.085	858.54	205.06	2791.73	666.79	1933.19	461.74	2.8620
17	204.30	0.117	8.575	871.82	208.23	2793.37	667.18	1921.55	458.95	2.9036
18	207.11	0.110	9.065	884.55	211.27	2794.81	667.53	1910.27	456.26	2.9445
19	209.79	0.105	9.556	896.78	214.19	2796.09	667.83	1899.31	453.64	2.9849
20	212.37	0.100	10.047	908.56	217.01	2797.21	668.10	1888.65	451.10	3.0248
21	214.85	0.095	10.539	919.93	219.72	2798.18	668.33	1878.25	448.61	3.0643
22	217.24	0.091	11.032	930.92	222.35	2799.03	668.54	1868.11	446.19	3.1034
23	219.55	0.087	11.525	941.57	224.89	2799.77	668.71	1858.20	443.82	3.1421

Absolute pressure	Boiling point	Specific volume (steam)	Density (steam)	Specific enthalpy of liquid water (sensible heat)		Specific enthalpy of steam (total heat)		Latent heat of vaporization		Specific heat
(bar)	*(^oC)*	*(m^3/kg)*	*(kg/m^3)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg)*	*(kcal/kg)*	*(kJ/kg.K)*
24	221.78	0.083	12.020	951.90	227.36	2800.39	668.86	1848.49	441.50	3.1805
25	223.94	0.080	12.515	961.93	229.75	2800.91	668.99	1838.98	439.23	3.2187
26	226.03	0.077	13.012	971.69	232.08	2801.35	669.09	1829.66	437.01	3.2567
27	228.06	0.074	13.509	981.19	234.35	2801.69	669.17	1820.50	434.82	3.2944
28	230.04	0.071	14.008	990.46	236.57	2801.96	669.24	1811.50	432.67	3.3320
29	231.96	0.069	14.508	999.50	238.73	2802.15	669.28	1802.65	430.56	3.3695
30	233.84	0.067	15.009	1008.33	240.84	2802.27	669.31	1793.94	428.48	3.4069

Bibliography

1. **Engineering Toolbox.** http://www.engineeringtoolbox.com/saturated-steam-properties-. [Online] [Riportato: 17 01 2012.]

ANNEX 3 STEAM PROPERTIES (US Units)

Table A.1. Saturated vapor properties—pressure

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb$_m$)	Internal energy (Btu/lb$_m$)	Enthalpy (Btu/lb$_m$)	Entropy (Btu/lb$_m$°R)	Quality (%)
102	1.0	333.54579	1,044.22	1,105.94	1.98473	100.0
162	5.0	73.52409	1,063.07	1,131.09	1.84342	100.0
193	10.0	38.41991	1,072.20	1,143.29	1.78571	100.0
212	14.7	26.79334	1,077.53	1,150.41	1.75442	100.0
228	20.0	20.08862	1,081.90	1,156.25	1.72980	100.0
240	25.0	16.30338	1,085.13	1,160.55	1.71218	100.0
250	30.0	13.74552	1,087.79	1,164.10	1.69791	100.0
259	35.0	11.89768	1,090.06	1,167.11	1.68594	100.0
267	40.0	10.49823	1,092.02	1,169.73	1.67564	100.0
274	45.0	9.40041	1,093.76	1,172.04	1.66661	100.0
281	50.0	8.51542	1,095.31	1,174.10	1.65857	100.0
293	60.0	7.17489	1,097.98	1,177.64	1.64475	100.0
303	70.0	6.20609	1,100.22	1,180.61	1.63316	100.0
312	80.0	5.47216	1,102.12	1,183.13	1.62318	100.0
320	90.0	4.89626	1,103.78	1,185.32	1.61443	100.0
328	100.0	4.43190	1,105.23	1,187.24	1.60665	100.0
341	120.0	3.72834	1,107.66	1,190.45	1.60242	100.0
353	140.0	3.21974	1,109.61	1,193.02	1.58520	100.0
364	160.0	2.83434	1,111.21	1,195.13	1.57044	100.0
373	180.0	2.53188	1,112.55	1,196.88	1.55753	100.0
382	200.0	2.28796	1,113.66	1,198.34	1.54607	100.0
390	220.0	2.08695	1,114.60	1,199.56	1.53578	100.0
397	240.0	1.91833	1,115.40	1,200.59	1.52645	100.0
404	260.0	1.77480	1,116.07	1,201.46	1.51791	100.0
411	280.0	1.65108	1,116.64	1,202.19	1.51005	100.0
417	300.0	1.54330	1,117.12	1,202.80	1.50277	100.0
423	320.0	1.44854	1,117.53	1,203.31	1.49599	100.0
429	340.0	1.36455	1,117.87	1,203.72	1.48965	100.0
434	360.0	1.28957	1,118.14	1,204.05	1.48369	100.0
440	380.0	1.22221	1,118.37	1,204.31	1.47808	100.0
445	400.0	1.16136	1,118.55	1,204.51	1.47278	100.0
449	420.0	1.10610	1,118.69	1,204.65	1.46775	100.0
454	440.0	1.05569	1,118.78	1,204.74	1.46298	100.0
459	460.0	1.00951	1,118.85	1,204.78	1.45843	100.0
463	480.0	0.96705	1,118.88	1,204.78	1.45408	100.0
467	500.0	0.92787	1,118.89	1,204.74	1.44993	100.0
471	520.0	0.89159	1,118.87	1,204.66	1.44595	100.0
475	540.0	0.85791	1,118.83	1,204.55	1.44213	100.0
479	560.0	0.82655	1,118.76	1,204.42	1.43846	100.0
483	580.0	0.79727	1,118.68	1,204.25	1.43493	100.0
486	600.0	0.76988	1,118.58	1,204.06	1.43153	100.0

Table A.1. (continued)

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb$_m$)	Internal energy (Btu/lb$_m$)	Enthalpy (Btu/lb$_m$)	Entropy (Btu/lb$_m$°R)	Quality (%)
490	620.0	0.74419	1,118.46	1,203.84	1.42824	100.0
493	640.0	0.72006	1,118.32	1,203.60	1.42507	100.0
497	660.0	0.69733	1,118.18	1,203.34	1.42200	100.0
500	680.0	0.67590	1,118.02	1,203.07	1.41903	100.0
503	700.0	0.65564	1,117.84	1,202.77	1.41615	100.0
506	720.0	0.63648	1,117.66	1,202.46	1.41335	100.0
509	740.0	0.61831	1,117.46	1,202.13	1.41064	100.0
512	760.0	0.60106	1,117.26	1,201.79	1.40801	100.0
515	780.0	0.58467	1,117.04	1,201.43	1.40545	100.0
518	800.0	0.56907	1,116.82	1,201.06	1.40296	100.0
521	820.0	0.55421	1,116.59	1,200.68	1.40053	100.0
524	840.0	0.54003	1,116.35	1,200.29	1.39817	100.0
527	860.0	0.52648	1,116.10	1,199.89	1.39587	100.0
529	880.0	0.51353	1,115.85	1,199.47	1.39362	100.0
532	900.0	0.50113	1,115.59	1,199.05	1.39143	100.0
535	920.0	0.48926	1,115.32	1,198.62	1.38929	100.0
537	940.0	0.47787	1,115.05	1,198.18	1.38719	100.0
540	960.0	0.46694	1,114.78	1,197.73	1.38515	100.0
542	980.0	0.45645	1,114.50	1,197.27	1.38315	100.0
545	1,000.0	0.44635	1,114.21	1,196.81	1.38119	100.0

Table A.2. Saturated vapor properties—temperature

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb_m)	Internal energy (Btu/lb_m)	Enthalpy (Btu/lb_m)	Entropy (Btu/lb_m°R)	Quality (%)
100	0.9	350.34470	1,043.66	1,105.20	1.98949	100.0
120	1.7	203.26536	1,050.01	1,113.67	1.93738	100.0
140	2.9	123.00672	1,056.26	1,122.01	1.89043	100.0
160	4.7	77.29142	1,062.39	1,130.19	1.84794	100.0
180	7.5	50.22845	1,068.35	1,138.16	1.80933	100.0
200	11.5	33.64085	1,074.14	1,145.89	1.77411	100.0
212	14.7	26.80026	1,077.52	1,150.40	1.75444	100.0
220	17.2	23.14935	1,079.74	1,153.36	1.74188	100.0
240	25.0	16.32189	1,085.11	1,160.53	1.71227	100.0
260	35.4	11.76240	1,090.24	1,167.35	1.68500	100.0
280	49.2	8.64488	1,095.08	1,173.79	1.65980	100.0
300	67.0	6.46697	1,099.58	1,179.77	1.63644	100.0
320	89.6	4.91524	1,103.72	1,185.25	1.61473	100.0
340	118.0	3.78954	1,107.43	1,190.15	1.60433	100.0
360	153.0	2.95925	1,110.68	1,194.44	1.57540	100.0
380	195.6	2.33743	1,113.42	1,198.04	1.54847	100.0
400	247.1	1.86514	1,115.64	1,200.92	1.52334	100.0
420	308.5	1.50170	1,117.29	1,203.03	1.49982	100.0
440	381.2	1.21864	1,118.37	1,204.33	1.47776	100.0
460	466.4	0.99568	1,118.85	1,204.79	1.45701	100.0
480	565.7	0.81821	1,118.72	1,204.37	1.43745	100.0
500	680.4	0.67558	1,118.00	1,203.06	1.41897	100.0
520	812.3	0.55991	1,116.67	1,200.83	1.40146	100.0
540	963.0	0.46531	1,114.75	1,197.66	1.38485	100.0
560	1,134.3	0.38734	1,112.24	1,193.54	1.36905	100.0
580	1,328.3	0.32262	1,109.14	1,188.44	1.35399	100.0
600	1,547.0	0.26856	1,105.48	1,182.36	1.33960	100.0
620	1,792.7	0.22316	1,101.25	1,175.28	1.32584	100.0
640	2,067.8	0.18485	1,096.45	1,167.18	1.27863	100.0
660	2,374.9	0.15241	1,091.07	1,158.05	1.24458	100.0
680	2,716.9	0.12487	1,085.09	1,147.87	1.21237	100.0
700	3,096.8	0.10147	1,078.47	1,136.62	1.18183	100.0

Table A.3. Saturated liquid properties—pressure

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb$_m$)	Internal energy (Btu/lb$_m$)	Enthalpy (Btu/lb$_m$)	Entropy (Btu/lb$_m$°R)	Quality (%)
102	1.0	0.01613	69.71	69.71	0.13261	0.0
162	5.0	0.01640	130.10	130.12	0.23468	0.0
193	10.0	0.01659	161.14	161.17	0.28341	0.0
212	14.7	0.01671	180.05	180.09	0.31198	0.0
228	20.0	0.01683	196.11	196.18	0.33565	0.0
240	25.0	0.01692	208.35	208.43	0.35330	0.0
250	30.0	0.01700	218.74	218.83	0.36805	0.0
259	35.0	0.01708	227.81	227.92	0.38077	0.0
267	40.0	0.01715	235.90	236.03	0.39196	0.0
274	45.0	0.01721	243.23	243.37	0.40199	0.0
281	50.0	0.01727	249.93	250.09	0.41107	0.0
293	60.0	0.01738	261.89	262.08	0.42708	0.0
303	70.0	0.01748	272.37	272.60	0.44091	0.0
312	80.0	0.01757	281.74	282.00	0.45312	0.0
320	90.0	0.01766	290.25	290.54	0.46407	0.0
328	100.0	0.01774	298.06	298.38	0.47401	0.0
341	120.0	0.01789	312.03	312.43	0.49158	0.0
353	140.0	0.01803	324.33	324.80	0.50680	0.0
364	160.0	0.01815	335.37	335.91	0.52027	0.0
373	180.0	0.01827	345.42	346.03	0.53239	0.0
382	200.0	0.01838	354.67	355.35	0.54343	0.0
390	220.0	0.01849	363.27	364.02	0.55358	0.0
397	240.0	0.01860	371.30	372.13	0.56299	0.0
404	260.0	0.01870	378.87	379.77	0.57177	0.0
411	280.0	0.01879	386.02	386.99	0.58001	0.0
417	300.0	0.01889	392.81	393.86	0.58778	0.0
423	320.0	0.01898	399.29	400.41	0.59514	0.0
429	340.0	0.01907	405.48	406.68	0.60213	0.0
434	360.0	0.01916	411.42	412.69	0.60880	0.0
440	380.0	0.01924	417.13	418.48	0.61517	0.0
445	400.0	0.01933	422.63	424.06	0.62128	0.0
449	420.0	0.01941	427.94	429.45	0.62714	0.0
454	440.0	0.01949	433.08	434.67	0.63279	0.0
459	460.0	0.01958	438.07	439.73	0.63823	0.0
463	480.0	0.01966	442.90	444.65	0.64349	0.0
467	500.0	0.01974	447.60	449.42	0.64858	0.0
471	520.0	0.01982	452.17	454.08	0.65351	0.0
475	540.0	0.01989	456.62	458.61	0.65830	0.0
479	560.0	0.01997	460.97	463.04	0.66294	0.0
483	580.0	0.02005	465.21	467.36	0.66746	0.0
486	600.0	0.02013	469.36	471.59	0.67186	0.0

Table A.3. (continued)

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb_m)	Internal energy (Btu/lb_m)	Enthalpy (Btu/lb_m)	Entropy [Btu/lb_m°R]	Quality (%)
490	620.0	0.02020	473.41	475.73	0.67615	0.0
493	640.0	0.02028	477.38	479.78	0.68033	0.0
497	660.0	0.02035	481.27	483.76	0.68441	0.0
500	680.0	0.02043	485.09	487.66	0.68840	0.0
503	700.0	0.02050	488.83	491.49	0.69230	0.0
506	720.0	0.02058	492.51	495.25	0.69612	0.0
509	740.0	0.02065	496.12	498.94	0.69986	0.0
512	760.0	0.02073	499.66	502.58	0.70352	0.0
515	780.0	0.02080	503.16	506.16	0.70711	0.0
518	800.0	0.02087	506.59	509.68	0.71064	0.0
521	820.0	0.02095	509.97	513.15	0.71410	0.0
524	840.0	0.02102	513.31	516.57	0.71750	0.0
527	860.0	0.02109	516.59	519.95	0.72084	0.0
529	880.0	0.02117	519.83	523.28	0.72412	0.0
532	900.0	0.02124	523.03	526.56	0.72736	0.0
535	920.0	0.02131	526.18	529.81	0.73054	0.0
537	940.0	0.02139	529.29	533.01	0.73367	0.0
540	960.0	0.02146	532.37	536.18	0.73676	0.0
542	980.0	0.02153	535.41	539.31	0.73980	0.0
545	1,000.0	0.02161	538.41	542.41	0.74280	0.0

Table A.4. Saturated liquid properties—temperature

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb_m)	Internal energy (Btu/lb_m)	Enthalpy (Btu/lb_m)	Entropy (Btu/lb_m°R)	Quality (%)
100	0.9	0.01613	67.97	67.97	0.12951	0.0
120	1.7	0.01620	87.91	87.92	0.16448	0.0
140	2.9	0.01629	107.87	107.88	0.19830	0.0
160	4.7	0.01639	127.86	127.88	0.23107	0.0
180	7.5	0.01650	147.89	147.91	0.26289	0.0
200	11.5	0.01663	167.96	168.00	0.29381	0.0
212	14.7	0.01671	180.03	180.07	0.31196	0.0
220	17.2	0.01677	188.09	188.14	0.32390	0.0
240	25.0	0.01692	208.27	208.35	0.35320	0.0
260	35.4	0.01708	228.54	228.65	0.38178	0.0
280	49.2	0.01726	248.90	249.06	0.40969	0.0
300	67.0	0.01745	269.37	269.59	0.43698	0.0
320	89.6	0.01766	289.98	290.27	0.46371	0.0

340	118.0	0.01788	310.73	311.12	0.48995	0.0
360	153.0	0.01811	331.65	332.17	0.51576	0.0
380	195.6	0.01836	352.78	353.44	0.54117	0.0
400	247.1	0.01863	374.12	374.97	0.56626	0.0
420	308.5	0.01893	395.70	396.78	0.59107	0.0
440	381.2	0.01925	417.56	418.92	0.61565	0.0
460	466.4	0.01960	439.74	441.43	0.64006	0.0
480	565.7	0.02000	462.28	464.37	0.66434	0.0
500	680.4	0.02043	485.24	487.81	0.68856	0.0
520	812.3	0.02092	508.70	511.84	0.71280	0.0
540	963.0	0.02147	532.77	536.59	0.73716	0.0
560	1,134.3	0.02209	557.58	562.22	0.76179	0.0
580	1,328.3	0.02280	583.32	588.93	0.78689	0.0
600	1,547.0	0.02361	610.22	616.98	0.81273	0.0
620	1,792.7	0.02452	638.58	646.72	0.83968	0.0
640	2,067.8	0.02557	668.79	678.57	0.86822	0.0
660	2,374.9	0.02677	701.30	713.06	0.89899	0.0
680	2,716.9	0.02813	736.71	750.85	0.93282	0.0
700	3,096.8	0.02969	775.74	792.75	0.97074	0.0

Table A.5. Superheated steam properties

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb$_m$)	Internal energy (Btu/lb$_m$)	Enthalpy (Btu/lb$_m$)	Entropy (Btu/lb$_m$°R)	Quality (%)
228	20.0	20.08862	1,081.90	1,156.25	1.72980	100.0
250	20.0	20.79400	1,090.31	1,167.27	1.74760	****
275	20.0	21.58306	1,099.65	1,179.53	1.76459	****
300	20.0	22.36341	1,108.85	1,191.62	1.78077	****
325	20.0	23.13727	1,117.97	1,203.60	1.79628	****
350	20.0	23.90620	1,127.03	1,215.51	1.81122	****
375	20.0	24.67129	1,136.06	1,227.37	1.82565	****
281	50.0	8.51542	1,095.31	1,174.10	1.65857	100.0
300	50.0	8.77247	1,103.11	1,184.28	1.67209	****
325	50.0	9.10358	1,113.12	1,197.35	1.68903	****
350	50.0	9.42849	1,122.88	1,210.12	1.70504	****
375	50.0	9.74874	1,132.46	1,222.66	1.72030	****
400	50.0	10.06539	1,141.92	1,235.05	1.73493	****
425	50.0	10.37923	1,151.31	1,247.34	1.74902	****
328	100.0	4.43190	1,105.23	1,187.24	1.60665	100.0
350	100.0	4.59216	1,115.12	1,200.09	1.61882	****
375	100.0	4.76689	1,125.85	1,214.06	1.63581	****
400	100.0	4.93702	1,136.21	1,227.57	1.65176	****
425	100.0	5.10365	1,146.31	1,240.75	1.66688	****
450	100.0	5.26758	1,156.22	1,253.70	1.68131	****
475	100.0	5.42936	1,166.01	1,266.48	1.69517	****
358	150.0	3.01465	1,110.45	1,194.13	1.57756	100.0
375	150.0	3.09940	1,118.41	1,204.45	1.58194	****
400	150.0	3.22251	1,129.90	1,219.35	1.59953	****
425	150.0	3.34135	1,140.87	1,233.62	1.61589	****
450	150.0	3.45696	1,151.47	1,247.43	1.63129	****
475	150.0	3.57007	1,161.81	1,260.91	1.64591	****
500	150.0	3.68122	1,171.96	1,274.14	1.65988	****
382	200.0	2.28796	1,113.66	1,198.34	1.54607	100.0
400	200.0	2.36110	1,122.94	1,210.33	1.55943	****
425	200.0	2.45715	1,134.96	1,225.90	1.57729	****
450	200.0	2.54937	1,146.37	1,240.73	1.59382	****
475	200.0	2.63870	1,157.35	1,255.01	1.60931	****
500	200.0	2.72578	1,168.01	1,268.90	1.62397	****
525	200.0	2.81109	1,178.44	1,282.48	1.63795	****
401	250.0	1.84380	1,115.75	1,201.05	1.52209	100.0
425	250.0	1.92394	1,128.54	1,217.54	1.54514	****
450	250.0	2.00285	1,140.90	1,233.56	1.56299	****
475	250.0	2.07839	1,152.62	1,248.77	1.57949	****
500	250.0	2.15139	1,163.86	1,263.39	1.59493	****
525	250.0	2.22241	1,174.76	1,277.58	1.60952	****
550	250.0	2.29185	1,185.40	1,291.43	1.62342	****

Table A. 5. (continued)

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb_m)	Internal energy (Btu/lb_m)	Enthalpy (Btu/lb_m)	Entropy ($Btu/lb_m°R$)	Quality (%)
417	300.0	1.54330	1,117.12	1,202.80	1.50277	100.0
425	300.0	1.56597	1,121.54	1,208.48	1.51676	****
450	300.0	1.63670	1,135.02	1,225.88	1.53616	****
475	300.0	1.70353	1,147.58	1,242.15	1.55381	****
500	300.0	1.76747	1,159.49	1,257.61	1.57013	****
525	300.0	1.82919	1,170.91	1,272.46	1.58541	****
550	300.0	1.88918	1,181.98	1,286.86	1.59985	****
432	350.0	1.32603	1,118.01	1,203.90	1.48662	100.0
450	350.0	1.37346	1,128.69	1,217.65	1.51187	****
475	350.0	1.43454	1,142.23	1,235.14	1.53084	****
500	350.0	1.49233	1,154.87	1,251.53	1.54815	****
525	350.0	1.54763	1,166.88	1,267.12	1.56419	****
550	350.0	1.60102	1,178.42	1,282.11	1.57922	****
575	350.0	1.65291	1,189.60	1,296.65	1.59345	****
445	400.0	1.16136	1,118.55	1,204.51	1.47278	100.0
450	400.0	1.17436	1,121.86	1,208.79	1.48922	****
475	400.0	1.23161	1,136.52	1,227.68	1.50971	****
500	400.0	1.28511	1,150.01	1,245.13	1.52814	****
525	400.0	1.33582	1,162.66	1,261.54	1.54502	****
550	400.0	1.38442	1,174.71	1,277.19	1.56071	****
575	400.0	1.43137	1,186.30	1,292.25	1.57545	****
456	450.0	1.03211	1,118.82	1,204.77	1.46067	100.0
475	450.0	1.07262	1,130.42	1,219.74	1.48984	****
500	450.0	1.12311	1,144.86	1,238.38	1.50953	****
525	450.0	1.17047	1,158.24	1,255.71	1.52735	****
550	450.0	1.21549	1,170.85	1,272.07	1.54376	****
575	450.0	1.25872	1,182.90	1,287.71	1.55907	****
600	450.0	1.30054	1,194.51	1,302.81	1.57349	****
467	500.0	0.92787	1,118.89	1,204.74	1.44993	100.0
475	500.0	0.94428	1,123.90	1,211.27	1.47081	****
500	500.0	0.99269	1,139.41	1,231.26	1.49193	****
525	500.0	1.03760	1,153.60	1,249.60	1.51080	****
550	500.0	1.07991	1,166.83	1,266.75	1.52800	****
575	500.0	1.12027	1,179.37	1,283.02	1.54392	****
600	500.0	1.15910	1,191.38	1,298.62	1.55882	****
477	550.0	0.84195	1,118.80	1,204.49	1.44028	100.0
500	550.0	0.88517	1,133.64	1,223.73	1.47505	****
525	550.0	0.92830	1,148.73	1,243.21	1.49509	****
550	550.0	0.96856	1,162.64	1,261.22	1.51315	****
575	550.0	1.00667	1,175.71	1,278.17	1.52973	****
600	550.0	1.04313	1,188.14	1,294.31	1.54515	****
625	550.0	1.07830	1,200.10	1,309.85	1.55965	****

Table A.5. (continued)

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb_m)	Internal energy (Btu/lb_m)	Enthalpy (Btu/lb_m)	Entropy ($Btu/lb_m°R$)	Quality (%)
486	600.0	0.76988	1,118.58	1,204.06	1.43153	100.0
500	600.0	0.79477	1,127.51	1,215.75	1.45865	****
550	600.0	0.87535	1,158.27	1,255.46	1.49901	****
600	600.0	0.94626	1,184.81	1,289.87	1.53229	****
650	600.0	1.01152	1,209.03	1,321.34	1.56131	****
700	600.0	1.07317	1,231.90	1,351.06	1.58752	****
750	600.0	1.13239	1,253.97	1,379.70	1.61170	****
495	650.0	0.70853	1,118.25	1,203.48	1.42352	100.0
500	650.0	0.71746	1,120.99	1,207.29	1.44255	****
550	650.0	0.79607	1,153.70	1,249.45	1.48542	****
600	650.0	0.86407	1,181.36	1,285.30	1.52008	****
650	650.0	0.92599	1,206.30	1,317.68	1.54995	****
700	650.0	0.98411	1,229.65	1,348.03	1.57670	****
750	650.0	1.03967	1,252.07	1,377.12	1.60127	****
503	700.0	0.65564	1,117.84	1,202.77	1.41615	100.0
525	700.0	0.69098	1,132.50	1,222.01	1.45100	****
575	700.0	0.76160	1,163.89	1,262.54	1.49118	****
625	700.0	0.82360	1,190.95	1,297.63	1.52431	****
675	700.0	0.88052	1,215.60	1,329.66	1.55319	****
725	700.0	0.93419	1,238.86	1,359.87	1.57924	****
775	700.0	0.98564	1,261.26	1,388.93	1.60327	****
511	750.0	0.60958	1,117.36	1,201.96	1.40932	100.0
525	750.0	0.63187	1,126.49	1,214.19	1.43684	****
575	750.0	0.70113	1,159.64	1,256.94	1.47923	****
625	750.0	0.76103	1,187.72	1,293.34	1.51360	****
675	750.0	0.81551	1,213.03	1,326.21	1.54324	****
725	750.0	0.86656	1,236.73	1,357.00	1.56979	****
775	750.0	0.91532	1,259.45	1,386.48	1.59417	****
518	800.0	0.56907	1,116.82	1,201.06	1.40296	100.0
525	800.0	0.57955	1,120.14	1,205.93	1.42277	****
575	800.0	0.64792	1,155.21	1,251.13	1.46759	****
625	800.0	0.70612	1,184.40	1,288.93	1.50329	****
675	800.0	0.75853	1,210.40	1,322.69	1.53373	****
725	800.0	0.80733	1,234.57	1,354.08	1.56080	****
775	800.0	0.85375	1,257.62	1,384.01	1.58555	****
525	850.0	0.53318	1,116.22	1,200.09	1.39701	100.0
550	850.0	0.56859	1,133.17	1,222.61	1.43417	****
600	850.0	0.63009	1,166.39	1,265.50	1.47566	****
650	850.0	0.68342	1,194.68	1,302.18	1.50950	****
700	850.0	0.73196	1,220.24	1,335.37	1.53877	****
750	850.0	0.77746	1,244.19	1,366.47	1.56503	****
800	850.0	0.82088	1,267.15	1,396.27	1.58917	****

Table A.6. Subcooled liquid properties

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb_m)	Internal energy (Btu/lb_m)	Enthalpy (Btu/lb_m)	Entropy ($Btu/lb_m°R$)	Quality (%)
212	14.7	0.01671	180.05	180.09	0.31198	0.0
200	14.7	0.01663	167.95	168.00	0.29381	****
150	14.7	0.01634	117.83	117.88	0.21481	****
100	14.7	0.01613	67.93	67.97	0.12951	****
50	14.7	0.01598	18.02	18.06	0.03601	****
281	50.0	0.01727	249.93	250.09	0.41107	0.0
200	50.0	0.01663	167.84	168.00	0.29381	****
150	50.0	0.01634	117.72	117.88	0.21481	****
328	100.0	0.01774	298.06	298.38	0.47401	0.0
200	100.0	0.01663	167.69	168.00	0.29381	****
150	100.0	0.01634	117.57	117.88	0.21481	****
358	150.0	0.01809	329.99	330.49	0.51372	0.0
200	150.0	0.01663	167.53	168.00	0.29381	****
150	150.0	0.01634	117.42	117.88	0.21481	****
382	200.0	0.01838	354.67	355.35	0.54343	0.0
200	200.0	0.01663	167.38	168.00	0.29381	****
150	200.0	0.01634	117.27	117.88	0.21481	****
401	250.0	0.01865	375.14	376.00	0.56745	0.0
200	250.0	0.01663	167.23	168.00	0.29381	****
150	250.0	0.01634	117.12	117.88	0.21481	****
417	300.0	0.01889	392.81	393.86	0.58778	0.0
200	300.0	0.01663	167.07	168.00	0.29381	****
150	300.0	0.01634	116.97	117.88	0.21481	****
432	350.0	0.01911	408.48	409.72	0.60550	0.0
200	350.0	0.01663	166.92	168.00	0.29381	****
150	350.0	0.01634	116.82	117.88	0.21481	****
445	400.0	0.01933	422.63	424.06	0.62128	0.0
200	400.0	0.01663	166.77	168.00	0.29381	****
150	400.0	0.01634	116.67	117.88	0.21481	****
456	450.0	0.01954	435.59	437.22	0.63554	0.0
200	450.0	0.01663	166.61	168.00	0.29381	****
150	450.0	0.01634	116.52	117.88	0.21481	****
467	500.0	0.01974	447.60	449.42	0.64858	0.0
200	500.0	0.01663	166.46	168.00	0.29381	****
150	500.0	0.01634	116.36	117.88	0.21481	****
477	550.0	0.01993	458.81	460.84	0.66064	0.0
200	550.0	0.01663	166.30	168.00	0.29381	****
150	550.0	0.01634	116.21	117.88	0.21481	****
486	600.0	0.02013	469.36	471.59	0.67186	0.0
200	600.0	0.01663	166.15	168.00	0.29381	****
150	600.0	0.01634	116.06	117.88	0.21481	****

Tables A.1–A.6 were developed based on data in “Steam Program Function Subroutines Written in Fortran,” *Mechanical Engineering News*, **19**(3), 11–12 (August 1982).

ANNEX 4 ENTHALPY

Enthalpy

Enthalpy(from Wikipedia) (1) is the amount of heat content used or released in a system at constant pressure. Enthalpy is usually expressed as the change in enthalpy. The change in enthalpy is related to a change in internal energy (U) and a change in the volume (V), which is multiplied by the constant pressure of the system.

Introduction

Enthalpy (H) is the sum of the internal energy (U) and the product of pressure and volume (PV) given by the equation:

$$\mathbf{H = U + PV}$$

When a process occurs at constant pressure, the heat evolved (either released or absorbed) is equal to the change in enthalpy. Enthalpy is a state function which depends entirely on the state functions T, P and U. Enthalpy is usually expressed as the change in enthalpy (ΔH) for a process between initial and final states:

$$\mathbf{\Delta H = \Delta U + \Delta PV}$$

If temperature and pressure remain constant through the process and the work is limited to pressure-volume work, then the **enthalpy change** is given by the eqation:

$$\mathbf{\Delta H = \Delta U + P\Delta V}$$

Also **at constant pressure** the heat flow(q) for the process is equal to the change in enthalpy defined by the equation:

$$\mathbf{\Delta H = q}$$

By looking at whether q is exothermic or endothermic we can determine a relationship between ΔH and q. If the reaction absorbs heat it is endothermic meaning the reaction consumes heat from the surroundings so $q > 0$ (positive). Therefore, at constant temperature and pressure, by the equation above, if q is positive then ΔH is also positive. And the same goes for if the reaction releases heat, then it is exothermic, meaning the system gives off heat to its surroundings, so $q < 0$ (negative). And if q is negative then ΔH will also be negative.

Enthalpy Change Accompanying a Change in State of Matter

When a liquid vaporizes the liquid must absorb heat from its surroundings to replace the energy taken by the vaporizing molecules in order for the temperature to remain constant. This heat required to vaporize the liquid is called enthalpy, or often, heat of vaporization. For the vaporization of one mole of water the enthalpy is given as:

ΔH = 44.0 kJ at 298K

When a solid melts, the required energy is similarly called enthalpy, or heat of fusion. For one mole of ice the enthalpy is given as:

ΔH = 6.01 kJ at 273.15K

Equation #1

$$\Delta H = \Delta U + p \times \Delta V$$

Enthalpy can also be expressed as a molar enthalpy, ΔH_m, by dividing the enthalpy or change in enthalpy by the number of moles.

Enthalpy is a state function. This implies that when a system changes from one state to another, the change in enthalpy is independent of the path between two states of a system.

If there is no non-expansion work on the system and the pressure is still constant, then the change in enthalpy will equal the heat consumed or released by the system (q).
Equation #2

$$\Delta H = q$$

This relationship can help to determine whether a reaction is endothermic or exothermic. At constant pressure, an endothermic reaction is when heat is absorbed. This means that the system consumes heat from the surroundings, so q is greater than zero. Therefore according to the second equation, the ΔH will also be greater than zero. On the other hand, an exothermic reaction at constant pressure is when heat is released. This implies that the system gives off heat to the surroundings, so q is less than zero. Furthermore, ΔH will be less than zero.

Effect of Temperature on Enthalpy

When the temperature increases, the amount of molecular interactions also increases. When the number of interactions increase, then the internal energy of the system rises. According to the first equation given, if the internal energy (U) increases then the ΔH increases as temperature rises. We can use the equation for heat capacity and Equation #2 to derive this relationship.

$$C = \frac{q}{\Delta T}$$

At constant pressure, substitute Equation #2:

$$C_p = \frac{\Delta H}{\Delta T}$$

The Enthalpy of Phase Transition

Enthalpy can be represented as the standard enthalpy, ΔH^o. This is the enthalpy of a substance at standard state. The standard state is defined as the pure substance held constant at 1 bar of pressure.

Phase transitions, such as ice to liquid water, require or absorb a particular amount of standard enthalpy:

- *Standard Enthalpy of Vaporization* - $\Delta_{vap} H^o$ is the energy that must be supplied as heat at constant pressure per mole of molecules vaporized (liquid to gas).
- *Standard Enthalpy of Fusion* - $\Delta_{fus} H^o$ is the energy that must be supplied as heat at constant pressure per mole of molecules melted (solid to liquid).
- *Standard Enthalpy of Sublimation* - $\Delta_{sub} H^o$ is the energy that must be supplied as heat at constant pressure per mole of molecules converted to vapor from a solid.

$$\Delta_{sub} H^o = \Delta_{fus} H^o + \Delta_{vap} H^o$$

The enthalpy of condensation is the reverse of the enthalpy of vaporization and the enthalpy of freezing is the reverse of the enthalpy of fusion. The enthalpy change of a reverse phase transition is the negative of the enthalpy change of the forward phase transition. Also the enthalpy change of a complete process is the sum of the enthalpy changes for each of the phase transitions incorporated in the process.

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References

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Problems

1. Calculate the enthalpy (ΔH) for the process in which 45.0g of water is converted from liquid at 10?C to vapor at 25?C.

Solution

Part 1: Heating water from 10.0 to 25.0 ?C

$\Delta kJ = 45.0g\ H_20 \times (4.184J/gH_20?C) \times (25.0 - 10.0)?C \times 1kJ/1000J = 2.82\ kJ$

Part 2: Vaporizing water at 25.0?C

$\Delta kJ = 45.0\ g\ H_2O \times 1\ mol\ H_2O/18.02\ g\ H_2O \times 44.0\ kJ/1\ mol\ H_2O = 110\ kJ$

Part 3: Total Enthalpy Change

$\Delta H = 2.82\ kJ + 110kJ$

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ANNEX 5 HEAT OF COMBUSTION

Heat of combustion

From Wikipedia, the free Encyclopedia (1)

The **heat of combustion** (ΔH_c^0) is the energy released as heat when a compound undergoes complete combustion with oxygen under standard conditions. The chemical reaction is typically a hydrocarbon reacting with oxygen to form carbon dioxide, water and heat. It may be expressed with the quantities:

- energy/mole of fuel (kJ/mol)
- energy/mass of fuel
- energy/volume of fuel

The heat of combustion is conventionally measured with a bomb calorimeter. It may also be calculated as the difference between the heat of formation ($\Delta_f H^0$) of the products and reactants.

Heating value

The **heating value** or **energy value** of a substance, usually a fuel or food (see food energy), is the amount of heat released during the combustion of a specified amount of it. The energy value is a characteristic for each substance. It is measured in units of energy per unit of the substance, usually mass, such as: kJ/kg, kJ/mol, kcal/kg, Btu/lb. Heating value is commonly determined by use of a bomb calorimeter.

The heat of combustion for fuels is expressed as the HHV, LHV, or GHV.

Higher heating value

The quantity known as higher heating value (**HHV**) (or *gross energy* or *upper heating value* or *gross calorific value* (**GCV**) or *higher calorific value* (**HCV**)) is determined by bringing all the products of combustion back to the original pre-combustion temperature, and in particular condensing any vapor produced. Such measurements often use a temp. of 25°C. This is the same as the thermodynamic heat of combustion since the enthalpy change for the reaction assumes a common temperature of the compounds before and after combustion, in which case the water produced by combustion is liquid.

The higher heating value takes into account the latent heat of vaporization of water in the combustion products, and is useful in calculating heating values for fuels where condensation of the reaction products is practical (e.g., in a gas-fired boiler used for space heat). In other words, HHV assumes all the water component is in liquid state at the end of combustion (in product of combustion).

Lower heating value

The quantity known as lower heating value (**LHV**) (*net calorific value* (**NCV**) or *lower calorific value* (**LCV**)) is determined by subtracting the heat of vaporization of the water vapor from the higher heating value. This treats any H_2O formed as a vapor. The energy required to vaporize the water therefore is not realized as heat.

LHV calculations assume that the water component of a combustion process is in vapor state at the end of combustion, as opposed to the higher heating value (HHV) (a.k.a. *gross calorific value* or*gross CV*) which assumes that all of the water in a combustion process is in a liquid state after a combustion process.

The LHV assumes that the latent heat of vaporization of water in the fuel and the reaction products is not recovered. It is useful in comparing fuels where condensation of the combustion products is impractical, or heat at a temperature below 150°C cannot be put to use.

The above is but one definition of lower heating value adopted by the American Petroleum Institute (API) and uses a reference temperature of 60°F (15.56°C).

Another definition, used by Gas Processors Suppliers Association (GPSA) and originally used by API (data collected for API research project 44), is the enthalpy of all combustion products minus the enthalpy of the fuel at the reference temperature (API research project 44 used 25°C. GPSA currently uses 60°F), minus the enthalpy of the stoichiometric oxygen (O_2) at the reference temperature, minus the heat of vaporization of the vapor content of the combustion products.

The distinction between the two is that this second definition assumes that the combustion products are all returned to the reference temperature and the heat content from the condensing vapor is considered not to be useful. This is more easily calculated from the higher heating value than when using the preceding definition and will in fact give a slightly different answer.

Gross heating value

- **Gross heating value** (see **AR**) accounts for water in the exhaust leaving as vapor, and includes liquid water in the fuel prior to combustion. This value is important for fuels like wood or coal, which will usually contain some amount of water prior to burning.

Measuring heating values

The higher heating value is experimentally determined in a bomb calorimeter. The combustion of a stoichiometric mixture of fuel and oxidizer (e.g., two moles of hydrogen and one mole of oxygen) in a steel container at 25° is initiated by an ignition device and the reactions allowed to complete. When hydrogen and oxygen react during combustion, water vapor is produced. The vessel and its contents are then cooled to the original 25°C and the higher heating value is determined as the heat released between identical initial and final temperatures.

When the lower heating value (LHV) is determined, cooling is stopped at 150°C and the reaction heat is only partially recovered. The limit of 150°C is an arbitrary choice.

Note: Higher heating value (HHV) is calculated with the **product of water being in liquid form** while lower heating value (LHV) is calculated with the **product of water being in vapor form**.

Relation between heating values

The difference between the two heating values depends on the chemical composition of the fuel. In the case of pure carbon or carbon monoxide, the two heating values are almost identical, the difference being the sensible heat content of carbon dioxide between 150°C and 25°C (sensible heat exchange causes a change of temperature. In contrast, latent heat is added or subtracted forphase changes at constant temperature. Examples: heat of vaporization or heat of fusion). For hydrogen the difference is much more significant as it includes the sensible heat of water vapor between 150°C and 100°C, the latent heat of condensation at 100°C, and the sensible heat of the condensed water between 100°C and 25°C. All in all, the higher heating value of hydrogen is 18.2% above its lower heating value (142 MJ/kg vs. 120 MJ/kg). For hydrocarbons the difference depends on the hydrogen content of the fuel. For gasoline and diesel the higher heating value exceeds the lower heating value by about 10% and 7% respectively, and for natural gas about 11%.

A common method of relating HHV to LHV is:

$$\mathrm{HHV} = \mathrm{LHV} + h_v \times (n_{\mathrm{H2O,out}}/n_{\mathrm{fuel,in}})$$

where h_v is the heat of vaporization of water, $n_{\mathrm{H2O,out}}$ is the moles of water vaporized and $n_{\mathrm{fuel,in}}$ is the number of moles of fuel combusted.[1]

Most applications that burn fuel produce water vapor, which is unused and thus wastes its heat content. In such applications, the lower heating value is the applicable measure. This is particularly relevant for natural gas, whose high hydrogen content produces much water. The gross energy value is relevant for gas burned in condensing boilers and power plants with flue-gas condensation that condense the water vapor produced by combustion, recovering heat which would otherwise be wasted.

Usage of terms

For historical reasons, the efficiency of power plants and combined heat and power plants in Europe is calculated based on the LHV, while in e.g. the U.S. it is generally based on the HHV. This has the peculiar result that contemporary combined heat and power plants, where flue-gas condensation is implemented, may report efficiencies exceeding 100% in Europe.

Many engine manufacturers rate their engine fuel consumption by the lower heating values. American consumers should be aware that the corresponding fuel-consumption figure based on the higher heating value will be somewhat higher.

The difference between HHV and LHV definitions causes endless confusion when quoters do not bother to state the convention being used.[2] since there is typically a 10% difference between the two methods for a power plant burning natural gas.

Accounting for moisture

Both HHV and LHV can be expressed in terms of AR (all moisture counted), MF and MAF (only water from combustion of hydrogen). AR, MF, and MAF are commonly used for indicating the heating values of coal:

- **AR** (As Received) indicates that the fuel heating value has been measured with all moisture and ash forming minerals present.
- **MF** (Moisture Free) or **Dry** indicates that the fuel heating value has been measured after the fuel has been dried of all inherent moisture but still retaining its ash forming minerals.
- **MAF** (Moisture and Ash Free) or **DAF** (Dry and Ash Free) indicates that the fuel heating value has been measured in the absence of inherent moisture and ash forming minerals.

Heat of combustion tables

Higher (HHV) and Lower (LHV) Heating of some common fuels[3]

Fuel	HHV MJ/kg	HHV BTU/lb	HHV	
Hydrogen	141.80	61,000		
Methane	55.50	23,900		
Ethane	51.90	22,400		
Propane	50.35	21,700		
Butane	49.50	20,900		
Pentane				
Gasoline	47.30	20,400		
Paraffin	46.00	19,900		
Kerosene	46.20	19,862		
Diesel	44.80	19,300		
Coal (Anthracite)	27.00	14,000		
Coal (Lignite)	15.00	8,000		
Wood (MAF)	21.7	9,400		
Peat (damp)	6.00	2,500		
Peat (dry)	15.00	6,500		

Higher heating value of some less common fuels[3]

Fuel	HHV MJ/kg	BTU/lb	kJ/mol
Methanol	22.7	9,800	726.0
Ethanol	29.7	12,800	1,300.0
Propanol	33.6	14,500	2,020.0
Acetylene	49.9	21,500	1,300.0
Benzene	41.8	18,000	3,270.0
Ammonia	22.5	9,690	382.0
Hydrazine	19.4	8,370	622.0
Hexamine	30.0	12,900	4,200.0
Carbon	32.8	14,100	393.5

Heat of Combustion for some common fuels (higher value)

Fuel	kJ/g	kcal/g	BTU/lb
Hydrogen	141.9	33.9	61,000
Gasoline	47.0	11.3	20,000
Diesel	45.0	10.7	19,300
Ethanol	29.7	7.1	12,000
Propane	49.9	11.9	21,000
Butane	49.2	11.8	21,200
Wood	15.0	3.6	6,000
Coal (Lignite)	15.0	4.4	8,000
Coal (Anthracite)	27.0	7.8	14,000
Natural Gas	54.0	13.0	23,000

References
1. **Wikipedia.** [Online] [Cited: 31 03 2012.]

ANNEX 3 STEAM PROPERTIES (US Units)

Tables A.1–A.6 were developed based on data in “Steam Program Function Subroutines Written in Fortran,” *Mechanical Engineering News*, **19**(3), 11–12 (August 1982).

Table A.1. Saturated vapor properties—pressure

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb$_m$)	Internal energy (Btu/lb$_m$)	Enthalpy (Btu/lb$_m$)	Entropy (Btu/lb$_m$°R)	Quality (%)
102	1.0	333.54579	1,044.22	1,105.94	1.98473	100.0
162	5.0	73.52409	1,063.07	1,131.09	1.84342	100.0
193	10.0	38.41991	1,072.20	1,143.29	1.78571	100.0
212	14.7	26.79334	1,077.53	1,150.41	1.75442	100.0
228	20.0	20.08862	1,081.90	1,156.25	1.72980	100.0
240	25.0	16.30338	1,085.13	1,160.55	1.71218	100.0
250	30.0	13.74552	1,087.79	1,164.10	1.69791	100.0
259	35.0	11.89768	1,090.06	1,167.11	1.68594	100.0
267	40.0	10.49823	1,092.02	1,169.73	1.67564	100.0
274	45.0	9.40041	1,093.76	1,172.04	1.66661	100.0
281	50.0	8.51542	1,095.31	1,174.10	1.65857	100.0
293	60.0	7.17489	1,097.98	1,177.64	1.64475	100.0
303	70.0	6.20609	1,100.22	1,180.61	1.63316	100.0
312	80.0	5.47216	1,102.12	1,183.13	1.62318	100.0
320	90.0	4.89626	1,103.78	1,185.32	1.61443	100.0
328	100.0	4.43190	1,105.23	1,187.24	1.60665	100.0
341	120.0	3.72834	1,107.66	1,190.45	1.60242	100.0
353	140.0	3.21974	1,109.61	1,193.02	1.58520	100.0
364	160.0	2.83434	1,111.21	1,195.13	1.57044	100.0
373	180.0	2.53188	1,112.55	1,196.88	1.55753	100.0
382	200.0	2.28796	1,113.66	1,198.34	1.54607	100.0
390	220.0	2.08695	1,114.60	1,199.56	1.53578	100.0
397	240.0	1.91833	1,115.40	1,200.59	1.52645	100.0
404	260.0	1.77480	1,116.07	1,201.46	1.51791	100.0
411	280.0	1.65108	1,116.64	1,202.19	1.51005	100.0
417	300.0	1.54330	1,117.12	1,202.80	1.50277	100.0
423	320.0	1.44854	1,117.53	1,203.31	1.49599	100.0
429	340.0	1.36455	1,117.87	1,203.72	1.48965	100.0
434	360.0	1.28957	1,118.14	1,204.05	1.48369	100.0
440	380.0	1.22221	1,118.37	1,204.31	1.47808	100.0
445	400.0	1.16136	1,118.55	1,204.51	1.47278	100.0
449	420.0	1.10610	1,118.69	1,204.65	1.46775	100.0
454	440.0	1.05569	1,118.78	1,204.74	1.46298	100.0
459	460.0	1.00951	1,118.85	1,204.78	1.45843	100.0
463	480.0	0.96705	1,118.88	1,204.78	1.45408	100.0
467	500.0	0.92787	1,118.89	1,204.74	1.44993	100.0
471	520.0	0.89159	1,118.87	1,204.66	1.44595	100.0
475	540.0	0.85791	1,118.83	1,204.55	1.44213	100.0
479	560.0	0.82655	1,118.76	1,204.42	1.43846	100.0
483	580.0	0.79727	1,118.68	1,204.25	1.43493	100.0
486	600.0	0.76988	1,118.58	1,204.06	1.43153	100.0

Table A.1. (continued)

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb_m)	Internal energy (Btu/lb_m)	Enthalpy (Btu/lb_m)	Entropy ($Btu/lb_m°R$)	Quality (%)
490	620.0	0.74419	1,118.46	1,203.84	1.42824	100.0
493	640.0	0.72006	1,118.32	1,203.60	1.42507	100.0
497	660.0	0.69733	1,118.18	1,203.34	1.42200	100.0
500	680.0	0.67590	1,118.02	1,203.07	1.41903	100.0
503	700.0	0.65564	1,117.84	1,202.77	1.41615	100.0
506	720.0	0.63648	1,117.66	1,202.46	1.41335	100.0
509	740.0	0.61831	1,117.46	1,202.13	1.41064	100.0
512	760.0	0.60106	1,117.26	1,201.79	1.40801	100.0
515	780.0	0.58467	1,117.04	1,201.43	1.40545	100.0
518	800.0	0.56907	1,116.82	1,201.06	1.40296	100.0
521	820.0	0.55421	1,116.59	1,200.68	1.40053	100.0
524	840.0	0.54003	1,116.35	1,200.29	1.39817	100.0
527	860.0	0.52648	1,116.10	1,199.89	1.39587	100.0
529	880.0	0.51353	1,115.85	1,199.47	1.39362	100.0
532	900.0	0.50113	1,115.59	1,199.05	1.39143	100.0
535	920.0	0.48926	1,115.32	1,198.62	1.38929	100.0
537	940.0	0.47787	1,115.05	1,198.18	1.38719	100.0
540	960.0	0.46694	1,114.78	1,197.73	1.38515	100.0
542	980.0	0.45645	1,114.50	1,197.27	1.38315	100.0
545	1,000.0	0.44635	1,114.21	1,196.81	1.38119	100.0

Table A.2. Saturated vapor properties—temperature

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb_m)	Internal energy (Btu/lb_m)	Enthalpy (Btu/lb_m)	Entropy ($Btu/lb_m°R$)	Quality (%)
100	0.9	350.34470	1,043.66	1,105.20	1.98949	100.0
120	1.7	203.26536	1,050.01	1,113.67	1.93738	100.0
140	2.9	123.00672	1,056.26	1,122.01	1.89043	100.0
160	4.7	77.29142	1,062.39	1,130.19	1.84794	100.0
180	7.5	50.22845	1,068.35	1,138.16	1.80933	100.0
200	11.5	33.64085	1,074.14	1,145.89	1.77411	100.0
212	14.7	26.80026	1,077.52	1,150.40	1.75444	100.0
220	17.2	23.14935	1,079.74	1,153.36	1.74188	100.0
240	25.0	16.32189	1,085.11	1,160.53	1.71227	100.0
260	35.4	11.76240	1,090.24	1,167.35	1.68500	100.0
280	49.2	8.64488	1,095.08	1,173.79	1.65980	100.0
300	67.0	6.46697	1,099.58	1,179.77	1.63644	100.0
320	89.6	4.91524	1,103.72	1,185.25	1.61473	100.0
340	118.0	3.78954	1,107.43	1,190.15	1.60433	100.0
360	153.0	2.95925	1,110.68	1,194.44	1.57540	100.0
380	195.6	2.33743	1,113.42	1,198.04	1.54847	100.0
400	247.1	1.86514	1,115.64	1,200.92	1.52334	100.0
420	308.5	1.50170	1,117.29	1,203.03	1.49982	100.0
440	381.2	1.21864	1,118.37	1,204.33	1.47776	100.0
460	466.4	0.99568	1,118.85	1,204.79	1.45701	100.0
480	565.7	0.81821	1,118.72	1,204.37	1.43745	100.0
500	680.4	0.67558	1,118.00	1,203.06	1.41897	100.0
520	812.3	0.55991	1,116.67	1,200.83	1.40146	100.0
540	963.0	0.46531	1,114.75	1,197.66	1.38485	100.0
560	1,134.3	0.38734	1,112.24	1,193.54	1.36905	100.0
580	1,328.3	0.32262	1,109.14	1,188.44	1.35399	100.0
600	1,547.0	0.26856	1,105.48	1,182.36	1.33960	100.0
620	1,792.7	0.22316	1,101.25	1,175.28	1.32584	100.0
640	2,067.8	0.18485	1,096.45	1,167.18	1.27863	100.0
660	2,374.9	0.15241	1,091.07	1,158.05	1.24458	100.0
680	2,716.9	0.12487	1,085.09	1,147.87	1.21237	100.0
700	3,096.8	0.10147	1,078.47	1,136.62	1.18183	100.0

Table A.3. Saturated liquid properties—pressure

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb_m)	Internal energy (Btu/lb_m)	Enthalpy (Btu/lb_m)	Entropy ($Btu/lb_m°R$)	Quality (%)
102	1.0	0.01613	69.71	69.71	0.13261	0.0
162	5.0	0.01640	130.10	130.12	0.23468	0.0
193	10.0	0.01659	161.14	161.17	0.28341	0.0
212	14.7	0.01671	180.05	180.09	0.31198	0.0
228	20.0	0.01683	196.11	196.18	0.33565	0.0
240	25.0	0.01692	208.35	208.43	0.35330	0.0
250	30.0	0.01700	218.74	218.83	0.36805	0.0
259	35.0	0.01708	227.81	227.92	0.38077	0.0
267	40.0	0.01715	235.90	236.03	0.39196	0.0
274	45.0	0.01721	243.23	243.37	0.40199	0.0
281	50.0	0.01727	249.93	250.09	0.41107	0.0
293	60.0	0.01738	261.89	262.08	0.42708	0.0
303	70.0	0.01748	272.37	272.60	0.44091	0.0
312	80.0	0.01757	281.74	282.00	0.45312	0.0
320	90.0	0.01766	290.25	290.54	0.46407	0.0
328	100.0	0.01774	298.06	298.38	0.47401	0.0
341	120.0	0.01789	312.03	312.43	0.49158	0.0
353	140.0	0.01803	324.33	324.80	0.50680	0.0
364	160.0	0.01815	335.37	335.91	0.52027	0.0
373	180.0	0.01827	345.42	346.03	0.53239	0.0
382	200.0	0.01838	354.67	355.35	0.54343	0.0
390	220.0	0.01849	363.27	364.02	0.55358	0.0
397	240.0	0.01860	371.30	372.13	0.56299	0.0
404	260.0	0.01870	378.87	379.77	0.57177	0.0
411	280.0	0.01879	386.02	386.99	0.58001	0.0
417	300.0	0.01889	392.81	393.86	0.58778	0.0
423	320.0	0.01898	399.29	400.41	0.59514	0.0
429	340.0	0.01907	405.48	406.68	0.60213	0.0
434	360.0	0.01916	411.42	412.69	0.60880	0.0
440	380.0	0.01924	417.13	418.48	0.61517	0.0
445	400.0	0.01933	422.63	424.06	0.62128	0.0
449	420.0	0.01941	427.94	429.45	0.62714	0.0
454	440.0	0.01949	433.08	434.67	0.63279	0.0
459	460.0	0.01958	438.07	439.73	0.63823	0.0
463	480.0	0.01966	442.90	444.65	0.64349	0.0
467	500.0	0.01974	447.60	449.42	0.64858	0.0
471	520.0	0.01982	452.17	454.08	0.65351	0.0
475	540.0	0.01989	456.62	458.61	0.65830	0.0
479	560.0	0.01997	460.97	463.04	0.66294	0.0
483	580.0	0.02005	465.21	467.36	0.66746	0.0
486	600.0	0.02013	469.36	471.59	0.67186	0.0

Table A.3. (continued)

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb_m)	Internal energy (Btu/lb_m)	Enthalpy (Btu/lb_m)	Entropy [Btu/lb_m°R]	Quality (%)
490	620.0	0.02020	473.41	475.73	0.67615	0.0
493	640.0	0.02028	477.38	479.78	0.68033	0.0
497	660.0	0.02035	481.27	483.76	0.68441	0.0
500	680.0	0.02043	485.09	487.66	0.68840	0.0
503	700.0	0.02050	488.83	491.49	0.69230	0.0
506	720.0	0.02058	492.51	495.25	0.69612	0.0
509	740.0	0.02065	496.12	498.94	0.69986	0.0
512	760.0	0.02073	499.66	502.58	0.70352	0.0
515	780.0	0.02080	503.16	506.16	0.70711	0.0
518	800.0	0.02087	506.59	509.68	0.71064	0.0
521	820.0	0.02095	509.97	513.15	0.71410	0.0
524	840.0	0.02102	513.31	516.57	0.71750	0.0
527	860.0	0.02109	516.59	519.95	0.72084	0.0
529	880.0	0.02117	519.83	523.28	0.72412	0.0
532	900.0	0.02124	523.03	526.56	0.72736	0.0
535	920.0	0.02131	526.18	529.81	0.73054	0.0
537	940.0	0.02139	529.29	533.01	0.73367	0.0
540	960.0	0.02146	532.37	536.18	0.73676	0.0
542	980.0	0.02153	535.41	539.31	0.73980	0.0
545	1,000.0	0.02161	538.41	542.41	0.74280	0.0

Table A.4. Saturated liquid properties—temperature

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb$_m$)	Internal energy (Btu/lb$_m$)	Enthalpy (Btu/lb$_m$)	Entropy (Btu/lb$_m$°R)	Quality (%)
100	0.9	0.01613	67.97	67.97	0.12951	0.0
120	1.7	0.01620	87.91	87.92	0.16448	0.0
140	2.9	0.01629	107.87	107.88	0.19830	0.0
160	4.7	0.01639	127.86	127.88	0.23107	0.0
180	7.5	0.01650	147.89	147.91	0.26289	0.0
200	11.5	0.01663	167.96	168.00	0.29381	0.0
212	14.7	0.01671	180.03	180.07	0.31196	0.0
220	17.2	0.01677	188.09	188.14	0.32390	0.0
240	25.0	0.01692	208.27	208.35	0.35320	0.0
260	35.4	0.01708	228.54	228.65	0.38178	0.0
280	49.2	0.01726	248.90	249.06	0.40969	0.0
300	67.0	0.01745	269.37	269.59	0.43698	0.0
320	89.6	0.01766	289.98	290.27	0.46371	0.0
340	118.0	0.01788	310.73	311.12	0.48995	0.0
360	153.0	0.01811	331.65	332.17	0.51576	0.0
380	195.6	0.01836	352.78	353.44	0.54117	0.0
400	247.1	0.01863	374.12	374.97	0.56626	0.0
420	308.5	0.01893	395.70	396.78	0.59107	0.0
440	381.2	0.01925	417.56	418.92	0.61565	0.0
460	466.4	0.01960	439.74	441.43	0.64006	0.0
480	565.7	0.02000	462.28	464.37	0.66434	0.0
500	680.4	0.02043	485.24	487.81	0.68856	0.0
520	812.3	0.02092	508.70	511.84	0.71280	0.0
540	963.0	0.02147	532.77	536.59	0.73716	0.0
560	1,134.3	0.02209	557.58	562.22	0.76179	0.0
580	1,328.3	0.02280	583.32	588.93	0.78689	0.0
600	1,547.0	0.02361	610.22	616.98	0.81273	0.0
620	1,792.7	0.02452	638.58	646.72	0.83968	0.0
640	2,067.8	0.02557	668.79	678.57	0.86822	0.0
660	2,374.9	0.02677	701.30	713.06	0.89899	0.0
680	2,716.9	0.02813	736.71	750.85	0.93282	0.0
700	3,096.8	0.02969	775.74	792.75	0.97074	0.0

Table A.5. Superheated steam properties

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb_m)	Internal energy (Btu/lb_m)	Enthalpy (Btu/lb_m)	Entropy ($Btu/lb_m°R$)	Quality (%)
228	20.0	20.08862	1,081.90	1,156.25	1.72980	100.0
250	20.0	20.79400	1,090.31	1,167.27	1.74760	****
275	20.0	21.58306	1,099.65	1,179.53	1.76459	****
300	20.0	22.36341	1,108.85	1,191.62	1.78077	****
325	20.0	23.13727	1,117.97	1,203.60	1.79628	****
350	20.0	23.90620	1,127.03	1,215.51	1.81122	****
375	20.0	24.67129	1,136.06	1,227.37	1.82565	****
281	50.0	8.51542	1,095.31	1,174.10	1.65857	100.0
300	50.0	8.77247	1,103.11	1,184.28	1.67209	****
325	50.0	9.10358	1,113.12	1,197.35	1.68903	****
350	50.0	9.42849	1,122.88	1,210.12	1.70504	****
375	50.0	9.74874	1,132.46	1,222.66	1.72030	****
400	50.0	10.06539	1,141.92	1,235.05	1.73493	****
425	50.0	10.37923	1,151.31	1,247.34	1.74902	****
328	100.0	4.43190	1,105.23	1,187.24	1.60665	100.0
350	100.0	4.59216	1,115.12	1,200.09	1.61882	****
375	100.0	4.76689	1,125.85	1,214.06	1.63581	****
400	100.0	4.93702	1,136.21	1,227.57	1.65176	****
425	100.0	5.10365	1,146.31	1,240.75	1.66688	****
450	100.0	5.26758	1,156.22	1,253.70	1.68131	****
475	100.0	5.42936	1,166.01	1,266.48	1.69517	****
358	150.0	3.01465	1,110.45	1,194.13	1.57756	100.0
375	150.0	3.09940	1,118.41	1,204.45	1.58194	****
400	150.0	3.22251	1,129.90	1,219.35	1.59953	****
425	150.0	3.34135	1,140.87	1,233.62	1.61589	****
450	150.0	3.45696	1,151.47	1,247.43	1.63129	****
475	150.0	3.57007	1,161.81	1,260.91	1.64591	****
500	150.0	3.68122	1,171.96	1,274.14	1.65988	****
382	200.0	2.28796	1,113.66	1,198.34	1.54607	100.0
400	200.0	2.36110	1,122.94	1,210.33	1.55943	****
425	200.0	2.45715	1,134.96	1,225.90	1.57729	****
450	200.0	2.54937	1,146.37	1,240.73	1.59382	****
475	200.0	2.63870	1,157.35	1,255.01	1.60931	****
500	200.0	2.72578	1,168.01	1,268.90	1.62397	****
525	200.0	2.81109	1,178.44	1,282.48	1.63795	****
401	250.0	1.84380	1,115.75	1,201.05	1.52209	100.0
425	250.0	1.92394	1,128.54	1,217.54	1.54514	****
450	250.0	2.00285	1,140.90	1,233.56	1.56299	****
475	250.0	2.07839	1,152.62	1,248.77	1.57949	****
500	250.0	2.15139	1,163.86	1,263.39	1.59493	****
525	250.0	2.22241	1,174.76	1,277.58	1.60952	****
550	250.0	2.29185	1,185.40	1,291.43	1.62342	****

Table A. 5. (continued)

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb$_m$)	Internal energy (Btu/lb$_m$)	Enthalpy (Btu/lb$_m$)	Entropy (Btu/lb$_m$°R)	Quality (%)
417	300.0	1.54330	1,117.12	1,202.80	1.50277	100.0
425	300.0	1.56597	1,121.54	1,208.48	1.51676	****
450	300.0	1.63670	1,135.02	1,225.88	1.53616	****
475	300.0	1.70353	1,147.58	1,242.15	1.55381	****
500	300.0	1.76747	1,159.49	1,257.61	1.57013	****
525	300.0	1.82919	1,170.91	1,272.46	1.58541	****
550	300.0	1.88918	1,181.98	1,286.86	1.59985	****
432	350.0	1.32603	1,118.01	1,203.90	1.48662	100.0
450	350.0	1.37346	1,128.69	1,217.65	1.51187	****
475	350.0	1.43454	1,142.23	1,235.14	1.53084	****
500	350.0	1.49233	1,154.87	1,251.53	1.54815	****
525	350.0	1.54763	1,166.88	1,267.12	1.56419	****
550	350.0	1.60102	1,178.42	1,282.11	1.57922	****
575	350.0	1.65291	1,189.60	1,296.65	1.59345	****
445	400.0	1.16136	1,118.55	1,204.51	1.47278	100.0
450	400.0	1.17436	1,121.86	1,208.79	1.48922	****
475	400.0	1.23161	1,136.52	1,227.68	1.50971	****
500	400.0	1.28511	1,150.01	1,245.13	1.52814	****
525	400.0	1.33582	1,162.66	1,261.54	1.54502	****
550	400.0	1.38442	1,174.71	1,277.19	1.56071	****
575	400.0	1.43137	1,186.30	1,292.25	1.57545	****
456	450.0	1.03211	1,118.82	1,204.77	1.46067	100.0
475	450.0	1.07262	1,130.42	1,219.74	1.48984	****
500	450.0	1.12311	1,144.86	1,238.38	1.50953	****
525	450.0	1.17047	1,158.24	1,255.71	1.52735	****
550	450.0	1.21549	1,170.85	1,272.07	1.54376	****
575	450.0	1.25872	1,182.90	1,287.71	1.55907	****
600	450.0	1.30054	1,194.51	1,302.81	1.57349	****
467	500.0	0.92787	1,118.89	1,204.74	1.44993	100.0
475	500.0	0.94428	1,123.90	1,211.27	1.47081	****
500	500.0	0.99269	1,139.41	1,231.26	1.49193	****
525	500.0	1.03760	1,153.60	1,249.60	1.51080	****
550	500.0	1.07991	1,166.83	1,266.75	1.52800	****
575	500.0	1.12027	1,179.37	1,283.02	1.54392	****
600	500.0	1.15910	1,191.38	1,298.62	1.55882	****
477	550.0	0.84195	1,118.80	1,204.49	1.44028	100.0
500	550.0	0.88517	1,133.64	1,223.73	1.47505	****
525	550.0	0.92830	1,148.73	1,243.21	1.49509	****
550	550.0	0.96856	1,162.64	1,261.22	1.51315	****
575	550.0	1.00667	1,175.71	1,278.17	1.52973	****
600	550.0	1.04313	1,188.14	1,294.31	1.54515	****
625	550.0	1.07830	1,200.10	1,309.85	1.55965	****

Table A.5. (continued)

Temperature (°F)	**Pressure (psia)**	**Specific volume (ft^3/lb_m)**	**Internal energy (Btu/lb_m)**	**Enthalpy (Btu/lb_m)**	**Entropy $(Btu/lb_m°R)$**	**Quality (%)**
486	600.0	0.76988	1,118.58	1,204.06	1.43153	100.0
500	600.0	0.79477	1,127.51	1,215.75	1.45865	****
550	600.0	0.87535	1,158.27	1,255.46	1.49901	****
600	600.0	0.94626	1,184.81	1,289.87	1.53229	****
650	600.0	1.01152	1,209.03	1,321.34	1.56131	****
700	600.0	1.07317	1,231.90	1,351.06	1.58752	****
750	600.0	1.13239	1,253.97	1,379.70	1.61170	****
495	650.0	0.70853	1,118.25	1,203.48	1.42352	100.0
500	650.0	0.71746	1,120.99	1,207.29	1.44255	****
550	650.0	0.79607	1,153.70	1,249.45	1.48542	****
600	650.0	0.86407	1,181.36	1,285.30	1.52008	****
650	650.0	0.92599	1,206.30	1,317.68	1.54995	****
700	650.0	0.98411	1,229.65	1,348.03	1.57670	****
750	650.0	1.03967	1,252.07	1,377.12	1.60127	****
503	700.0	0.65564	1,117.84	1,202.77	1.41615	100.0
525	700.0	0.69098	1,132.50	1,222.01	1.45100	****
575	700.0	0.76160	1,163.89	1,262.54	1.49118	****
625	700.0	0.82360	1,190.95	1,297.63	1.52431	****
675	700.0	0.88052	1,215.60	1,329.66	1.55319	****
725	700.0	0.93419	1,238.86	1,359.87	1.57924	****
775	700.0	0.98564	1,261.26	1,388.93	1.60327	****
511	750.0	0.60958	1,117.36	1,201.96	1.40932	100.0
525	750.0	0.63187	1,126.49	1,214.19	1.43684	****
575	750.0	0.70113	1,159.64	1,256.94	1.47923	****
625	750.0	0.76103	1,187.72	1,293.34	1.51360	****
675	750.0	0.81551	1,213.03	1,326.21	1.54324	****
725	750.0	0.86656	1,236.73	1,357.00	1.56979	****
775	750.0	0.91532	1,259.45	1,386.48	1.59417	****
518	800.0	0.56907	1,116.82	1,201.06	1.40296	100.0
525	800.0	0.57955	1,120.14	1,205.93	1.42277	****
575	800.0	0.64792	1,155.21	1,251.13	1.46759	****
625	800.0	0.70612	1,184.40	1,288.93	1.50329	****
675	800.0	0.75853	1,210.40	1,322.69	1.53373	****
725	800.0	0.80733	1,234.57	1,354.08	1.56080	****
775	800.0	0.85375	1,257.62	1,384.01	1.58555	****
525	850.0	0.53318	1,116.22	1,200.09	1.39701	100.0
550	850.0	0.56859	1,133.17	1,222.61	1.43417	****
600	850.0	0.63009	1,166.39	1,265.50	1.47566	****
650	850.0	0.68342	1,194.68	1,302.18	1.50950	****
700	850.0	0.73196	1,220.24	1,335.37	1.53877	****
750	850.0	0.77746	1,244.19	1,366.47	1.56503	****
800	850.0	0.82088	1,267.15	1,396.27	1.58917	****

Table A.6. Subcooled liquid properties

Temperature (°F)	Pressure (psia)	Specific volume (ft^3/lb_m)	Internal energy (Btu/lb_m)	Enthalpy (Btu/lb_m)	Entropy ($Btu/lb_m°R$)	Quality (%)
212	14.7	0.01671	180.05	180.09	0.31198	0.0
200	14.7	0.01663	167.95	168.00	0.29381	****
150	14.7	0.01634	117.83	117.88	0.21481	****
100	14.7	0.01613	67.93	67.97	0.12951	****
50	14.7	0.01598	18.02	18.06	0.03601	****
281	50.0	0.01727	249.93	250.09	0.41107	0.0
200	50.0	0.01663	167.84	168.00	0.29381	****
150	50.0	0.01634	117.72	117.88	0.21481	****
328	100.0	0.01774	298.06	298.38	0.47401	0.0
200	100.0	0.01663	167.69	168.00	0.29381	****
150	100.0	0.01634	117.57	117.88	0.21481	****
358	150.0	0.01809	329.99	330.49	0.51372	0.0
200	150.0	0.01663	167.53	168.00	0.29381	****
150	150.0	0.01634	117.42	117.88	0.21481	****
382	200.0	0.01838	354.67	355.35	0.54343	0.0
200	200.0	0.01663	167.38	168.00	0.29381	****
150	200.0	0.01634	117.27	117.88	0.21481	****
401	250.0	0.01865	375.14	376.00	0.56745	0.0
200	250.0	0.01663	167.23	168.00	0.29381	****
150	250.0	0.01634	117.12	117.88	0.21481	****
417	300.0	0.01889	392.81	393.86	0.58778	0.0
200	300.0	0.01663	167.07	168.00	0.29381	****
150	300.0	0.01634	116.97	117.88	0.21481	****
432	350.0	0.01911	408.48	409.72	0.60550	0.0
200	350.0	0.01663	166.92	168.00	0.29381	****
150	350.0	0.01634	116.82	117.88	0.21481	****
445	400.0	0.01933	422.63	424.06	0.62128	0.0
200	400.0	0.01663	166.77	168.00	0.29381	****
150	400.0	0.01634	116.67	117.88	0.21481	****
456	450.0	0.01954	435.59	437.22	0.63554	0.0
200	450.0	0.01663	166.61	168.00	0.29381	****
150	450.0	0.01634	116.52	117.88	0.21481	****
467	500.0	0.01974	447.60	449.42	0.64858	0.0
200	500.0	0.01663	166.46	168.00	0.29381	****
150	500.0	0.01634	116.36	117.88	0.21481	****
477	550.0	0.01993	458.81	460.84	0.66064	0.0
200	550.0	0.01663	166.30	168.00	0.29381	****
150	550.0	0.01634	116.21	117.88	0.21481	****
486	600.0	0.02013	469.36	471.59	0.67186	0.0
200	600.0	0.01663	166.15	168.00	0.29381	****
150	600.0	0.01634	116.06	117.88	0.21481	****

ANNEX 6 HIGH CALORIFIC VALUES

Higher calorific values for some common fuels - coke, oil, wood, hydrogen and others (1)

The calorific value of a fuel is the quantity of heat produced by its combustion - at constant pressure and under "normal" conditions, the combustion process generates water vapor and certain techniques may be used to recover the quantity of heat contained in this water vapor by condensing it.

The Higher Calorific Value (or Gross Calorific Value - GCV) suppose that the water of combustion is entirely condensed and that the heat contained in the water vapor is recovered.

The Lower Calorific Value (or Net Calorific Value - NCV) suppose that the products of combustion contains the water vapor and that the heat in the water vapor is not recovered.

Fuel	**Higher Calorific Value (Gross Calorific Value - GCV)**	
	kJ/kg	*Btu/lb*
Acetone	29,000	
Alcohol, 96%	30,000	
Anthracite	32,500 - 34,000	14,000 - 14,500
Bituminous coal	17,000 - 23,250	7,300 - 10,000
Butane	49,510	20,900
Carbon	34,080	
Charcoal	29,600	12,800
Coal	15,000 - 27,000	8,000 - 14,000
Coke	28,000 - 31,000	12,000 - 13,500

Fuel	**Higher Calorific Value (Gross Calorific Value - GCV)**	
	kJ/kg	*Btu/lb*
Diesel	44,800	19,300
Ethanol	29,700	12,800
Ether	43,000	
Gasoline	47,300	20,400
Glycerin	19,000	
Hydrogen	141,790	61,000
Lignite	16,300	7,000
Methane	55,530	
Oils, vegetable	39,000 - 48,000	
Peat	13,800 - 20,500	5,500 - 8,800
Petrol	48,000	
Petroleum	43,000	
Propane	50,350	
Semi anthracite	26,700 - 32,500	11,500 - 14,000
Sulfur	9,200	

Fuel	**Higher Calorific Value (Gross Calorific Value - GCV)**	
	kJ/kg	*Btu/lb*
Tar	36,000	
Turpentine	44,000	
Wood (dry)	14,400 - 17,400	6,200 - 7,500
	kJ/m³	*Btu/ft³*
Acetylene	56,000	
Butane C_4H_{10}	133,000	3200
Hydrogen	13,000	
Natural gas	43,000	950 - 1150
Methane CH_4	39,820	
Propane C_3H_8	101,000	2550
Town gas	18,000	
	kJ/l	*Btu/Imp gal*
Gas oil	38,000	164,000
Heavy fuel oil	41,200	177,000
Kerosene	35,000	154,000

- *1 kJ/kg = 1 J/g = 0.4299 Btu/ lb_m = 0.23884 kcal/kg*

- *1 Btu/lb$_m$ = 2.326 kJ/kg = 0.55 kcal/kg*
- *1 kcal/kg = 4.1868 kJ/kg = 1.8 Btu/lb$_m$*
- *1 dm^3 (Liter) = 10^{-3} m^3 = 0.03532 ft^3 = 1.308x10^{-3} yd^3 = 0.220 Imp gal (UK) = 0.2642 Gallons (US)*

REFERENCES

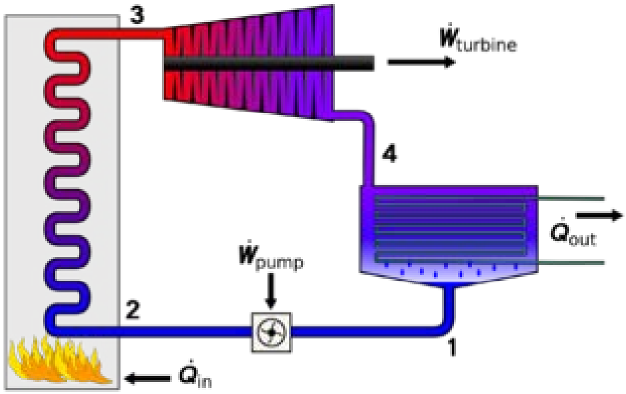
1. **Enginnering Toolbex.** http://www.engineeringtoolbox.com/fuels-higher-calorific-values-d_169.html. [Online] [Cited: 03 31, 2012.]

ANNEX 7 THE RANKINE CYCLE

The Rankine cycle

The **Rankine cycle** (1) is a cycle that converts heat into work. The heat is supplied externally to a closed loop, which usually uses water. This cycle generates about 90% of all electric power used throughout the world,[1] including virtually all solar thermal, biomass, coal and nuclear power plants. It is named after William John Macquorn Rankine, a Scottish polymath and Glasgow University professor. The Rankine cycle is the fundamental thermodynamic underpinning of the steam engine.

Description



Physical layout of the four main devices used in the Rankine cycle

The Rankine cycle most closely describes the process by which steam-operated heat engines most commonly found in power generation plants generate power. The two most common heating processes used in these power plants are nuclear fission and the combustion of fossil fuels such as coal, natural gas, and oil.

The Rankine cycle is sometimes referred to as a practical Carnot cycle because, when an efficient turbine is used, the TS diagram begins to resemble the Carnot cycle. The main difference is that heat addition (in the boiler) and rejection (in the condenser) are isobaric in the Rankine cycle and isothermal in the theoretical Carnot cycle. A pump is used to pressurize the working fluid received from the condenser as a liquid instead of as a gas. All of the energy in pumping the working fluid through the complete cycle is lost, as is most of the energy of vaporization of the working fluid in the boiler. This energy is lost to the cycle because the condensation that can take place in the turbine is limited to about 10% in order to minimize blade erosion; the vaporization energy is rejected from the cycle through the condenser. But pumping the working fluid through the cycle as a liquid requires a very small fraction of the energy needed to transport it as compared to compressing the working fluid as a gas in a compressor (as in the Carnot cycle).

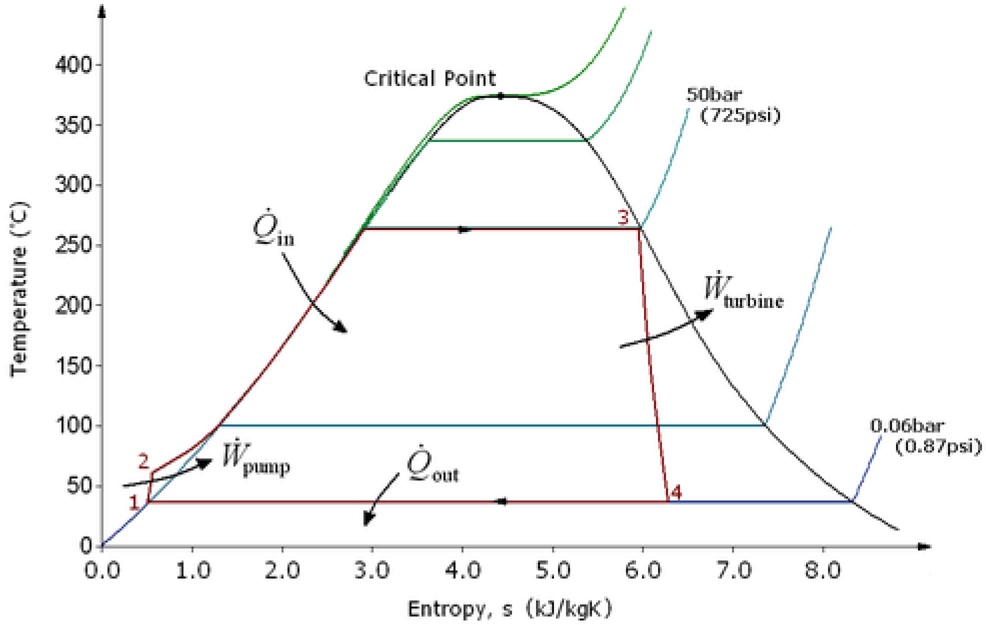
The efficiency of a Rankine cycle is usually limited by the working fluid. Without the pressure reaching super critical levels for the working fluid, the temperature range the cycle can operate over is quite small: turbine entry temperatures are typically 565°C (the creep limit of stainless steel) and condenser temperatures are around 30°C. This gives a theoretical Carnot efficiency of about 63%

compared with an actual efficiency of 42% for a modern coal-fired power station. This low turbine entry temperature (compared with a gas turbine) is why the Rankine cycle is often used as a bottoming cycle in combined-cycle gas turbine power stations.

The working fluid in a Rankine cycle follows a closed loop and is reused constantly. The water vapor with entrained droplets often seen billowing from power stations is generated by the cooling systems (not from the closed-loop Rankine power cycle) and represents the waste heat energy (pumping and condensing) that could not be converted to useful work in the turbine. Note that cooling towers operate using the latent heat of vaporization of the cooling fluid. While many substances could be used in the Rankine cycle, water is usually the fluid of choice due to its favorable properties, such as nontoxic and nonreactive chemistry, abundance, and low cost, as well as its thermodynamic properties.

One of the principal advantages the Rankine cycle holds over others is that during the compression stage relatively little work is required to drive the pump, the working fluid being in its liquid phase at this point. By condensing the fluid, the work required by the pump consumes only 1% to 3% of the turbine power and contributes to a much higher efficiency for a real cycle. The benefit of this is lost somewhat due to the lower heat addition temperature. Gas turbines, for instance, have turbine entry temperatures approaching 1500°C. Nonetheless, the efficiencies of actual large steam cycles and large modern gas turbines are fairly well matched.

The four processes in the Rankine cycle



Ts diagram of a typical Rankine cycle operating between pressures of 0.06bar and 50bar

There are four processes in the Rankine cycle. These states are identified by numbers (in brown) in the above Ts diagram.

Process 1-2: The working fluid is pumped from low to high pressure. As the fluid is a liquid at this stage the pump requires little input energy.

Process 2-3: The high pressure liquid enters a boiler where it is heated at constant pressure by an external heat source to become a dry saturated vapor. The input energy required can be easily calculated using mollier diagram or h-s chart or enthalpy-entropy chart also known as steam tables.

Process 3-4: The dry saturated vapor expands through a turbine, generating power. This decreases the temperature and pressure of the vapor, and some condensation may occur. The output in this process can be easily calculated using the Enthalpy-entropy chart or the steam tables.

Process 4-1: The wet vapor then enters a condenser where it is condensed at a constant temperature to become a saturated liquid.

In an ideal Rankine cycle the pump and turbine would be isentropic, i.e., the pump and turbine would generate no entropy and hence maximize the net work output. Processes 1-2 and 3-4 would be represented by vertical lines on the T-S diagram and more closely resemble that of the Carnot cycle. The Rankine cycle shown here prevents the vapor ending up in the superheat region after the expansion in the turbine, [1] which reduces the energy removed by the condensers.

Variables

$\dot{Q}$	Heat flow rate to or from the system (energy per unit time)
$\dot{m}$	Mass flow rate (mass per unit time)
$\dot{W}$	Mechanical power consumed by or provided to the system (energy per unit time)
η_{therm}	Thermodynamic efficiency of the process (net power output per heat input, dimensionless)
η_{pump},η_{turb}	Isentropic efficiency of the compression (feed pump) and expansion (turbine) processes, dimensionless
h_1,h_2,h_3,h_4	The "specific enthalpies" at indicated points on the T-S diagram
h_{4s}	The final "specific enthalpy" of the fluid if the turbine were isentropic
p_1,p_2	The pressures before and after the compression process

Equations

In general, the efficiency of a simple Rankine cycle can be defined as:

$$\eta_{therm} = \frac{\dot{W}_{turbine} - \dot{W}_{pump}}{\dot{Q}_{in}} \approx \frac{\dot{W}_{turbine}}{\dot{Q}_{in}}$$

Each of the next four equations[1] is easily derived from the energy and mass balance for a control volume. ηtherm defines the thermodynamic efficiency of the cycle as the ratio of net power output to heat input. As the work required by the pump is often around 1% of the turbine work output, it can be simplified.

$$\frac{\dot{Q}_{in}}{\dot{m}} = h_3 - h_2$$

$$\frac{Q_{out}}{\dot{m}} = h_4 - h_1$$

$$\frac{W_{pump}}{\dot{m}} = h_2 - h_1$$

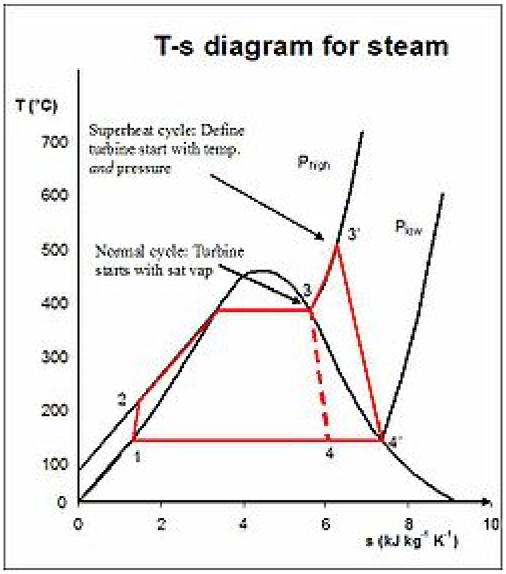
$$\frac{\dot{W}_{turbine}}{\dot{m}} = h_3 - h_4$$

When dealing with the efficiencies of the turbines and pumps, an adjustment to the work terms must be made.

$$\dot{W}_{\mathrm{pump}}/\dot{m} = h_2\text{-}h_1 \approx v_1\Delta \mathrm{p}/\eta_{\mathrm{pump}} \approx v_1(p_2\text{-}p_1)/\eta_{\mathrm{pump}}$$

$$\dot{W}_{\mathrm{turbine}}/\dot{m} = h_3\text{-}h_4 \approx (h_3\text{-}h_4)^*\eta_{\mathrm{turbine}}$$

Real Rankine cycle (non-ideal)

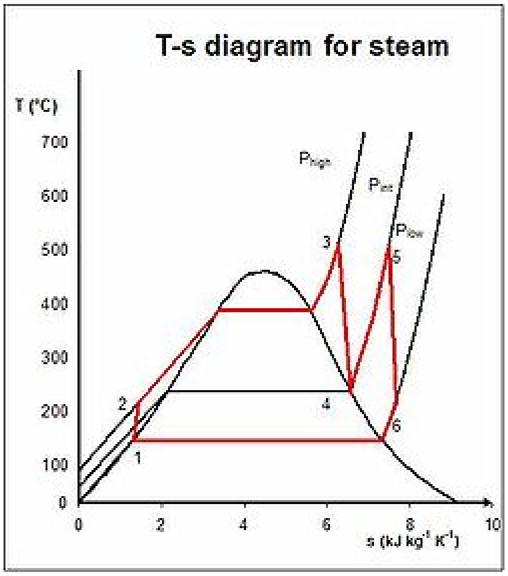


Rankine cycle with superheat

In a real Rankine cycle, the compression by the pump and the expansion in the turbine are not isentropic. In other words, these processes are non-reversible and entropy is increased during the two processes. This somewhat increases the power required by the pump and decreases the power generated by the turbine.

In particular the efficiency of the steam turbine will be limited by water droplet formation. As the water condenses, water droplets hit the turbine blades at high speed causing pitting and erosion, gradually decreasing the life of turbine blades and efficiency of the turbine. The easiest way to overcome this problem is by superheating the steam. On the Ts diagram above, state 3 is above a two phase region of steam and water so after expansion the steam will be very wet. By superheating, state 3 will move to the right of the diagram and hence produce a drier steam after expansion.

Variations of the basic Rankine cycle



Rankine cycle with reheat

The overall thermodynamic efficiency (of almost any cycle) can be increased by raising the average heat input temperature $\left(\bar{T}_{in} = \frac{\int_2^3 T\,ds}{Q_{in}}\right)$ of that cycle. Increasing the temperature of the steam into the superheat region is a simple way of doing this. There are also variations of the basic Rankine cycle which are designed to raise the thermal efficiency of the cycle in this way; two of these are described below.

Rankine cycle with reheat

In this variation, two turbines work in series. The first accepts vapor from the boiler at high pressure. After the vapor has passed through the first turbine, it re-enters the boiler and is reheated before passing through a second, lower pressure turbine. Among other advantages, this prevents the vapor from condensing during its expansion which can seriously damage the turbine blades, and improves the efficiency of the cycle, as more of the heat flow into the cycle occurs at higher temperature.

Regenerative Rankine cycle

The regenerative Rankine cycle is so named because after emerging from the condenser (possibly as a subcooled liquid) the working fluid is heated by steam tapped from the hot portion of the cycle. On the diagram shown, the fluid at 2 is mixed with the fluid at 4 (both at the same pressure) to end up with the saturated liquid at 7. This is called "direct contact heating". The Regenerative Rankine cycle (with minor variants) is commonly used in real power stations.

Another variation is where bleed steam from between turbine stages is sent to feedwater heaters to preheat the water on its way from the condenser to the boiler. These heaters do not mix the input steam and condensate, function as an ordinary tubular heat exchanger, and are named "closed feedwater heaters".

The regenerative features here effectively raise the nominal cycle heat input temperature, by reducing the addition of heat from the boiler/fuel source at the relatively low feedwater temperatures that would exist without regenerative feedwater heating. This improves the efficiency of the cycle, as more of the heat flow into the cycle occurs at higher temperature.

References

1. **Wikipedia.** [Online] [Cited: 18 2 2012.]

ANNEX 8 CLASSIFICATION OF COALS

Classification of Coals

- Classification of coal based on volatile matter and cooking power of clean material (1)
- Coal is a readily combustible rock containing more than 50 percent by weight of carbonaceous material formed from compaction and indurations of variously altered plant remains similar to those in peat.
- After a considerable amount of time, heat, and burial pressure, it is metamorphosed from peat to lignite. Lignite is considered to be "immature" coal at this stage of development because it is still somewhat light in color and it remains soft.
- Lignite increases in maturity by becoming darker and harder and is then classified as sub-bituminous coal. After a continuous process of burial and alteration, chemical and physical changes occur until the coal is classified as bituminous - dark and hard coal.
- Bituminous coal ignites easily and burns long with a relatively long flame. If improperly fired bituminous coal is characterized with excess smoke and soot.
- Anthracite coal is the last classification, the ultimate maturation. Anthracite coal is very hard and shiny.

Class	**Volatile matter**1) ***(weight %)***	**General description**	
101	< 6.1	Anthracites	
102	3.1 - 9.0		
201	9.1 - 13.5	Dry steam coals	Low volatile steam coals
202	13.6 - 15.0		
203	15.1 - 17.0	Cooking steams coals	
204	17.1 - 19.5		
206	19.1 - 19.5	Heat altered low volatile steam coals	
301	19.6 - 32.0	Prime cooking coals	Medium volatile coals
305	19.6 - 32.0	Mainly heat altered coals	

Class	**Volatile matter[1]** *(weight %)*	**General description**	
306	19.6 - 32.0		
401	32.1 - 36.0	Very strongly coking coals	High volatile coals
402	> 36.0		
501	32.1 - 36.0	Strongly coking coals	
502	> 36.0		
601	32.1 - 36.0	Medium coking coals	
602	> 36.0		
701	32.1	Weakly coking coals	
702	> 36.0		
801	32.1 - 36.0	Very weakly coking coals	
802	> 36.0		
901	32.1 - 36.0	Non-coking coals	
902	> 36.0		

1) Volatile matter - dry mineral matter free basis. In coal, those products, exclusive of moisture, given off as gas and vapor determined analytically.

Anthracite coal creates a steady and clean flame and is preferred for domestic heating. Furthermore it burn longer with more heat than the other types.

Typical Sulfur Content in Coal

- Anthracite Coal : *0.6 - 0.77 weight %*
- Bituminous Coal : *0.7 - 4.0 weight %*
- Lignite Coal : *0.4 weight %*

Typical Moisture Content in Coal

- Anthracite Coal : *2.8 - 16.3 weight %*
- Bituminous Coal : *2.2 - 15.9 weight %*
- Lignite Coal : *39 weight %*

Typical Fixed Carbon Content in Coal

- Anthracite Coal : *80.5 - 85.7 weight %*
- Bituminous Coal : *44.9-78.2 weight %*
- Lignite Coal : *31.4 weight %*

Typical Bulk Density of Coal

- Anthracite Coal : *50 - 58 (lb/ft^3), 800 - 929 (kg/m^3)*
- Bituminous Coal : *42 - 57 (lb/ft^3), 673 - 913 (kg/m^3)*
- Lignite Coal : *40 - 54 (lb/ft^3), 641 - 865 (kg/m^3)*

Typical Ash Content in Coal

- Anthracite Coal : *9.7 - 20.2 weight %*
- Bituminous Coal : *3.3-11.7 weight %*
- Lignite Coal : *4.2 weight %*

References

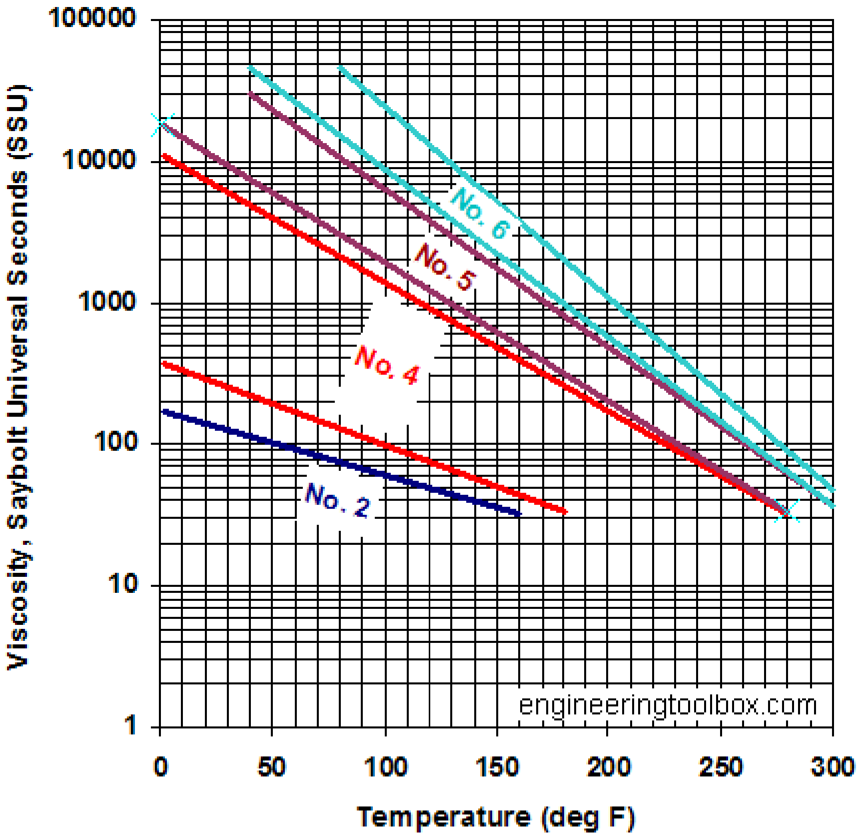
1. **Engineering Toolbox.** http://www.engineeringtoolbox.com/classification-coal-d_164.html. [Online]

ANNEX 9 FUEL OIL VISCOSITIES

Fuel Oils Viscosities

Fuels oils - their viscosity versus temperature (1)

Viscosity - Saybolt Universal Seconds SSU, versus temperature for typical fuel oils are indicated in the diagram below:



- $T_F = T_C\, 9 / 5 + 32$
- *SSU (Saybolt Universal Seconds) = Centistokes (cSt) x 4.55*
- *4 - 5000 SSU* is the maximum practical limit for pumping
- *150 - 300 SSU* is the atomization range fuel oil no. 5 and 6

References
1. **e<ngineering Toolbox.** http://www.engineeringtoolbox.com/viscosity-fuel-oils-d_1143.html. [Online]

ANNEX 10 FUEL OIL STORAGE TANKS

Fuel Oil Storage Tanks (1)

Dimensions of fuel oil storage tanks

Dimensions of cylindrical fuel oil storage tanks according **National Board Standards** are indicated in the table below.

Capacity (gallons)	Diameter (inches)	Length (Feet - Inches)	Shell Thickness (inches)	Head Thickness (inches)	Weight (lb)
550	48	6-0	3/16	3/16	800
1000	48	10-10	3/16	3/16	1300
1100	48	11-11	3/16	3/16	1400
1500	48	15-8	3/16	3/16	1650
	65	9-0	3/16	3/16	1500
2000	65	11-10	3/16	3/16	2050
2500	65	14-10	3/16	3/16	2275
3000	65	17-8	3/16	3/16	2940
4000	65	23-8	3/16	3/16	3600
5000	72	23-8	1/4	1/4	5800
	84	17-8	1/4	1/4	5400
7500	84	26-6	1/4	1/4	7150
	96	19-8	1/4	1/4	6400
10000	96	26-6	1/4	5/16	8540
	120	17-0	1/4	5/16	8100
12000	96	31-6	1/4	5/16	10500
	120	20-8	1/4	5/16	9500
15000	108	31-6	5/16	5/16	13300
	120	25-6	5/16	5/16	12150
20000	120	34-6	5/16	5/16	15500
25000	120	42-6	3/8	3/8	22300

30000	120	51-3	3/8	3/8	28000

Double-jacketed tanks under **European Standards** EN-12285-1 and EN-12285-2

Capacity (litre)	Diameter (mm)	Length (mm)	Weight (kg)
1500	1250	1580	580
2000	1250	2000	700
3000	1250	2720	880
4000	1250	3560	1100
5000	1500	3150	1200
6000	1500	3710	1370
8000	1900	3260	1760
10000	1900	3960	2060
12000	1900	4670	2380
15000	1900	5910	2940
20000	1900	7860	3820
	2500	4680	3610
25000	1900	9810	4720
	2500	5680	4230
30000	1900	11510	5571
	2500	6680	4950
40000	2500	8830	6390
	3000	6280	6200
50000	2500	10820	7600
	3000	7820	7470
60000	2500	12970	9100
	3000	9170	8680
80000	3000	12220	11160
100000	3000	15080	13590
120000	3000	17700	15930

References

1. **Engineering Toolbox.** http://www.engineeringtoolbox.com/fuel-oil-storage-tanks-dimensions-d_1585.html. [Online]

ANNEX 11 CLEAN DEVELOPMENT MECHANISM

Clean Development Mechanism

From Wikipedia, the free encyclopedia

The **Clean Development Mechanism** (CDM) is one of the "flexibility" mechanisms defined in the Kyoto rotocol (IPCC, 2007). It is defined in Article 12 of the Protocol, and is intended to meet two objectives: (1) to assist parties not included in Annex I in achieving sustainable development and in contributing to the ultimate objective of the United Nations ramework Convention on Climate Change (UNFCCC), which is to prevent dangerous climate change; and (2) to assist parties included in Annex I in achieving compliance with their quantified emission limitation and reduction commitments (greenhouse gas (GHG) emission caps). "Annex I" parties are those countries that are listed in Annex I of the treaty, and are the industrialized countries. Non-Annex I parties are developing countries.

Objective (2) is achieved by allowing the Annex I countries to meet part of their caps using "Certified Emission Reductions" from CDM emission reduction projects in developing countries (Carbon Trust, 2009, p. 14).[2] This is subject to oversight to ensure that these emission reductions are real and "additional." The CDM is supervised by the CDM Executive Board (CDM EB) and is under the guidance of the Conference of the Parties (COP/MOP) of the United Nations Framework Convention on Climate Change (UNFCCC).

The CDM allows industrialized countries to invest in emission reductions wherever it is cheapest globally (Grubb, 2003, p. 159). Between 2001, which was the first year CDM projects could be registered and by 2012, the end of the Kyoto commitment period, the CDM is expected to produce some 1.5 billion tons of carbon dioxide equivalent (CO_2e) in emission reductions. Most of these reductions are through renewable energy, energy efficiency, and fuel switching (World Bank, 2010, p. 262). Carbon capture and storage (CCS) was included in the CDM carbon offsetting scheme in December 2011. However, a number of weaknesses of the CDM have been identified (World Bank, 2010, p. 265-267). Several of these issues are addressed by a new modality, the Program of Activities (PoA) that moves away from accrediting single projects but bundles all projects of one type of activity and accredits them together.

History and purpose

The CDM is one of the "flexibility mechanisms" that is defined in the Kyoto Protocol. The flexibility mechanisms are designed to allow Annex B countries to meet their emission reduction commitments with reduced impact on their economies (IPCC, 2007).[1] The flexibility mechanisms were introduced to the Kyoto Protocol by the US government. Developing countries were highly skeptical and fiercely opposed to the flexibility mechanisms (Carbon Trust, 2009, p. 6).[2] However, in the international negotiations over the follow-up to the Kyoto Protocol, it has been agreed that the mechanisms will continue.

The purpose of the CDM is to promote clean development in developing countries, i.e., the "non-Annex I" countries (countries that aren't listed in Annex I of the Framework Convention). The CDM is one of the Protocol's "project-based" mechanisms, in that the CDM is designed to promote projects that reduce emissions. The CDM is based on the idea of emission reduction "production" (Toth *et al*., 2001, p. 660). These reductions are "produced" and then subtracted against a hypothetical "baseline" of emissions. The emissions baseline are the emissions that are predicted to occur in the absence of a particular CDM project. CDM projects are "credited" against this baseline, in the sense that developing countries gain credit for producing these emission cuts.

The economic basis for including developing countries in efforts to reduce emissions is that emission cuts are thought to be less expensive in developing countries than developed countries (Goldemberg *et al*., 1996, p. 30; Grubb, 2003, p. 159).[3] For example, in developing countries, environmental regulation is generally weaker than it is in developed countries (Sathaye *et al*., 2001, p. 387-389).[8] Thus, it is widely thought that there is greater potential for developing countries to reduce their emissions than developed countries.

From the viewpoint of bringing about a global reduction in emissions, emissions from developing countries are projected to increase substantially over this century (Goldemberg *et al*., 1996, p. 29) Infrastructure decisions made in developing countries could therefore have a very large influence on future efforts to limit total global emissions (Fisher *et al*., 2007). The CDM is designed to start off developing countries on a path towards less pollution, with industrialized (Annex B) countries paying for these reductions.

There were two main concerns about the CDM (Carbon Trust, 2009, pp. 14–15). One was over the additionality of emission reductions produced by the CDM (see the section on *additionality*). The other was whether it would allow rich, northern countries, and in particular, companies, to impose projects that were contrary to the development interests of host countries. To alleviate this concern, the CDM requires host countries to confirm that CDM projects contribute to their own sustainable development. International rules also prohibit credits for some kind of activities, notably from nuclear power and avoided deforestation.

To prevent industrialized countries from making unlimited use of CDM, the framework has a provision that use of CDM be ‘supplemental’ to domestic actions to reduce emissions.

ANNEX 12 BIOMASS DENSITIES AND HEATING VALUES

BIOMASS DENSITIES AND HEATING VALUES

WOOD DENSITIES

The density of seasoned & dry wood are indicated in the table below (1):

Solid	**Density**	
	(10^3 kg/m^3)	*(lb/ft^3)*
Alder	0.4 - 0.7	26 - 42
Afrormosia	0.71	
Agba	0.51	
Apple	0.65 - 0.85	41 - 52
Ash, white	0.65 - 0.85	40 - 53
Ash, black	0.54	33
Ash, European	0.71	
Aspen	0.42	26
Balsa	0.16	7 - 9
Bamboo	0.3 - 0.4	19 - 25
Basswood	0.3 - 0.6	20 - 37

Solid	**Density**	
	(10^3 kg/m^3)	*(lb/ft^3)*
Beech	0.7 - 0.9	32 - 56
Birch, British	0.67	42
Birch, European	0.67	
Box	0.95 - 1.2	59 - 72
Butternut	0.38	24
Cedar of Lebanon	0.58	
Cedar, western red	0.38	23
Cherry, European	0.63	43- 56
Chestnut, sweet	0.56	30
Cottonwood	0.41	25
Cypress	0.51	32
Dogwood	0.75	47
Douglas Fir	0.53	33
Ebony	1.1 - 1.3	69 - 83
Elm, American	0.57	35

Solid	Density	
	$(10^3\ kg/m^3)$	(lb/ft^3)
Elm, English	0.55 - 0.6	34 - 37
Elm, Dutch	0.56	
Elm, Wych	0.69	
Elm, Rock	0.82	50
Gaboon	0.43	
Greenheart	1.04	
Gum, Black	0.59	36
Gum, Blue	0.82	50
Gum, Red	0.54	35
Hackberry	0.62	38
Hemlock, western	0.50	
Hickory	0.83	37 - 58
Holly	0.75	47
Iroko	0.66	
Juniper	0.55	35

Solid	**Density**	
	(10^3 kg/m^3)	*(lb/ft^3)*
Keruing	0.74	
Larch	0.5 - 0.55	31 - 35
Lignum Vitae	1.17 - 1.33	73 - 83
Lime, European	0.56	
Locust	0.65 - 0.7	42 - 44
Logwood	0.9	57
Madrone	0.74	45
Magnolia	0.57	35
Mahogany, African	0.5 - 0.85	31 - 53
Mahogany, Cuban	0.66	40
Mahogany, Honduras	0.65	41
Mahogany, Spanish	0.85	53
Maple	0.6 - 0.75	39 - 47
Meranti, dark red	0.71	
Myrtle	0.66	40

Solid	**Density**	
	(10^3 kg/m^3)	*(lb/ft^3)*
Oak	0.6 - 0.9	37 - 56
Oak, American Red	0.74	45
Oak, American White	0.77	47
Oak, English Brown	0.74	45
Obeche	0.39	
Oregon Pine	0.53	33
Parana Pine	0.56	35
Pear	0.6 - 0.7	38 - 45
Pecan	0.77	47
Persimmon	0.9	55
Philippine Red Luan	0.59	36
Pine, pitch	0.67	52 - 53
Pine, Corsican	0.51	
Pine, radiata	0.48	
Pine, Scots	0.51	

Solid	**Density**	
	(10^3 kg/m^3)	*(lb/ft^3)*
Pine, white	0.35 - 0.5	22 - 31
Pine, yellow	0.42	23 - 37
Plane, European	0.64	
Plum	0.65 - 0.8	41 - 49
Poplar	0.35 - 0.5	22 - 31
Ramin	0.67	
Redwood, American	0.45	28
Redwood, European	0.51	32
Rosewood, Bolivian	0.82	50
Rosewood, East Indian	0.90	55
Sapele	0.64	
Satinwood	0.95	59
Spruce	0.4 - 0.7	25 - 44
Spruce, Canadian	0.45	28
Spruce, Norway	0.43	

Solid	**Density**	
	(10^3 kg/m^3)	*(lb/ft^3)*
Spruce, Sitka	0.45	28
Spruce, western white	0.45	
Sycamore	0.4 - 0.6	24 - 37
Tanguile	0.64	39
Teak, Indian	0.65 - 0.9	41 - 55
Teak, African	0.98	61
Teak, Burma	0.74	45
Utile	0.66	
Walnut	0.65 - 0.7	40 - 43
Walnut, Amer Black	0.63	38
Walnut, Claro	0.49	30
Walnut, European	0.57	35
Water gum	1	62
Whitewood, European	0.47	
Willow	0.4 - 0.6	24 - 37

Solid	**Density**	
	(10^3 kg/m^3)	*(lb/ft^3)*
Yew	0.67	
Zebrawood	0.79	48

- *1 kg/m^3 = 0.001 g/cm^3 = 0.0005780 oz/in^3 = 0.16036 oz/gal (Imperial) = 0.1335 oz/gal (U.S.) = 0.0624 lb/ft^3 = 0.000036127 lb/in^3 = 1.6856 lb/yd^3 = 0.010022 lb/gal (Imperial) = 0.008345 lb/gal (U.S) = 0.0007525 ton/yd^3*

Wood and Combustion Heat Values

Firewood and combustion heat values - Pine, Elm, Hickory and many more species

Type of wood - whether it is hardwood or softwood - burned in the combustion process is important for the heat value and the energy efficiency.

Hardwoods have less resin and burn slower and longer. Softwoods burn quickly. In addition the seasoned length influences on the fuel efficiency. Seasoning the wood refers to the allowed drying time before combustion.

Wood need to be dried at least 4 to 6 months before use.

Wood Heating values (2)

Samples	**Variety**	**HHV moisture free**	**HHV moisture free**
		ASTM D-2015	**ASTM D-2015**
		BTU / lb	**MJ / kg**
Hybrid Poplar	DN-34	8384	19,53
Black Locust	Robinia pseudoacacia	8418	19,61
Eucalyptus	Saligna	8384	19,53
American Sycamore	Platanus occidentalis	8414	19,60
Sugarcane Bagasse	Gramineae Saccharum var. 65-7052	8349	19,45
Sugarcane Bagasse	Gramineae Saccharum var. 65-7052	8186	19,07
Sugarcane Bagasse	Gramineae Saccharum var. 65-7052	8174	19,05
Corn Stover	Zea mays	7967	18,56
Corn Stover	Zea mays	7894	18,39
Sericea Lespedeza	Serala	8341	19,43
Switchgrass	Alamo	7998	18,64
Big Bluestem	Genotype, Greene County, AL		0,00

Tall Fescue	John Stone		0,00
Sweet Sorghum	Cultivar M81E		0,00
Forage Sorghum	Sorghum-sudangrass hybrid FRR201		0,00
Sugarcane Bagasse	Saccharum spp.	8149	18,99
Eastern Cottonwood (Populus Deltoides)	Stoneville #66	8431	19,64
Monterey Pine (Pinus Radiata)		8422	19,62
Wheat Straw (Triticum aestivum)	Thunderbird	7481	17,43

The Combustion Process of Burning Wood

1. Wood heats up to approximately *212 ^{o}F (100 ^{o}C)* evaporating the moisture in it. There is no heating from the wood at this point
2. Wood solids starts to break down converting the fuel gases (*near 575 ^{o}F, 300 ^{o}C*)
3. From *575 ^{o}F to 1100 ^{o}F* (*300 - 600 ^{o}C*) the main energy in the wood is released when fuel vapors containing *40% to 60%* of the energy burn
4. After burning fuel vapors and evaporated the moisture, only charcoal remains burning at temperatures higher than 1100^{o} F

- $T_C = 5/9(T_F - 32)$

Common bio fuels and their energy content

Approximately energy content in some common bio fuels are indicated in the table below.
1 MJ/kg = 430 Btu/lbm

Bio Fuel	Energy content (*MJ/kg*)
Charcoal	30
Coal	28
Commercial wastes	16
Domestic refuse	9

Bio Fuel	Energy content (*MJ/kg*)
Dung, dried	16
Grass, fresh	4
Methane from biogas	55
Paper, newspaper	17
Oil	42
Straw, harvested, baled	15
Sugar cane residues	17
Wood, green with 60% moisture	6
Wood, air-dried to 20% moisture	15
Wood, oven-dried to 0% moisture	18

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2. **US department of energy EERE.** http://www.afdc.energy.gov/biomass/progs/search3.cgi?25017. [Online] [Riportato: 14 2 2012.]

ANNEX 13 STANDARD REFERENCE FUELS

Standard Reference Fuels and their Equivalents (1)

Fuels equivalents are indicated in the table below

Multiply with				
To	From			
	1 ton fuel oil equivalent	1 ton oil equivalent (ton oe)	1 tonne coal equivalent (tce)	1 barrel oil equivalent (boe)
10^6 Btu gross	41.4	43	27.337	5.8
10^6 kcal gross	10.433	10.836	6.888	1462
Boe (BOE)	7.138	7.414	4.713	1
ton oe (TOE)	0.9628	1	0.6357	0.1349
tce	1.5144	1.5730	1	0.21217
ft^3 natural gas	41400	43000	27333	5800
Nm^3 natural gas	1109.9	1152.8	732.9	155.5
kWh	12133	12602	8012	1700
GJ	43.68	45.37	28.84	6.12

References

1. **Engineering Toolbox.** http://www.engineeringtoolbox.com/fuels-reference-equivalents-d_1089.html. [Online] [Riportato: 31 03 2012.]

ANNEX - PCDD/PCDF Formation (1)

Formation from Thermal processes

Carbon, oxygen, hydrogen and chlorine, whether in elemental, organic or inorganic form, are needed.
At some point in the synthesis process, whether present in a precursor or generated by a chemical reaction, the carbon must assume an aromatic structure.
There are two main pathways by which these compounds can be synthesized: from precursors such as chlorinated phenols or de novo from carbonaceous structures in fly ash, activated carbon, soot or smaller molecule products of incomplete combustion. Under conditions of poor combustion, PCDD/PCDF can be formed in the burning process itself.
The mechanism associated with this synthesis can be homogeneous (molecules react all in the gas phase or all in the solid phase) or heterogeneous (involving reactions between gas phase molecules and surfaces).
PCDD/PCDF can also be destroyed when incinerated at sufficient temperature with adequate residence time and mixing of combustion gases and waste or fuel feed. Good combustion practices include management of the "3 Ts" – time of residence, temperature and turbulence, and sufficient excess oxygen to allow complete oxidation. Use of a fast temperature quench and other known processes are necessary to prevent reformation.
Variables known to impact the thermal formation of PCDD/PCDF include:

- Technology: PCDD/PCDF formation can occur either in poor combustion or in poorly managed post-combustion chambers and air pollution control devices. Combustion techniques vary from the very simple and very poor, such as open burning, to the very complex and greatly improved, such as incineration using best available techniques;
- Temperature: PCDD/PCDF formation in the post-combustion zone or air pollution control devices has been reported to range between 200° C and 650° C; the range of greatest formation is generally agreed to be 200–450° C, with a maximum of about 300° C;
- Metals: Copper, iron, zinc, aluminium, chromium and manganese are known to catalyse PCDD/PCDF formation, chlorination and dechlorination;
- Sulphur and nitrogen: Sulphur and some nitrogen-containing chemicals inhibit the formation of PCDD/PCDF, but may give rise to other unintended products;
- Chlorine must be present in organic, inorganic or elemental form. Its presence in fly ash or in the elemental form in the gas phase may be especially important;
- PCB are also precursors for the formation of PCDF.

Research has shown that other variables and combinations of conditions are also important.

Industrial-chemical processes

As with thermal processes, carbon, hydrogen, oxygen and chlorine are needed. PCDD/PCDF formation in chemical processes is thought to be favoured by one or more of the following conditions:

- Elevated temperatures (> 150° C);
- Alkaline conditions;
- Metal catalysts;
- Ultraviolet (UV) radiation or other radical starters.

In the manufacture of chlorine-containing chemicals, the propensity for PCDD/PCDF formation has been reported as follows:
Chlorophenols > chlorobenzenes > chlorinated aliphatics > chlorinated inorganics

References

1. **unep.** *Revised draft Guidelines on best available techniques and provisional guidance on best environmental practices relevant to article 5 and Annex C of the Stockholn Convention on POPs.* Geneva 2006.

ANNEX 14 RETURN OF INVESTMENT (ROI)

Rate of return (1)

From Wikipedia, the free encyclopedia http://en.wikipedia.org/wiki/Rate_of_return

In finance, **rate of return** (**ROR**), also known as **return on investment** (**ROI**), **rate of profit** or sometimes just **return**, is the ratio of money gained or lost (whether realized or unrealized) on aninvestment relative to the amount of money invested. The amount of money gained or lost may be referred to as interest, profit/loss, gain/loss, or net income/loss. The money invested may be referred to as the asset, capital, principal, or the cost basis of the investment. ROI is usually expressed as a percentage.

Calculation

The initial value of an investment, V_i, does not always have a clearly defined monetary value, but for purposes of measuring ROI, *the expected value must be clearly stated* along with the rationale for this initial value. Similarly, the final value of an investment, V_f, also does not always have a clearly defined monetary value, but for purposes of measuring ROI, *the final value must be clearly stated* along with the rationale for this final value.[citation needed]

The rate of return can be calculated over a single period, or expressed as an average over multiple periods of time.

Single-period

Arithmetic return

The **arithmetic return** is:

$$r_{arith} = \frac{V_f - V_i}{V_i}$$

r_{arith} is sometimes referred to as the **yield**. See also: effective interest rate, effective annual rate (EAR) or annual percentage yield (APY).

[edit]Logarithmic or continuously compounded return

The **logarithmic return** or **continuously compounded return**, also known as force of interest, is defined as:Logarithmic return

$$r_{log} = \frac{\ln\left(\frac{V_f}{V_i}\right)}{t}$$

or

$$R = Pe^{rt}$$

where: R = Return P = Principal amount r = rate t = time period It is the reciprocal of the e-folding time.

Multiperiod average returns

Arithmetic average rate of return

The **arithmetic average rate of return** over n periods is defined as:

$$\bar{r}_{arithmetic} = \frac{1}{n}\sum_{i=1}^{n} r_{arith,i} = \frac{1}{n}(r_{arith,1} + \cdots + r_{arith,n})$$

[edit]Geometric average rate of return

Main article: True Time-Weighted Rate of Return

The **geometric average rate of return**, also known as the **True Time-Weighted Rate of Return**, over n periods is defined as:

$$\bar{r}_{geometric} = \left(\prod_{i=1}^{n}(1 + r_{arith,i})\right)^{1/n} - 1$$

The geometric average rate of return calculated over n years is also known as the **annualized return**.

Time-weighted rates of return (TWRR) are important because they eliminate the impact of cash flows. This is helpful when assessing the job that a money manager did for his/her clients, where typically the clients control these cash flows.[1]

[edit]Internal rate of return

Main article: Internal rate of return

The **internal rate of return** (IRR), also known as the **dollar-weighted rate of return** or the **money-weighted rate of return** (MWRR), is defined as the value(s) of $\bar{r}$ that satisfies the following equation:

$$\mathrm{NPV} = \sum_{t=0}^{n} \frac{C_t}{(1+\bar{r})^t} = 0$$

where:

- NPV = net present value of the investment
- C_t = cashflow at time t

When the cost of capital r is smaller than the IRR rate $\bar{r}$, the investment is profitable, i.e., $NPV > 0$. Otherwise, the investment is not profitable.

MWRR are helpful in that they take cash flows into consideration. This is especially helpful when evaluating cases where the money manager controls cash flows (for private equity investments, for example, as well as sub-portfolio rates of return) as well as to provide the investor with their return. Contrast with TWRR.

Comparisons between various rates of return

Arithmetic and logarithmic return

The value of an investment is doubled over a year if the annual ROR r_{arith} = +100%, that is, if r_{log} = ln($200 / $100) = ln(2) = 69.3%. The value falls to zero when r_{arith} = -100%, that is, if r_{log}= -∞.

Arithmetic and logarithmic returns are not equal, but are approximately equal for small returns. The difference between them is large only when percent changes are high. For example, an arithmetic return of +50% is equivalent to a logarithmic return of 40.55%, while an arithmetic return of -50% is equivalent to a logarithmic return of -69.31%.

Logarithmic returns are often used by academics in their research. The main advantage is that the continuously compounded return is symmetric, while the arithmetic return is not: positive and negative percent arithmetic returns are not equal. This means that an investment of $100 that yields an arithmetic return of 50% followed by an arithmetic return of -50% will result in $75, while an investment of $100 that yields a logarithmic return of 50% followed by a logarithmic return of -50% it will remain $100.

Comparison of arithmetic and logarithmic returns for initial investment of $100

Initial investment, V_i	$100	$100	$100	$100	$100
Final investment, V_f	$0	$50	$100	$150	$200
Profit/loss, $V_f - V_i$	−$100	−$50	$0	$50	$100
Arithmetic return, r_{arith}	−100%	−50%	0%	50%	100%
Logarithmic return, r_{log}	−∞	−69.31%	0%	40.55%	69.31%

Arithmetic average and geometric average rates of return

Both arithmetic and geometric average rates of returns are averages of periodic percentage returns. Neither will accurately translate to the actual dollar amounts gained or lost if percent gains are averaged with percent losses.[2] A 10% loss on a $100 investment is a $10 loss, and a 10% gain on a $100 investment is a $10 gain. When percentage returns on investments are calculated, they are calculated for a period of time – not based on original investment dollars, but based on the dollars in the investment at the beginning and end of the period. So if an investment of $100 loses 10% in the first period, the investment amount is then $90. If the investment then gains 10% in the next period, the investment amount is $99.

A 10% gain followed by a 10% loss is a 1% loss. The order in which the loss and gain occurs does not affect the result. A 50% gain and a 50% loss is a 25% loss. An 80% gain plus an 80% loss is a 64% loss. To recover from a 50%

loss, a 100% gain is required. The mathematics of this are beyond the scope of this article, but since investment returns are often published as "average returns", it is important to note that average returns do not always translate into dollar returns.

Example #1 Level Rates of Return

	Year 1	Year 2	Year 3	Year 4
Rate of Return	5%	5%	5%	5%
Geometric Average at End of Year	5%	5%	5%	5%
Capital at End of Year	$105.00	$110.25	$115.76	$121.55
Dollar Profit/(Loss)	$5.00	$10.25	$15.76	$21.55
Compound Yield	5%			5.4%

Example #2 Volatile Rates of Return, including losses

	Year 1	Year 2	Year 3	Year 4
Rate of Return	50%	-20%	30%	-40%
Geometric Average at End of Year	50%	9.5%	16%	-1.6%
Capital at End of Year	$150.00	$120.00	$156.00	$93.60
Dollar Profit/(Loss)				($6.40)
Compound Yield				-1.6%

Example #3 Highly Volatile Rates of Return, including losses

	Year 1	Year 2	Year 3	Year 4
Rate of Return	-95%	0%	0%	115%
Geometric Average at End of Year	-95%	-77.6%	-63.2%	-42.7%
Capital at End of Year	$5.00	$5.00	$5.00	$10.75
Dollar Profit/(Loss)				($89.25)
Compound Yield				-22.3%

Annual returns and annualized returns

Care must be taken not to confuse annual and annualized returns. An annual rate of return is a single-period return, while an annualized rate of return is a multi-period, arithmetic average return.

An annual rate of return is the return on an investment over a one-year period, such as January 1 through December 31, or June 3, 2006 through June 2, 2007. Each ROI in the cash flow example above is an annual rate of return.

An annualized rate of return is the return on an investment over a period other than one year (such as a month, or two years) multiplied or divided to give a comparable one-year return. For instance, a one-month ROI of 1% could be stated as an annualized rate of return of 12%. Or a two-year ROI of 10% could be stated as an annualized rate of return of 4.88% (((1+0.1)^(12/24))-1).

In the cash flow example below, the dollar returns for the four years add up to $265. The annualized rate of return for the four years is: $265 ÷ ($1,000 x 4 years) = 6.625%.

Uses

- ROI is a measure of cash[citation needed] generated by or lost due to the investment. It measures the cash flow or income stream from the investment to the investor, relative to the amount invested. Cash flow to the investor can be in the form of profit, interest, dividends, or capital gain/loss. Capital gain/loss occurs when the market value or resale value of the investment increases or decreases. Cash flow here does not include the return of invested capital.

Cash Flow Example on $1,000 Investment

	Year 1	**Year 2**	**Year 3**	**Year 4**
Dollar Return	$100	$55	$60	$50
ROI	10%	5.5%	6%	5%

- ROI values typically used for **personal financial decisions** include Annual Rate of Return and Annualized Rate of Return. For nominal risk investments such as savings accounts or Certificates of Deposit, the personal investor considers the effects of reinvesting/compounding on increasing savings balances over time. For investments in which capital is at risk, such as stock shares, mutual fund shares and home purchases, the personal investor considers the effects of price volatility and capital gain/loss on returns.

- Profitability ratios typically used by financial analysts to **compare a company's profitability over time or compare profitability between companies** include Gross Profit Margin, Operating Profit Margin, ROI ratio, Dividend yield, Net profit margin, Return on equity, and Return on assets.[3]

- During capital budgeting, companies compare the rates of return of different projects to select which projects to pursue in order to generate maximum return or wealth for the company's stockholders. Companies do so by considering the average rate of return, payback period, net present value, profitability index, and internal rate of return for various projects.[4]

- A return may be adjusted for taxes to give the after-tax rate of return. This is done in geographical areas or historical times in which taxes consumed or consume a significant portion of profits or income. The after-tax rate of return is calculated by multiplying the rate of return by the tax rate, then subtracting that percentage from the rate of return.
- A return of 5% taxed at 15% gives an after-tax return of 4.25%

0.05 x 0.15 = 0.0075

0.05 - 0.0075 = 0.0425 = 4.25%

- A return of 10% taxed at 25% gives an after-tax return of 7.5%

0.10 x 0.25 = 0.025

0.10 - 0.025 = 0.075 = 7.5%

Investors usually seek a higher rate of return on taxable investment returns than on non-taxable investment returns.

- A return may be adjusted for inflation to better indicate its true value in purchasing power. Any investment with a nominal rate of return less than the annual inflation rate represents a loss of value, even though the nominal rate of return might well be greater than 0%. When ROI is adjusted for inflation, the resulting return is considered an increase or decrease in purchasing power. If an ROI value is adjusted for inflation, it is stated explicitly, such as "The return, adjusted for inflation, was 2%."

- Many online poker tools include ROI in a player's tracked statistics, assisting users in evaluating an opponent's profitability.

Cash or potential cash returns

Time value of money

Investments generate cash flow to the investor to compensate the investor for the time value of money.

Except for rare periods of significant deflation where the opposite may be true, a dollar in cash is worth less today than it was yesterday, and worth more today than it will be worth tomorrow. The main factors that are used by investors to determine the rate of return at which they are willing to invest money include:

- estimates of future **inflation rates**
- estimates regarding the **risk of the investment** (e.g. how likely it is that investors will receive regular interest/dividend payments and the return of their full capital)
- whether or not the investors want the money available **("liquid")** for other uses.

The time value of money is reflected in the interest rates that banks offer for deposits, and also in the interest rates that banks charge for loans such as home mortgages. The "risk-free" rate is the rate on U.S. Treasury Bills, because this is the highest rate available without risking capital.

The rate of return which an investor expects from an investment is called the Discount Rate. Each investment has a different discount rate, based on the cash flow expected in future from the investment. The higher the risk, the higher the discount rate (rate of return) the investor will demand from the investment.

Compounding or reinvesting

Compound interest or other reinvestment of cash returns (such as interest and dividends) does not affect the discount rate of an investment, but it does affect the Annual Percentage Yield, because compounding/reinvestment increases the capital invested.

For example, if an investor put $1,000 in a 1-year Certificate of Deposit (CD) that paid an annual interest rate of 4%, compounded quarterly, the CD would earn 1% interest per quarter on the account balance. The account balance includes interest previously credited to the account.

Compound Interest Example

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Capital at the beginning of the period	$1,000	$1,010	$1,020.10	$1,030.30
Dollar return for the period	$10	$10.10	$10.20	$10.30
Account Balance at end of the period	$1,010.00	$1,020.10	$1,030.30	$1,040.60
Quarterly ROI	1%	1%	1%	1%

The concept of 'income stream' may express this more clearly. At the beginning of the year, the investor took $1,000 out of his pocket (or checking account) to invest in a CD at the bank. The money was still his, but it was no longer available for buying groceries. The investment provided a cash flow of $10.00, $10.10, $10.20 and $10.30. At the end of the year, the investor got $1,040.60 back from the bank. $1,000 was return of capital.

Once interest is earned by an investor it becomes capital. Compound interest involves reinvestment of capital; the interest earned during each quarter is reinvested. At the end of the first quarter the investor had capital of $1,010.00, which then earned $10.10 during the second quarter. The extra dime was interest on his additional $10 investment. The Annual Percentage Yield or Future value for compound interest is higher than for simple interest because the interest is reinvested as capital and earns interest. The **yield** on the above investment was 4.06%.

Bank accounts offer contractually guaranteed returns, so investors cannot lose their capital. Investors/Depositors lend money to the bank, and the bank is obligated to give investors back their capital plus all earned interest. Because investors are not risking losing their capital on a bad investment, they earn a quite low rate of return. But their capital steadily increases.

Returns when capital is at risk

Capital gains and losses

Many investments carry significant risk that the investor will lose some or all of the invested capital. For example, investments in company stock shares put capital at risk. The value of a stock share depends on what someone is willing to pay for it at a certain point in time. Unlike capital invested in a savings account, the capital value (price) of a stock share constantly changes. If the price is relatively stable, the stock is said to have “low volatility.” If the price often changes a great deal, the stock has “high volatility.” All stock shares have some volatility, and the change in price directly affects ROI for stock investments.

Stock returns are usually calculated for holding periods such as a month, a quarter or a year.

Example: Stock with low volatility and a regular quarterly dividend, reinvested

End of:	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Dividend	$1	$1.01	$1.02	$1.03
Stock Price	$98	$101	$102	$99
Shares Purchased	0.010204	0.01	0.01	0.010404
Total Shares Held	1.010204	1.020204	1.030204	1.040608
Investment Value	$99	$103.04	$105.08	**$103.02**
Quarterly ROI	-1%	4.08%	1.98%	-1.96%

Reinvestment when capital is at risk: rate of return and yield

Yield is the compound rate of return that includes the effect of reinvesting interest or dividends.

To the right is an example of a stock investment of **one share purchased at the beginning of the year for $100**.

- The quarterly dividend is reinvested at the quarter-end stock price.
- The number of shares purchased each quarter = ($ Dividend)/($ Stock Price).
- The final investment value of $103.02 is a **3.02% Yield** on the initial investment of $100. This is the compound yield, and this return can be considered to be the return on the investment of $100.

To calculate the rate of return, the investor includes the reinvested dividends in the total investment. The investor received a total of $4.06 in dividends over the year, all of which were reinvested, so the investment amount increased by $4.06.

- Total Investment = Cost Basis = $100 + $4.06 = $104.06.
- Capital gain/loss = $103.02 - $104.06 = -$1.04 (a capital loss)
- ($4.06 dividends - $1.04 capital loss) / $104.06 total investment = **2.9% ROI**

The disadvantage of this ROI calculation is that it does not take into account the fact that not all the money was invested during the entire year (the dividend reinvestments occurred throughout the year). The advantages are: (1) it uses the cost basis of the investment, (2) it clearly shows which gains are due to dividends and which gains/losses are due to capital gains/losses, and (3) the actual dollar return of $3.02 is compared to the actual dollar investment of $104.06.

For U.S. income tax purposes, if the shares were sold at the end of the year, dividends would be $4.06, cost basis of the investment would be $104.06, sale price would be $103.02, and the capital loss would be $1.04.

Since all returns were reinvested, the ROI might also be calculated as a **continuously compounded return** or **logarithmic return**. The effective continuously compounded rate of return is the natural log of the final investment value divided by the initial investment value:

- V_i is the initial investment ($100)
- V_f is the final value ($103.02)

$$\mathrm{ROI}_{\mathrm{Log}} = \ln\left(\frac{V_f}{V_i}\right) = \ln\left(\frac{103.02}{100}\right) = 2.98\%$$

.

Mutual fund and investment company returns

Mutual funds, exchange-traded funds (ETFs), and other equitized investments (such as unit investment trusts or UITs, insurance separate accounts and related variable products such as variable universal life insurance policies and variable annuity contracts, and bank-sponsored commingled funds, collective benefit funds or common trust funds) are essentially portfolios of various investment securities such as stocks, bonds and money market instruments which are equitized by selling shares or units to investors. Investors and other parties are interested to know how the investment has performed over various periods of time.

Performance is usually quantified by a fund's total return. In the 1990s, many different fund companies were advertising various total returns—some cumulative, some averaged, some with or without deduction of sales loads or commissions, etc. To level the playing field and help investors compare performance returns of one fund to another, the U.S. Securities and Exchange Commission(SEC) began requiring funds to compute and report total returns based upon a standardized formula—so called "SEC Standardized total return" which is the average annual total return assuming reinvestment of dividends and distributions and deduction of sales loads or charges. Funds may compute and advertise returns on other bases (so-called "non-standardized" returns), so long as they also publish no less prominently the "standardized" return data.

Subsequent to this, apparently investors who'd sold their fund shares after a large increase in the share price in the late 1990s and early 2000s were ignorant of how significant the impact of income/capital gain taxes was on their fund "gross" returns. That is, they had little idea how significant the difference could be between "gross" returns (returns before federal taxes) and "net" returns (after-tax returns). In reaction to this apparent investor ignorance, and perhaps for other reasons, the SEC made further rule-making to require mutual funds to publish in their annual prospectus, among other things, total returns before and after the impact of U.S federal individual income taxes. And further, the after-tax returns would include 1) returns on a hypothetical taxable account after deducting taxes on dividends and capital gain distributions received during the illustrated periods and 2) the impacts of the items in #1) as well as assuming the entire investment shares were sold at the end of the period (realizing capital gain/loss on liquidation of the shares). These after-tax returns would apply of course only to taxable accounts and not to tax-deferred or retirement accounts such as IRAs.

Lastly, in more recent years, "personalized" investment returns have been demanded by investors. In other words, investors are saying more or less the fund returns may not be what their actual account returns are based upon the actual investment account transaction history. This is because investments may have been made on various dates and additional purchases and withdrawals may have occurred which vary in amount and date and thus are unique to the particular account. More and more fund and brokerage firms have begun providing personalized account returns on investor's account statements in response to this need.

With that out of the way, here's how basic earnings and gains/losses work on a mutual fund. The fund records income for dividends and interest earned which typically increases the value of the mutual fund shares, while expenses set aside have an offsetting impact to share value. When the fund's investments increase in market value, so too does the value of the fund shares (or units) owned by the investors. When investments increase (decrease) in market value, so too the fund shares value increases (or decreases). When the fund sells investments at a profit, it turns or reclassifies that paper profit or unrealized gain into an actual or realized gain. The sale has no effect on the value of fund shares but it has reclassified a component of its value from one bucket to another on the fund books—which will have future impact to investors. At least annually, a fund usually pays dividends from its net income (income less expenses) and net capital gains realized out to shareholders as an IRS requirement. This way, the fund pays no taxes but rather all the investors in taxable accounts do. Mutual fund share prices are typically valued each day the stock or bond markets are open and typically the value of a share is the net asset value of the fund shares investors own.

Total returns

This section addresses only total returns without the impact of U.S. federal individual income and capital gains taxes.

Mutual funds report **total returns** assuming reinvestment of dividend and capital gain distributions. That is, the dollar amounts distributed are used to purchase additional shares of the funds as of the reinvestment/ex-dividend date. Reinvestment rates or factors are based on total distributions (dividends plus capital gains) during each period.

- $$\text{Year 1 Reinvestment Factor} = \frac{\text{Year 1 Total Distribution}}{\text{Year 1 Share Price}} + 1$$
- $$\text{Year 2 Reinvestment Factor} = \frac{\text{Year 2 Total Distribution} \times \text{Year 1 Reinvestment}}{\text{Year 2 Share Price}}$$
- $$\text{Year 3 Reinvestment Factor} = \frac{\text{Year 3 Total Distribution} \times \text{Year 2 Reinvestment}}{\text{Year 3 Share Price}}$$
- $$\text{Year 4 Reinvestment Factor} = \frac{\text{Year 4 Total Distribution} \times \text{Year 3 Reinvestment}}{\text{Year 4 Share Price}}$$
- $$\text{Year 5 Reinvestment Factor} = \frac{\text{Year 5 Total Distribution} \times \text{Year 4 Reinvestment}}{\text{Year 5 Share Price}}$$
- $$\text{Total Return} = \frac{\text{Final Price} \times \text{Last Reinvestment Factor}}{\text{Beginning Price}} - 1$$

Average annual total return (geometric)

US mutual funds are to compute average annual total return as prescribed by the U.S. Securities and Exchange Commission (SEC) in instructions to form N-1A (the fund prospectus) as the average annual compounded rates of return for 1-year, 5-year and 10-year periods (or inception of the fund if shorter) as the "average annual total return" for each fund. The following formula is used:[5]

$$\mathrm{P}\,(1+\mathrm{T})^{\mathrm{n}} = \mathrm{ERV}$$

Where:

P = a hypothetical initial payment of $1,000.

T = average annual total return.

n = number of years.

ERV = ending redeemable value of a hypothetical $1,000 payment made at the beginning of the 1-, 5-, or 10-year periods at the end of the 1-, 5-, or 10-year periods (or fractional portion).

Solving for T gives

$$\mathrm{T} = \left(\frac{\mathrm{ERV}}{\mathrm{P}}\right)^{1/\mathrm{n}} - 1$$

Example

Example: Balanced mutual fund during boom times with regular annual dividends, reinvested at time of distribution, initial investment $1,000 at end of year 0, share price $14.21

	Year 1	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Dividend per share	$0.26	$0.29	$0.30	$0.50	$0.53
Capital gain distribution per share	$0.06	$0.39	$0.47	$1.86	$1.12
Total Distribution Per Share	$0.32	$0.68	$0.77	$2.36	$1.65
Share Price At End Of Year	$17.50	$19.49	$20.06	$20.62	**$19.90**

Reinvestment factor	1.01829	1.03553	1.03975	1.11900	**1.09278**
Shares owned before distribution	70.373	71.676	74.125	76.859	84.752
Total distribution	$22.52	$48.73	$57.10	$181.73	$141.60
Share price at distribution	$17.28	$19.90	$20.88	$22.98	$21.31
Shares purchased	1.303	2.449	2.734	7.893	6.562
Shares owned after distribution	71.676	74.125	76.859	84.752	**91.314**

- Total return = (($19.90 × 1.09278) / $14.21) - 1 = 53.04%
- Average annual total return (geometric) = ((($19.90 × 91.314) / $1,000) ^ (1 / 5)) - 1 = 12.69%

Using a Holding Period Return calculation, after five years, an investor who reinvested owned 91.314 shares valued at $19.90 per share. ((($19.90 × 91.314) / $1,000) - 1) / 5 = 16.34% return. An investor who did not reinvest received total cash payments of $5.78 per share. ((($19.90 + $5.78) / $14.21) - 1) / 5 = 16.14% return.

Mutual funds include capital gains as well as dividends in their return calculations. Since the market price of a mutual fund share is based on net asset value, a capital gain distribution is offset by an equal decrease in mutual fund share value/price. From the shareholder's perspective, a capital gain distribution is not a net gain in assets, but it is a realized capital gain.

Summary: overall rate of return

Rate of Return and **Return on Investment** indicate cash flow from an investment to the investor over a specified period of time, usually a year.

ROI is a measure of investment profitability, not a measure of investment size. While compound interest and dividend reinvestment can increase the size of the investment (thus potentially yielding a higher dollar return to the investor), **Return on Investment** is a percentage return based on capital invested.

In general, the higher the investment risk, the greater the potential investment return, and the greater the potential investment loss.

References

1. **Wikipedia.** http://en.wikipedia.org/wiki/Rate_of_return. [Online] [Riportato: 24 03 2012.]

ANNEX 15 STACK LOSS TABLES

Table B.1. Natural gas stack loss (%)(1)

Flue gas O_2 content (%)	**Flue gas temperature—combustion air temperature (°F)**														
	230	**250**	**270**	**290**	**310**	**330**	**350**	**370**	**390**	**410**	**430**	**450**	**470**	**490**	**510**
1.00	14.49	14.92	15.36	15.79	16.23	16.67	17.11	17.55	17.99	18.43	18.88	19.32	19.77	20.21	20.66
2.00	14.72	15.17	15.63	16.09	16.55	17.01	17.47	17.93	18.39	18.86	19.32	19.79	20.26	20.73	21.20
3.00	14.98	15.46	15.94	16.42	16.90	17.38	17.87	18.36	18.84	19.33	19.82	20.31	20.80	21.30	21.79
4.00	15.26	15.77	16.28	16.79	17.29	17.81	18.32	18.83	19.35	19.86	20.38	20.90	21.41	21.93	22.46
5.00	15.59	16.12	16.66	17.20	17.74	18.28	18.82	19.36	19.91	20.46	21.00	21.55	22.10	22.65	23.20
6.00	15.96	16.52	17.10	17.67	18.24	18.82	19.39	19.97	20.55	21.13	21.71	22.29	22.88	23.46	24.05
7.00	16.38	16.98	17.59	18.20	18.82	19.43	20.04	20.66	21.28	21.90	22.52	23.14	23.77	24.39	25.02
8.00	16.86	17.51	18.16	18.82	19.48	20.14	20.80	21.46	22.12	22.79	23.46	24.12	24.79	25.47	26.14
9.00	17.42	18.13	18.83	19.54	20.25	20.96	21.68	22.39	23.11	23.83	24.55	25.27	25.99	26.72	27.44
10.00	18.09	18.86	19.62	20.39	21.16	21.94	22.71	23.49	24.27	25.05	25.83	26.62	27.41	28.19	28.98
11.00	18.89	19.73	20.57	21.42	22.26	23.11	23.96	24.81	25.67	26.52	27.38	28.24	29.10	29.97	30.83
12.00	19.87	20.80	21.73	22.66	23.60	24.54	25.48	26.43	27.37	28.32	29.27	30.22	31.18	32.13	33.09

Table B.2. No. 2 Fuel oil stack loss (%)

Flue gas O_2 content (%)	**Flue gas temperature—combustion air temperature (°F)**														
	230	**250**	**270**	**290**	**310**	**330**	**350**	**370**	**390**	**410**	**430**	**450**	**470**	**490**	**510**
1.00	10.33	10.74	11.16	11.58	12.00	12.43	12.85	13.28	13.70	14.13	14.56	14.99	15.42	15.85	16.28
2.00	10.55	10.99	11.43	11.87	12.31	12.75	13.20	13.64	14.09	14.54	14.99	15.44	15.89	16.34	16.79
3.00	10.79	11.25	11.72	12.18	12.65	13.11	13.58	14.05	14.52	14.99	15.46	15.94	16.41	16.89	17.36
4.00	11.07	11.56	12.04	12.53	13.02	13.52	14.01	14.50	15.00	15.50	15.99	16.49	17.00	17.50	18.00
5.00	11.38	11.89	12.41	12.93	13.45	13.97	14.49	15.01	15.54	16.07	16.59	17.12	17.65	18.18	18.72
6.00	11.73	12.28	12.83	13.38	13.93	14.48	15.04	15.59	16.15	16.71	17.27	17.83	18.40	18.96	19.53
7.00	12.13	12.72	13.30	13.89	14.48	15.07	15.66	16.26	16.85	17.45	18.05	18.65	19.25	19.85	20.45
8.00	12.60	13.22	13.85	14.48	15.11	15.75	16.38	17.02	17.66	18.30	18.94	19.58	20.23	20.88	21.52
9.00	13.14	13.81	14.49	15.17	15.85	16.54	17.22	17.91	18.60	19.29	19.98	20.68	21.38	22.07	22.77
10.00	13.77	14.51	15.25	15.99	16.73	17.47	18.22	18.96	19.71	20.46	21.22	21.97	22.73	23.49	24.25
11.00	14.54	15.35	16.15	16.96	17.78	18.59	19.41	20.23	21.05	21.87	22.70	23.52	24.35	25.18	26.02
12.00	15.48	16.37	17.26	18.16	19.06	19.96	20.87	21.77	22.68	23.59	24.51	25.42	26.34	27.26	28.18

Table B.3. No. 6 Fuel oil stack loss (%)

Flue gas O_2 content (%)	Flue gas temperature—combustion air temperature (°F)														
	230	**250**	**270**	**290**	**310**	**330**	**350**	**370**	**390**	**410**	**430**	**450**	**470**	**490**	**510**
1.00	9.81	10.23	10.66	11.08	11.50	11.93	12.36	12.78	13.21	13.64	14.07	14.51	14.94	15.38	15.81
2.00	10.04	10.48	10.92	11.36	11.81	12.26	12.70	13.15	13.60	14.05	14.51	14.96	15.41	15.87	16.33
3.00	10.28	10.75	11.21	11.68	12.15	12.62	13.09	13.56	14.03	14.51	14.99	15.46	15.94	16.42	16.90
4.00	10.56	11.05	11.54	12.03	12.53	13.02	13.52	14.02	14.52	15.02	15.52	16.02	16.53	17.03	17.54
5.00	10.87	11.39	11.91	12.43	12.96	13.48	14.01	14.53	15.06	15.59	16.12	16.66	17.19	17.72	18.26
6.00	11.23	11.78	12.33	12.88	13.44	14.00	14.56	15.12	15.68	16.24	16.81	17.37	17.94	18.51	19.08
7.00	11.63	12.22	12.81	13.40	13.99	14.59	15.18	15.78	16.38	16.98	17.59	18.19	18.79	19.40	20.01
8.00	12.10	12.73	13.36	13.99	14.63	15.27	15.91	16.55	17.19	17.84	18.49	19.13	19.78	20.43	21.09
9.00	12.64	13.32	14.00	14.69	15.38	16.06	16.75	17.45	18.14	18.84	19.54	20.23	20.94	21.64	22.34
10.00	13.28	14.02	14.76	15.51	16.26	17.00	17.75	18.51	19.26	20.02	20.78	21.54	22.30	23.06	23.83
11.00	14.05	14.87	15.68	16.49	17.31	18.13	18.95	19.78	20.61	21.43	22.27	23.10	23.93	24.77	25.61
12.00	15.00	15.89	16.79	17.70	18.60	19.51	20.42	21.33	22.25	23.17	24.09	25.01	25.93	26.86	27.79

Table B.4. Typical bituminous coal stack loss (%)

Flue gas O_2 content (%)	Flue gas temperature—combustion air temperature (°F)														
	230	**250**	**270**	**290**	**310**	**330**	**350**	**370**	**390**	**410**	**430**	**450**	**470**	**490**	**510**
1.00	8.37	8.80	9.23	9.67	10.11	10.55	10.99	11.43	11.87	12.31	12.76	13.21	13.65	14.10	14.55
2.00	8.59	9.05	9.50	9.96	10.42	10.88	11.34	11.80	12.27	12.73	13.20	13.67	14.14	14.61	15.08
3.00	8.85	9.32	9.80	10.28	10.76	11.25	11.73	12.22	12.71	13.20	13.69	14.18	14.67	15.17	15.66
4.00	9.13	9.63	10.14	10.64	11.15	11.66	12.17	12.68	13.20	13.71	14.23	14.75	15.27	15.79	16.31
5.00	9.44	9.98	10.51	11.05	11.59	12.12	12.67	13.21	13.75	14.30	14.84	15.39	15.94	16.49	17.05
6.00	9.80	10.37	10.94	11.51	12.08	12.65	13.22	13.80	14.38	14.96	15.54	16.12	16.70	17.29	17.88
7.00	10.22	10.82	11.42	12.03	12.64	13.25	13.86	14.48	15.10	15.71	16.33	16.95	17.58	18.20	18.83
8.00	10.69	11.34	11.99	12.64	13.29	13.95	14.60	15.26	15.92	16.58	17.25	17.91	18.58	19.25	19.92
9.00	11.24	11.94	12.64	13.34	14.05	14.75	15.46	16.17	16.89	17.60	18.32	19.04	19.75	20.48	21.20
10.00	11.90	12.66	13.42	14.18	14.94	15.71	16.48	17.25	18.03	18.80	19.58	20.36	21.14	21.92	22.71
11.00	12.68	13.51	14.35	15.18	16.02	16.86	17.70	18.55	19.39	20.24	21.10	21.95	22.81	23.66	24.52
12.00	13.64	14.56	15.48	16.41	17.33	18.26	19.19	20.13	21.07	22.01	22.95	23.89	24.84	25.79	26.74

References

1. **Steam Survey Guide - Greg Harrel.** http://www1.eere.energy.gov/manufacturing/tech_deployment/pdfs/steam_survey_guide.pdf. [Online] [Riportato: 03 06 2012.]

2. **Harrell, EERE USA-Steam Survey Guide by Greg.** http://www1.eere.energy.gov/manufacturing/tech_deployment/pdfs/steam_survey_guide.pdf. [Online] 2001. [Riportato: 28 03 2012.]

ANNEX 16 ASSESSMENT OF COGENERATION SYSTEMS

ASSESSMENT OF COGENERATION SYSTEMS

Performance Terms & Definitions (1)

Overall Plant Performance

$$\frac{Ms\ x\ (hs-hw)}{Power\ Output\ (kW)}$$

Where,

Ms = Mass Flow Rate of Steam (kg/hr)
hs = Enthalpy of Steam (kCal/kg)
hw = Enthalpy of Feed Water (kCal/kg)

Overall Plant Fuel Rate (kg/kWh)

$$\frac{Fuel\ Consumption*(kg/hr)}{Power\ Output\ (kW)}$$

Total Fuel for Turbine & Steam

Steam turbine performance

Steam Turbine Efficiency (%):

$$\frac{Actual\ Enthalpy\ Drop\ across\ the\ Turbine\ (kCal/kg)}{Isentropic\ Enthalpy\ drop\ across\ the\ Turbine\ (kCal/kg)}\ x\,100$$

Gas turbine performance

Overall Gas Turbine Efficiency (%) (Turbine & Compressor):

$$\frac{Power\ Output\ (kW)\ x\,860}{Fuel\ Input\quad for\ Gas\ Turbine\ (kg/hr)\ x\ GCV\ of\ \ Fuel\ (kCal/kg)}\ x\,100$$

Heat recovery steam generator (hrsg) performance

Heat Recovery Steam Generator Efficiency (%):

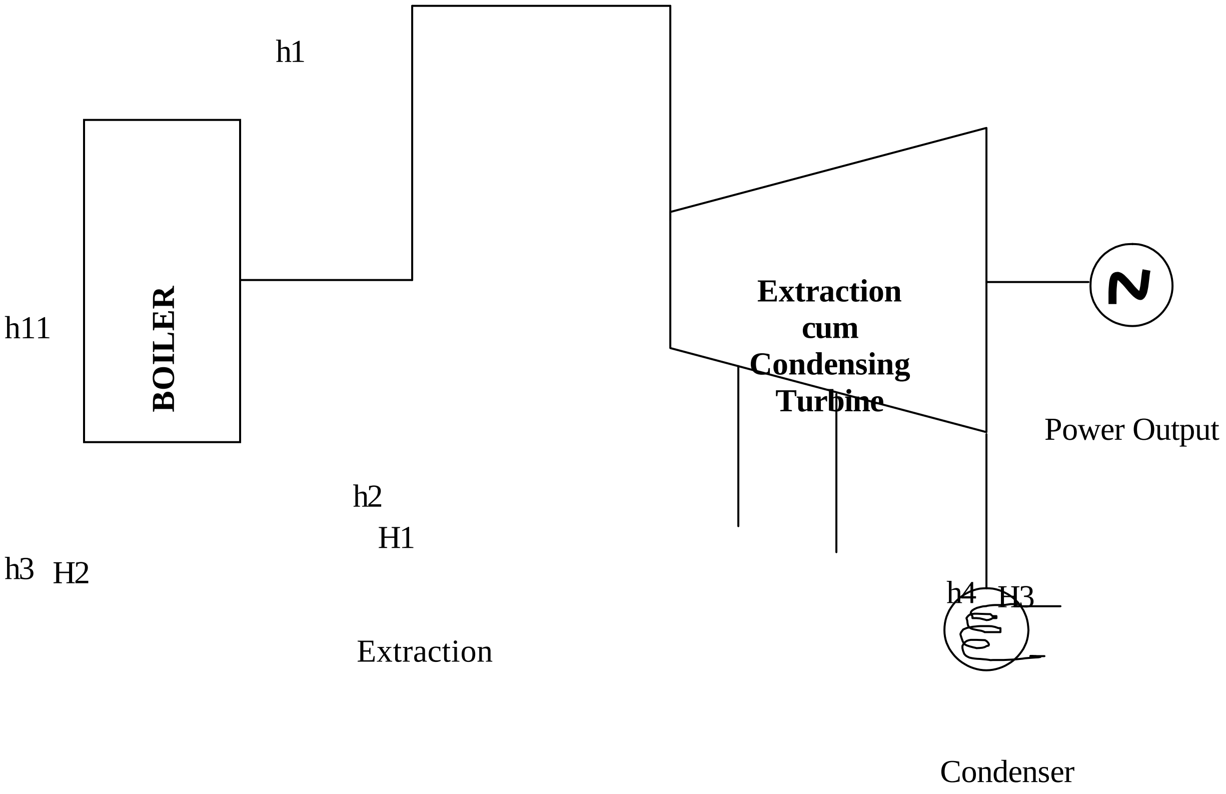
$$\frac{M_s\ \ x\,(h_s\quad h_w)}{[M_f\qquad x\,Cp\ (t_{in}\quad t_{out})]\quad [M_{aux}\ \ x\,GCV\ of\ \ Fuel\,(kCal/kg)]}\ x\,100$$

Where,

M_s = Steam Generated (kg/hr)
h_s = Enthalpy of Steam (kCal/kg)
h_w = Enthalpy of Feed Water (kCal/kg)
M_f = Mass flow of Flue Gas (kg/hr)
t_{in} = Inlet Temperature of Flue Gas (^{0}C)
t_{out} = Outlet Temperature of Flue Gas (^{0}C)
M_{aux} = Auxiliary Fuel Consumption (kg/hr)

Calculations For Steam Turbine Cogeneration System

The figure below illustrates the four steps to calculate the performance of a steam turbine cogeneration system, which is the most common cogeneration system in industry. *Note: while the methodology will apply to all cogeneration systems, the formulas used below only apply to the steam turbine cogeneration system*.



Step 1: Calculate the actual heat extraction in turbine at each stage

Steam Enthalpy at Turbine Inlet : h1, kCal/kg
Steam Enthalpy at stage 1 extraction : h2, kCal/kg Steam
Enthalpy at stage 2 extraction : h3, kCal/kg Steam
Enthalpy Condenser : h4*, kCal/kg

* Due to wetness of steam in the condensing stage, the enthalpy of steam cannot be considered as equivalent to saturated steam. Typical dryness value is 0.88 — 0.92. This dryness value can be used as first approximation to estimate heat drop in the last stage. However it is suggested to calculate the last stage efficiency from the overall turbine efficiency and other stage efficiency.

Heat extraction from inlet to Stage 1 extraction (h5):

h5 = (h1 —h2) kCal/kg

Heat extraction from stage 1 to stage 2 extraction (h6):

h6 = (h2 —h3) kCal/kg

Heat extraction from stage 2 extraction to condenser (h7):

h7 = (h3 —h4) kCal/kg

Step 2: Estimate theoretical heat extraction

From the Mollier diagram (H-f Diagram) estimate the theoretical heat extraction for the conditions mentioned in Step 1. This is done as follows:

- Plot the turbine inlet condition point in the Mollier chart — corresponding to steam pressure and temperature.
- Since expansion in turbine is an adiabatic process, the entropy is constant. Hence draw a vertical line from inlet point (parallel to y-axis) up to the condensing conditions.
- Read the enthalpy at points where the extraction and condensing pressure lines meet the vertical line drawn.
- Compute the theoretical heat drop for different stages of expansion.

Theoretical Enthalpy after 1st Extraction : H1
Theoretical Enthalpy after 2nd Extraction : H2
Theoretical Enthalpy at Condenser Condition : H3

Theoretical Heat Extraction from Inlet to Stage 1 Extraction (h8): h8 = h1 —H1
Theoretical Heat Extraction from Stage 1 to Stage 2 Extraction (h9): h9 = H1 —H2
Theoretical Heat Extraction from Stage 2 Extraction Condensation (h10): h10 = H2 —H3

Step 3: Compute turbine efficiency

Efficiency of stage 1 $\frac{h5}{h8} = \frac{Heat\ Extraction\ Actual}{Heat\ Extraction\ Theoretical} = \frac{h1 \quad h2}{h1 \quad H1}$

Efficiency of stage 2 $\frac{h6}{h9} = \frac{Heat\ Extraction\ Actual}{Heat\ Extraction\ Theoretical} = \frac{h2 \quad h3}{H1 \quad H2}$

Efficiency of condensing stage $\frac{h7}{h10} = \frac{Heat\ Extraction\ Actual}{Heat\ Extraction\ Theoretical} = \frac{h3 \quad h4}{H2 \quad H3}$

Step 4: Calculate the plant heat rate

Heat rate (kcal/kWh) = $\frac{M\ x\ (h1 \quad h11)}{P}$

Where,
M = Mass flow rate of steam (kg/hr)
h_1 = Enthalpy of inlet steam (kCal/kg)
h_{11} = Enthalpy of feed water (kCal/kg)
P = Average power generated (kW)

4. ENERGY EFFICIENCY OPPORTUNITIES

Energy Efficiency Opportunities in Steam Turbine Cogeneration System

Energy efficiency improvements in relation to cogeneration are described in the following modules:

1. **Boilers:** please refer to the module 'Boilers and Thermic Fluid Heaters"

2. **Steam Turbine:**

a. Condenser vacuum:

Condenser vacuum or back-pressure is the most important factor since a small deviation from optimum can produce a significant change in efficiency. There are a number of reasons why the condenser vacuum may vary from the optimum value such as:

- The cooling water inlet temperature is different from the design value - this is the most common reason for variations in condenser vacuum because the temperature of the cooling water is significantly influenced by weather conditions such as temperature and humidity. Hot, humid weather could result in the cooling water temperature increasing, the condenser vacuum degrading and the turbine output reducing (with a consequential reduction in thermal efficiency). On the other hand, cool, dry weather conditions could have the reverse effects:
- The cooling water flow rate is not the correct value;
- The condenser tubes are fouled or some are blocked
- Air leaks into the condenser.

b. Steam temperature and pressure:

If the steam temperature and pressure conditions at the inlet to the steam turbine vary from the design optimum conditions, the turbine may not be able to operate at maximum efficiency.

Variations in steam conditions can be due to errors in plant design (including sizing), incorrect plant operation or fouling within the boiler.

c. Part load operation and starting & stopping:

The efficiencies of the generating unit at part loads can be maintained close to the design values by giving due attention to all the above items. However, market decisions to operate the generating unit at certain loads for certain periods will have the major influence on its average thermal efficiency. Similarly, market decision on when the plant is to come on and off line also has a bearing on average thermal efficiency because of energy losses while starting or stopping the system.

3. **Steam distribution and utilization:** Please refer the Module on 'Steam Distribution and Utilization"

4.2 Energy Efficiency Opportunities in a Gas Turbine Cogeneration System

Energy efficiency improvements can be made in the following sections of Steam Turbine Cogeneration Systems:

1. **Air Compressor:** Please refer to the Module ‘Compressors and Compressed Air System”

2. **Gas Turbine:**

- Gas temperature and pressure: If the gas temperature and pressure conditions at the inlet to the gas turbine vary from the design optimum conditions, the turbine may not be able to operate at maximum efficiency. Variations in gas conditions can be due to errors in plant design (including sizing) or incorrect plant operation.
- Part load operation and starting & stopping: The efficiencies of the generating unit at part loads can be maintained close to the design values by paying due attention to all the above items. However, market decisions to operate the generating unit at certain loads for certain periods will have the major influence on its average thermal efficiency. Similarly, market decision on when the plant is to come on and off line also has a bearing on average thermal efficiency because of energy losses while starting or stopping the system.
- The temperature of the hot gas leaving the combustors. Increased temperature generally results in increased power output;
- The temperature of the exhaust gas. Reduced temperature generally results in increased power output;
- The mass flow through the gas turbine. In general, higher mass flows result in higher power output;
- The drop in pressure across the exhaust gas silencers, ducts and stack. A decrease in pressure loss increases power output;
- Increasing the pressure of the air entering or leaving the compressor. An increase in pressure increases power output.

References

1. **UNEP.** http://www.energyefficiencyasia.org/energyequipment/ee_ts_cogeneration.html. [Online] [Riportato: 21 2 2012.]