



Report on conventional and PHES heat production: technologies, system layouts, RE resources

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**INNOVATIVE MARKET BASED TRUST FOR ENERGY EFFICIENCY INVESTMENTS IN
INDUSTRY**

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Table of Contents

1	Executive summary	3
2	Heat production technologies and costs	5
2.1	Process heat production via boilers	7
2.1.1	<i>Solid fuel combustion systems</i>	7
2.1.2	<i>Liquid and gas fired boilers</i>	15
2.2	Cogeneration systems	19
2.2.1	<i>Steam turbine</i>	20
2.2.2	<i>Gas turbine</i>	22
2.2.3	<i>Internal combustion engine</i>	23
2.3	Solar thermal plant	26
2.3.1	<i>Technology description</i>	26
2.3.2	<i>Technology costs</i>	32
2.4	Solid biomass plant	35
2.4.1	<i>Technology description</i>	35
2.4.2	<i>Performance parameters</i>	39
2.4.3	<i>Installation and operation requirements</i>	42
2.4.4	<i>Technology costs</i>	43
2.5	Biogas plant	46
2.5.1	<i>Technology description</i>	46
2.5.2	<i>Technology costs</i>	52
2.6	Heat exchangers	54
2.6.1	<i>Technology description</i>	54
2.6.2	<i>Technology cost</i>	63
3	Energy sources and costs	66
3.1	Conventional energy sources	66
3.1.1	<i>Natural gas</i>	66
3.1.2	<i>LPG (liquid petroleum gas)</i>	67
3.1.3	<i>Heavy fuel oil</i>	69
3.1.4	<i>Heating gas oil</i>	72
3.1.5	<i>Coal</i>	74
3.2	Renewable energy sources	78
3.2.1	<i>Solar energy</i>	78
3.2.2	<i>Biomass</i>	81
3.2.3	<i>Biowaste</i>	89
4	References	94

1 Executive summary

The report provides a comprehension of conventional heat production in industrial applications including information on heat production technologies, their costs, available conventional energy sources and energy costs (per region if available). Besides conventional heat production technologies also PHES (**P**rocess **H**eat **E**fficiency and **S**ustainability) technologies are characterized in terms of technological concept, installation and operation requirements, performance parameters, system layout and technology costs. The objective of this report is not to compare different heat production systems but rather giving an overview of different systems applied in the European industry.

Combustion boilers are the main heat production system in the European industry. In general, the systems can be divided into solid fuel combustion boilers and liquid and gas fired boilers. For solid fuel combustion systems the two relevant solid fuels used to generate process heat in the European industry: coal and biomass. Coal is mainly used to produce high temperature heat ($>500^{\circ}\text{C}$), while biomass is mainly used for the supply of heat at low temperatures ($100\text{-}200^{\circ}\text{C}$). Systems for solid fuel combustion have several technologies that are commercially available and mature. In industrial applications fixed bed, fluidized bed and suspension or pulverized combustion boilers are used most frequently. The investment costs are mainly related with the fuel supply equipment and facilities (reception, storage, preparation and feeding), the combustion system equipment (boiler and pollutant emissions control) and their facilities, and the heat distribution network. For liquid and gas fired boilers fuel oil and natural gas are the most often used fuels. Liquid and gas fired boilers are mainly divided into water tube and fire tube boilers.

Also the combined production of heat and power in CHP systems is used in several industries like the pulp and paper, chemical, wood and food processing sectors. The main technologies applied in CHP utilize a combustion boiler (burning solid, gas or liquid fuels) that operates with a steam turbine, a gas turbine or both in a combined cycle, where each turbine is connected to an electricity generator and the rejected heat is used for heating processes. CHP systems based on reciprocating internal combustion engines, using liquid and gaseous fuels, and nuclear plants are also used in industrial applications.

Next to the conventional heat production technologies PHES technologies (Solar thermal heat, biomass, biogas and heat exchangers for heat recovery) were analysed.

Solar thermal heat applications are suited by well-established technologies covering the range of process temperatures found in different industrial sectors: low ($T < 100^{\circ}\text{C}$), medium ($100^{\circ}\text{C} < T < 250^{\circ}\text{C}$) or high temperature ($250^{\circ}\text{C} < T < 400^{\circ}\text{C}$). The system, mainly consisting of a solar heat collector, heat exchangers and storage, varies depending on different aspects like the integration point, operating temperatures, heat transfer fluid, etc. Also the system costs can vary depending on the size of the system: 220-630 €/m² for small and medium size systems ($< 1,000\text{ m}^2$) and 220-480 €/m² for large size systems ($> 1,000\text{ m}^2$). The annual available radiant energy depends on the geographical location and meteorological conditions – values range between 2,200 kWh/(m².a) in Spain to 800 kWh/(m², a) in UK.

The anaerobic digestion of organic residues at agro-industrial biogas plants is an already consolidated technology in several European countries and several strategies have been implemented for the constant co-substrates provisioning (energy crops). The system layout is especially depending on the type of substrate. Especially in agriculture and food industry the technology is widespread due to free available waste streams (e.g. waste from fruit and vegetable processing; organic load wastewater). Very different types of by-products from food industry can be used as raw material for biogas production. When using animal by-products EU rules for their movement, processing and disposal have to be observed. The investment costs are depending on the substrate used and on the installed power of the CHP.

The primary energy production of biomass has been consistently increasing since 1990. The largest producer of solid biomass was Germany followed by France, Sweden and Finland. The country with the greatest dependence on solid biofuels imports was the United Kingdom, followed by Italy, Denmark, Belgium and Poland. As the use of solid biomass has grown the structure of the wood energy markets has also changed. At present, there are several established markets for the commercialization of solid biomass for energy purposes being wood logs/firewood, wood chips and refined fuels such as wood pellets and wood briquettes the main solid biofuels traded.

Besides conventional and renewable technologies for process heat production, heat exchangers for heat recovery were considered. By means of a heat exchanger it is possible to reuse the heat energy for heating cold process streams. In process industries, shell and tube heat exchangers (STHE) are used in great numbers, far more than any other type of exchanger. More than 90 % of heat exchangers used in industry are of the shell and tube type. To analyze potential for heat recovery for an industrial process or a total industrial site and to design utilities for energy supply the Pinch Analysis is used as a classical methodology. Further it can be used for the design of the best heat recovery and utility mix based on a fixed utility system (e.g. envisioned solar heat supply). The investment costs of a heat exchanger are in general decreasing with increasing power of the heat exchanger.

2 Heat production technologies and costs

Heat consumption in the industrial sector is relevant for the total energy consumption in EU-28, since it represents around **18 % of the EU energy consumption** and also relies heavily on fossil fuels. Looking at the energy consumed by the industry in 2012, the share of heating in the **final energy demand** of the **European industry** was **71 %** (60 % for process heating and 11 % for space heating) (Fraunhofer et al., 2016).

The thermal systems that are conventionally used by the industrial sector to generate process heat rely on fuel combustion. In some industries, the heat produced by those systems may be also utilized for power generation, in combined heat and power (CHP) systems.

Process heat is delivered in different forms depending on the specificities of the production process. In industry, the most-widely used heat carriers are **steam** and **hot gases** from the combustion process. **Combustion boilers** are, therefore, commonly used in industry as the **main heat production system**. When **power generation** is sought, combustion often provides thermal energy for steam and gas turbine generators, where energy is converted into mechanical energy used to generate electricity. Internal combustion engines coupled to a generator shaft for direct conversion of fuel energy into mechanical energy can also be used. For providing **temperature levels above 1,000 °C** (e.g. in the non-metallic mineral sector) specific combustion systems, such as glass melting furnaces, kilns for cement clinker production and ovens or kilns for ceramic manufacture are used.

Table 1 presents a flow diagram for the possible energy production systems usually applied in industrial facilities. The **design of heat supply systems** in industry is primarily influenced by the **fuel being used** and the **heat transfer fluid** (e.g. hot water, thermal oil, steam, air). The fuels listed in the table require an energy conversion plant on-site to produce thermal energy, with direct electrically heated processes and processes supplied via district heating being the only exceptions. Also renewable energy sources (biomass, biogas and solar energy) and conversion technologies (e.g. solar collector) are listed.

In the following chapters of this deliverable different conventional conversion technologies for process heat (boilers, steam and gas turbines, internal combustion engines, solar thermal plants, biomass and biogas plants as well as heat exchangers) are described in detail. Additionally, a compilation of technology costs is presented.

Table 1: Schematic heat production system layout possibilities usually applied in industrial facilities

Fuel	Energy conversion technology	Heat transfer fluid	Industrial process loads
Solid fuels	Combustion plant	Process heat carrier	
Coal; Lignite; Wood biomass fuels; Wood-derived waste; Other waste	Fixed bed boilers	Hot water	
Gaseous fuels	Gas/Oil firing		
Natural gas Butane Propane Biogas	Fluidized bed boiler	Steam	
Liquid fuels	Steam turbine		Process heat
	Gas turbine		
	Combined cycle	Hot gases	
	Internal combustion Engine		
Light fuel oil Heavy fuel oil	Solar collector	Glycol	
	Non-Concentrating collectors (Stationary collectors)		
	Concentrating collectors (Tracking collectors)		
	Generator	Electricity	Process electricity

2.1 Process heat production via boilers

Combustion boilers are commonly used in industry as the main heat production system. The **combustion boilers** used in industrial heat production plants can differ in **technology, thermal capacity, fuels burnt, load conditions and purpose**. The choice of a specific system is strongly dependent on the energy load requirements and availability of fuels. Important parameters of the different boiler types are their start-up and shutdown times as well as the time needed to adjust the heating power supply to demand variations in different configurations. Boilers for solid fuels require much longer times for starting and shutting down, therefore their reaction time to load changes is much longer. This leads to heat storages often being employed in such systems. Liquid fuel boilers and burners on the other hand can react quickly to load changes and can be controlled easily within a large range of load variations (Hassine et al., 2015).

The **main components** of a boiler are the **burner**, the **combustion chamber** and the **heat exchanger**. Regarding the heat exchange process, there are **two main types of boilers: water-tube and fire-tube boilers**. In water-tube boilers, the water is heated in tubes and the hot combustion gases flow in the space around the tubes. In fire-tube boilers, the hot flue gases flow inside tubes and the water is heated while circulating around these tubes. In steam applications, water-tube boilers are preferable because they have greater capacity to support high pressure conditions (Vatopoulos et al., 2012).

The advantages of **steam as energy carrier** are its **low toxicity, safety** in use with flammable or explosive materials, **ease of distribution, high efficiency, high heat capacity and low cost**. Steam holds a significant amount of energy on a unit mass basis (**2300-2900 kJ/kg**), mainly stored as latent heat, so a large quantities of heat can be transferred efficiently at a constant temperature, which is a useful attribute in many process heating applications. Steam pressure is directly related to temperature, so that, temperature can be adapted easily by modifying the pressure.

Water can be used as heat transfer media where the required temperature **do not exceed 100 °C**, but pressurised water (to avoid boiling) can be used for temperatures above 100 °C. **Thermal oils** have a **higher boiling point**; however, they typically have lower heat capacities and heat transfer coefficients than steam.

In process heating, the steam transfers its latent heat to a process fluid in a heat exchanger. Any condensate (steam that has condensed) is captured and returned to the condensate return system for reuse.

2.1.1 Solid fuel combustion systems

2.1.1.1 Technology description

The only **two relevant solid fuels** used to generate process heat in the **European industry** are **coal** and **biomass**. Coal is mainly used to produce high temperature heat (>500° C), while biomass is mainly used for the supply of heat at low temperatures (100-200° C) (Fraunhofer et al., 2016).

Depending on the scale of implementation, solid fuel systems for heat production are made up of different facilities, components and equipment. Usually, industrial applications

integrate a fuel supply zone, with reception area, storage facilities and an automatic system to feed the fuel into the energy conversion system. The conversion technology is typically based on a combustion boiler operating with a system to control and treat the air pollutant emissions (gases and aerosols) that result from the solid fuel combustion. It is also common that the boiler operates with automatic bottom ash removal.

Systems for solid fuel combustion have several technologies that are commercially available and mature; examples are **fixed bed, fluidized bed and suspension or pulverized combustion boilers** (EPA, 2007).

Technical reliability, economic feasibility and environmental sustainability are crucial factors for choosing an energy conversion system for process heat generation in industry. The parameters considered fundamental for the evaluation of the energy system are the fuel type and its properties, the system conversion efficiency, and the costs of the initial investment, system operation and maintenance and fuel supply. Industrial solid fuel boilers can operate with coal or biomass. Co-combustion of solid biomass fuels with coal also constitutes a reliable solution, with the advantages of reducing the specific cost, increasing the conversion efficiency and decreasing pollutant emissions of the biomass systems (Nussbaumer, 2003). In general, **solid fuel combustion boilers** typically operate with **efficiencies between 70 % and 90 %** (Vatopoulos et al., 2012), depending significantly on the water content of the fuels used and on the combustion conditions in the furnace. The initial investment costs to implement a solid fuel system are related with the system engineering, procurement and construction; however they represent only a small fraction of the total costs along the life-cycle of the system (Vatopoulos et al., 2012). Higher environmental sustainability is achieved when using fuels with higher heating value and reduced water content, conversion equipment with higher efficiencies and best performing systems to control and treat pollutant emissions.

2.1.1.1.1 Fuel supply: reception, preparation, storage and feeding

In general, the supply of solid fuels to industrial end-users requires facilities prepared to receive, store, process/prepare and/or automatically feed the fuel into the combustion boiler (see Figure 1).

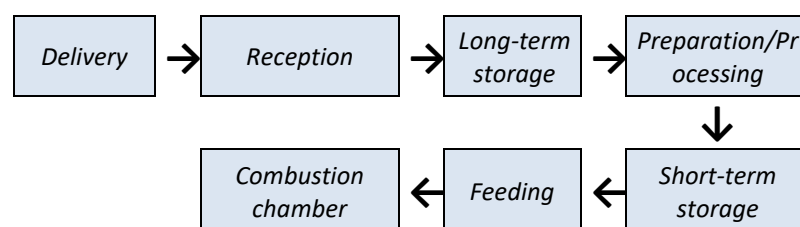


Figure 1: Simplified flowchart for solid fuel supply

Delivery and reception: Different operation methods for solid fuel reception are used in small, medium and large scale heat production systems. Reception methods are dependent on the layout of the industrial facilities and how the fuel load is to be stored. Before storage

fuels can be checked and analysed to control their properties. Fuel unload and transport to storage or process areas can be fully automated. However, some industrial installations have a fuel reception zone with a certain degree of manual handling or are totally based on manual handling. An example of this is when fuel unload and on-site handling is done by equipment operated by men.

Fuels preparation and processing: In order to meet the operation requirements of the combustion chamber, environmental and health security, and also for a possible cost reduction in fuel handling, solid fuels may need preparation and/or processing before storage. This can include the removal of non-combustible materials and fuel sizing, mixing and drying. The performance of the combustion technology used can be very dependent on solid fuel properties and so, fuels preparation and processing can be of extreme importance in order to achieve high energy conversion efficiency.

Fuel storage and feeding system: Solid fuel storage facilities are either located in outdoor areas, with no control of the ambient conditions, or in interior areas, where environmental conditions are normally conditioned. The later includes interior compartments, bunkers, containers, silos, among others. There are applications where both long-term and short-term or buffer storage areas are needed; others where the fuel is unloaded into a silo for short-term storage and directly fed into the combustion chamber. In some cases, the facilities are relatively simple and fuels are received, stored and prepared in the same area. For industrial facilities, the feeding system should be automatic and suitable for the fuel particle size and type of combustion technology. Fuel metering is required to control the amount of fuel supply to the combustion chamber.

2.1.1.1.2 Description of solid fuel combustion technologies

Solid fuel boiler technology can be characterised in terms of the behaviour of the gas-solid system inside the combustion chamber and in this way **three types of combustion technologies** can be distinguished: **fixed bed, fluidized bed** and **suspension combustion**; this last technology is mostly used for power generation in so-called pulverized coal plants (Souza-Santos, 2004).

a) Fixed bed/grate firing combustion technology

Fixed bed combustion systems can have different configurations, depending on the properties of the fuel, the type of burner/grate and the feeding system used. Usually, in this kind of systems, the fuel bed is set on a grate and its movement is imposed by the configuration/movement of the grate (see Figure 2). As its name indicates, in grate firing furnaces solid fuels are oxidized on a grate. Fuel particle size plays a very important role in the combustion process since particles that are too small fall unburned through the grate and particles that are too large are not completely burned (European Commission, 2006). Regarding the grate movement, grate furnaces can be classified as fixed grate, moving grate, vibrating grate and rotating grate.

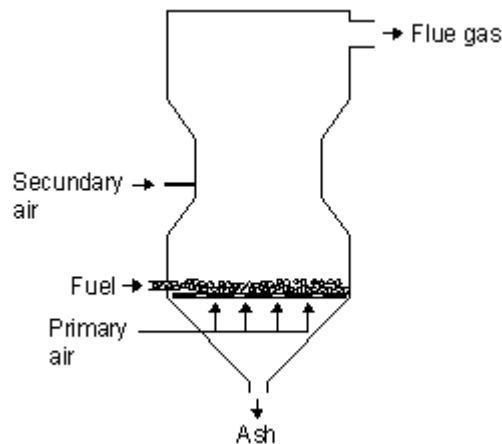


Figure 2: Fixed bed or grate firing boilers

Fixed grate furnace technology: In fixed grate furnaces, the fuel is transported over the grate due to fuel feeding and to the inclination of the grate itself. The disadvantage of this system is that the fuel mass flow cannot be well controlled and so, it is difficult to control the combustion process (Yin et al., 2008). Other disadvantage is the risk of avalanching of the fuel (Yin et al., 2008).

Fixed grate technology became obsolete for large-scale modern combustion plants, where it is no longer applied (van Loo and Koppejan, 2012). However, some fixed grate systems are designed to be fed with specific fuels such as wood chips, pellets, and are reliable systems for small-to medium-scale applications (Palmer et al., 2011).

Moving grate furnace technology: The moving grate furnace can be of two types: inclined moving or reciprocating grate and horizontally moving or travelling grate. The inclined moving grate or reciprocating grate system consists in a set of grate files fixed and movable, in which horizontal forward and reverse movements of movable files occur in an alternating manner (van Loo and Koppejan, 2012). This reciprocating process improves the mixing in the fuel bed, which enhances carbon burnout, and promotes the transport of the resulting solid particles to the ash pit located at the final part of the grate (Yin et al., 2008). In the horizontally moving or travelling grate furnaces, the grate files are in diagonal position, so all the fuel bed is displayed horizontally. The fuel is transported from the feeding side of the grate to the burning area side where the ash pit is located (Yin et al., 2008). The main advantages of moving grate technologies are: *i*) improved control and more homogeneous distribution of the burning material on the grate surface, which increases the carbon burnout efficiency; *ii*) no slag formation due to hot spots and *iii*) less overall height (van Loo and Koppejan, 2012; Yin et al., 2008).

Vibrating grate furnace technology: Vibrating grate furnaces integrate a system that forces a vibration regime on the grate, which promotes a uniform distribution of the fuel on it (Yin et al., 2008). The vibrators transport the fuel and the ash. One advantage of this system is the inhibition of the formation of large slag particles; this makes the system also suitable for fuels with sintering and slagging tendencies (e.g., straw and waste wood). Their disadvantages are the higher fly ash and CO emissions due to the vibrations and the incomplete burnout of the bottom ash, which results from the difficulty in controlling both

ash and fuel transport (van Loo and Koppejan, 2012). Yin et al. (2008) refer that among the different grate technologies, the vibrating systems can have the longest life.

For this type of technology, the thermal power output typically varies between 150 kW_{th} and 20 MW_{th}. Depending on fuel water content, conversion efficiencies of 95% can be achieved. High water content in fuels is admissible (upon 60%) and fuel flexibility is high, in particular for the moving grate technology, where all wood fuels and most types of biomass can be burned (Nussbaumer, 2003). It should be noted that, even for small-scale systems, the cost of investment is low; although for efficient nitrogen oxide (NO_x) emission reduction, additional specific systems are needed, thus increasing the investment costs. It also important to note that grate firing systems are practically insensible to slag formation when compared to fluidized bed combustion systems (Yin et al., 2008).

b) Fluidized bed combustion (FBC) technology

In fluidized bed combustion (FBC), solid fossil fuels are fed into a bed of suspended material (e.g., sand, gravel, ash or limestone), which is fluidized by a gas (usually pre-heated air) injected from the bottom of a porous and perforated plate at a sufficient velocity to suspend the solid material in it. During the process, larger particles have the tendency to cease the fluidization and fine particles tend to be blown out of the fluidized bed.

Fluidized bed combustion systems have two main configurations that are mature technologies (Koornneef et al., 2007); one is denominated stationary or bubbling fluidized bed combustion (BFBC) and the other is called circulating fluidized bed combustion (CFBC). BFBC and CFBC boilers operate at atmospheric pressures. Other types of systems operate at higher pressures, as the pressurized fluidized bed combustion (PFBC) technology. PFBC is not discussed in this report, since it is not a mature technology and is still under development for power generation (Vatopoulos et al., 2012). According to Leckner (2016), the recent developments in fluidized bed combustion technologies are focused on systems operating at atmospheric pressures and not on PFBC.

In BFBC boilers, the fluidized bed does not extend throughout the entire furnace and occupies only a low region in the furnace (see Figure 3), since the superficial velocity of the gas is relatively low (and lower when compared to CFBC). The bubbles formation phase starts when the superficial velocity reaches the minimum bubbling velocity and at this point, and for higher velocities, the gas pressure drop across the bed (pressure loss per unit bed length) remains almost constant. On the other hand, in CFBC the superficial velocity of the injected gas (primary air and/or steam) is high enough so that the process extends throughout the entire volume of the furnace in a fast fluidized bed regime. The bigger particles remain fluidized near the bottom of the furnace or are carried away (to the cyclone system) after size reduction due to chemical consumption, thermal shocks and grinding (mostly caused by particles attrition). The main structural difference between the bubbling and the circulating fluidized bed boiler is that circulating boilers include a cyclone separation system directly connected to the combustion chamber (or furnace) that allows capturing particles to be recycled into the fluidized bed.

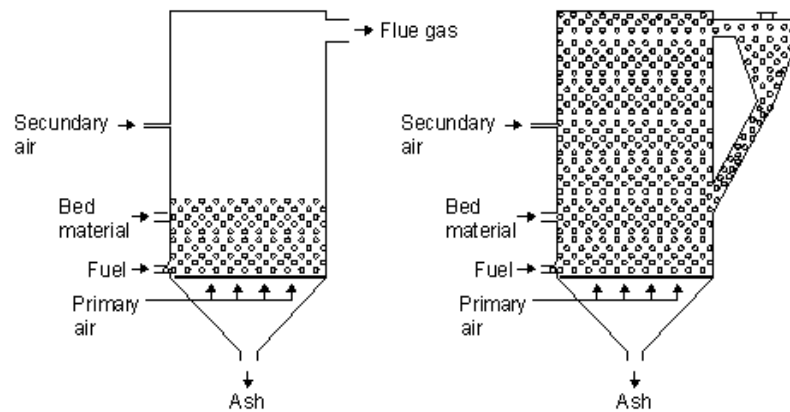


Figure 3: Basic scheme of flow conditions in fluidized bed combustion boilers. Left: BFBC; right: CFBC

For this type of technology, the thermal power output typically varies between 5 MW_{th} and 250 MW_{th} for applications in industry and can reach up to 600 MW_{th} in commercial power plants. Various types of solid fuels can be used; yet fuel particles are usually restricted to sizes less than 10 mm. With respect to fuel moisture, fluidized bed combustion technology can operate upon 60 % of water content. Relevant advantages of FBC technology are the efficiency of primary measures (air staging) for emission control of NO_x reduction, and also the high flexibility in relation to fuel moisture content and mixtures of fuels. Contrary to CFBC, in BFBC there is also relative high flexibility in terms of particle size and economy of scale starts to reduce the investment costs for capacities above 10 MW_{th}. Even so, CFBC may be preferred to BFBC, since higher combustion efficiencies for higher thermal capacities can be achieved. This is due to more homogeneous combustion conditions in the furnace if several fuel injectors are used, and to high specific heat transfer capacity promoted by intense turbulence.

c) Pulverized, suspension or pneumatic transport combustion technology

In pulverized combustion, the gas-solid system inside the furnace acquires a physical behaviour similar to the phenomenon of suspended particles in a gas (Souza-Santos, 2004). The general operation principle of pulverized solid fuel combustion is that fuel is reduced to powder to be fed into the combustion chamber. Most of the systems operating with this principle use particle sizes smaller than those used in grate firing and fluidized bed systems. Coal and lignite burners can be single wall-fired (see Figure 4), opposed wall-fired, tangential-fired and vertical-fired.

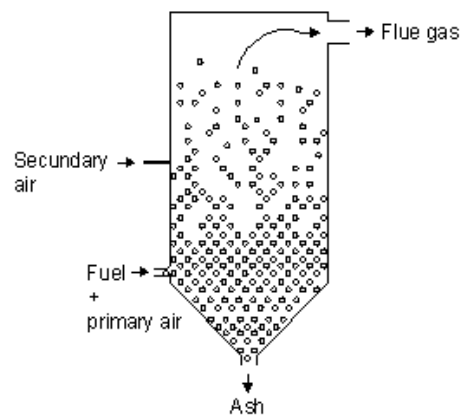


Figure 4: Basic layout of a pulverized fuel combustion boiler with a single wall-fired burner

Pulverized coal fired boilers (PCFB) are widely used for power generation, presenting two types of technology: dry bottom boilers and wet bottom boilers. Dry bottom systems have operating temperatures well below the melting point of the ash to ensure there is no slag formation over the chamber walls and the heat exchanger; bottom ashes are collected in the solid state and flying ashes carried out by flue-gases are removed in electrostatic precipitators. Coal and lignite are widely used with this type of systems. Wet bottom systems operate at temperatures above the melting point of the ash to ensure that the ashes are liquid. Liquid ashes flow down the chamber walls and are collected through the boiler bottom. The flying ashes can be recycled into the combustion chamber to generate slag and then be removed by the bottom ash collector. Having low amounts of volatile compounds, hard coal (anthracite) is mostly used in this system.

When coal is co-fired with biomass, the two relevant techniques are direct and parallel co-firing. In the former, solid biomass and coal are prepared and directly fed into the boiler, while in the latter biomass and coal are fed into separated boilers; it should be noted that the co-combustion of solid biomass and coal occurs in a very flexible manner in fluidized bed combustion systems. Other techniques involving initial gasification of the solid biomass are also possible.

For this type of technology, the thermal power output typically varies between 100 MW_{th} and 1 GW_{th}. Coal, lignite and various types of solid biomass can be used in this systems, yet fuel particles are usually restricted to sizes less than 5 mm for biomass, and less than 1 mm for coal and lignite (Nussbaumer, 2003; European Commission, 2006). For optimal

combustion conditions, pulverized combustion technology should operate with moisture content less than 20 % for lignite and biomass fuels, and a maximum of 1 to 2 % for coal (Nussbaumer, 2003; European Commission, 2006). It should be noted that suspension or pulverized combustion systems for solid biomass or for the co-combustion of biomass with coal are associated with the dust combustor technology, working in an entrained flow regime (Nussbaumer, 2003), or with the cyclone burner technology (Bhattacharya, 1998).

2.1.1.1.3 System layout

Figure 5 shows the general layout for **heat generation systems fired with solid fuels**. The choice of system employed at an industrial facility is based mainly on economic, technical, environmental and local considerations, such as the availability of fuels and requirements for system operation. Knowing the energy consumption profiles is determinant for planning the logistics, facilities and equipment for the solid biomass system. The conversion technology chosen should have high thermal efficiency and environmental performance, and, the fuel properties need to be suitable for the combustion technology used in order not to decrease significantly the overall efficiency of the system and consequently not to increase pollutant emissions.

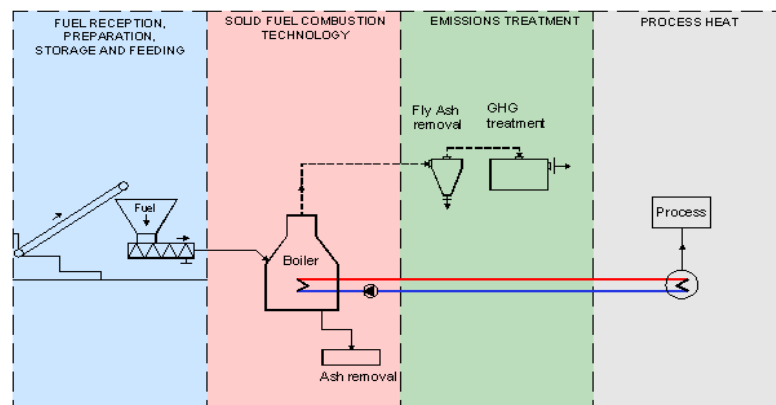


Figure 5: Layout of the reference system for solid fuel process heat generation

Usually, applications in industry require boilers for process heat generation with a power ranging from the order of a few hundred kilowatts to a few hundred megawatts. Fixed bed combustion or grate firing systems are very suitable for the thermal power range in question. In general, fixed bed combustion technologies present lower conversion efficiency than the other combustion technologies. This can be a heavy disadvantage when compared to fluidized bed and dust combustion technologies. However, the wide range of thermal capacities over the small-to medium-scale applications, their flexibility to largest sizes of fuel particles and also, their tolerance to higher water content in fuels are very relevant advantages. The better example of a fixed bed system well-fitting those features are the moving grate boilers. Moreover, moving grate systems are also very flexible in respect to the type of fuels they can burn and to the amount of ash contained on it.

2.1.1.2 Technology costs

Techno-economic feasibility studies of heat production plants need to consider several costs related to the implementation and exploitation phases of those energy systems. In this section, the **investment capital cost refers to the overnight investment cost needed to implement the heat production system fired with solid fuels and encompasses only the total installed cost**. Depending on the system, this cost is mainly related with the fuel supply equipment and facilities (reception, storage, preparation and feeding), the combustion system equipment (boiler and pollutant emissions control) and their facilities, and the heat distribution network. During the lifetime of the energy system fired with solid fuels, the recurring costs are mainly related to fuel consumption costs, which typically account for more than 90 % of the costs during the lifetime of the system (Vatopoulos, 2012), and the operation and maintenance costs (O&M). The latter is related with labour, equipment maintenance, parasitic electricity and other costs depending on the system.

Table 2 presents the **total installed costs** and **O&M costs per unit of installed power**, obtained from several sources for solid biomass and coal heat production systems. Note that the application scale and geographic location can impose significant variations on capital and O&M costs, and in the case of the biomass energy, investment incentives in such systems, driven by national policies, could be determinant for the project to achieve economic viability.

Table 2: Costs for solid biomass heat production systems¹.

Application	Installed cost (€/kW)	O&M cost (€/kW.year)	Source
Solid biomass (0.1- 5 MW in industry)	435 to 696	undefined	Eisentraut and Brown (2014)
Solid biomass (small applications in industry)	574	30	IRENA (2015)
Solid biomass (large applications in industry)	505	26	IRENA (2015)
Solid biomass (District heating)	500 ± 219	85 ± 25	NREL (2016)
Solid biomass (small to large applications in district heating)	330 to 400	2 % of the installed cost	Börjesson and Algrehn (2010)
Coal (20 MW in industry)	405	10	IRENA (2015)
Coal (small to large applications in district heating)	300 to 370	2.5 % of the installed cost	Börjesson and Algrehn (2010)

2.1.2 Liquid and gas fired boilers

2.1.2.1 Technology description

The system of liquid and gas fired boilers comprises of **3 main modules** (UNEP 2006):

¹ Conversion from US Dollar using a conversion factor of 0.87 €/\$.

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

Fuel oil and natural gas are widely used in combustion boilers. Both fuels have similar moisture and ash content, release similar amounts of flue gas during combustion and also burn in gaseous conditions with closely homogenous combustion flame (Teir, 2002). These characteristics make the design of gaseous and liquid boilers similar and allow coupling to the boiler chamber liquid and gaseous fuel burners operating in a fuel co-combustion mode. All clean gaseous and liquid fuels can be combusted at the boiler bottom since they have reduced amounts of ashes. Only heavy fuel oils have high amounts of ash.

In gas and liquid boilers fuel is directly fired with air and the burners are disposed in several levels in the combustion chamber walls (single wall-fired or opposed wall-fired configuration) or tangentially in the corners of the chamber. In liquid boilers fuel is sprayed into the furnace through nozzles producing very small droplets atomized by high pressure steam.

There are two main types of boiler: **water tube and fire tube**. Water tube boilers heat water in tubes and the hot combustion gases are contained in the space around the tubes. Fire tube boilers have hot combustion gases contained inside tubes and the water is circulated around these.

The main components of a boiler system are as follows and are also indicated in Figure 20: (Queensland Government, 2010)

- Deaerator tank to help remove dissolved oxygen
- Equipment to treat water prior to entering the boiler
- Economiser (optional) pre-heats feed water using the flue gases from the boiler's chimney
- Boiler to produce hot water and/or steam
- Process or heat-exchanger where the heat is transferred
- Condensate tank where steam that has condensed is captured and returned to the aerator for reuse
- blown down to purge a portion of the circulating water to prevent that contaminants in the circulating water can cause biological growth, corrosion or deposition.

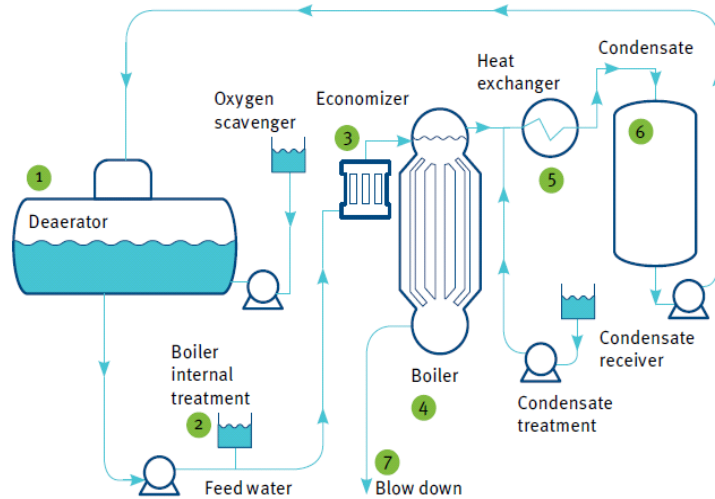


Figure 6: Main components of a boiler system (Queensland Government, 2010)

2.1.2.2 Technology costs

The **investment cost** of a boiler can be estimated by the following formula:

$$\text{Investment (€)} = 1371.9 * \text{Installed power (kW)}^{0.6932}$$

Average investment costs of different power ranges can be found in Table 3.

Table 3: Average investment costs of boilers by power ranges (own research)

BOILER INVESTMENT COSTS	
Power range (Thermal) (kW)	Investment cost (€/KW)
<100	359
100<kW<250	282
250<kW<500	231
>500	177

Other reference (BEIS 2050 calculator- NERA & AEA) estimated investment of a small industrial gas boiler (**96-1,000 kW**) as **30-65 €/kW**.

However, the price of a boiler system depends on the characteristics of the different piece of the system, such as the own boiler, stack gas recovery systems, condensate recovery systems (deaerators, etc.), oxygen trim systems, blow down control, blow down heat recovery systems, etc.

Operational costs:

The cost of generating steam from the boiler is the sum of the following cost components (EERE 2003):

1. Fuel
2. Raw water supply
3. Boiler feed water treatment—including clarification, softening, demineralization
4. Feedwater pumping power
5. Combustion air fan power
6. Sewer charges for boiler blowdown
7. Ash disposal
8. Environmental emissions control
9. Maintenance materials and labour

The costs for fuel are usually the dominant component, accounting for as much as **90 % of the total costs**. In principle, one should calculate the individual cost components rigorously for the site-specific conditions. In practice, it is usually sufficient to use an approximation:

$$\text{Operational cost} = \text{Fuel cost} (1 + 0.30)$$

However, it could be more in smaller facilities.

On other hand, the effect of each single piece of equipment can be a significant part of the overall transfer of energy from the fuel burned to the thermal energy of the steam or hot water delivered. So that, efficiency gains from each piece of equipment need to be evaluated individually in the context of the overall system to determine the incremental fuel cost savings the performance of equipment. (Clever Brooks, 2017)

2.2 Cogeneration systems

Cogeneration (CHP) is the **production of heat and power in one single and integrated system**, with the advantage of reducing fuel costs and emissions as the fuels are used more efficiently. Other relevant advantages of CHP systems are high flexibility to fuel type, varied heat to power ratio, flexibility to diverse heating requirements, availability for a wide range of capacities, long lifetime and high reliability and availability (Vatopoulos et al., 2012). Relevant disadvantages are related with the high capital costs (see Table 4) and high heat to power ratio (Vatopoulos et al., 2012). The type of a CHP system suitable for a certain industry is strongly dependent on the specificities of the application. The most important requirement for CHP system applications is that the industry should demand heat and electricity (Vatopoulos et al., 2012). Thermal and electric load demand profile and heat-to-power ratio required for a specific application impose the type of technology and operation mode of a CHP application, and therefore, also determines the total installed and O&M costs, which strongly influence the economic viability of the plant. In an ideal situation the heat-to-power ratio of a CHP system should satisfy the required heat-to-power ratio of the industry.

In Europe, at present there are several industries with CHP systems installed; mainly in the pulp and paper, chemical, wood and food processing sectors. In the energy and industry sectors, respectively, about 90 % and 98 % of the transformation output² in CHP systems is obtained using a combustion system to generate thermal energy (Eurostat, 2017). Cogeneration of heat and power applications integrate a system to generate thermal energy and a system to convert the thermal energy into electricity. The main technologies applied in CHP utilize a combustion boiler (burning solid, gas or liquid fuels) that operates with a steam turbine, a gas turbine or both in a combined cycle, where each turbine is connected to an electricity generator and the rejected heat is used for heating processes. CHP systems based on reciprocating internal combustion engines, using liquid and gaseous fuels, and nuclear plants are also used. Fuel cell CHP applications exist in industry although the transformation output (not used internally) represents about 2.5 % of the total transformation output in CHP systems (Eurostat, 2017). Stirling engines are also an available technology for CHP applications.

In EU28 about ¼ of the energy used as transformation input³ in CHP systems are for industry and the remaining for the energy sector (Eurostat, 2017). Coal, natural gas and solid biomass are the energy sources most used in CHP systems; nuclear heat, biogas, oil, renewable and non-renewable municipal wastes represent the other relevant sources. Other fuels are used such as liquid biofuels and non-renewable industrial wastes, but these represents less than 1 % of the total fuels used in CHP systems. Figure 7 shows the contribution of each energy source used in CHP systems as input into transformation plants in the European industry; fossil gaseous fuels and solid biomass have the highest share.

² Note that the reported transformation output from CHP plants operating in autoproducer facilities does not consider the energy consumed at the industry, i.e., it only includes the energy sold to third parties. Autoproducer thermal power stations are defined as undertakings which generate electricity wholly or partly for their own use as an activity which supports their primary activity (Eurostat, 2015).

³It only includes the inputs related to energy (heat/or electricity) sold to third parties and does not consider the quantities used internally.

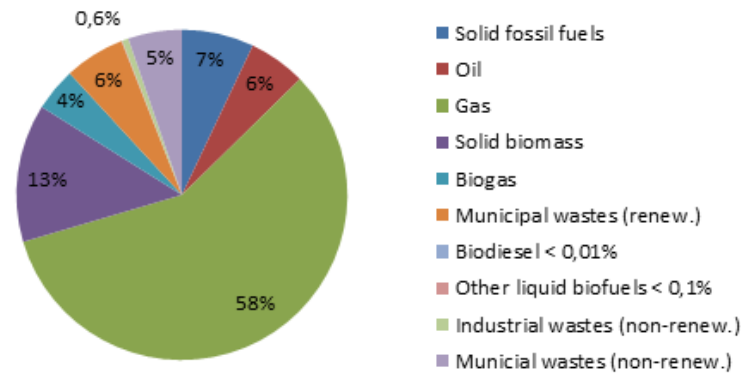


Figure 7: Share of energy sources used as input into transformation auto producer CHP plants for EU28 in 2015 (Eurostat, 2017)

2.2.1 Steam turbine

2.2.1.1 Technology description

A steam turbine converts high pressure and high temperature steam thermal energy into electrical energy. There are two main types of steam turbine applications in CHP systems: extraction condensing turbines and back-pressure turbines. In extraction condensing turbines (Figure 8 left), steam is extracted from the turbine at one or more intermediate pressure levels and used for process heat, while the remaining steam continues to expand until it reaches the condensing pressure. The condenser can be a cooling tower, a lake or the sea. In the simple back-pressure turbine configuration (Figure 8 right), all steam flow, after expanding in the turbine, is exhausted at the exhaust pressure of the turbine and used for process heat. If a fraction of the steam, after expanding in the turbine, is extracted into one or more intermediate pressure levels, the system is often called extraction back-pressure turbine. The steam extracted will supply the process heat demand at pressure levels higher than the exhaust pressure of the turbine.

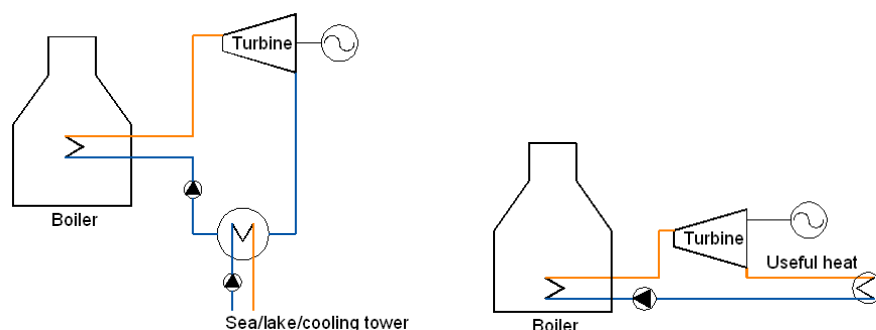


Figure 8: Basic layout for an extracting condensing steam turbine system (left) and an extracting back pressure steam turbine system (right)

Systems with extraction condensing turbines are usually applied where electricity demand is more relevant than heat demand because they have higher electric efficiency and power to heat ratio compared with the back-pressure system; yet this last configuration has a

higher overall thermal efficiency, compared with the extraction condensing turbine, because all the exhaust heat is used for thermal processes instead of being rejected in the condenser.

Table 4: Performance parameters for steam turbine CHP systems (adopted from Vatopoulos et al., 2012).

Steam turbine parameters	Back-pressure	Extraction-Condensing
Heat-to-power ratio (kW_{th}/kW_e)	4.0 – 14.3	2.0 – 10.0
Power output (as % of fuel input)	14 – 28	22 – 40
Overall efficiency (%)	84 – 92	60 – 80

Table 4 presents typical performance parameters for steam turbine CHP systems such as heat-to-power ratio, power output and overall efficiency. CHP systems with steam turbine technology have a wide range of heat-to-power ratio and operate with high overall efficiencies. Regarding the combustion system, steam turbine technology can operate with combustion boilers suitable for solid biomass (wood fuels, pellets and briquettes), coal (hard coal, lignite, peat, lignite and peat briquettes), gas (natural gas, blast furnace gas and coke-oven gas) and oil (heating/diesel oil and heavy fuel oil) fuels.

2.2.1.2 Technology costs

Total installed and O&M costs strongly influence the feasibility of a CHP plant. According to EPA (2015), the **total installed costs** for **solid fuel CHP plants** can be over **4,350 €/W_e**. The referred cost includes the fuel supply chain (preparation, storage and feeding), the boiler, the steam turbine generator system and the equipment to control the pollutant emissions. The annual **non-fuel O&M costs** are typically **0.039 €/kWh** and the main expenses concern the maintenance of the fuel handling equipment, boiler and turbine, and labour. Based on NREL (2016) and IEA ETSAP (2010), Table 5 presents a compilation of the total installed and O&M costs ranges for solid fuel CHP plants with steam turbine technology. It is important to note that both total installed and O&M costs can vary significantly with the application scale of the plant and geographic location of the facilities.

Table 5: Total installed and O&M costs for CHP systems with steam turbine technology.⁴

System	Total installed costs (€/kW _e)	O&M costs (€/kW _e .year)	Source
Renewable wood-fired steam systems ¹	5,039 ± 2,403	85 ± 25	NREL (2016)
Coal steam systems ²	3045±435	91 ± 13	IEA ETSAP (2010)

¹Cost information are for grid-tied distributed generation (DG) scale systems appropriate for residential, commercial, industrial, and federal facilities, and, for system sizes between 100 kW_e and 10 MW_e.

²Costs refer to CHP systems with FBC boiler technology.

2.2.2 Gas turbine

2.2.2.1 Technology description

The **basic layout** of a **gas turbine system** can be seen in **Figure 9**. They operate in a similar manner to steam turbines. However, in gas turbine systems, it is the combustion products that expand in the turbine (instead of steam). The turbine also drives a compressor that supplies air to the combustion chamber, where gas or liquid fuels are also fed. Only clean fuels can be used with gas turbines since flying ashes can damage the turbine.

Gas turbine systems operate on the Brayton thermodynamic cycle, which consists of a **compressor**, a **combustion chamber**, and an **expansion turbine** (see **Figure 9**).

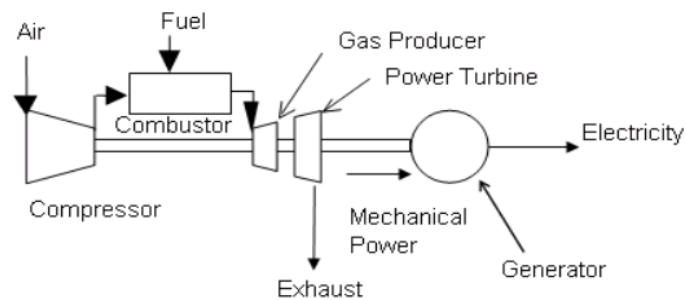


Figure 9: Basic layout for a simple cycle gas turbine system.

The operation of gas turbines is described as following in EPA 2015. *“The compressor heats and compresses the inlet air which is then further heated by the addition of fuel in the combustion chamber. The hot air and combustion gas mixture drives the expansion turbine producing enough energy to provide shaft-power to the generator or mechanical process and to drive the compressor as well. The power produced by an expansion turbine and consumed by a compressor is proportional to the absolute temperature of the gas passing through the device”.*

⁴ Conversion from dollar to euro using a factor of 0.87 €/\$.

The main advantages of the gas turbines as CHP system are: **high reliability, low emissions, high grade heat available and no cooling required**. Main disadvantages are: **require high pressure gas or in-house gas compressor, poor efficiency at low loading, and output falls as ambient temperature rises** (EPA 2015).

2.2.2.2 Technology costs

The **investment cost** of the Gas Turbine can be estimated according the installed power of the generation unit in the range **960-2,640 €/kW_e** for a power range from **4-50 MW**. The **O&M costs** can be estimated as **0,007-0.010 €/kWh_e** (EPA 2015).

2.2.3 Internal combustion engine

2.2.3.1 Technology description

Reciprocating internal combustion engines are a well-established and widely used technology and they are available in sizes from **10 kW to over 18 MW**, and can produce **hot water** or **low pressure steam**.

There are **two primary designs**:

1. Spark ignition Otto-cycle engine: use a spark plug to ignite a pre-mixed air fuel mixture
2. Compression ignition Diesel-cycle engine. The air introduced into the cylinder to a high pressure, raising its temperature to the auto-ignition temperature of the fuel that is injected at high pressure.

Internal combustion engines can have one or more cylinders in which fuel combustion occurs. The engine is connected to the shaft of the generator, providing the mechanical energy to drive the generator to produce electricity.

CHP systems can recover 45 to 55 % of the waste heat from engine systems (thermal energy contained in the exhaust gas and cooling systems), which generally represents 60 to 70 % of the inlet fuel energy. Most of the waste heat is available in the engine exhaust and jacket coolant, while smaller amounts can be recovered from the lube oil cooler and the turbocharger's intercooler and aftercooler (if so equipped).

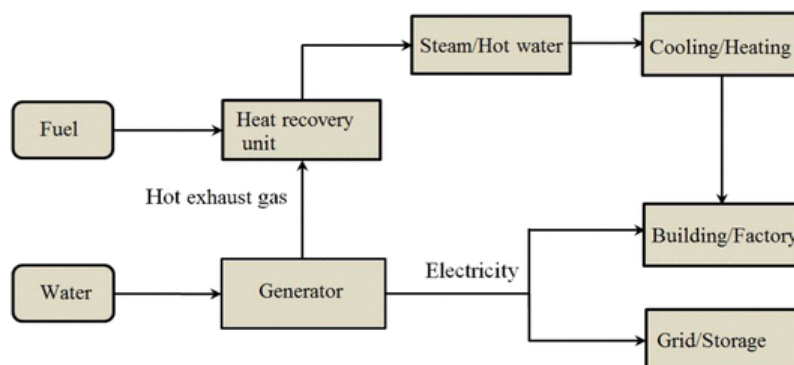


Figure 10: Basic layout for a CHP system (Ellamla et al., 2015)

Three main methods of recovering engine heat in CHP are described in EPA (2015):

1. **Closed-loop cooling systems:** the engine is cooled by forced circulation of a coolant through engine passages and an external heat exchanger. An excess heat exchanger transfers engine heat to a cooling tower or a radiator when there is excess heat generated.
2. **Ebullient Cooling Systems:** the engine is cooled by natural circulation of a boiling coolant through the engine. This type of cooling system is typically used in conjunction with exhaust heat recovery for production of low-pressure steam.
3. **Exhaust Heat Recovery:** is typically used to generate hot water of up to about 110 °C or steam up to 27 at. Only a portion of the exhaust heat can be recovered since exhaust gas temperatures are generally kept above temperature thresholds to prevent the corrosive effects of condensation in the exhaust piping. For this reason, most heat recovery units are designed for a 120 to 177 °C exhaust outlet temperature. Exhaust heat recovery can be independent of the engine cooling system or coupled with it.

A typical industrial application for engine CHP would be a food processing plant with a 2 MW natural gas or gas-oil engine-driven CHP system comprised of multiple 500 to 800 kW engine gensets. The system provides baseload power to the facility and approximately 2.2 MW_{th} low pressure steam for process heating and washdown. Overall efficiency for a CHP system of this type approaches 75 %.

The main advantages of reciprocating internal combustion engines as CHP system are: high power efficiency with part-load operational flexibility, fast start-up, relatively low investment cost, good load following capability, can be overhauled on site with normal operators and operate on low-pressure gas. Main disadvantages are: high maintenance costs, limited to lower temperature cogeneration applications, relatively high air emissions, must be cooled even if recovered heat is not used and high levels of low frequency noise (EPA 2015)

2.2.3.2 Technology costs

The cost of the CHP can be estimated according the installed power of the generation unit in the range of **400 €/kW_e** (Simander et al. 2006), **776 €/kW_e** (Energy International, 2013) or **1,200-2,320 €/kW_e** (EPA 2015).

Other reference to calculate the investment cost of a CHP (>100 kW_e) can be estimated by the following formula (source: AINIA own estimation):

$$\text{Investment (€)} = 5247,6 * \text{Installed power (kW)}^{0,8063}$$

Table 6: Average investment costs of CHP by power ranges

AVERAGE CHP INVESTMENT COSTS	
Power range (electricity) (kW _e)	Investment cost (€/kW _e)
kW _e <100	2.414
100<kW _e <250	2.012
250<kW _e <500	1.733
kW _e >500	1.375

Non-fuel cost O&M costs can be estimated as **0.007-0.0205 €/kWh_e**

2.3 Solar thermal plant

2.3.1 Technology description

Unlike fossil fuel based heat production systems, able to deliver power instantaneously, solar thermal systems build upon the concept of harvesting energy along the day, suiting a given daily load distribution. Under poor irradiation conditions, the system might not be able to fulfil the energy requirements of the consumer process(es). To this end, a backup system is always required assuring the load profile is met.

A solar fraction is thus defined as the ratio of heat produced by the solar system and the total heat requirements of the load profile. After this concept, its design optimization is a function of the solar fraction achieved with a prescribed system layout and composition.

The boundaries of the solar thermal system are set by the solar field aperture area, where solar radiation is converted into heat, and the connection to the heat consumer process(es).

Considering the impact of operating temperatures in solar collector performance the higher the temperature, the lower the efficiency in view of increased thermal losses – the concept of “solar priority” should be followed on its layout. This means that heat being produced in the solar system shall be delivered directly to the consumer process(es), when its temperature is suitable, or be regarded as a pre-heating to the (fossil fuel based) backup heating system, thus ensuring that solar collectors operate at the lower possible temperature and that all solar heat is delivered into the consumer process(es).

In the present SHIP applications are suited by well-established technologies covering the range of process temperatures found in different industrial sectors: low ($T < 100^{\circ}\text{C}$), medium ($100^{\circ}\text{C} < T < 250^{\circ}\text{C}$) or high temperature ($250^{\circ}\text{C} < T < 400^{\circ}\text{C}$).

A solar collector converts solar irradiation hitting a surface into heat by heating a suitable heat transport media. This surface is called absorber and is physically attached to a hydraulic circuit containing the heat transport media, the Heat Transport Fluid (HTF). As both the absorber and HTF in the collector present a temperature higher than the surrounding air temperature, thermal losses occur to the surroundings.

In solar collectors, efficiency is thus directly related to the operating temperature and determines, upon a collector cost, the final cost of heat being produced at a given temperature.

Regardless of the performance enhancement strategies adopted, **collector technologies** might be **divided into two different** categories, related to the use of concentration and thus to the use of tracking systems:

1. **Stationary collectors:** technologies without concentration or with very moderate concentration factor (typically $C < 2$) suitable for a fixed positioning;
2. **Tracking collectors:** solar concentrators (typically $C > 10$) requiring the use of tracking systems enabling incidence conditions within the collector acceptance, thus following the Sun along its trajectory throughout the day.

2.3.1.1 Description of key components

The basic composition of a solar thermal system, when regarded as a group of components sufficing the heat requirements of a prescribed load diagram, relies on four main components:

1. **Solar field** – a group of interconnected solar collectors performing the thermal conversion of solar radiation, whose aperture (irradiated) area is usually dimensioned as a function of annual yield;
2. **Primary circuit** – hydraulic circuit interconnecting the solar field and the thermal storage system and enabling the circulation of a heat transfer fluid between these two components, removing heat from the solar field and delivering it in the thermal storage;
3. **Thermal storage system (TES)** – a volume of a given heat storage media receiving the heat from the solar field and delivering it to the heat consuming process(es) according to a given load profile;
4. **Backup system** – an instantaneous power based equipment enabling the fulfilment of the load profile at any given moment, regardless of the instantaneous solar fraction conditions;
5. **Control system** – a temperature driven control system commanding the circulation of the HTF on the solar field assures that such circulation occurs only when heat is available at the solar field at useful temperatures, i.e., that the solar field outlet temperature is higher than the TES (or consumer process outlet) temperature, thus preventing dissipation of energy in the solar field. Such control system might be used also to implement anti-freezing or anti-stagnation strategies.

Heat transfer between these components might be accomplished through direct circulation of the heat transfer fluid or by means of a suitable heat exchanger. Resulting on an additional cost and on a reduction of the overall system efficiency, the use of heat exchangers is mandatory when connecting two different hydraulic circuits, either using different HTF media or not (as in the case of integrating solar energy on a preexisting circuit). Often an heat exchanger is placed in between the solar field and the thermal storage system, but different layouts are possible, depending on the HTFs used on solar field and consumer process(es), respectively.

2.3.1.2 System layout

The final layout of a Solar Process Heat system depends on different aspects: HTF selection, solar integration into pre-existing circuits, operating temperature, etc. - and its optimization must favour the combination of system cost and efficiency resulting in the lower energy cost, within the bounds of the consumer process(es) constrains.

Some basic system layouts are presented in Figure 11, Figure 12 and Figure 13 as an illustration of aforementioned concepts such as “solar priority”, location of heat exchangers, direct or indirect circulation.

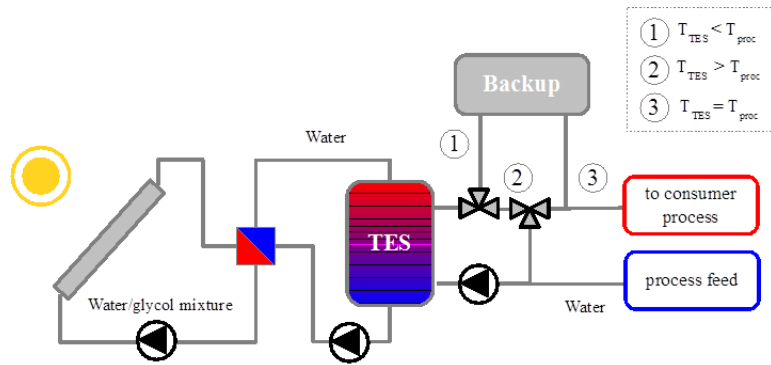


Figure 11: Indirect circulation system layout with water/glycol mixture HTF and water as heat delivery media

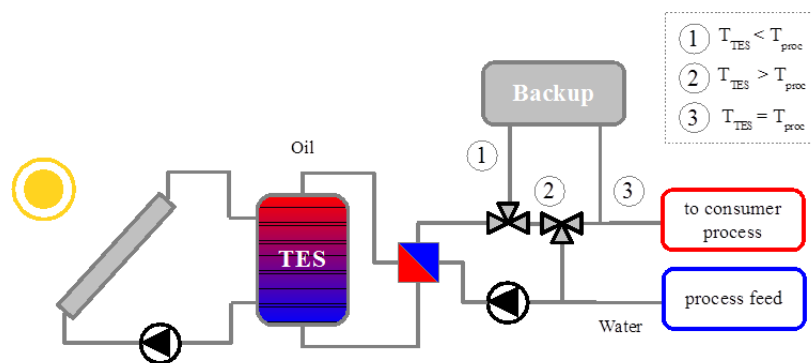


Figure 12: Indirect circulation system layout with thermal oil HTF and water as heat delivery media

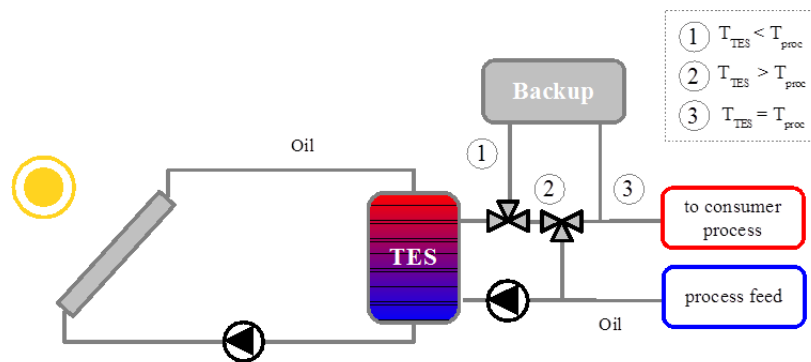


Figure 13: Direct circulation system layout with thermal oil HTF and heat delivery media

The system design and the dimensioning of each of these components aims at the optimization of the solar fraction, following a balance of solar system and backup energy costs such as to optimize final energy costs: the higher the backup energy cost, the higher the optimal solar fraction; the higher the solar system costs, the lower the solar fraction.

2.3.1.3 Operating temperatures

Not neglecting concepts such as evacuated flat-plate collectors, **the most common stationary technologies** currently available as marketed products are:

- **Flat-plate collectors (FPC):** (selective) flat absorber with back and side thermal insulation and with/without single or multiple flat glazing cover; hydraulic circuit attached to the back of the absorber surface; stationary collector suitable to the low temperature range ($T < 100^{\circ}\text{C}$);
- **Evacuated tube collectors (ETC):** selective absorber layer coating the outer surface of the inner glass wall of a Dewar evacuated tube; hydraulic circuit based on a U-pipe or on heat pipes, mounted inside the evacuated tube sleeve; stationary collector suitable to the low and lower boundary of medium temperature ranges ($T < 120^{\circ}\text{C}$);
- **Compound Parabolic Concentrator (CPC) collectors:** stationary line-focus concentrator (with low concentration factor) designed after non-imaging optics concepts for ideal concentrators; might be combined with evacuated tubes (with external concentrator reflectors) or with flat (or flat-type) absorbers with external glazing; depending on the absorber and on the effective concentration factor is suitable to the low and medium temperature ranges ($T < 100^{\circ}\text{C} - 150^{\circ}\text{C}$).

The development of solar concentration technologies, driven from the early 1980's by Solar Thermal Electricity (STE) established the technological ground for R&D and product development activities. Such developments were led by Parabolic Trough Collector (PTC) technology and more recently by derivate line-focus concepts, such as the Linear Fresnel Reflector (LFR) technology, to mention the most prominent.

- **Parabolic Trough Concentrator (PTC):** tracking line-focus concentrator designed after the parabola geometrical feature of reflecting any ray incident on its aperture parallel to its axis to the parabola focus; one-axis tracking around the longitudinal (absorber) axis; coupled with evacuated or non-evacuated (single-pass) absorber tubes; depending on the absorber and on the effective concentration factor is suitable to the medium temperature ranges ($100^{\circ}\text{C} < T < 250^{\circ}\text{C}$);
- **Linear Fresnel Reflector (LFR) Concentrator:** tracking line-focus concentrator designed after the Fresnel principle of dividing a parabola into segments displaced in (or close to) a horizontal plane; individual mirror one-axis tracking around the longitudinal axis; coupled with evacuated or non-evacuated (single-pass) absorber tubes located at a vertical displacement related to its focal length; used with a secondary concentrator located around the absorber to enhance its optical behavior; depending on the absorber and on the effective concentration factor is suitable to the medium temperature ranges ($100^{\circ}\text{C} < T < 250^{\circ}\text{C}$).

In view of the operating temperature dependence of solar collector thermal losses, the selection of the most suitable solar collector technology is directly related to the heat demand temperature (in turn related with the solar integration strategy adopted in the definition of the system layout: process or supply level (Hassine et al., 2015)

Considering both the range of process temperature in different industrial sectors (Lauterbach et al., 2012) and the most suitable range of operating temperatures of the different collector technologies, the scheme presented in Figure 14 summarizes this information and can be regarded as a preliminary step into defining the most suitable technologies for the operating conditions found on a prescribed project.

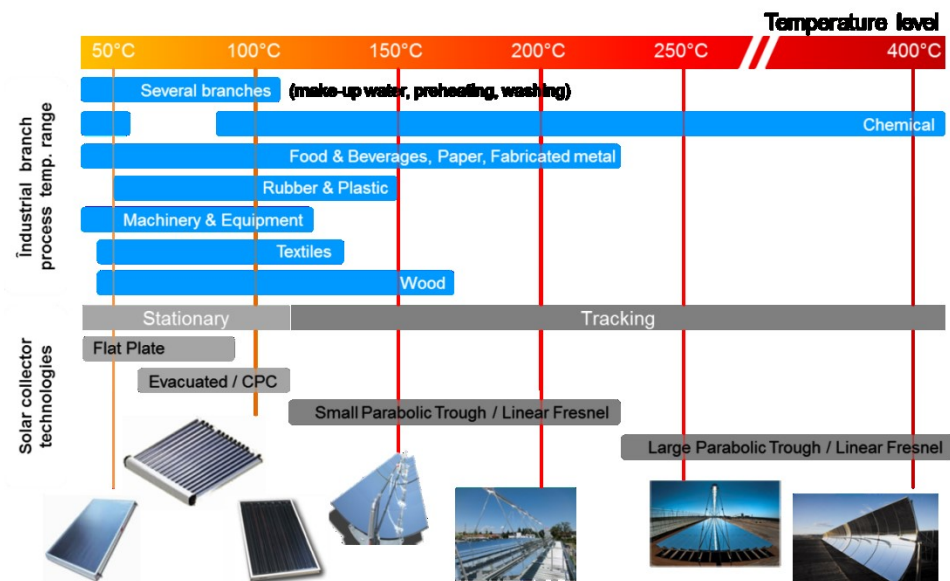


Figure 14: Stationary and tracking solar collector technologies related to operation temperature and process temperature range in different industrial branches (Horta, 2016).

2.3.1.4 Performance parameters

The performance of a solar collector depends not only on its thermal behaviour, determining how much heat is lost to the surroundings when its temperature raises, but also on its optical behaviour, determining the amount of irradiation which effectively hits the absorber and its transformed in heat on the HTF. As so, solar collector efficiency is not a fixed value, as it depends on the collector operating temperature, but is rather represented by a curve - the efficiency curve (see Figure 15).

Solar collector models are built upon the separation of optical and thermal losses, following inherently the different dependencies of both phenomena. As so, it may be stated that from a threshold (maximum) temperature independent efficiency (accounting only for optical losses), collector instantaneous efficiency is decreased with increased operating temperature levels due to the temperature dependence of thermal losses.

The efficiency curve is thus a representation of collector instantaneous efficiency with increasing temperature differential between collector (or mean heat transfer fluid) and ambient temperatures.

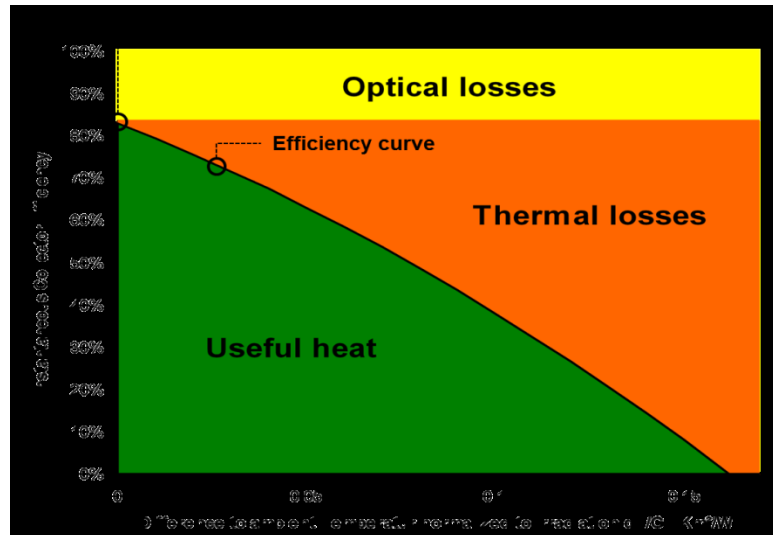


Figure 15: Solar collector efficiency curve (Horta, 2016)

As represented in Figure 15 the efficiency curve starts with the optical (or zero-loss) efficiency value and presents a downward evolution with increasing temperature differential (to ambient temperature), standing for increasing thermal losses and thus reduced instantaneous efficiency values. The slope of the efficiency curve is directly related to the thermal loss coefficients obtained as thermal characterization parameters as result of the solar collector testing procedures.

The collector efficiency curve, relating the performance of the collector with the operating temperature, is thus one (not the only (Giovannetti & Horta, 2015)) of the available tools enabling an early assessment of the suitability of a specific collector or collector technology for a specific application.

Optical and thermal characterization parameters obtained after one (or both) of the solar collector models presented in ISO 9806:2013 are available, for certified solar collectors, at the Solar Keymark database. Promoted by ESTIF – European Solar Thermal Industry Federation, Solar Keymark is a voluntary third-party certification mark for solar thermal products, demonstrating to end-users that a product conforms to the relevant European standards and fulfils additional requirements. The Solar Keymark is used in Europe and increasingly recognized worldwide.

Besides ISO 9806:2013, directly linked to the Solar Keymark database, other solar collector standards are available (e.g. ASHRAE 93-2003 applicable to non-tracking collectors or ASTM E 905-87 applicable to tracking collectors (Hofer et al., 2016)).

2.3.1.5 Installation and operation requirements

The commissioning procedures aim at ensuring the quality and conformity of the delivered goods and / or services through testing procedures aiming:

- the performance of critical components
- the operation of the equipment and/or system
- Confirmation of the supplied services / goods compliance with the planned layout

and with all the applicable regulations / standardization

The controlling parameters depend on the composition of the supplied goods and / or services, yet their definition aims:

- the performance of critical components (e.g. control of solar field performance, heat exchangers, storage heat losses)
- the operation of the equipment and/or system (different operation modes: normal / safety / maintenance, etc)
- Confirmation of the supplied services / goods compliance with the planned layout (quantities, design, component location) and with all the applicable regulations / standardization (depending on applicable standards)

Besides documentation related checks, the operational procedures might include:

- Solar field performance: measurement of HTF flow, inlet and outlet temperatures and available solar radiation, calculating the solar field performance and comparing with solar collector efficiency curve
- HX performance: measurement of hot and cold stream mass flow and inlet / outlet temperatures enabling the calculation of HX effectiveness and comparison with equipment specifications
- Control system: test of relevant operation conditions including solar field stagnation, 3-way valve operation, HTF mass flow control after controlled variation of control variables (temperatures, pressures, etc.)
- Safety: control of safety valves

2.3.2 Technology costs

The costs for solar thermal plants can vary significantly, depending on the temperature level, integration concept, system size, system location and load profile. When comparing different costs it is important to differentiate between **collector costs** and **system costs**:

The **total system costs** include the costs for the collector field, erection, support structure, piping, heat exchanger, pumps, storage, control system and planning. The **collector costs** include only the collector field. (DGS, 2005)

The charts below show the specific system costs for existing SHIP plants all over the world documented in the SHIP Database⁵. The data fully depend on the data provided by the various companies. Figure 16 shows the specific costs of flat plate collectors. The expected fall of specific system price for larger systems cannot fully be confirmed, but a slow trend downwards can be seen.

⁵ <http://ship-plants.info/>

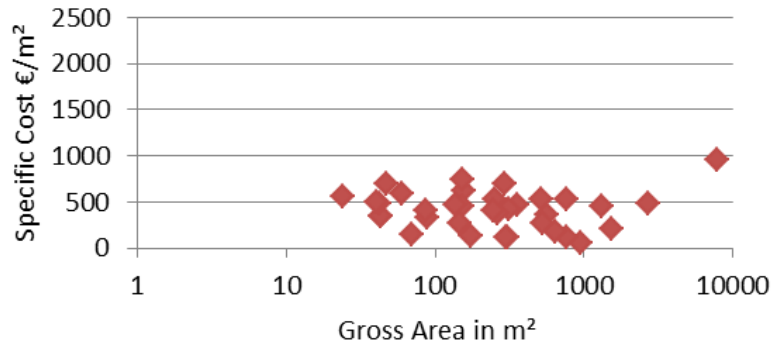


Figure 16: Specific cost analysis of flat plate collectors (SHIP Database)

Evacuated tube collectors are a common alternative to the flat plate technology due the **better efficiency** at **higher temperatures**. The chart shows a clear drop of specific system prices when it comes to bigger realisations.

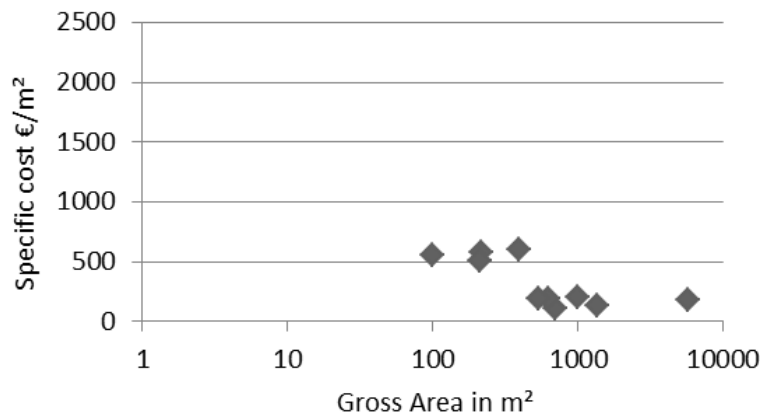


Figure 17: Specific cost analysis of Evacuated tube collectors (SHIP Database)

Air collectors are used in SHIP applications mainly for drying purposes and room conditioning. The system price is between **400 and 500 €/m²** (Figure 18). Two applications with bigger gross area have lower specific costs; however this cannot be validated with additional data and must thus be treated with care.

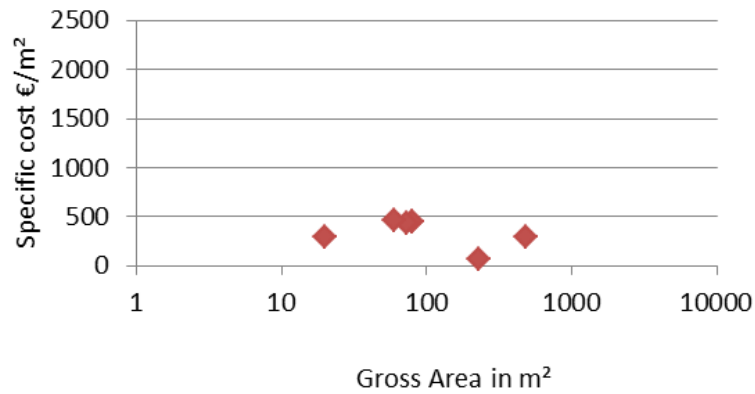


Figure 18: Specific cost analysis of Air collectors (SHIP Database)

In Table 7 system costs for solar thermal process heat systems are shown from a different source (DGS, 2005).

Table 7: Total system costs for various collector types (DGS, 2005)

Collector type	Costs [€/m ²]
Flat-plate collector	250-300
Compound parabolic concentrator (CPC)	300-350
Parabolic trough collector	300-400
Evacuated flat-plate collector	400-600
Evacuated tube collector	400-600
Evacuated tube collector with CPC	400-600

The maintenance costs for conventional collectors account for 2.5 €/m². For parabolic collectors they amount approximately 5 €/m². (DGS, 2005)

Regarding heat production costs, a range of average costs between 0.02-0.05 €/kWh for low-temperature applications and EUR 0.05-0.15 €/kWh for medium-temperature systems was pointed out in 2007 and 2011 (Battisti et al., 2007; Hess & Oliva, 2011). IRENA presents a current heat production costs range of 0.07-0.23 €/kWh, showing that SHIP is currently close to competitiveness only in low temperature applications (IRENA, 2014). In Southern and Central Europe, the European Technology Platform on Renewable Heating and Cooling (Stryi-Hipp et al., 2012), presents SHIP costs in between 0.04-0.12 €/kWh.

2.4 Solid biomass plant

2.4.1 Technology description

Solid biomass combustion systems used in industrial facilities for heat production can differ in **technology, thermal capacity, feeding system, load conditions, heat carriers and purpose**. The choice of a specific system is strongly dependent on the type and availability of biomass used and on the energy load requirements. In most industries, combustion boilers are the most used technology for the conversion of solid biomass into thermal energy (Chan et al., 2015). Alternatively to the use of boilers, the heat from combustion can be used directly in certain processes without being transferred into a thermal medium. This is the case of certain types of kilns, furnaces, ovens and dryers used for specific industrial applications, as the ones used in the cement, non-ferrous metal and petroleum refining industries.

Chapter **2.1.1 Solid fuel combustion systems** presented a general description of the industrial solid fuel combustion systems used to produce heat via boilers. This section will not repeat this information, but focuses on combustion boiler systems that are specific in solid biomass applications.

2.4.1.1 Fixed bed combustion technology

Fixed bed combustion systems can have different configurations, depending on the properties of the biomass, the type of burner/grate and the feeding system used. The following types of fixed bed furnaces can be found: **firewood boilers, grate firing furnaces, understoker furnaces, cigar burners, whole bale furnaces and straw furnaces**.

a) Firewood boilers

Firewood boilers are suitable for solid biomass fuels with large material parts and are flexible to fuel quality variations. Though respecting the responsiveness to load changes, these systems can be slow (Bhattacharya, 1998). Firewood fuels, such as wood logs and sticks, are the proper fuels for most types of systems, albeit boilers for different solid fuels and co-firing of firewood with various ranks of coal, coke and other solid fuels are available.

Some manufacturers offer this type of combustion technology with capacities reaching 100 kW_{th} and the systems can operate about one third below the nominal capacity. Very small thermal capacities are available up to a minimum of around 5 kW_{th}. High water content is not admissible (<30 %), but flexibility related to the size of the firewood fuels used is high. It is possible to use logs and sticks with lengths ranging from about 30 to 100 cm. Depending on the fuel water content, conversion efficiencies of 75 to 80 % can be achieved with the conventional one-stage air injection combustion systems, and of 80 to 90 % in the case of downdraft boilers with inverse and two-stage air injection combustion systems. The burner is manually fed, yet a large part of the commercially available boilers has automatic ignition systems; most of them work with an electric resistance and the rest are equipped with a hot-air generator automatically controlled to produce the ignition flame (Míguez et al., 2012). With regard to the control of operation, some of the systems operate with modern controllers connected to a lambda probe to ensure a proper oxygen level and promote complete combustion (Míguez et al., 2012). This technique is applied in two-stage

air injection systems to control the secondary air supply; however in most of the systems the air supply is manually adjusted (Míguez et al., 2012). Some systems already have modular control with an electronic panel informing about the operation mode and possible operation errors, and, that automatically shut down the system when fuel ends, detect if the fuel charging door is open or activate the integrated refrigeration circuit to prevent system overheating. The main energy carrier in these systems is hot water with a maximum output temperature between 85 and 95 °C. The system can also control the water temperature in the storage tank and the water supply pump. Also, there are systems that can supply hot air as thermal energy output; these are often referred as hot-air generators.

b) Grate firing boilers

Grate firing boilers for solid biomass applications usually operate with a stoker burner or with an underfed stoker burner. In the stoker burner configuration, the fuel is horizontally fed into a fixed grate disposed after the feed auger. In the underfed stoker burner or understoker furnace the fuel is fed from the bottom of the furnace and is forced upwardly into the combustion chamber forming a dome where combustion occurs. Primary and secondary air injection and fuel-feeding are entirely controlled by automation systems. Stoker and understoker furnaces are designed to achieve considerable fast response to thermal load demands although the flexibility to water content is reduced (up to 30 % w.b.) (Palmer et al., 2011). Nevertheless, both systems can operate in automated mode in terms of fuel feeding, ignition, combustion control, bottom ash removal and thermal energy output. Thermal energy output provided by the boiler can be in the form of steam, hot water, heating thermal oil and hot gases. High water content in fuels is admissible (up to 60%) and fuel flexibility is high, in particular for the moving grate technology where all wood fuels and most types of biomass residues can be burned (Nussbaumer, 2003).

In addition, pellet boilers are also manufactured with top-fed burners, on which pellets are fed from the top of the furnace and dropped down to the fuel bed. Míguez et al. (2012) refer that top-fed burners have the advantage of better control on the amount of fuel fed but have the disadvantage of forming a greater quantity of unburned particles and dust; moreover, it is referred that this type of system is only preferred for very-small scale applications (<50 kW_{th}).

It should be noted that there are particular boiler designs for the combustion of biomass bales, e.g., straw bales. For capacities less than 1 MW it is common to use batch firing systems and for larger applications the cigar burner technology is used (Bhattacharya, 1998). These systems have been developed to operate in combination with straw baling, transport and storage equipment, and also to overcome combustion-related difficulties due to high alkali and chlorine content of straw (Faaij, 2006). Nussbaumer (2003) indicates that the water content of the straw bales should not be higher than 20% and systems are available from about 100 kW to 5 MW of thermal capacity.

Based on Obernberger (1998), a summary of the advantages and disadvantages of the grate firing technologies is presented in Table 8. It should be noted that, even for small-scale systems, the cost of investment is low; although for efficient nitrogen oxide (NO_x) emission reduction, additional specific systems are needed, thus increasing the investment costs. It

also important to note that grate firing systems are practically insensible to slag formation when compared to fluidized bed combustion systems (Yin et al., 2008).

Table 8: Advantages and disadvantages of grate firing boilers (adopted from Obernberger, 1998).

Grate firing technology	
Advantages	Disadvantages
Low investment costs for plants <10 MW _{th}	No mixtures of wood fuels and straw/cereals possible
Low operating costs	Efficient NO _x reduction requires special technology
Low dust load in the flue gas	Higher excess oxygen decreases the efficiency
Good burn-out of fly ash particles	Combustion conditions not as homogeneous as in fluidized bed combustion furnaces
Good operation at partial load possible	
Less sensible to slagging than fluidized bed combustion furnaces	

2.4.1.2 Fluidized bed combustion technology

The typical conversion efficiencies of fluidized bed combustion (FBC) are higher than those of fixed bed combustion. FBC technology is highly flexible to diverse types of solid biomass and tolerates fuels with considerable amount of water content. However, economic feasibility is better achieved for larger applications with lower specific capital and O&M costs. As presented in section **2.1.1 Solid fuel combustion systems**, FBC technology has two main configurations for heat production, the bubbling and the circulating fluidized bed combustion, BFBC and CFBC, respectively. Based on the work of Obernberger (1998), a summary of the advantages and disadvantages of BFBC and CFBC technologies is presented in Table 9.

Table 9: Advantages and disadvantages of BFBC and CFBC furnaces (adopted from Obernberger, 1998)

	Advantages	Disadvantages
BFBC	<ul style="list-style-type: none"> - Low investment costs for plants >10MW_{th} - No moving parts in the hot combustion chamber - NO_x reduction by air staging works well - High flexibility concerning particle size, moisture and mixtures of biomass fuels content - Lower excess oxygen raises the efficiency 	<ul style="list-style-type: none"> - High operating costs - Higher dust load in the flue gas than grate furnaces - Good operation at partial load requires special technology - Medium sensibility concerning ash slagging - Medium erosion of heat exchanger tubes
CFBC	<ul style="list-style-type: none"> - No moving parts in the hot combustion chamber - NO_x reduction by air staging works well - High flexibility concerning moisture content and of biomass fuels mixtures - Homogeneous combustion conditions in the furnace if several fuel injectors are used - High specific heat transfer capacity due to high turbulence - Easy addition of additives - Efficient S fixation in the ash if enough Ca available 	<ul style="list-style-type: none"> - High investment costs (interesting only for plants >30 MW_{th}) - High operating costs - High dust load in the flue gas - Partial-load operation requires a second bed - Loss of bed material with the ash - High sensibility concerning ash slagging - Medium erosion of heat exchanger tubes - Low flexibility concerning particle size of the fuel

Table 10 presents an overall comparison between GF (grate firing), BFBC and CFBC technologies for solid biomass energy conversion. It summarizes, for these three types of technologies, the fuel characteristics, application scale, system operation and performance. It should be noted that the co-combustion of solid biomass and coal occurs in a very flexible manner in fluidized bed combustion systems; however, the scale of applications comprises larger capacities, which range from 50 to 150 MW for BFBC and from 100 to 300 MW for CFBC (Nussbaumer, 2003).

Table 10: Comparison between grate firing, BFBC and CFBC boilers (adopted from Nussbaumer, 2003; Koornneef et al., 2007; Yin et al., 2008 and Saidur et al., 2011)

	GF	BFBC	CFBC
Typical thermal capacity range	125 kW - 20 MW	5 MW - 15 MW	15 MW - 100 MW
Fuel type flexibility	Very high, all wood fuels and most types of biomass	High, various biomass	High, various biomass
Fuel particles size flexibility	High but for greater sizes	High but for smaller sizes (<25mm)	High but for smaller sizes (<50mm)
Tolerance to fuel water content	Up to 60%	Up to 60%	Up to 60%
Tolerance to fuel ash content	Up to 50%	Up to 50%	Up to 50%
Partial load operation	Good	requires special technology	requires special technology
Combustion efficiency	High (85%)	High (90%)	High (> 90%)
Feeding	Automatic	Automatic	Automatic

2.4.1.3 System layout

The system layout for a solid biomass heat production plant is similar to the one presented in section **2.1.1.1.3 System layout**. Usually, biomass-fired heat plants have three main components: *i*) fuel supply equipment and facilities; *ii*) the combustion system; and *iii*) a heat distribution network. In the fuel supply area, the fuel is received, stored and automatically fed into the combustion system. Biomass pre-treatment can also take place. Storage is mainly determined by the user energy demand, fuel energy density and supply rate. Typical solutions adopted for storage are indoor compartments, bunkers or outdoor containers (for example metallic silos) adjacent to the combustion system room. The automatic feeding system is very dependent on the configuration between storage and boiler facilities, and also on the fuel mass flow needed to feed the combustion boiler. The combustion system typically operates with equipment to control and treat flue gas emissions and bottom ashes are automatically removed. A description of the different combustion technologies, their advantages and disadvantages was made above.

2.4.2 Performance parameters

2.4.2.1 Solid biomass fuels properties relevant for heat production

When using solid biomass for energy purposes, it is fundamental to know and understand its characteristics. Among the different physical and chemical properties of solid biomass fuels, the following are considered relevant in terms of biomass thermochemical conversion: Elemental composition, ash and volatile matter contents, heating value, bulk density and moisture content (Quaak et al., 1999).

Typically, the most abundant organic element in solid biomass is carbon, followed by oxygen and hydrogen; nitrogen, sulphur and chlorine are also found, usually in quantities less than

1 %db (Jenkins et al., 1998). Table 11 based on the work of Vassilev et al. (2015), presents mean values for the elemental composition of biomass and also a range of values corresponding to a wide variety of biomass materials such as wood, woody materials, herbaceous species, agricultural biomass, animal biomass, algae and contaminated biomass. Since biomass systems have high potential for co-firing with coal and/or substitution of coal systems, a comparison between the properties of biomass and different types of coal is also presented.

Table 11: Comparison between biomass and coal properties (mean and range values on air-dried basis) (adapted from Vassilev et al., 2015)

	Biomass	Coal
Proximate analysis		
<i>Fixed carbon</i> (wt %)	16.0 (6.5–35.3)	43.9 (17.9–70.4)
<i>Volatile matter</i> (wt %)	64.4 (30.4–79.7)	30.8 (12.2–44.5)
<i>Ash</i> (wt %)	4.9 (0.1–34.3)	19.8 (5.0–48.9)
<i>Moisture content</i> (wt %)	14.7 (2.5–62.9)	5.5 (0.4–20.2)
Ultimate analysis		
<i>C</i> (wt %)	51.1 (42.2–60.5)	78.2 (62.9–86.9)
<i>O</i> (wt %)	41.4 (20.8–49.0)	13.6 (4.4–29.9)
<i>H</i> (wt %)	6.2 (3.2–10.2)	5.2 (3.5–6.3)
<i>N</i> (wt %)	1.1 (0.1–12.2)	1.3 (0.5–2.9)
<i>S</i> (wt %)	0.20 (0.01–1.69)	1.7 (0.2–9.8)
Ash analysis		
<i>SiO₂</i> (wt %)	29.14 (0.02–94.48)	54.06 (32.04–68.35)
<i>CaO</i> (wt %)	25.99 (0.97–83.46)	6.57 (0.43–27.78)
<i>K₂O</i> (wt %)	19.40 (2.19–63.90)	1.60 (0.29–4.15)
<i>P₂O₅</i> (wt %)	5.92 (0.54–40.94)	0.50 (0.10–1.70)
<i>Al₂O₃</i> (wt %)	4.49 (0.10–15.12)	23.18 (11.32–35.23)
<i>MgO</i> (wt %)	5.60 (0.19–16.21)	1.83 (0.31–3.98)
<i>Fe₂O₃</i> (wt %)	3.41 (0.22–36.27)	6.85 (0.79–16.44)
<i>SO₃</i> (wt %)	3.27 (0.01–14.74)	3.54 (0.27–14.42)
<i>Na₂O</i> (wt %)	2.54 (0.09–29.82)	0.82 (0.09–2.90)
<i>TiO₂</i> (wt %)	0.24 (0.01–2.02)	1.05 (0.62–1.61)
<i>Bulk density</i> (kg/m ³)	563 (250–954)	1,250 (1,100–1,300)
<i>HHV</i> (MJ/kg)	18.0 (14.0–22.0)	25.0 (16.0–34.0)

Usually, when talking about biomass, the volatile matter is high and relatively low fixed carbon (see Table 11). In terms of combustion, this presents an advantage of biomass over coal; however, for some types of biomass, volatile mater content can be lower than that of some types of coal. The same happens with ask content: typically, biomass presents lower ash content than coal, which presents an advantage; however, for some types of biomass, this is not case. When talking about solid biomass, the diversity of feedstock is big and knowing its characteristics is paramount for the success of implementing an energy conversion system fired with biomass.

Table 11 also highlights disadvantages of biomass when compared to fossil fuels: the low energy density resulting from the lower bulk densities and heating values. Compared to conventional primary energy sources, such as coal and oil, biomass energy densities are approximately 10 to 40 % that of fossil fuels (Vassilev et al., 2015). One of the characteristic of biomass that results in a low heating value is its moisture content. Table 12 presents some of the most important physical properties of different solid biomass fuels such as the moisture content (MC), lower heating value and bulk density (BD). Densified fuels present higher heating values and bulk densities and therefore higher energy density. The latter is very important because it influences the necessary storage volume and the process control of the fuel supply system of the furnace (Oberberger, 1998).

Table 12: Biomass physical properties

	MC (% w.b.)	LHV (MJ/kg)	BD (kg/m³)
Biomass fuels^{1,2}			
Wood chips (hard and soft wood), pre-dried	30.0	12.2	320
Wood chips (hard and soft wood)	50.0	7.9	450
Grass: high pressure bales	18.0	13.7	200
Bark	50.0	8.3	320
Triticale (cereals): high pressure bales	15.0	14.4	175
Densified biomass fuels^{3,4}			
Wood pellets	7.7	19.0	591
Wood briquettes	8,0	18.9	-
Straw pellets	7.2	17.4	650
Bark briquettes	7.4	18.8	-

¹Data obtained from Oberberger (1998)

²wet basis

³Data obtained from Oberberger and Thek (2004)

⁴dry basis

2.4.2.2 Thermal efficiency of biomass combustion systems

The efficiency of the energy conversion is one of the most important parameters for the evaluation of a given energy conversion system or for the comparison of energy production systems. Table 13 presents typical overall thermal conversion efficiencies for solid biomass combustion boilers that are technically proven and marketed nowadays.

Table 13: Typical boiler efficiencies

Boiler	η_{th}	Source
FBC ¹	75-92 %	Koornneef et al. (2007)
Domestic, up to 50kW _{th} , and industrial boilers, 1-5MW _{th} ²	70-90 %	Faaij (2006)
Underfeed pile burner/understoker boiler (0.03 - 5 MW _{th})	75 %	Dornburg and Faaij (2001)
Grate firing (1 – 20 MW _{th})	75-94 %	
Co-firing in pulverized coal boiler (10-20% of biomass: wood, straw, sewage sludge; MC 15-18%)	90-92 %	Pronobis (2006)

¹efficiency defined using the HHV

²efficiency defined using the LHV

2.4.3 Installation and operation requirements

Solid biomass systems need to be installed and operated under certain health and safety principles. Hazards that may arise from plant design and operation should be evaluated and addressed, so that the biomass heat production systems are safe and the accident and health impact risks are minimized or totally eliminated. Since biomass systems have a modular nature, the process of hazard identification (HAZID) and risk assessment needs to be implemented considering the system as a whole rather than its separate components (CEA, 2011). For combustion systems operating with solid biomass, the potential risk areas include (CEA, 2011): fuel delivery and reception, fuel storage and handling, and boiler operation and combustion.

During the delivery and reception of a certain solid biomass fuel load, three groups of operations pose potential accident and health impact risks: fuel unload, reception and handling.

As far as fuel storage and handling is concerned, risks and hazards can have the following nature (CEA, 2011; Koppejan et al., 2013):

- Fire from fuel auto-ignition;
- Fire due to other ignition sources;
- Off-gassing from lignocellulosic fuels;
- Dust and gas explosions;
- Mechanical failure of the walls of the storage area;
- Slips, falls, sharps and trauma hazards, e.g., injuries due to contact with machinery and moving parts.

Commercial boilers need to be certified under standardized normative documents, directives and specific legal regulations, which establish, for example, operation requirements related to certain parameters such as the boiler energy conversion efficiency and the amount of pollutant gases and particles generated. A very important aspect in terms of boiler design and construction is the safety of the boiler pressure system and the associated pressure parts. These should be in accordance with specific regulations such as the Pressure Equipment Directive 2014/68/EU (PED), and, if applicable, systems should

meet the requirements of national regulatory documents respecting pressure systems safety.

The main possible hazards from the operation of combustion boilers are related to (CEA, 2011; Koppejan et al., 2013): (1) risk of excess temperature and pressure due to a sudden shut down of the boiler; (2) risk of explosion due to the build-up of explosive gas mixtures (CO, CH₄, H₂) and consequent ignition inside the combustion chamber or flue gas exhaustion system, particularly on a large static fire bed of considerable depth and area; (3) risk of CO poisoning; and (4) risk of fire.

CEA (2011) presents a guide that analysis potential hazards and possible mitigation measures from biomass fuel delivery, reception, storage and handling and boiler operation and combustion. The reader is redirected to this document for further reading.

The thermochemical conversion of solid biomass through combustion results in pollutant emissions, being fuel composition and burning conditions determinant for the amount and nature of the pollutant emissions from combustion systems (Jenkins et al., 1998; Nussbaumer, 2003). Table 14 presents emission factors for the main pollutants under specific combustion conditions taken from Beauchemin and Tampier (2008).

Table 14: Pollutant emission factors from solid biomass combustion (Beauchemin and Tampier, 2008)

	CO (g/GJ)	NOx (g/GJ)	SOx (g/GJ)	PM ² (mg/m ³)	PM ₁₀ (mg/m ³)	PM _{2.5} (mg/m ³)
Grate firing ¹	645	86	-	330-540	-	-
Fluidized bed combustion ¹	65	69	-		-	-
Dry wood ²	-	211	10.8	412	371	320
Wet wood ²	-	95	10.8	340	299	258
Wet bark/bark and wood ²	-	-	-	577	516	443

¹Measured (average from several plants); ²Guidance values from EPA (1993)

Since environmental protection policies impose limits on these emissions, mitigation measures and control systems must be planned and installed according to the legal requirements.

2.4.4 Technology costs

As described in **2.1.1.2 Technology costs**, the total installed cost for solid biomass systems for heat production integrates costs related with three main components: Fuel supply equipment and facilities, the combustion system and heat network distribution. Fuel storage facilities, preparation equipment and feeding system represent the main costs related with the fuel supply. Many plants do not process the biomass, since it is received with the appropriate properties for combustion and storage maintains these properties. The combustion system represents the major contribution for the total installed costs and integrates the combustion boiler, the flue gas cleaning and exhaustion system and the ash removal system. The combustion boiler is the most expensive component of the system

although in certain applications the economic viability of the project is strongly dependent on the flue gas cleaning costs.

Table 15: Costs for solid biomass heat production systems (EPA, 2007)

	System capacity (MW)	Installed cost (€/kW)	O&M cost (€/kW.year)
Grate firing	10.4	387.3	46.8
	87.2	233.8	14.1
	130.8	201.9	9.5
Fluidized bed combustion	10.4	803.9	55.2
	87.2	385.7	15.1
	130.8	261.8	10.2

Table 15 presents, for medium to large capacities, the specific costs (€/kW) related to the initial investment and the recurring costs of operation and maintenance for the grate firing and fluidized bed combustion technologies, which represent the main technologies for heat production using solid biomass fuels. Specific total installed and O&M costs are significantly affected by scale economy and tend to decrease with system up-scaling (Dornburg and Faaij, 2001). The data in Table 15 clearly shows the decrease in cost as the size of the systems increases. For grate firing technology, the total installed cost of larger systems is around 50% lower than the smaller systems considered, and for fluidized bed technology the reduction reaches almost 70 %. The O&M costs can range between 4 % and 12 % of the total installed cost for grate firing systems and 4 % to 8 % for fluidized bed combustion.

Table 16: Costs for solid biomass heat production systems⁶ (Haas, 2011).

	System capacity (kW)	Installed cost (€/kW)	O&M cost (€/kW.year)
Wood log boiler	50	449	9.0
Pellet boiler	50	448	9.0
Wood chip boiler	50	489	10.0
Wood chip-fired heating plants	500	750	22.5
	2000	510	15.3
	5000	470	14.1
Wood chip-fired process heat plant	5000	635	19.0
Straw-fired heating plants	500	1125	28.8
	2000	765	19.6
	5000	705	18.1

Table 16 presents, for small to medium capacities, the specific costs related to the total installed costs and O&M cost for diverse applications. The systems include all the main components of a solid biomass heat production system. For systems with capacities above

⁶ Conversion from US dollar using a conversion factor of 0.87 €/\$.

500 kW and that refer to heating plants, costs integrate a peak-load boiler and consider a full load operation time of 3,000 h. For the wood chip-fired process heat plant, full load operation time is 6,000 h.

2.5 Biogas plant

2.5.1 Technology description

Biogas, a mixture of methane and carbon dioxide, together with other minority compounds (hydrogen, hydrogen sulphide, etc.) is produced via anaerobic digestion in a biogas plant.

2.5.1.1 Anaerobic digestion system

Anaerobic Digestion (AD) is a biological process in which organic substrates are degraded by microbial consortia in an oxygen-free environment generating as final products, biogas and a digestion fraction so called digestate.

AD occurs by the action of several kinds of bacterial strains which operate sequential but mutually integrated each other. The microbial activity varies with its age and temperature, showing optimal conditions at mesophilic (35 °C) and thermophilic (55 °C) ranges (Demeyer et al., 1981). The anaerobic degradation of organic substrates can be described by the following four steps:

- **Hydrolysis:** large polymers are broken down by enzymes
- **Acidogenesis:** acidogenetic fermentations are most important, acetate is the main end product. Volatile fatty acids are also produced along with carbon dioxide and hydrogen.
- **Acetogenesis:** Breakdown of volatile acids to acetic acid, hydrogen and carbon dioxide.
- **Methanogenesis:** Acetate, hydrogen are converted to methane and carbon dioxide.

Stable AD process, requires periodic feeding of digesters with organic substrates (feeding mixture). The constant methane production at a biogas plant depends on keeping the organic loading rate (OLR) as equilibrated and high as possible but avoiding unstabilisation of the process mainly due accumulation of ammonia, sulphuric acid or volatile fatty acids which leads to lowering pH of digesters.

The required feeding mixtures conditions vary according the kind of digester, the regime of the process (mesophilic, thermophilic), etc. Adequate biogas feeding mixtures should keep equilibrate solid content (about 5-7 %), C/N ratio of about 25-30 and a high proportion of biodegradable substrates (not all the substrates organic content is turned in biogas).

Biogas is a gas mixture composed by methane (CH₄; 55 – 75 Vol. %), carbon dioxide (CO₂; 25 – 45 Vol. %) and other gases (hydrogen sulphide 0.01 – 0.4 Vol. %, traces of ammonia, hydrogen, nitrogen and carbon monoxide) that can be used as an energy source mainly due the high methane heating value (35,793 kJ/m³).

Beside the generation of biogas, the operation of AD plants leads to obtain a liquid phase, so called as digestate, which contains water, remaining organic substrates and minerals. The composition of digestate varies according the digested substrates, the biogas plant characteristics and regime, etc. However, despite the variability from one digestate to each other, all of them contain high content of nutrients. Digestate can be used as a valuable

fertiliser and/or organic amendment for agricultural crops which is important for full nutrients recycling of the biogas plants (Wheatley, 1990; Martin et al 2013).

2.5.1.2 System layout

Figure 19 schematize a general anaerobic digestion plant (agro-industry biogas plant or WWTP sludge anaerobic systems). Some of those elements can vary according the characteristics of the installation, location and type of co-substrates used with orange waste.

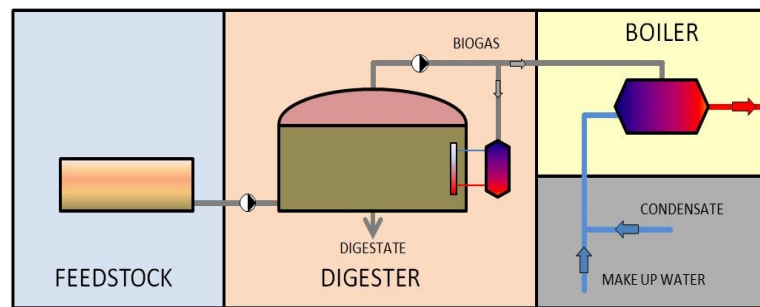


Figure 19: General scheme of agricultural biogas plant. (Own research)

2.5.1.3 Biowaste resources at industrial scale

AD of organic residues at agro-industrial biogas plants is an already consolidated technology in several European countries as Germany, Denmark or Austria, (with more than 6,000 plants) and where several strategies have been implemented for the constant co-substrates provisioning (energy crops). In other countries such as Spain, Italy or Greece, the agro-industrial biogas plants are not yet enough consolidated or are growing up. In these countries, biogas technology has a high potential, given that the amount of agro-residues produced by agriculture and food industry.

Food industry also generates high organic load wastewater and sewage sludge from industrial WWTPs which can also be biologically treated by anaerobic digestion.

The use anaerobic digestion technology is of particular relevance in food industry where high production of bio-waste and high thermal energy demand coincides.

The anaerobic digestion (AD) can then produce both renewable energy (biogas) and digestate from a variety of organic materials including by-products from the food & beverage industry but also livestock manure, crops residues, biowaste from municipalities, etc. Digestate can be considered as a valuable organic fertiliser.

As explained in the JRC report "Towards a better exploitation of the technical potential of waste-to-energy (2016)", it is not possible to estimate the amount of biogas produced from wastes using the Eurostat Energy Statistics, since the treatment of biodegradable wastes for biogas production is considered in the same code where are includes other waste treatment technologies as composting and other biological transformation processes.

As commented, very different types of by-products from food industry can be used as raw material for biogas production.

2.5.1.4 Components of a biogas system

Biomass pre-treatment

Most bio-wastes from food industry becomes rapidly damaged, hence they need to be adequately stored for preventing non-controlled fermentation and production of leachates.

Food waste commonly needs to be ground up into a liquid pulp before being fed to the digester. Different grinding technology can be used depending on the characteristics of food waste as chopper pumps, macerators, hammermills, or hydropulpers.

ABP's are materials of animal origin that people do not consume. They are categorised in three categories (1, 2 and 3). Category 2 and 3 can be transformed into biogas. However, pre-treatment of the materials is necessary. ABP category 2 can be transformed into biogas:

- following processing by pressure sterilisation and permanent marking of the resulting material; or
- in the case of manure, digestive tract and its content, milk, milk-based products, colostrum, eggs and egg products which the competent authority does not consider representing a risk for the spread of any serious transmissible disease, following or without prior processing;

Animal by-products must be pasteurised/hygenized at 70 °C during one hour, with a maximum particle size of 12 mm before entering the unit.

Digester

The digester is the main component of a biogas plants and is where the AD process occurs. Several configurations for anaerobic digestion of wastewater reactor are available: continuous stirred tank reactors (CSTR), Upflow Anaerobic Sludge Blanket (UASB), Internal Circulation (IC), Expanded Granular Sludge Bed (EGSB), etc.

Most typical configuration of a biowaste anaerobic digestion reactor is the CSTR "continuous stirred tank reactors" (Figure 20).

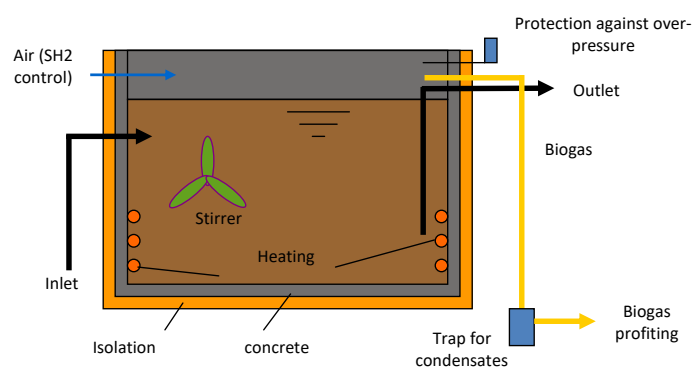


Figure 20: Continuous stirred tank reactors (CSTR) (Own research)

Heating system

Digesters need to be kept warm (setting temperature) for proper bacteriological function. Heating system can be installed inside the tank itself, placed within concrete tank walls or even an external heat exchanger where digestate is recirculated. In facilities where biogas is used as fuel in a combined heat and power (CHP), excess heat is used to keep the digester warm. For systems without CHP units or other sources of heat, a boiler system should supply indirectly the required heat through heat exchanger.

Mixing

Good mixing is important for digesters to ensure proper contact between the microbes and the waste and also to prevent decantation of solids. Various configurations of mixers are available depending on the type of digester design.

Phases

The two-phases system is an adequate configuration to reduce the HRT (and then the volume of the digesters) for some types of bio-wastes with high cellulosic content. In the two-phases system, the hydrolysis and acidogenesis take place in the first digester and the methanogenesis (methane production) in the second one. The main advantage of the separation of the phases lies in the fact that it is possible to achieve the best operating conditions for each of the microbial populations and, therefore, the rice straw degradation and the biogas production are increased.

Operating temperature

The operating temperature of the conventional anaerobic digesters is in the range of 37°C (mesophilic range), but they can also be operated in the range of 55°C (thermophilic range). Thermophilic anaerobic bacteria have higher hydrolysis kinetics, and, therefore, it is possible to reduce the HRT and consequently the digester volume. Moreover, temperatures reached at thermophilic ranges provide higher results on sanitation of digestate. In contrast, thermophilic digestion is more difficult to operate due to thermophilic bacteria are more sensitive to temperature or pH changes, and presence of inhibitory substances.

Biogas combustion

The produced Biogas can satisfy part of the own energy demand of the agro-food industries. Biogas can be used as fuel in boiler installations or in Combined Heat and Power engines.

However, the presence of hydrogen sulfide and water vapor in the biogas above certain levels can entail some restrictions in the use of biogas as fuel in boilers and especially in CHP.

Hydrogen sulfide is found in all biogas streams to a varying degree based on the type of feedstocks. Depending on the application, H₂S levels can range from under 100 ppm to over several thousand ppm. Due to its corrosive properties H₂S can cause corrosion in pipes and boilers. When H₂S concentration is higher than the boiler/CHP specifications, a system for removing the H₂S is required.

There are different technologies to reduce the H₂S content in biogas: chemicals based on iron salt chemistry (ferric or ferrous Chloride, ferric hydroxide or iron oxide), injection of O₂ in the digester, water scrubber, iron sponge filters, biofilters.

The biogas inside the digester is saturated with water vapor. As the gas cools, vapor forms liquid condensate which can plug gas piping and cause corrosion in gas piping and in the combustion equipment. Condensate Traps installed inline after the digesters is a simply way to remove water vapor before it cools and condenses in the piping.

Boiler

Biogas can be used as fuel in existing boilers for heat production (hot water or steam) Energy and cost savings are related to the quantity of biogas produced from bio-waste that substitute fossil fuels. Thermal efficiencies of heat boilers very much depend on the technology and fuel type. Efficiencies range from 75 to 90 %.

Gas natural boiler burners are not designed to burn biogas; therefore, burners have to be replaced if biogas is utilized as fuel in this system. Depending on the type (fire-tube or water-tube) and design of the boiler (number of pass system) natural gas should be added to the fuel mixture in order to maintain the efficiency of the boiler.

CHP

Biogas can also be used as fuel in CHP engines. The total efficiency is ranging up to 85 %. The heat produced by the engine can be recovered through the exhaust gases and the cooling liquids by mean heat exchangers.

Digestate line

Digestate is the material remaining after the anaerobic digestion. It contains water, nutrients and no-degraded organic material.

Despite the chemical composition of digestate vary on the type of feedstock and the AD process conditions; it can be used as fertilizer in agriculture.

To facilitate the subsequent valorization in agriculture, digestate is subjected to a solid-liquid separation. The most common separation technologies for solid-liquid separation are decanter and screw press and bow screen.

- A decanter centrifuge separates the solid content from liquid in digestate, based on gravitational separation. The dry matter content in the solid fraction is high approx. 25-30 %. The decanter has a high-energy consumption and high equipment and maintenance costs.
- A screw press separates the solid content from liquid by gravity drainage as the material is conveyed from the inlet to the discharge end of the screw press. The equipment has low capital and operational costs and relatively limited maintenance costs. The dry matter content is high approx. 20-30 %.
- Bow screen: Separation of solids by means of static and vibrating bow screen. It consists of a bended wedge wire screen plate that can be of varied sizes. The equipment has low capital and operational costs and minimal maintenance costs as well. The dry matter content is lower, around 5-10 % TS. Here the most useful screen sizes were determined as 0.5 and 0.75 mm. Both types are available but only a small static one was tested.

In some countries, digestate must be stocked a period before it can be spread as fertilizer.

2.5.1.5 Performance parameters

Operational parameters related to feeding system:

- Organic Loading Rate (OLR) indicates the weight of dry organic matter (volatile solids) that can be fed into the digester per volume unit of digester and per day. It is normally expressed as kg VS/m³.d. Typically, values are between 2 to 3 kg VS m⁻³ day⁻¹. As a rule of thumb, you can take 4 kg m⁻³ day⁻¹ as a maximum value. Above that, the activity of the bacteria diminishes.
- Hydraulic retention time (HRT) is the duration that the substrate stays in the digester. Taking into account that the growth rate of methanogenic bacteria is between 5 and 15 days; lower HRT will flush them out.

Performance parameter for biogas plant operation:

Instrumentation and control in biogas plants is normally implemented by monitoring some parameters on the liquid phase (pH, Temperature, etc.) and the biogas (flow, methane content ...) characteristics. In most of cases, these parameters are easy to measure and register by using commercial sensor/equipment.

a) Biogas parameters:

- Biogas flow: it can be easily measured with commercial equipment (gas flowmeters)
- Biogas composition. Methane is a key parameter that can be easily measured with IR sensors. Other relevant parameters are H₂S and CO₂. These parameters are informative but not really predictive of process failure. Hydrogen concentration can be used in some cases as predictive variable.

b) Liquid phase parameters:

- FOS/TAC. The FOS/TAC ratio is the quotient of the acid concentration and the buffer capacity in the fermentation substrate. The TAC value is an estimation of the buffer capacity of the sample and the FOS value corresponds to the volatile fatty acids content. It is an indicator for assessing fermentation processes.
- Total Volatile Fatty Acids: it is the sum of all SVFA (acetic, propionic, butyric, iso-butyric, valeric, iso-valeric...). Total VFA can be measured by means of an automatic on-line titrator.
- pH: a fall in pH is indicative of a depletion of alkalinity buffering capacity. It is easy to measure, but it is not a predictive parameter for process control. This parameter serve as a sign of a failed rather than a failing system.

Optimization

Anaerobic Digestion is a biological process where microbial consortia of hundreds of different microorganisms take part. Each consortium is different depending on the substrate and the operating conditions, and can vary throughout time even in the same digester. Optimization of the process is then not simple since these microorganisms have different growing rates and optimal growing conditions.

pH, methane concentration or total VFA give advise of the process malfunctioning when process has already failed, and then, they are not useful as predictive parameters for process optimization.

- VFA profile provides the concentration of each individual compounds of the VFA (acetic, propionic, butyric, iso-butyric, valeric, iso-valeric...). Some of them have

been used as input variables because they predict failure in anaerobic digestion process. In practice, the cost and long-time required for the analysis of VFA profile reduce is value as predictive parameter.

2.5.1.6 Installation and operation requirements

A biogas plant requires some basic auxiliary services such as: water supply for cleaning purposes (tap water quality not required), electricity supply to power the equipment (when it is not produced by a CHP unit) and compressed air for the pneumatic valves.

2.5.2 Technology costs

2.5.2.1 Investment cost

Basic inversion cost (BIC) of a biogas plant is fixed by default in 75 €/co-substrates t.y (Murphy et al. 2004). Additionally, as a general rule, the whole biogas inversion cost can be obtained by applying the following formula (Flotats et al. 2008).

$$\text{Unitary inversion (€/kW)} = 16,272 * \text{Installed power (kW)} - 0.2114$$

The cost of the CHP is estimated according the installed power of the generation unit in 400 €/kWe (Simader et al. 2006)

The inversion for the installations for biogas conditioning has been set in 500 €/m³.h³ according (Moncayo, 2008).

A numerical model for biogas plants total investment costs has been developed in the TRUSTEE project. The results for different countries are summarized in Table 17 below:

Table 17: Estimated total investment cost of biogas plants per country (Own calculation)¹.

A) BIOGAS PLANT WITH BOILER				
	Investment cost (€/KW)			
Power range (Thermal) (kW)	GERMANY	SPAIN	FRANCE	ITALY
<100	2,903	2,709	4,151	3,565
100<kW<250	2,193	2,043	3,157	2,704
250<kW<500	1,761	1,640	2,541	2,175
>500	1,389	1,294	2,001	1,714
B) BIOGAS PLANT WITH CHP				
	Investment cost (€/kW _{el})			
Power range (electricity) (kW _{el})	GERMANY	SPAIN	FRANCE	ITALY
KW _{el} <100	7,286	6,336	10,296	8,003
100<kW _{el} <250	5,567	5,286	7,376	6,527
250<kW _{el} <500	4,397	4,185	5,761	5,120
kW _{el} >500	3,561	3,398	4,607	4,116

¹ Adapted from small scale AD technology model developed in Biogas3 project (<http://www.biogas3.eu/eng/>)

2.5.2.2 O&M costs

Operation and maintenance cost can be obtained by several ways:

- The inversion costs for operation and maintenance (COM) of biogas plants can be obtained by default as 1.5 % of the total inversion (Flotats et al. 2008).
- The cost of operation according the hand labour (CMH) is fixed by default 50.000 €/pers.y.; considering the need of 1.25 labour hands per each 200 kWel (Flotats et al. 2008)
- Operational and mountainous cost according the co-generation unit (COC) is fixed by default in 0.01 €/raw kWel.

Benefit from electricity selling

The main income from agricultural biogas plants comes from selling the electricity generated from CHPs. In most EU member states electricity utilities now buy electricity generated from renewable sources (as biogas) produced by individuals and companies. Prices paid for 'self-produced' electricity is called a "feed-in tariff". This tariff varies in the time and from one country to other.

The mentioned benefit needs to be subtracted from the cost of the feeding materials used for keeping stable and high the biogas production. Hence as cheap are the co-substrates as profitable is the biogas plant, especially if those co-substrates have a high bio-methane potential, high biodegradability and are closely located regarding the biogas plant.

On the other hand, considering typical efficiencies of CHP (of about 40 %) the generated thermal energy produced would be about 2,100,000 kWh per year. This energy (in case of adequately adapted the plant) can be exploited on the same or a different installation.

2.6 Heat exchangers

2.6.1 Technology description

“A heat exchanger is a heat transfer device that is used for transfer of internal thermal energy between two or more fluids available at different temperatures. In most heat exchangers, the fluids are separated by a heat transfer surface, and ideally they do not mix.” (Thulukkanam, 2013)

In industrial companies a large amount of process heat that is applied to process streams is normally dissipated through cooling utilities. By means of a heat exchanger it is possible to reuse the heat energy for heating cold process streams. Such a system is called **heat recovery system** that consists of a set of heat exchangers including heaters, coolers, condensers, re-boilers, or other equipment and attachments for heat transfer between process streams. (VDI, 2010)

2.6.1.1 Heat exchanger classification and types

A heat exchanger consists of **heat-exchanging elements** such as a core or matrix containing the heat transfer surface, and **fluid distribution elements** such as headers or tanks, inlet and outlet nozzles or pipes, etc.

The heat transfer surface is in direct contact with fluids through which heat is transferred by conduction. The portion of the surface that separates the fluids is referred to as the primary or direct contact surface. To increase heat transfer area, secondary surfaces known as fins may be attached to the primary surface.

In general, industrial heat exchangers can be classified according to **(1)** construction, **(2)** transfer processes, **(3)** degrees of surface compactness, **(4)** flow arrangements, **(5)** pass arrangements, **(6)** phase of the process fluids, and **(7)** heat transfer mechanisms. (Thulukkanam, 2013)

In the following chapters, the most often used classifications - construction and flow arrangement - are described in more detail.

2.6.1.1.1 Heat exchanger construction

According to the **construction** heat exchangers can be classified as follows: (Thulukkanam, 2013)

- Tubular heat exchangers
- Plate heat exchangers
- Extended surface heat exchangers
- Regenerators

Tubular heat exchangers

Tubular heat exchangers are further differentiated in **double pipe, shell and tube** as well as **coiled tube** heat exchangers. (Thulukkanam, 2013)

In process industries, **shell and tube heat exchangers** (STHE) are used in great numbers, far more than any other type of exchanger. More than **90 % of heat exchangers used in**

industry are of the shell and tube type. STHes (shown in Figure 21) are the “workhorses” of industrial process heat transfer. They are the first choice because of well-established procedures for design and manufacture from a wide variety of materials, many years of satisfactory service, and availability of codes and standards for design and fabrication. They are produced in the widest variety of sizes and styles. There is virtually no limit on the operating temperature and pressure.

The major components of a shell and tube exchanger are tubes, baffles, shell, front head, rear head, and nozzles (Figure 21).

STHE are operating between -20 °C up to 500 °C. The operating pressure is max. 600 bar. STHE are extremely flexible and have a robust design, are easy to maintain and repair. However, there are also some disadvantages like the requirement of large site area for installation and often needed extra space to remove the bundle. Furthermore the construction is heavy. (Thulukkanam, 2013)

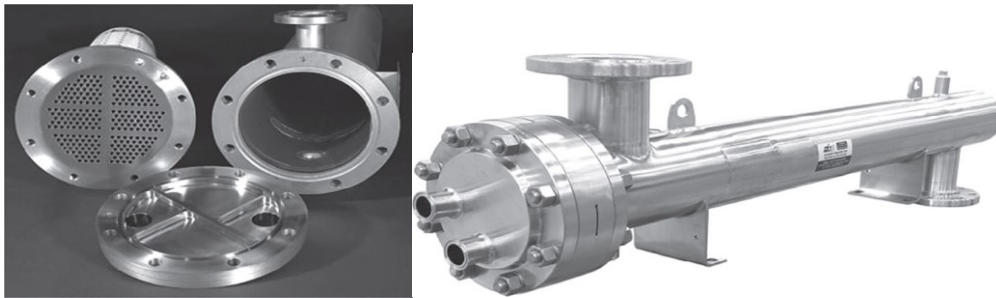


Figure 21: Shell and tube heat exchanger. Left: Components and right: heat exchanger. (Thulukkanam, 2013)

Plate heat exchangers

PHEs are less widely used than tubular heat exchangers but offer certain important advantages. PHEs can be classified into three principal groups:

1. **Plate and frame or gasketed PHEs** used as an alternative to tube and shell exchangers for low- and medium-pressure liquid–liquid heat transfer applications
2. **Spiral heat exchanger** used as an alternative to shell and tube exchangers where low maintenance is required, particularly with fluids tending to sludge or containing slurries or solids in suspension
3. **Panel heat exchangers** made from embossed plates to form a conduit or coil for liquids coupled with fins

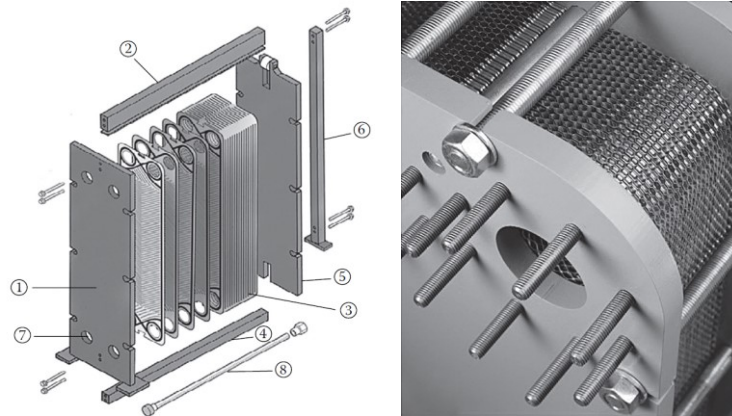


Figure 22: Plate heat exchanger. Left: Construction details—schematic (Parts details: 1, Fixed frame plate; 2, Top carrying bar; 3, Plate pack; 4, Bottom carrying bar; 5, Movable pressure plate; 6, Support column; 7, Fluids port; and 8, Tightening bolts.) and right: closer view of assembled plates.

Plate coil heat exchangers are also called panel coil or embossed panel or jacketing. The panel coil serves as a heat sink or a heat source, depending upon whether the fluid within the coil is being cooled or heated. Panel coil heat exchangers are relatively inexpensive and can be made into any desired shape and thickness for heat sinks and heat sources under varied operating conditions. Hence, they have been used in many industrial applications such as cryogenics, chemicals, fibers, food, paints, pharmaceuticals, and solar absorbers. A few types of panel coil designs are shown in Figure 23. The panel coil is used in such industries as plating, metal finishing, chemical, textile, brewery, pharmaceutical, dairy, pulp and paper, food, nuclear, beverage, waste treatment, and many others.

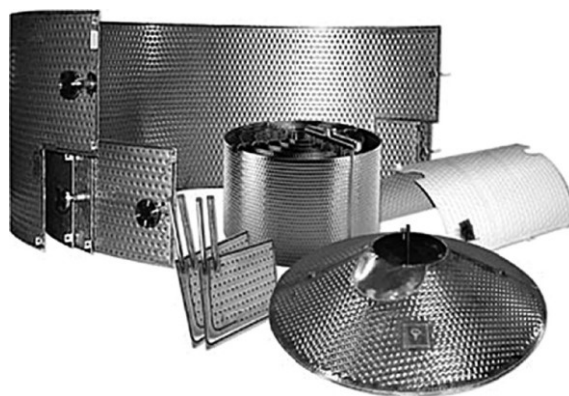


Figure 23: Different types of panel coil heat exchangers (Thulukkanam, 2013)

Panel coils provide the optimum method of heating and cooling process vessels in terms of control, efficiency, and product quality. Using a panel as a means of heat transfer offers the following advantages: (Thulukkanam, 2013)

- All liquids can be handled, as well as steam and other high-temperature vapors.
- Circulation, temperature, and velocity of heat transfer media can be accurately controlled.

- Panels may often be fabricated from a much less expensive metal than the vessel itself.
- Contamination, cleaning, and maintenance problems are eliminated.
- Maximum efficiency, economy, and flexibility are achieved.
- In designing reactors for specific process, this variety gives chemical engineers a great deal of flexibility in the choice of heat transfer medium.

2.6.1.1.2 Heat exchanger flow arrangement

According to the flow arrangement heat exchangers can be classified as follows:
(Thulukkanam, 2013)

1. Parallel flow
2. Counter flow
3. Cross flow

The choice of a the particular flow arrangement is dependent upon the required exchanger effectiveness, fluid flow paths, packaging envelope, allowable thermal stresses, temperature levels, and other design criteria. (Thulukkanam, 2013) Following the three flow arrangements are described in detail.

Parallel flow

In this flow arrangement both fluid streams enter at the same end of the heat exchanger and flow parallel to each other in the same direction and leave at the other end of the heat exchanger (see Figure 24). This arrangement has the lowest exchanger effectiveness among the single-pass exchangers for the same flow rates, capacity rate (mass \times specific heat) ratio, and surface area. Moreover, the existence of large temperature differences at the inlet end may induce high thermal stresses in the exchanger wall at inlet. Parallel flows are advantageous. **(a)** In heating very viscous fluids, parallel flow provides for rapid heating. The quick change in viscosity results in reduced pumping power requirements through the heat exchanger, **(b)** where the more moderate mean metal temperatures of the tube walls are required, and **(c)** where the improvements in heat transfer rates compensate for the lower LMTD. (Thulukkanam, 2013)

Although this flow arrangement is not used widely, it is preferred for the following reasons:
(Thulukkanam, 2013)

1. When there is a possibility that the temperature of the warmer fluid may reach its freezing point.
2. It provides early initiation of nucleate boiling for boiling applications.
3. For a balanced exchanger (i.e., heat capacity rate ratio $C^* = 1$), the desired exchanger effectiveness is low and is to be maintained approximately constant over a range of NTU values.
4. The application allows piping only suited to parallel flow.
5. Temperature-sensitive fluids such as food products, pharmaceuticals, and biological products are less likely to be “thermally damaged” in a parallel flow heat exchanger.
6. Certain types of fouling such as chemical reaction fouling, scaling, corrosion fouling, and freezing fouling are sensitive to temperature. Where control of

temperature-sensitive fouling is a major concern, it is advantageous to use parallel flow.

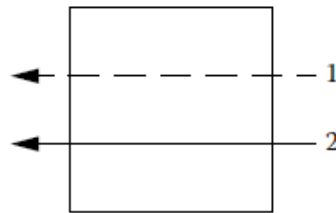


Figure 24: Schematic parallel flow arrangement (Thulukkanam, 2013)

Counter flow

In this type, as shown in Figure 1.18a, the two fluids flow parallel to each other but in opposite directions, and its temperature distribution may be idealized as shown in Figure 25. Ideally, this is the most efficient of all flow arrangements for single-pass arrangements under the same parameters. Since the temperature difference across the exchanger wall at a given cross section is the lowest, it produces minimum thermal stresses in the wall for equivalent performance compared to other flow arrangements. In certain types of heat exchangers, counter flow arrangement cannot be achieved easily, due to manufacturing difficulties associated with the separation of the fluids at each end, and the design of inlet and outlet header design is complex and difficult.

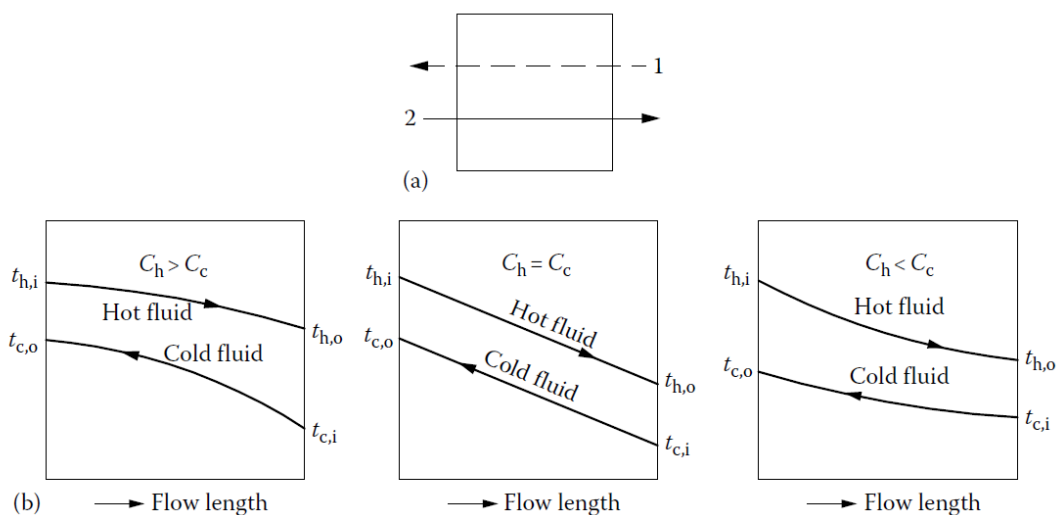


Figure 25: (a) Counterflow arrangement (schematic) and (b) temperature distribution (schematic). (Note: C_h and C_c are the heat capacity rate of hot fluid and cold fluid respectively, i refers to inlet, o refers to outlet conditions and t refers to fluid temperature.) (Thulukkanam, 2013)

Crossflow

In this type, as shown in Figure 26, the two fluids flow normal to each other. Important types of flow arrangement combinations for a single-pass cross flow exchanger include the following:

- Both fluids unmixed
- One fluid unmixed and the other fluid mixed
- Both fluids mixed

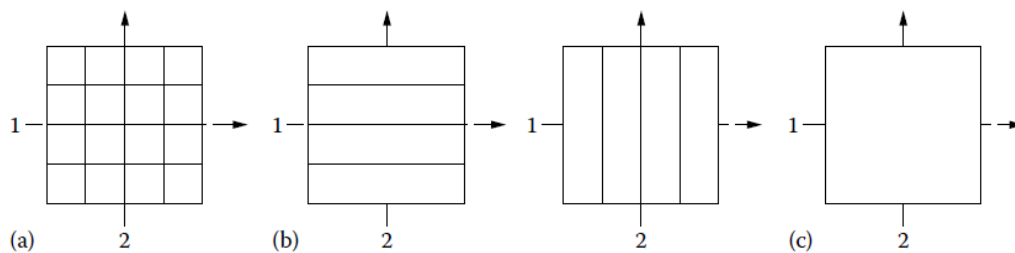


Figure 26: Crossflow arrangement: (a) unmixed–unmixed, (b) unmixed–mixed, and (c) mixed–mixed (Thulukkanam, 2013)

2.6.1.2 Operating and Maintenance

Periodical cleaning of heat exchangers will be necessary, even if the heat exchanger is well-designed and the fluid treatment is effective. Especially for various industries like the pharmaceutical, dairy and food industries quick access to internal components of the heat exchangers for frequent cleaning is necessary. Spiral plate exchangers can be made with both sides open at one edge, or with one side open and one closed. They can be made with channels between 5 and 25 mm wide, with or without studs. STHS can be made with fixed tubesheets or with a removable tube bundle, with small- or large-diameter tubes, or small or wide pitch. A lamella heat exchanger bundle is removable and thus fairly easy to clean on the shellside. Inside, the lamella, however, cannot be drilled to remove the hard fouling deposits. Gasketed PHEs are easy to open, especially when all nozzles are located on the stationary end-plate side. The plate arrangement can be changed for other duties within the frame and nozzle capacity.

Repair of some of the shell and tube exchanger components is possible, but the repair of expansion joint is very difficult. Tubes can be renewed or plugged. Repair of compact heat exchangers of tube-fin type is very difficult except by plugging of the tube. Repair of the plate-fin exchanger is generally very difficult. For these two types of heat exchangers, extension of units for higher thermal duties is generally not possible. All these drawbacks are easily overcome in a PHE. It can be easily repaired, and plates and other parts can be easily replaced. Due to modular construction, PHEs possess the flexibility of enhancing or reducing the heat transfer surface area, modifying the pass arrangement, and addition of more than one duty according to the heat transfer requirements at a future date. (Thulukkanam, 2013)

2.6.1.3 Integration of Heat Exchangers

A heat recovery system can be treated as a heat exchanger network with different kinds of exchangers in which hot process streams can be cooled by the cold streams to be heated, and vice versa. In this way, the heating and cooling loads from external sources (hot and cold utilities) can be dramatically reduced. (VDI, 2010)

To analyse potential for heat recovery for an industrial process or a total industrial site and to design utilities for energy supply the **Pinch Analysis** is used as a classical methodology. Further it can be used for the design of the best heat recovery and utility mix based on a fixed utility system (e.g. envisioned solar heat supply). (Hassine et al., 2015)

For the Pinch Analysis a list of heating requirements (cold streams) and the cooling requirements (hot streams) of the whole industrial site is established (see Figure 27). Also streams which are not necessary for the process (e.g. waste water) can be included when they are used for heating or cooling of other streams. The streams are defined by the following parameters: a) mass flow, b) specific heat capacity and c) inlet and target temperature. (Hassine et al., 2015)

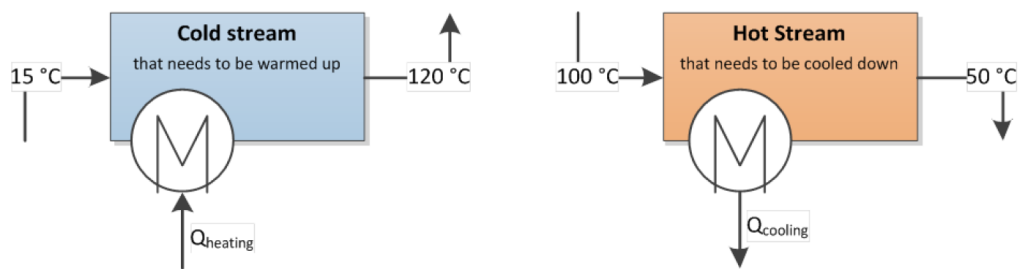


Figure 27: Left: Cold streams; Right: Hot streams in the Pinch Analysis (Hassine et al., 2015)

To determine and illustrate the heat recovery potential, the individual temperature enthalpy profiles of cold streams are combined into one global profile (resulting in the so-called cold composite curve CCC as seen in Figure 28), and similarly for the hot streams (resulting in the hot composite curve HCC). (Hassine et al., 2015)

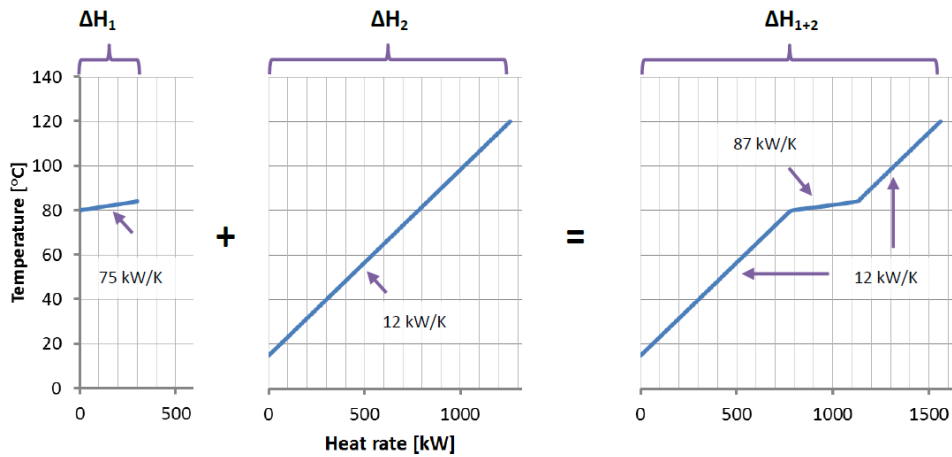


Figure 28: The cold composite curve – it is constructed by summing up the enthalpy changes of each stream in each temperature interval. In temperature intervals with several cold streams, the slope values are added. (Hassine et al., 2015)

Both curves are then drawn on the same temperature-heat duty diagram in such a way that the cold streams (i.e. cold composite) are at a lower temperature than the hot streams (i.e. hot composite) everywhere in the diagram (see Figure 29). This can be achieved by moving the curves along the energy axis, as an energy value always represents a relative and not an absolute measurement. This way the maximum possible energy transfer (heat recovery) becomes visible. With the help of these composite curves (CCs) it is possible to determine some essential facts about the process. The curves are separated by a point of the lowest (vertical) temperature difference ΔT_{min} that is chosen by the user as the minimal ΔT over a possible heat exchanger in the system (this global ΔT_{min} is an economic parameter representing the optimal trade-off between energy savings and capital costs). This ΔT_{min} defines the temperature level in the system that can be explained as the thermodynamic bottleneck of the process, the so-called “Pinch”. The exact Pinch point lies in the middle between the HCC and the CCC, which is 77.5°C in Figure 29.

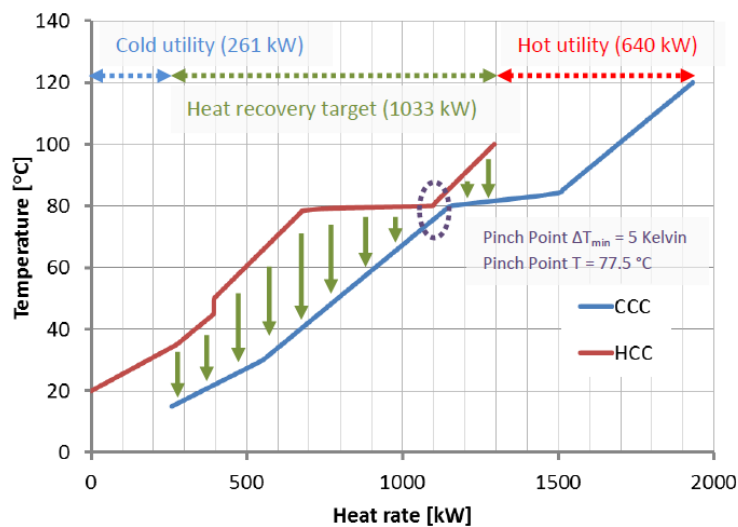


Figure 29: Hot and cold composite curve (Hassine et al., 2015)

The horizontal overlap between the curves in Figure 29 shows the maximum possible heat recovery. The minimum heating demand (hot utility) $Q_{H, \min}$, and the minimum cooling demand (cold utility) $Q_{C, \min}$ can also be identified from the figure. The minimum temperature difference ΔT_{\min} is determined by economical optimization, as a lower ΔT_{\min} increases the efficiency of heat exchange, but also increases heat exchanger surfaces and costs. The composite curve identifies the beneficial process modifications (change of operation conditions: pressure, temperature, etc.) that may shift the heat sinks or heat sources to increase the heat recovery potential.

The Pinch temperature cuts the system in two halves: in an area below the Pinch temperature (the part of composite curves on the left of Pinch) with a heat surplus that has to be removed by external cooling and an area above the Pinch temperature (the part of composite curves on the right of Pinch) with an energy deficit that has to be overcome by additional heating. Three important rules for heat integration follow:

- No external heating below the Pinch temperature (since there is enough waste heat available, an additional integration of heat sources below the Pinch will increase the cooling demand by cold utilities).
- No external cooling above the Pinch temperature (since cooling can be achieved by heating other cold process streams, otherwise unnecessary heating utility use is needed).
- Do not transfer heat from heat sources above to heat sinks below the Pinch

Of course, the target values given by the CCs hold for the ideally heat integrated situation assuming heat from hot process streams can be transferred to cold process streams i.e. the process heat transfer is technically feasible at affordable costs (e.g. not hindered by heavy fouling properties, etc.). If some streams obviously do not fulfill these requirements, these streams should not be included in the composite curves and the Pinch temperature may change.

Further, the CCs provide no information about the lowest temperature level at which the hot utility is actually required (respectively the highest temperature level of cold utility). To address this issue, necessary for the appropriate selection and optimization of utilities and especially relevant for selection the solar heat integration, another curve is used, called the grand composite curve (GCC). The GCC (Figure 30) represents then the temperature profile of the remaining heating (respectively the remaining cooling) requirements. The curve is directly derived from the hot and cold composite curves and its construction is demonstrated in Appendix A. The GCC, for example, is the essential basis for deciding whether a heat pump or a cogeneration unit is potentially attractive and, if they are, at which size. Similarly, for solar heat integration, the GCC provides the key information of the possible maximum heating rate contribution of the solar thermal system as a function of its operation temperatures. The GCC can also be drawn based on the existing utilities.

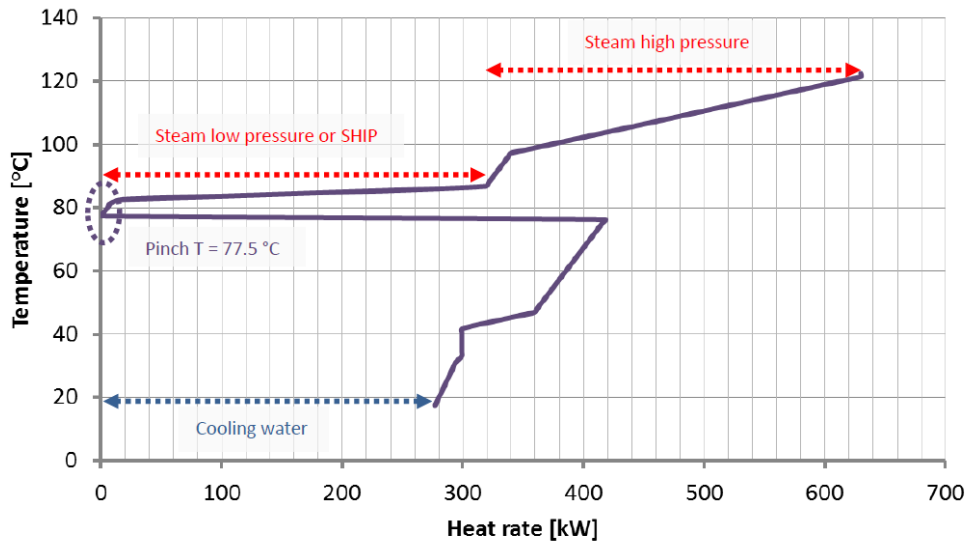


Figure 30: Grand composite curve (Hassine et al., 2015)

The GCC also allows evaluating the combined use of heat pumps and solar heat. According to the rules defined by the Pinch technology, heating below the Pinch and cooling above the Pinch is not allowed. For the correct placing of a heat pump this means that the evaporator (cold end) of the heat pump has to be placed below the Pinch and the condenser (hot end) above the Pinch. By doing so, there is a double effect: the heat pump reduces the cooling load and the heating load at the same time. Since both heat exchangers operate at constant temperatures (phase change of a single fluid), two horizontal lines will be added in the hot and cold composite curves, if the heat pump exchangers are treated like process equipment. The grand composite curve shows exactly the temperature levels and their power for heating or cooling. For solar heat integration there is the additional possibility to integrate low temperature solar heat together with waste heat as low temperature heat source for the heat pump.

Design: Once the utilities have been selected and sized (flows, operation temperatures) according to the GCC, one can integrate the utilities again in the composite curves. On this basis, the practical placement of the heat exchanger network can be identified. Here, automated optimization algorithms have been developed that suggest the most energy efficient and cost effective heat exchanger placement.

2.6.2 Technology cost

2.6.2.1 Investment costs

Heat exchangers are essential components in process technology. Therefore, the economic selection and design of heat exchangers plays an important role for the profitability of a process. (VDI, 2010)

There are two major costs to consider in designing a heat exchanger: the manufacturing cost and the operating costs, including maintenance costs. In general, the less the heat

transfer surface area and less the complexity of the design, the lower is the manufacturing cost. (Thulukkanam, 2013)

Via the platform of UNEX, 2017 the specific costs of water-water heat exchangers in a capacity range of 0-1,000 kW were calculated and the results are presented in Figure 31. The specific costs for water-water heat exchangers are between 2.5 and 34 €/kW. It can clearly be seen that the specific costs decrease with increasing power of the heat exchanger.

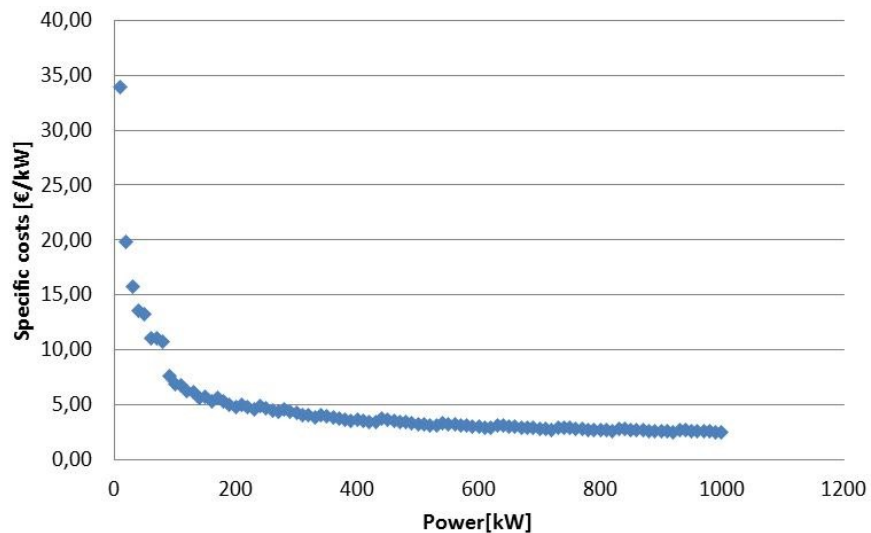


Figure 31: Specific costs of water-water heat exchanger (Own graphic based on platform of UNEX, 2017)

In Table 18 the specific cost calculations for different other heat exchanger types are shown.

Table 18: Specific cost analysis of different heat (Thessing, 2009)

Type	Material	Power [kW]	Specific cost [€/kW]
Air / Water	Stainless steel smooth pipe	82	194.6
Steam / thermal oil	Threaded plates	109	181.9
Steam / thermal oil	Threaded plates	224	145
Air / Water	Finned tube galvanized steel	244	132.2
Steam / thermal oil	Screwed plates	273	45.1
Air / Water	Finned tube galvanized steel	305	33.3
Air / Water	Finned tube galvanized steel	304	26.4
Thermal oil / air	Finned tube galvanized steel	456	35
Air / air	Straight pipe	674	40.8
Air / air	Plates	718	86.7
Air / air	Plates	762	92
Thermal oil / water	Screwed plates	840	8.7
Gas / water	Finned tube galvanized steel	273	24.3
Gas / water	Finned tube galvanized steel	456	18.3

Type	Material	Power [kW]	Specific cost [€/kW]
Gas / water	Steel smooth tube	810	29.3
Exhaust / thermal oil	Stainless Steel Straight Pipe	304	61.3
Exhaust / thermal oil	Finned tube galvanized steel	840	83.7
Exhaust / thermal oil	Steel smooth tube	3.220	84.6
Exhaust / thermal oil	Steel smooth tube	5.102	97
Exhaust / thermal oil	Steel smooth tube	6.800	82.4
Water / water	Tube steel smooth tube	2.000	8.2
Steam / water	Tube steel smooth tube	6.000	8.8
Water / water	Tube steel smooth tube	7.455	6
Steam / water	Tube steel smooth tube	32.100	2.2
Steam water	Tube steel smooth tube	61.340	2.3

2.6.2.2 Operating and Maintenance costs

The operating cost is the pumping cost due to pumping devices such as fans, blowers, and pumps. The maintenance costs include costs of spares that require frequent renewal due to corrosion, and costs due to corrosion/fouling prevention and control. Therefore, the heat exchanger design requires a proper balance between thermal sizing and pressure drop. (Thulukkanam, 2013)

If fouling occurs maintenance costs need to be spent on removing fouling deposits and costs for chemicals or other operating costs of antifouling devices. About 50 % of the maintenance costs of heat exchangers could be attributed to fouling. (VDI, 2010)

3 Energy sources and costs

3.1 Conventional energy sources

The prices of fossil derived fuels depends on a range of different supply and demand conditions, including the geopolitical situation, new technologies, global economic activity, network costs, environmental protection costs, taxation, etc. For example, horizontal drilling and multi-stage hydraulic fracturing are now utilized to access oil and natural gas resources from shale rock formations that were previously either technically impossible or uneconomic to produce (American Petroleum Institute, 2014)

Prices presented in this report generally include taxes, levies but exclude (deductible) VAT for industrial/business users.

3.1.1 Natural gas

3.1.1.1 Consumption and production in EU-28

The main EU gas producers are the UK, the Netherlands, Denmark, Germany and Romania. The production of natural gas in EU the reserves are expected to decline in the following years. Germany and Denmark are exposed to a gradually inevitable decline in natural gas production, while the UK is depending on new fields coming into operation in expensive areas like West of Shetland (European Union 2016).

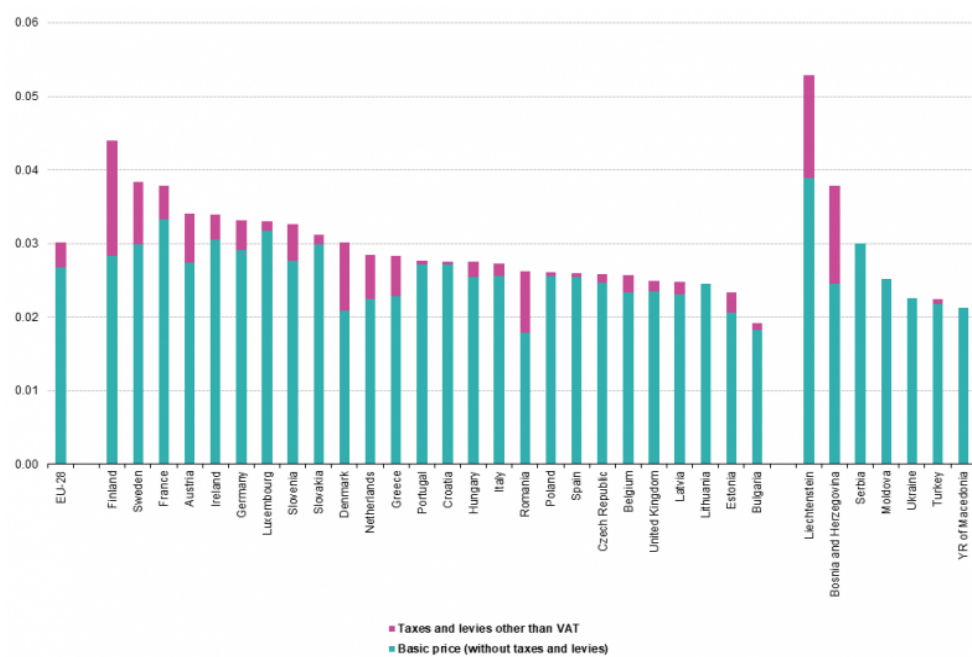
For **industrial consumers**, the medium standard industrial consumption corresponds to **annual natural gas consumption** between **10,000** and **100,000 GJ**. The most common way to refer prices of fossil fuels for industrial users correspond to the basic price and non-deductible taxes and levies but excluding deductible VAT.

According to Eurostat, across the EU-28, the price of natural gas for a medium-sized industrial consumer averaged **EUR 0.034 per kWh** in the second half of 2015. The difference in prices across the EU Member States was far less than that observed for household consumers. The lowest natural gas price for industrial consumers among the Member States was recorded in **Lithuania (EUR 0.022 per kWh)**; as a result, the highest prices (Finland and Sweden) were **1.9 times as high as in Lithuania**.

The relative share of tax and other levies (other than VAT) in the price of natural gas for industrial consumers was highest in Finland (32.9 %) and Romania (30.0 %), where close to one third of the final price was made up of taxes and levies, while taxes and levies also accounted for more than one fifth of the final price in Denmark, Austria and Sweden. By contrast, in Lithuania there were no taxes and levies applied to the price of natural gas for industrial consumers, while in Portugal, Croatia, Spain and Poland, the weight of taxes and other levies in the price of natural gas for industrial remained below 2.0 %.

Figure 32 shows the price of natural gas for industrial consumers during the second half of 2016. Price is presented as the average national price in Euro per Giga Joule (GJ) without taxes applicable for the first semester of each year for medium size industrial consumers (Consumption Band I3 with annual consumption between 10,000 and 100,000 GJ). Until 2007 the prices are referring to the status on 1st January of each year for medium size consumers (Standard Consumer I3-1 with annual consumption of 41,860 GJ).

For industrial consumers (defined for the purpose of this article as medium-size consumers with an annual consumption within the range of 10,000 GJ < consumption <100,000 GJ). Natural gas prices were highest among the EU Member States in Finland (EUR 0.044 per kWh), Sweden and France (both EUR 0.038 per kWh); they were lowest in Bulgaria (EUR 0.019 per kWh).



Note: annual consumption: 10 000 GJ < consumption < 100 000 GJ. Excluding VAT. Cyprus and Malta: not relevant.
Source: Eurostat (online data code: nrg_pc_203)

Figure 32: Natural gas prices for industrial consumers, second half 2016 (EUR per kWh) (Eurostat, 2017)

3.1.2 LPG (liquid petroleum gas)

Liquefied petroleum gas (LPG), also referred to as simply propane or butane, are flammable mixtures of hydrocarbon gases used as fuel in heating appliances. Table 19 shows the price (include taxes, levies and VAT), indirect taxes and VAT in EU-28.

Table 19: Price of LPG - motor fuel in EU (Weekly Oil Bulletin, 2017)

	Price	Indirect taxes	VAT
	[€/1,000L]	[€/1,000L]	[%]
Austria	-	-	-
Belgium	-	-	21
Bulgaria	445.50	93.96155026	20
Croatia	549.95	7.476585063	25
Cyprus	513.41		
Czech Republic	557.00	83.00030741	21
Denmark	742.00		
Estonia	531.96	69.92	20
Finland	691.25		
France	445.50	91.9	20
Germany	549.95	91.8	19
Greece			
Hungary	691.25	113.0198263	27
Ireland			
Italy	612.03	147.27	22
Latvia	528.33	118.58	21
Lithuania	520.88	161.17	21
Luxembourg	410.00	54.07	8
Malta	555.00		
Netherlands	427.89	185.79	21
Poland	549.00	110.769962	23
Portugal	493.39	140.05	23
Romania	561.00	67.93680705	19
Slovakia	633.77	98.28	20
Slovenia	603.01	114.54	22
Spain	612.03	32.41	21
Sweden			
United Kingdom			

3.1.3 Heavy fuel oil

3.1.3.1 Consumption and production in EU28

Heavy fuel oil is reported by Eurostat (2015) as residual fuel oil and is classified by its sulphur content in low (< 1%) or high (\geq 1%) sulphur heavy fuel oil.

Globally, for EU28 in 2015, the production of heavy fuel oil obtained from the transformation of primary oil products was around 68 Mtoe. The import and export market traded about 62 Mtoe and 78 Mtoe, respectively. Deliveries through international marine bunkers play an important role in the EU28 market of heavy fuel oil with a traded volume of 31 Mtoe. Figure 33 presents the production and trade of heavy fuel oil for EU28 countries in 2015. The transformation output and imports are inferior to 10 Mtoe for all EU28 countries with the exception of the Netherlands. Although presenting the highest production volume of heavy fuel oil, yet similar to that of the largest producers in the EU28, the Netherlands reaches a volume of imports and exports of 10 to 20 times higher than other countries with relevance in the fuel oil market. It is also the largest trader in terms of fuel oil quantities engaged in international marine bunkers. Market-relevant countries, in addition to the Netherlands, have comparable production, import and export volumes, namely France, Belgium, Spain, Germany, Italy, Greece, the United Kingdom, Denmark, Poland and Sweden.

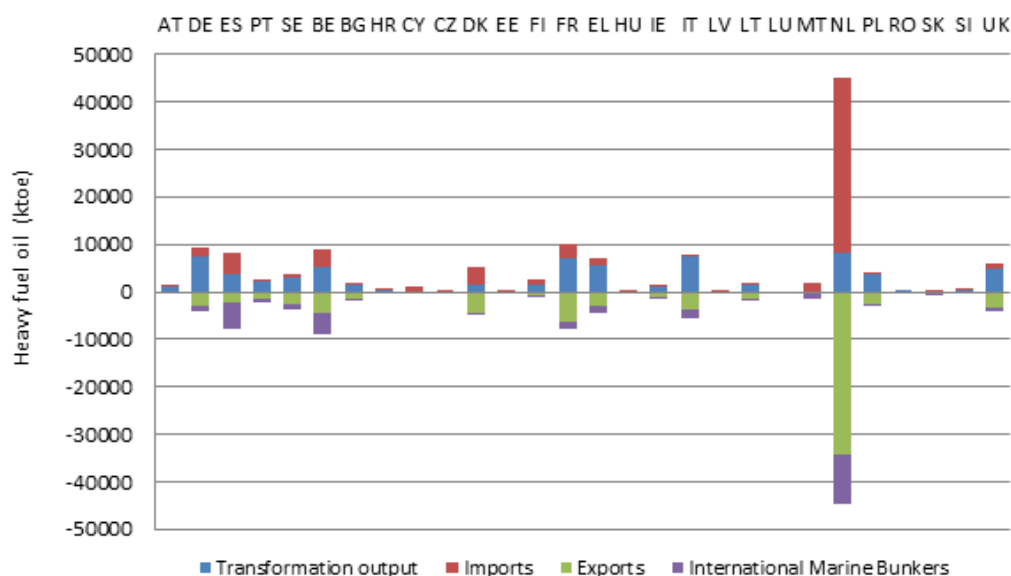


Figure 33: Transformation output, imports, exports and bunkers deliveries of heavy fuel oil for EU28 countries in 2015 (Eurostat, 2017)

The gross inland consumption of heavy fuel oil for EU28 in 2015 presents a negative value for most of the EU28 countries (the exceptions are Cyprus, Estonia, Latvia, Malta and Slovakia). Heavy fuel oil for transformation was used in conventional thermal power plants, where the main activity producer plants are responsible for 83 % of the heavy fuel transformation and autoproducers plants for 12 %. The remaining 5 % enters for transformation in district heating plants. Industry is responsible for 77 % of the total final

energy consumption of heavy fuel oil. The final consumption of fuel oil in industry is dominated by the chemical and petrochemical sector, responsible for 40 % of the total final consumption in industry, followed by the food and tobacco sector (15 %), the non-metallic minerals sector (12 %), the paper and pulp sector (9 %), and the iron and steel sector (8 %).

Figure 34 presents the consumption of heavy fuel oil in the EU28 countries in 2015. With regard to the final consumption of fuel oil in industry, most countries have 60 to 100% share in total final consumption; exceptions are Greece, Malta, Hungary (35 to 40 % share) and Netherlands (17 % share). In countries like Germany, Belgium, Ireland, Lithuania, Romania, Slovakia and Slovenia, the final consumption of fuel oil is fully realized in the industry. Latvia and Luxembourg do not have fuel oil consumption; Latvia, however, has international business although at reduced volumes (see Figure 33).

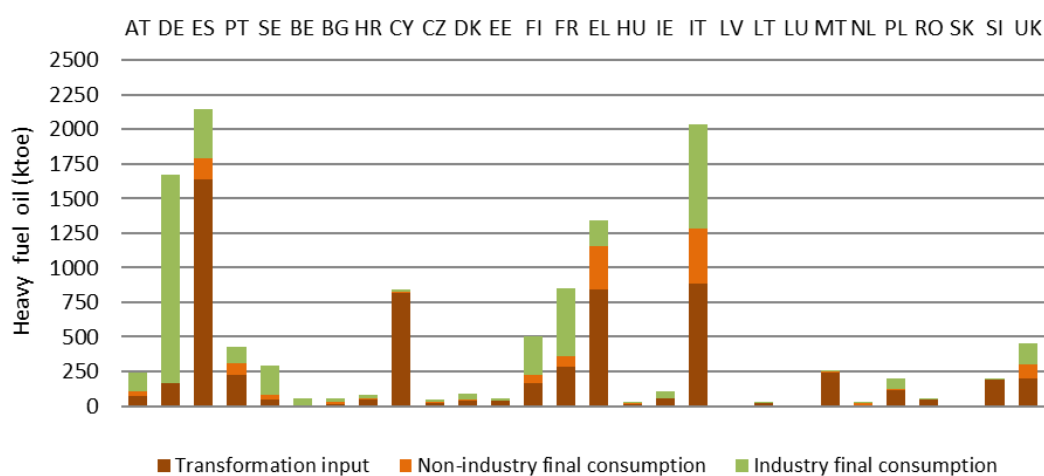


Figure 34: Consumption of heavy fuel oil for EU28 countries in 2015 (Eurostat, 2017)

3.1.3.2 Heavy fuel oil prices

Accordingly to IEA (2017), the average end-use total price for heavy fuel oil (low sulphur content) for industry in the last year (between July 2016 and June 2017) for France, Italy and Spain ranged from about 350 to 420 €/t (see Table 20). The price for Germany presented in the table is an average of the total prices from July 2016 to December 2016.

Table 20: Heavy fuel oil average end-use total price for industry (IEA, 2017)

Country	average end-use price¹ (€/t)
Germany	273
Spain	345
Italy	365
France	421

¹ VAT excluded from prices for France, Italy and Spain as it is refunded to industry.

Based on data presented by IEA (2016), Table 21 present the available low sulphur heavy fuel oil prices for industry in the European OECD countries, during the first quarter of 2016 or latest available quarter. Heavy fuel oil price reached the lowest value in Germany and the highest value in Sweden.

Table 21: Heavy fuel oil average price for industry (IEA, 2016)

Country	Price ⁷ (€/t)
Austria	233.2
Belgium	172.0
Czech Republic	391.2
Denmark	360.7
France	261.6
Germany	156.8
Greece	249.8
Hungary	268.7
Ireland	484.9
Italy	249.3
Netherlands	393.8
Poland	278.7
Portugal	446.9
Spain	217.2
Sweden	665.2

3.1.4 Heating gas oil

Heating gas-oil is a low viscosity, liquid petroleum product used as a fuel oil for boilers in industries. Heating oil consists of a mixture of petroleum-derived hydrocarbons in the 14- to 20-carbon atom range that condenses between 250 and 350 °C (482 and 662 °F) during oil refining. Heating oil produces 38.6 MJ/l and weighs 0.95 kg/l. Number 2 fuel oil has a flash point of 52 °C. (North American Manufacturing, 2010)

Heating oil is commonly delivered by tank truck to the industry and stored in above-ground storage tanks.

Most heating oil products are chemically very similar to diesel fuel used as motor fuel, but the taxation of heating oil is less than motor fuel. Since 2002, Solvent Yellow 124 has been added as a "Euromarker" in the European Union.

Table 22 shows the price of heating gas-oil in EU-28. The prices are delivered consumer prices for deliveries of 2,000 to 5,000 litres (for offtakes of less than 2,000 litres the industrial sector may be taken into consideration).

Comparisons between prices in different countries shall be carefully made. They are of limited validity because of differences in product quality, in marketing practices, in market structures, and to the extent that standard categories are representative of the total sales of a given product.

⁷ Prices were converted from USD to Euros using a factor of 0.87 €/USD

Table 22: Price of heating gas-oil in EU (Weekly Oil Bulletin)

	Price	Indirect taxes	VAT
	[€/1,000L]	[€/1,000L]	[%]
Austria	646,11	109,18	20,
Belgium	525,20	18,65	21,
Bulgaria	901,32	330,2996216	20,
Croatia	571,54	46,29004831	25,
Cyprus	760,67	135,43	19,
Czech Republic	594,60	91,26191208	21,
Denmark	1.092,37	329,2048251	25,
Estonia	696,00	110,95	20,
Finland	836,00	228,7	24,
France	681,38	118,9	20,
Germany	561,36	61,35	19,
Greece			
Hungary	1.111,60	366,9211863	27,
Ireland	579,80	122,28	13,5
Italy	1.126,63	403,21	22,
Latvia	576,68	29,36	21,
Lithuania	568,94	21,14	21,
Luxembourg	496,00	10	14,
Malta	1.000,00	232,09	18,
Netherlands	974,00	493,92	21,
Poland	642,58	55,13307985	23,
Portugal	1.004,00	346,95	23,
Romania	782,51	332,6263202	19,
Slovakia			
Slovenia	783,67	253,43	22,
Spain	595,08	89,28	21,
Sweden	1.052,12	422,3897876	25,
United Kingdom	526,83	124,6782317	5,
EUR 28 Weighted average	634,87		

3.1.5 Coal

3.1.5.1 Consumption and production in EU28

Primary coal products and their derived fuels are considered primary energy sources and include solid fuels and manufactured gases (IEA, 2005). Primary coal products such as anthracite, coking coal, other bituminous^{8,9} and sub-bituminous coal are considered hard coals with HHV (wb%) equal or higher to 24 MJ/kg, while lignite or brown coal and peat, represent a low grade category of coals with HHV (db%) less than 20 MJ/kg. Relevant coal derived fuels are coke-oven coke and brown coal briquettes (BKB). Coke-oven coke presents the highest heating value compared with the other coal solid fuels (primary and derived products) and is mainly derived from coking coal in coke-ovens (less than 0.5% is obtained from brown coal/lignite). All these coal products can be considered the most important fossil solid fuels concerning production, trade and consumption in EU28. Other fuels such as patent fuels and peat briquettes represent a very small fraction in the EU28 market of fossil solid fuels for energy generation. Like coke-oven coke, coal tar is also obtained by transformation of bituminous coal and brown coal in coke-ovens; about 94% of the coal tar available for final consumption is for non-energy uses (of which almost 3/4 is used in chemical/petrochemical industry).

The production of primary coal products for EU28 in 2015 was dominated by lignite (58%), followed by hard coal (41%) and a very small amount of peat (about 1%). Hard coal is mainly other bituminous coal (72%) and coking coal (25%), with anthracite representing only 3% of total hard coal production. Derived fuel production (about 32 Mtoe) is strongly based in coke-oven coke (85%) and BKB (11%). EU28 import market of coal fuels is directed to hard coal (95%) and a small fraction to coke-oven coke (4%). Exports are based in the same products, but hard coal has a lower contribution in total solid fuels exports.

Figure 35 presents the production and trade of coal products in EU28 countries for 2015. Poland and Germany were the main producers of primary coal products; together they represented 69% of the indigenous production of coal in EU28. Germany primary coal production is mainly lignite (89%) and the remaining is hard coal. Poland primary coal production is mainly hard coal, namely other bituminous coal (60%) and coking coal (17%), and the remaining production is lignite. Another relevant country is the Czech Republic, which contributes with 12% of the primary coal production in EU28 (mainly lignite (68%), coking coal (17%) and other bituminous coal (15%)). The imports of coal products (primary and derived) occur mostly in Germany and the Netherlands. Both countries import similar quantities of coal products and together contribute with 47% of the total imported coal products in EU28. Other relevant importers are the United Kingdom, Italy, Spain and Finland. As far as export markets are concerned, the Netherlands and Poland are the main exporters of coal products, representing together 84% of total exported primary coal products in EU28.

⁸ Include all bituminous coal that is not included under coking coal or anthracite.

⁹ Other bituminous coal is often denominated by steam coal and is mainly used for steam generation (heat or power).

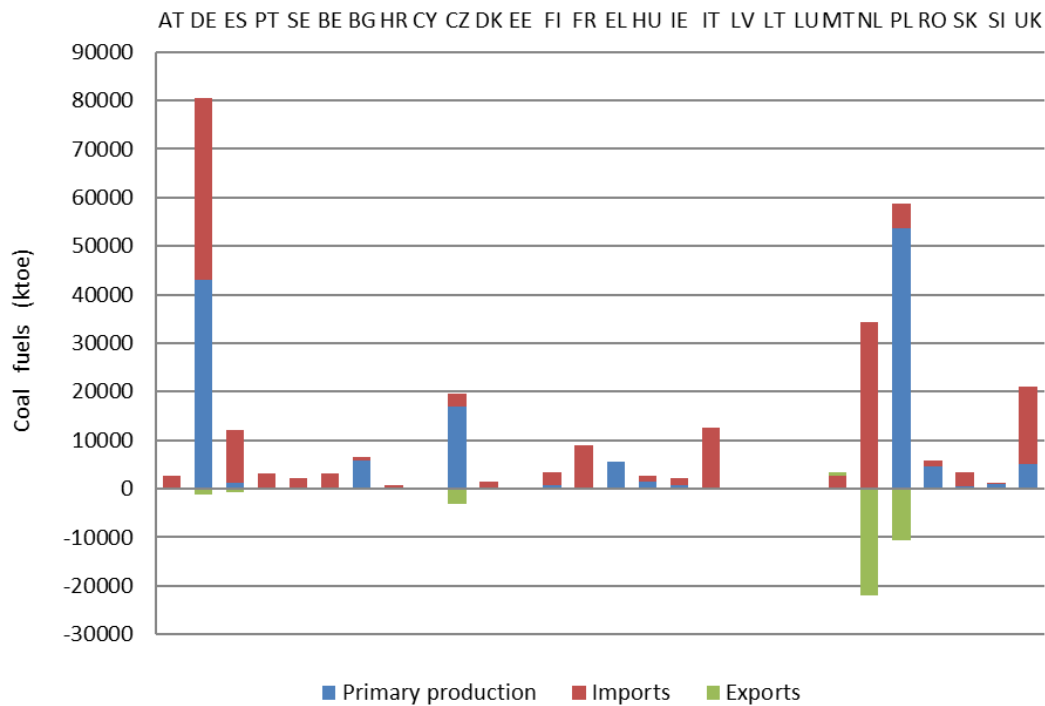


Figure 35: Primary production, imports and exports of primary coal products for EU28 countries in 2015 (Eurostat, 2017)

The gross inland consumption of primary coal fuels for EU28 in 2015 was dominated by hard coal products (68%), followed by lignite (31%) and a very small amount of peat (about 1%). Hard coal products are mainly other bituminous coal (73%) and coking coal (23%), with anthracite representing only 3% of total hard coal gross inland consumption. Coal fuels for transformation are mainly used in conventional thermal power plants (74% in main activity producers and 1% in autoproducers), followed by the transformation in coke-ovens (15%) and blast furnaces (5.5%). BKB/Peat briquettes plants and district heating plants represent, respectively, about 2% and 1.5% of the transformation input of solid fuels.

Industry is responsible for 3/4 of the total final energy consumption of solid fuels, being 57% related to hard coal, 35% to coke-oven coke, 5% to BKB, 2% to lignite and 1% concerning the remaining solid fuels, namely peat and coal tar. It is important to note that the iron and steel industry consumes 67% of the total solid fuels used by industry (50% is coke-oven coke, 49% is hard coal and 1% lignite, BKB and coal tar). The non-metallic mineral industry consumes 13% (60% other bituminous coal, 25% BKB and 7% coke-oven coke) and the chemical and petrochemical industry consumes 9% (about 3/4 is other bituminous coal). The remaining coal is mainly consumed in the food and tobacco industry and in pulp and paper industry (more than 3/4 is other bituminous coal for both industries).

Figure 36 presents the consumption of coal fuels (primary and derived products) in the EU28 countries in 2015. Germany and Poland are responsible for about half of the transformation input (49%) and final consumption of coal fuels (51%). Concerning the final consumption in industry these countries represent 40% of the EU28 total consumption of coal fuels in industry (mainly other bituminous coal and coke-oven coke for the iron and steel industry).

It should be noted that in almost all EU28 countries, the share of the final consumption of coal in industry in the total final consumption of coal is from 50 to 100%; exceptions are Malta, Ireland and Poland, with 8%, 21 and 3% share, respectively). In the majority of the countries, this share was higher than 90%.

In industry, steam coal represents 45% of the total solid fuels final consumption while lignite contributes only with 2% for the final consumption of solid fuels in industry. Coke-oven coke represents the other relevant fraction of the final consumption in industry of solid fuels with 35% of share; 94% of the coke-oven coke final consumption occurs in the iron and steel industry, and, accordingly with an ICF study (2015) only 5% of the applications using coal products is for steam generation purposes. The transformation input contribution from steam coal for conventional and district plants was 56% in 2015 for UE28; lignite was responsible for 39% of the input for the same applications.

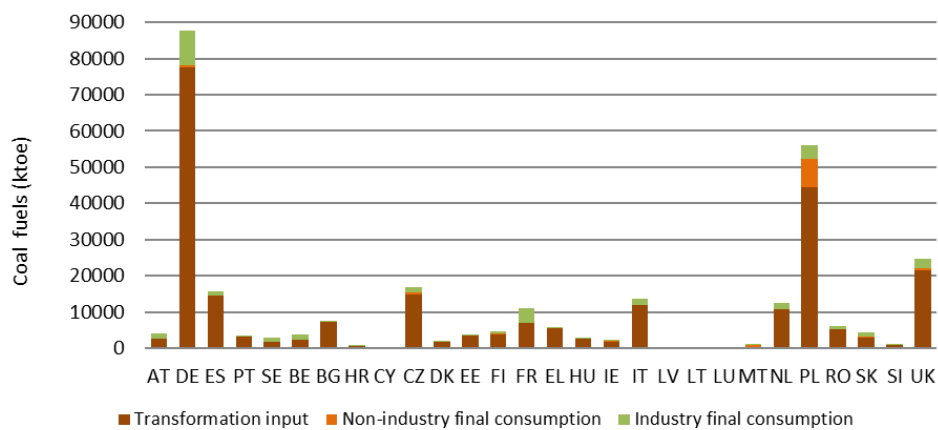


Figure 36: Consumption of coal fuels for EU28 countries in 2015 (Eurostat, 2017)

3.1.5.2 Coal prices

Figure 24 presents the steam coal prices for industry in the European OECD countries reported by IEA (2016). Steam coal prices reached the lowest value in Poland and the highest value in Finland.

Table 23: Steam coal prices for industry (IEA, 2016)

Country	Price ¹⁰ (€/t)
Austria	147.7
Finland	213.8
Poland	61.0
Portugal	95.0
Switzerland	85.9
UK	119.7

BP (2017) reports the Northwest Europe marker price calculated as CIF prices to be 52 €/t in 2016. At present, the industry standard reference price used to trade coal imported into northwest Europe is denominated by API 2 index. The API 2 index is an average of the Argus CIF Rotterdam assessment¹¹ and IHS McCloskey's northwest European steam coal marker¹².

¹⁰ Prices were converted from USD to Euros using a factor of 0.87 €/USD.

¹¹ The index is derived from multiple inputs by a broad spectrum of key market participants based on the physical buy/sell transactions and market assessment based on the Argus criteria.

¹² This marker is compiled through a combination of physical market activity (transactions and bid/offer levels) and a survey of active market participants.

3.2 Renewable energy sources

Renewable energy sources are derived from natural processes that are replenished constantly at a rate equal to or greater than the rate of consumption. In its various forms, renewable energy sources are derived directly or indirectly from the sun. Renewables come in many forms – electricity generated from solar, wind, biomass, geothermal, hydropower, and ocean sources; heat generated from solar thermal, geothermal and biomass sources; bio-fuels and hydrogen obtained from renewable sources. And, they are capable of supplying most of the world's energy needs and have the potential to support global economic development.

This chapter gives an overview of the availability of selected renewable energy sources in the European Union. It should be noted that only the renewable energy sources considered in the project TrustEE are described. Those are: **Solar energy, biomass and biogas**

3.2.1 Solar energy

Global, direct, and diffuse radiation is typically measured on a horizontal surface.

The **Global Horizontal Irradiation (GHI)** is the total amount of shortwave radiation received above by a surface horizontal to the ground. The value includes both Direct Normal Irradiation and Direct Horizontal Irradiation.

Direct Normal Irradiance (DNI) is the amount of solar radiation received per unit area by a surface that is always held perpendicular (or normal) to the rays that come in a straight line from the direction of the sun at its current position in the sky. Typically, you can maximize the amount of irradiance annually received by a surface by keeping it normal to incoming radiation. This quantity is of particular interest to concentrating solar thermal installations and installations that track the position of the sun.

Diffuse Horizontal Irradiance (DHI) is the amount of radiation received per unit area by a surface (not subject to any shade or shadow) that does not arrive on a direct path from the sun, but has been scattered by molecules and particles in the atmosphere and comes equally from all directions.

The relevant solar resource information to assess the solar system productivity depends on the solar technology being used. In the case of **stationary collectors**, the relevant parameters are the **GHI** and the **DHI**. In the case of **tracking collectors**, the relevant parameter is **DNI**.

The solar resources present a strong geographic dependence, thus the system location is a critical factor. In Central and Northern Europe, the diffuse radiation plays an important role for solar energy conversion. In these areas, the diffuse part of the global radiation energy amounts to between 40 % (summer) and 80 % (winter). In Southern countries, direct radiation can be used to produce high-temperature heat by using concentrating collectors.

The annual available radiant energy depends on the geographical location and meteorological conditions – values range between 2,200 kWh/(m².a) in Southern Europe to 800 kWh/(m², a) in UK (see Figure 37). The solar radiation on the earth's surface has seasonal variations, which can be 1:2 in the tropic zones and up to 1:10 in higher latitudes. The

seasonal changes of solar radiation have a larger effect on the available radiation at higher latitudes.

Figure 37 shows the GHI in Europe and Figure 38 shows the DNI in kWh per square meter. Both the global horizontal irradiation and the direct normal irradiation are increasing from the north of Europe to the south.

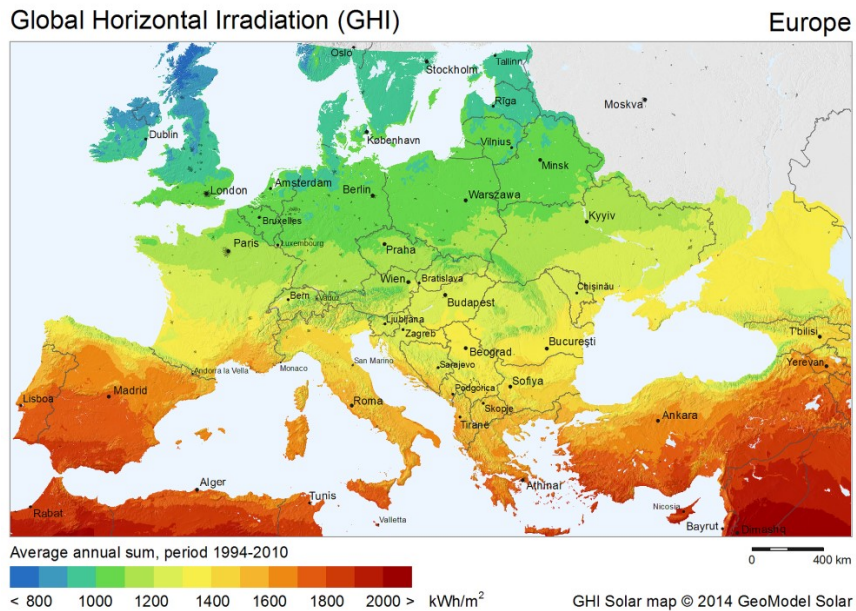


Figure 37: GHI resource map for Europe (Solargis, 2017)

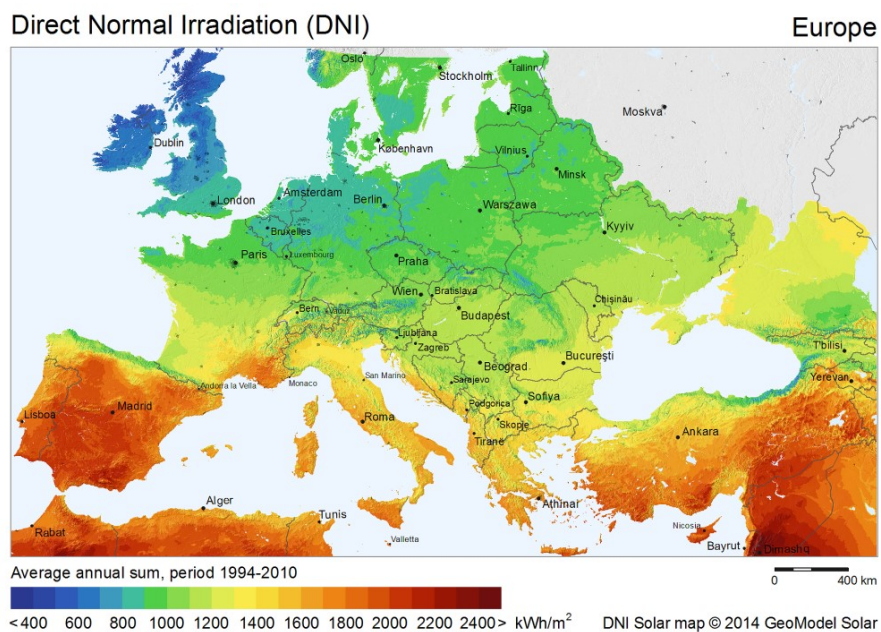


Figure 38: DNI resource map for Europe (SOLARGIS, 2017)

Data on solar resource worldwide is available in different platforms. Two often used and well-known platforms are:

1. **METEONORM:** It is a commercially available software. Solar resource yearly data series obtained either through monitored or interpolated data.

2. **SOLARGIS:** satellite based solar resource maps. Maps freely available. Data series commercially available.

3.2.2 Biomass

Solid biomass for energy purposes can be obtained from **a) residual organic matter** extracted from forests and uncultivated lands; **b) wastes and residues** produced in the industrial, **agricultural and forestry activities**, **c) municipal wastes** and **d) energy crops**. It can be used directly with no further processing or be transformed into a densified solid fuel with higher energy content and bulk density (e.g. pellets and briquettes). The main **advantages** of using biomass fuels instead of fossil fuels are related with the **reduction of greenhouse gas emissions and waste, possible energy cost savings and sustainable local economic development** (e.g., Dermibas, 2005; Abbasi and Abbasi, 2010; Singh, 2015). Biomass is considered as a CO₂-neutral energy source, since it is assumed that the carbon released in the atmosphere was recently stored during the trees' growth. Compared to other renewable resources, biomass fuels are able to generate heat and power in a flexible manner and are a more reliable resource, since they are not weather-dependent. Biomass can be stored and used in similar ways to fossil fuels.

3.2.2.1 Solid biomass fuels consumption and production in EU28

According to Eurostat, 2017 the total primary energy production in EU-28 of biomass fuels in 2015 was three times higher than in 1990 (biomass fuels include solid biofuels, charcoal, gaseous biofuels, liquid biofuels and renewable wastes). Figure 39 presents the evolution of the biomass primary energy production in EU-28 from 1990 until 2015. It can be seen that the biomass primary energy production has been consistently increasing. Two distinct periods can be observed in Figure 39: the first between 1990 and 2002 where the average annual growth rate of biomass primary energy production was 3.3 % and the second after 2002 where it almost doubled (on average it was 5.6 %). With respect to solid biomass, excluding charcoal, the primary energy production in 2015 for EU-28 was 90.4 million tonnes of oil equivalent (toe). This quantity represents 11.8 % of the total primary energy production in EU28 and 70 % of the total biomass primary energy production (Eurostat, 2017).

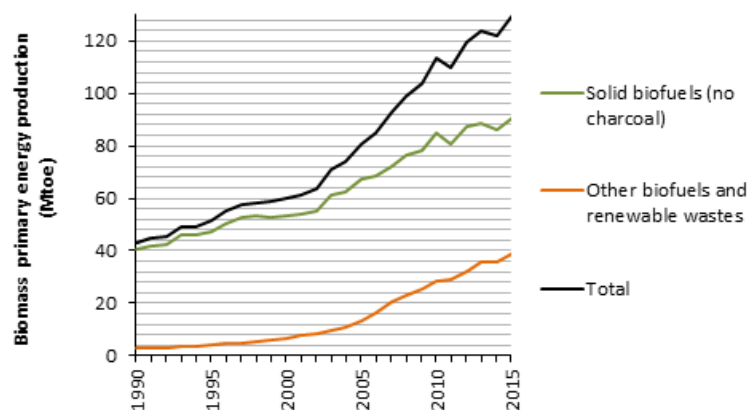


Figure 39: Biomass primary energy production for UE28 in 1990-2015 (Eurostat, 2017)

Germany was the largest producer of solid biomass fuels in the EU in 2015, with about 12.1 million toe, followed by France, Sweden and Finland, each one with productions between 8 and 10 million toe. These four countries had a share of about 41% in the EU28 in

2015. Italy, Poland, Spain and Austria accounted for 25% of the total primary energy production and Romania, United Kingdom, Portugal, Czech Republic, Latvia and Slovakia represented a share of 20%. The remaining fourteen countries had, in 2015, productions of less than 2 million toe, corresponding to a share of 14%. From Figure 40 it is quite clear that certain markets are more self-sufficient than others. In general, a large part of the EU countries did not import solid biofuels in 2015 or the imported volumes were inferior to 0.1 Mtoe. The country with the greatest dependence on solid biofuels imports was the United Kingdom, followed by Italy, Denmark, Belgium and Poland. With regard to the volume of exports, Latvia was the larger exporter, with a volume of 0.8 Mtoe, which was twice of Estonia, the second largest exporter.

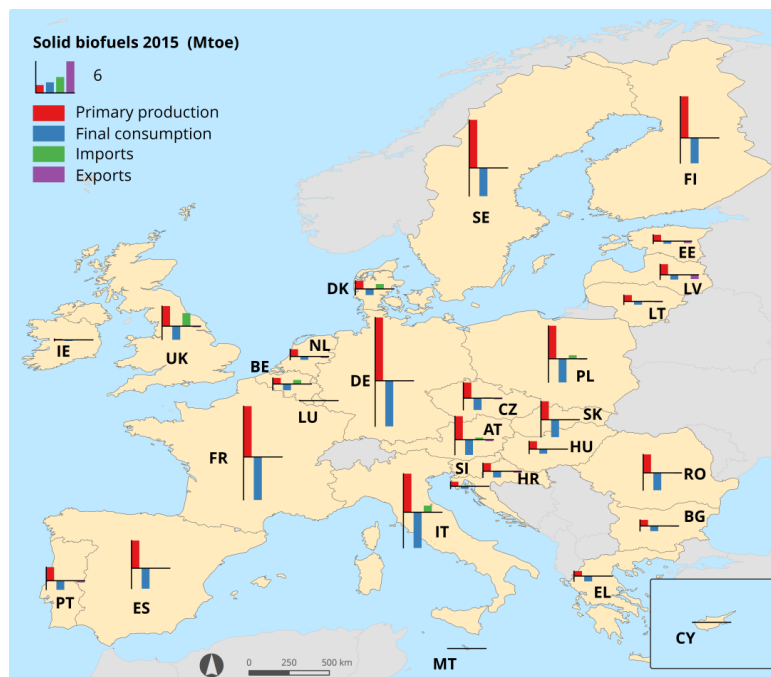


Figure 40: Primary production, final consumption, imports and exports of energy from solid biofuels for UE28 in 2015 (Eurostat, 2017)

According to AEBIOM reports (AEBIOM, 2015, 2016), solid biomass fuels are mostly composed by woody biomass and about 70% of total bioenergy feedstock is obtained from forestry and forest industries. The average consumption of wood products including wood-fuel, sawn wood, wood-based panels, paper and paper board, and (industrial) roundwood (in m^3 RWE per 10^3 inhabitants) in EU28 increased from 1990 to 2005 (1096.4 m^3 RWE per 10^3 inhabitants in 1990 and 1626.9 m^3 RWE per 10^3 inhabitants in 2005) and decreased from 2005 to 2010 (1522.0 m^3 RWE per 10^3 inhabitants) (FAO, 2015; FOREST EUROPE, 2015). The higher consumption of wood based energy is in central and northern Europe, corresponding both to larger forest resources and forest industry (Figure 41).

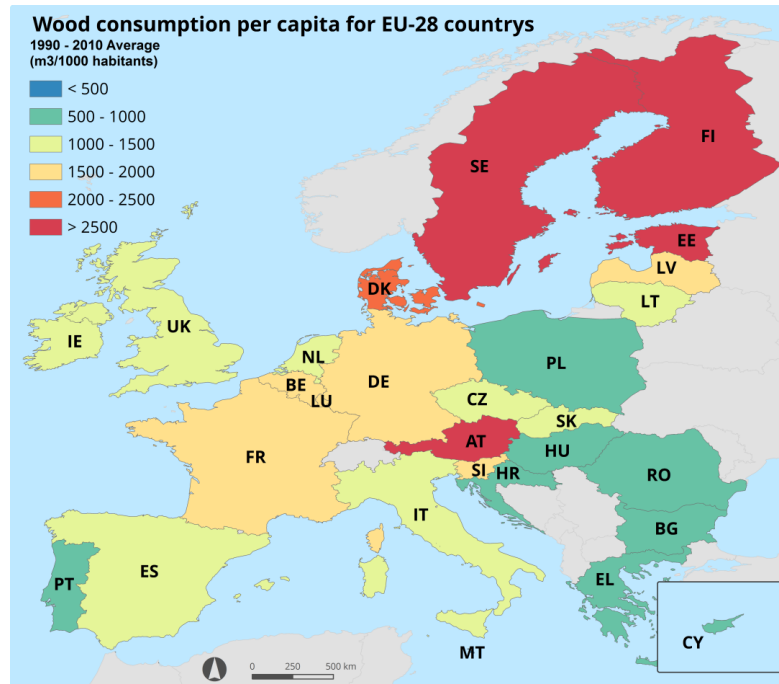


Figure 41: Wood consumption per capita for EU28 countries (FOREST EUROPE, 2015)

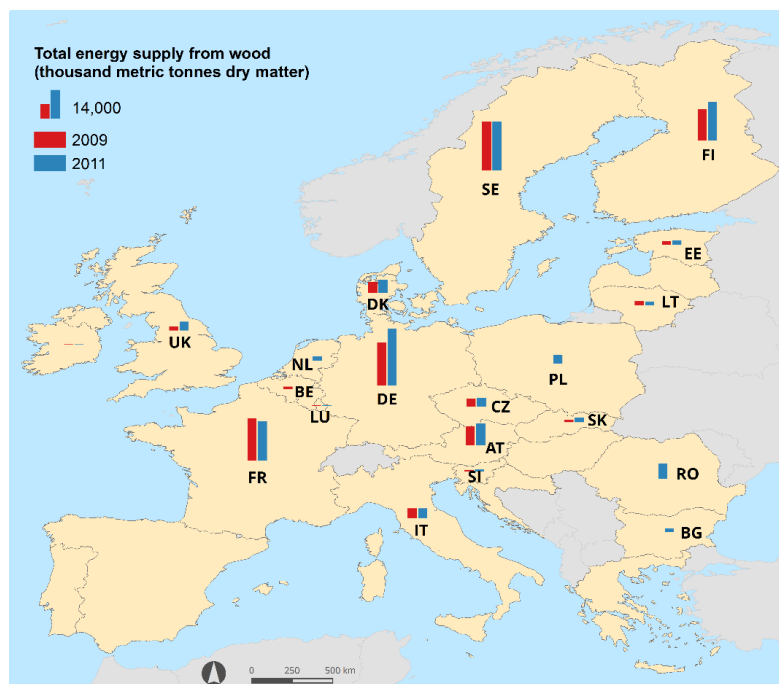


Figure 42: Total energy from wood in 17 EU countries (FOREST EUROPE, 2015)

For several reasons, in the analysis of the energy supply from wood reported by FOREST EUROPE (2015), only 17 countries were considered. From these (Figure 42), Sweden, Germany and France present the largest energy supply and Cyprus, Luxembourg and Ireland the smallest. FOREST EUROPE (2015) divided the energy supply from wood in 3 groups: energy from direct wood fibre sources; energy from co-products and residues of the wood processing industries; and energy from processed wood-based fuels (Figure 42). The first

two classes have a mean share of 43 % and 45 % and 45 % and 48 % of the total energy supply from wood in 2009 and 2011, respectively, while the later has a share of 6 % in 2009 and 7 % in 2011. The highest share of energy supply from wood (about 60 % in both surveys) comes from forests and other wooded lands.

Table 24: Total energy supply from wood (FOREST EUROPE, 2015)

Country	Total energy supply from wood	Energy from direct wood fibre sources			Energy from co-products and residues of the wood processing industries		Energy from processed wood-based fuels	
		Total	Forests & other wooded land	Other land	Total	Solid residues	Total	Imported
2009								
Austria	9,298	3,334	2,842	305	5,590	3,932	375	700
Belgium	1,188	-	-	-	637	266	292	89
Cyprus	13	2	1	1	1	1	10	10
Czech Republic	3,838	2,261	867	694	1,501	660	76	41
Denmark	5,302	2,648	1,479	1,169	479	479	1,622	1,427
Estonia	1,823	724	724	0	1,057	1,023	35	47
Finland	15,410	4,238	4,238	-	10,914	2,985	71	52
France	21,142	12,267	7,449	3,860	7,500	5,085	365	62
Germany	21,446	10,697	9,146	1,551	6,194	6,194	1,683	149
Ireland	308	61	61	0	146	146	47	24
Italy	5,040	3,422	-	-	1,100	1,100	-	547
Lithuania	2,097	1,105	980	126	751	616	86	-
Luxembourg	162	109	-	-	52	52	1	1
Slovakia	1,109	249	238	10	709	331	104	7
Slovenia	954	702	550	151	247	247	6	39
Sweden	24,316	6,583	0	0	14,767	3,410	2,484	452
United Kingdom	2,094	839	493	346	515	496	195	85
2011								
Austria	10,666	3,274	2,709	291	6,886	4,827	505	1,255
Belgium	0							
Bulgaria	1,993	1,450	1,450		538	318	5	0
Cyprus	17	4	0	4	1	1	11	11
Czech Republic	4,148	2,349	919	730	1,667	787	132	73
Denmark	6,368	2,640	1,697	943	635	635	2,427	2,233
Estonia	1,996	1,075	1,044	31	833	713	52	21
Finland	18,828	5,381	5,381	0	13,178	3,451	66	17
France	19,628	14,273	7,317	2,613	4,011	2,269	606	105
Germany	28,277	14,241	12,062	2,179	5,661	4,706	1,910	446
Italy	5,041	3,422			1,100	1,100		68
Lithuania	2,059	846	754	91	625	362	457	
Luxembourg	143	87			54	54	1	4
Slovakia	2,296	952	867	85	1,309	732	27	2
Slovenia	1,177	913	761	151	232	232	6	51
Sweden	24,334	6,898		42	14,755	3,413	2,238	688
United Kingdom	4,316	1,712	1,353	359	1,159	1,066	1,332	1,077

Figure 43 presents the production of wood fuel from forestry activities for EU28 in 2015 (FAOSTAT, 2017). France is the major producer with a share of 18%, followed by Germany

with 11%. Sweden, Finland, Austria, Poland and Romania are also important. These countries contribute with 31% for the total production, while the remaining represent 30%. In the latter Spain, Italy, Hungary and Bulgaria have the major contributions, which are related to their forest area and growing stock. Presently, the use of wood pellets represents 6% of the total solid biomass used in the EU, with a production around 14.1 million tonnes in 2015 (AEBIOM, 2016). The production of other agglomerates is less important, adding up to 2.4 million tonnes in 2015 (Figure 44). Germany is the major wood pellets producer followed by Sweden and Latvia. Other countries with a relevant role are France, Estonia, Portugal and Austria. The production of other agglomerates is not as important globally in the EU as the production of pellets. However, it is relevant in the Netherlands, representing 74% of their densified biomass fuels production. In fact, all densified wood fuels, the Netherlands reach a production of about 1 million tonnes, being the eighth largest producer in EU28.

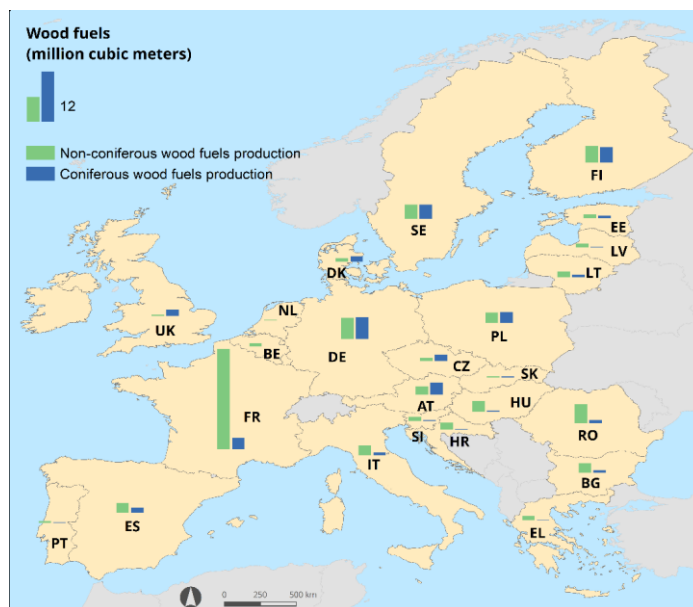


Figure 43: Production of wood fuel from forestry activities for UE28 in 2015. Data for Croatia and Slovenia are not available (FAOSTAT, 2017)

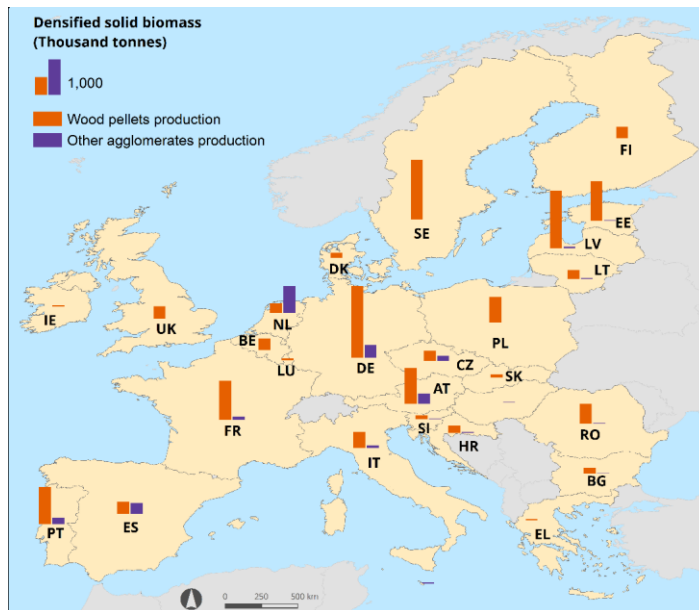


Figure 44: Production of densified solid biomass fuels (including briquettes) for EU-28 in 2015 (FAOSTAT, 2017)

3.2.2.2 Solid biofuel markets and prices

As the use of solid biomass has grown (see Figure 39 in section 3.2.2.1) the structure of the wood energy markets has also changed (Alakangas et al., 2002; Junginger et al., 2008). This means that the traditional market of woody biofuels, where production and consumption occurred at local or regional level, changed or has undergone a geographical enlargement with international trades occurring more and more (Heinimö et al., 2009; Lamers et al., 2012). Nevertheless, some solid biomass fuels trades still occur almost entirely within the domestic market, such as that of wood logs and other wood residues from trees or wood chips and particles directly derived from roundwood (Hagauer and Pasteiner; 2008).

At present, there are several established markets for the commercialization of solid biomass for energy purposes being wood logs/firewood, wood chips and refined fuels such as wood pellets and wood briquettes the main solid biofuels traded (CEN, 2014).

Firewood

Consumption markets: Wood logs/firewood is mainly consumed in the residential sector for heating purposes (AEBIOM, 2016; Proskurina et al., 2016); this sector continues to have the highest share on woody biomass fuels consumption followed by the industry sector (AEBIOM, 2016).

Trading: The business area is characterized mainly by domestic business transactions and also by international business transactions; the latter has a very small volume of trade when compared with the volume of domestic trades (Hagauer and Pasteiner, 2008).

Prices: Firewood prices vary depending on the length category of the wood and the material moisture content. Dimension categories are defined for lengths of L25, L33, L50 and L100 cm and moisture content of M20% or M50%.

Wood chips

Consumption markets: Wood chips are mostly used at industrial scale in installations over 1 MW, where 3/4 are heat plants, about 1/5 are CHP plants and the remaining are power plants (AEBIOM, 2015). Nonetheless, the use of wood chips in small-scale applications is gaining importance (González et al., 2015). AEBIOM (2016) reported that the industrial scale utilization of wood chips contributes with 24% of the gross inland energy consumption from solid biomass and the small scale use represents 14%.

Trading: The business area is characterized by domestic and international business transactions.

Prices: Wood chips prices vary depending on the particle size category and the material moisture content. Dimension categories are defined for particle sizes of P16, P31.5, P45, P63, P100 and moisture content of M20%, M30%, M40% or M55%.

Briquettes

Consumption markets: Briquettes are mainly consumed in the residential sector and in small industrial heat generation facilities (CEN, 2014).

Trading: The business area is characterized, mainly, by domestic business transactions.

Prices: The price of briquettes does not vary with the amount of water in the fuel since current quality requirements specify a moisture content of maximum 10%. Briquettes can be sold in bulk, big-bags or packages (15 to 20 kg).

Pellets

Consumption markets: According to AEBIOM (2016) wood pellets are mainly used for residential heating (42%) and industrial power generation (31%), followed by commercial heating plants (16%) and utility-scale CHP plants for heating (6%) and power (3%). The European consumption market for pellets continues to increase. In 2015, the consumption of pellets in EU28 was 20.3 million tonnes, which represented a 7.8% growth over the year (AEBIOM, 2016).

Trading: Wood pellets are traded in bulk for large and medium scale end-users normally associated with the power generation sector, industry sectors and district heating applications (Sikkema et al., 2011). Small-scale end-users are usually associated with the residential sector and small industries, where pellets distribution can either be delivered in bulk or in bags (Sikkema et al., 2011). In general, end-users with large scale production of heat and/or electricity deal directly with producers or with international operating traders in very large business transactions of bulk pellets, while small scale end-users deal with domestic traders for bulk pellets and with retailers for pellets in small bags (Sikkema et al., 2011).

Prices: The price of pellets does not vary with the amount of water in the fuel since current quality requirements specify a moisture content of maximum 10%. Pellets can be sold in bulk, big-bags (1 t) or small-bags (15 to 20 kg).

At present, private entities such as Argus, FOEX and proPellets report several commercial price indexes, covering different parts of Europe and the main regions of the world for international and/or intercontinental trade of wood fuels, such as wood pellets, wood chips,

forest biomass residues, and also of other wood materials, such as saw logs and birch logs. The major harbours in Europe for international pellet transshipments are Amsterdam and Rotterdam, in Holland, and Antwerp, in Belgium, normally referred to by the acronym ARA. Other harbours are also very important like Riga, in Latvia, St. Petersburg, in north-west Russia, Aveiro, in Portugal, Mobile, Panama city and Savannah, in south-east USA and Vancouver, in Canada. Table 25 presents the existing wood pellet price indexes and the region, harbour or spot associated with it, and Table 26 shows the existing wood chip and forest biomass price indexes available.

Table 25: Wood pellets price indexes for several European regions (Argus, 2017; FOEX, 2017; proPellets, 2017)

Region/harbour/spot	Pellet price index		Source/period
Amsterdam/Rotterdam/Antwerp (ARA)	CIF ARA (€/MWh)	29.39	ARGUS / 1Q -2016
Portugal	FOB Portugal (€/MWh)	22.16	ARGUS / 1Q -2016
Delivered in Northern Italy	Premium Bulk (€/t)	145	ARGUS / 1Q -2016
	Premium Bagged (€/t)	190	ARGUS / 1Q -2016
Baltic	FOB Baltic (€/MWh)	22.18	ARGUS / 1Q -2016
Continental Europe	PIX continental index (€/t)	202.8	FOEX / 3 Jan. 17
Nordic Europe	PIX nordic index–CIF (€/MWh)	27.31	FOEX / 17 Jan. 17
Austria	Pellet price index PPI06 (€/t)	12.3	proPellets / Jan. 17
Austria	Price survey (bulk) (€/kg)	0.3	proPellets / Jan. 17
Austria	Price survey (bags) (€/15 kg bag)	3.91	proPellets / Jan. 17

Table 26: Wood chips and forest biomass price indexes (Argus, 2017; FOEX, 2017)

Region/harbour/spot	Price index		Source/period
North western Europe	CIF NWE (€/GJ)	5.75 – 6.5	ARGUS / 1Q-16
International overseas trade	PIX Hardwood Chip Global (USD/tonne)	165.9	FOEX / 17 Jan.. 17
International overseas trade	PIX Softwood Chip Global (USD/tonne)	157.1	FOEX / 17 Jan.. 17
Finland	PIX Forest biomass Finland index (€/MWh)	19.1	FOEX / 10 Jan.. 17
Finland	PIX Sawlogs Finland (€/m ³)	54.8	FOEX / 24 Jan. 17
Finland	PIX birchlogs Finland (€/m ³)	41.21	FOEX / 24 Jan. 17

The acronym CIF means cost, insurance and freight. It is a trade term requiring the seller to arrange for the carriage of goods by sea to a port of destination, and provide the buyer with the documents necessary to obtain the goods from the carrier. With a CIF agreement, the seller assumes responsibility and pays costs until the goods reach the buyer's chosen port of destination. CIF is focused on import harbours.

Other trade term uses the acronym FOB that means transport with a free on board agreement. The seller arranges for the transport of goods to a designated port or other point of origin. Once the seller releases the goods to the buyer, when the goods are on-board the ship, the delivery is considered accomplished. Unlike CIF, however, the point at which responsibility shifts from the seller to the buyer occurs when the shipment reaches the point of origin. Furthermore, unlike CIF, FOB contracts are not limited to sea freight, and may also be used for inland and air shipments. FOB is focused on export harbours.

Other indexes are specific for the type of market. For example, for the countries of northern Europe and regions of the Baltic Sea, the wood pellet price index for the industrial market is given by the PIX Pellet Nordic Index (CIF). For Germany and Austria, the wood pellets reference price for medium-scale users is given by the PIX Pellet Continental Index. For Austria, Pro-pellets organization (proPellets, 2017) reports two survey prices, one directed for bulk pellets and other for bagged pellets, and a pellet price index named PPI06.

3.2.3 Biowaste

The anaerobic digestion (AD) can then produce both renewable energy (biogas) and digestate from a variety of organic materials including by-products from the food & beverage industry but also livestock manure, crops residues, biowaste from municipalities, etc. Digestate can be considered as a valuable organic fertiliser.

The use anaerobic digestion technology is of particular relevance in food industry where high production of bio-waste and high thermal energy demand coincides. Very different types of by-products from food industry can be used as raw material for biogas production (see Table 27).

Table 27: Biowaste from the Food Industry useful for biogas production

Sector	Subsector	Bio-material	Description
Aroma	Aroma	Vegetable waste (peels, pulp, seeds,...)	Main raw material for aroma products are vegetable or part of vegetables (fruits, juices, natural spices, herbs,...) A major source of solid waste generation during aroma processing is the pressing/extraction steps as peels, seeds, pulps are separated from the fruit juice. In some cases the aroma recovery is part of the juice production and then, the by-products are the same than indicated for juice production.
Bakery	Bread	Bread losses	Bread losses produced during dough division or remainders of the dough. Bakery waste. Bakery waste has to be pre-processed to turn it in to feed (crushing, drying, cleaning, milling, mixing)
Chocolate /coffee	Coffee	Spent coffee grounds	Spent coffee grounds is produced in the production of soluble coffee products
		Coffee chaff	Coffee chaff is produced in the coffee roasting process

Sector	Subsector	Bio-material	Description
Dairy	Cheese	Whey	<p>Cheese whey is produced in the cutting and cooking of curd.</p> <p>Cheese whey, which is a protein and lactose rich byproduct of the cheese industry, is very biodegradable (>99%) with very high organic content (up to a COD of 70 kg m³) and low alkalinity content (2.5 kg m³ as CaCO₃)</p>
		Wastewater	
		Fats and sludge from waste-water treatment	biological wastewater treatment plants
		Non-conforming products	During milk products processing, non-conforming products can be produced due to be outside quality or labelling standards.
		sludge from milk clarification and filtration	In reception, sludge is produced in filtration and clarification of milk. It consists mostly of dirt, cells from the cows' udders, blood corpuscles and bacteria
Fat/oils	seed oils	Fatty acids	<p>In a soapstock splitting plant, the fatty acid soaps react with sulphuric acid to form fatty acids back again. The process can either be continuous or discontinuous. The reaction medium is heated up to 70-100°C in order to increase the speed of the reaction and to improve the separation of the upper oil phase from the lower aqueous phase. Between the aqueous phase and the fatty acids, an intermediate layer of phosphatides can be formed, depending on the amount of phosphatides still present in the crude oil.</p>
Fruit and Vegetables	Vegetables	: Pomace from juice extraction	
		Scrap	<p>Large amounts of solid wastes are produced during fruit and vegetable processing. These are organic materials, including fruit and vegetables discarded during selection, and those from processes such as peeling or coring.</p> <p>These typically have a high nutritional value and can be used as animal feed. Undesired materials discarded from the first processing steps include soil and extraneous plant material, spoiled food stocks, and some trimmings, peels, pits, seeds and pulp</p> <p>Up to 50 % of fruit and typically 10 to 30 % of raw vegetable materials are wasted during processing. Part</p>

Sector	Subsector	Bio-material	Description
			of the waste goes to the waste water and significant amounts of solid wastes are also generated.
Sugar	Sugar	Molasses	Sugar beets contain some soluble non-sugar substances, 30 - 40 % of which are eliminated during purification of the juice with Ca ²⁺ precipitable anions, pectins and proteins. The remainder is left in the juice and prevents the complete crystallisation of the sugar, leaving a final syrup, called molasses. This is the major single loss of sugar in the process. 10 - 18 % of the sugar content of the beet is in molasses. About 38 kg molasses per tonne of sugar beet is generated. Molasses is about 80 % solid material and 20 % water. (EC, 2006)
Wine/beverage	Soft drinks	Peels and pulp	In case of extraction of vegetable or fruit juice, high amount of peels and pulp are produced. For example, the orange peels waste coming from the orange juice industry represents approximately 50-60% of the orange fruit transformed. The orange peel waste is composed by: whole peel or rind (pericarp), pulp (called rag in the industry), seeds and aqueous emulsions from citrus processing plant.

In the EU, over 20 million tons of ABPs emerge annually from slaughterhouses, plants producing food for human consumption, dairies and as fallen stock from farms. ABPs can spread animal diseases (e.g. BSE) or chemical contaminants (e.g. dioxins) and can be dangerous to animal and human health if not properly disposed of. EU rules regulate their movement, processing and disposal.

ABP are categorised according to their risk using the basic principles in Regulation (EC) 1069/2009 and Commission Regulation (EU) 142/2011. ABPs are categorised in three categories (categories 1, 2 and 3) which reflect the level of risk to public and animal health arising from those animal by-products. This Regulation lays down public health and animal health rules for animal by-products and derived products, in order to prevent and minimise risks to public and animal health arising from those products, and in particular to protect the safety of the food and feed chain.

Following table shows some EUROSTAT statistic on the amount of animal and vegetal wastes generated in European countries.

Table 28: Amount of animal and vegetal wastes generated in European countries, including all NACE activities plus households (Eurostat, 2015)

GEO/TIME	2006	2008	2010	2012	2014
	Tonnes				
Austria	2,017,912	3,711,597	1,661,218	1,892,661	1,887,723
Belgium	4,389,887	4,265,806	4,822,033	4,890,516	5,635,143
Bulgaria	984,288	976,507	731,091	1,129,778	983,646
Cyprus	180,561	199,867	:	220,713	112,018
Czech Republic	684,100	540,638	449,880	443,134	583,264
Germany (until 1990 former territory of the FRG)	12,051,569	12,231,406	12,932,869	14,086,695	15,011,037
Denmark	186,907	165,969	973,350	889,560	1,087,281
Estonia	299,616	287,052	280,338	83,782	149,633
Greece	4,779,350	137,599	444,635	491,888	575,225
Spain	20,664,875	15,647,005	9,763,484	8,297,358	8,058,640
European Union (15 countries)	:	:	:	:	:
European Union (27 countries)	:	:	:	:	:
Finland	1,074,358	1,242,875	899,527	988,318	1,079,091
France	6,225,650	7,590,660	9,405,994	11,281,262	11,304,205
Croatia	283,868	109,631	119,502	132,580	395,664
Hungary	3,359,813	1,378,997	808,058	791,369	699,238
Ireland	1,273,962	523,117	2,079,402	1,243,280	:
Iceland	:	159,873	116,899	139,063	:
Italy	9,346,007	9,405,736	9,489,613	9,975,760	6,921,585
Lithuania	900,947	1,061,890	535,615	578,215	551,038
Luxembourg	97,113	91,316	88,206	84,575	95,427
Latvia	203,538	144,507	166,304	137,353	105,480
Malta	12,371	15,108	15,758	:	16,607
Netherlands	12,289,462	13,255,112	14,587,937	14,544,708	14,718,640
Norway	1,081,175	1,173,097	944,728	961,529	866,632
Poland	8,290,718	7,123,817	6,355,505	5,929,556	4,679,634
Portugal	1,187,581	526,116	392,349	203,496	183,064
Romania	22,654,875	19,837,801	1,151,577	18,211,593	1,063,964
Sweden	1,754,330	1,788,043	1,684,156	1,841,839	2,205,186
Slovenia	296,747	256,251	264,075	309,839	289,773
Slovakia	1,229,045	1,224,526	903,514	863,110	920,337
Turkey	0	672,719	:	:	:
United Kingdom	12,024,979	12,842,425	9,187,396	:	10,365,788

Biowaste characteristic for biogas production

The organic waste generated in farming, agro-food industries or other sectors is usually able to be processed through anaerobic digestion (AD). It is well suited for various wet biodegradable organic wastes of high water content (over 80%), yielding methane-rich biogas. AD for biogas production can be also successfully applied to the municipal waste and wastewater treatment plants to treat organic wastes.

A table can be found in Annex I including the characteristics of the most common organic wastes suitable for anaerobic digestion.

Biowaste price

The industrial price/cost of a given biowaste at a given facility may differ significantly from the average costs for this biowaste. It is difficult to generalise the cost of biowaste across one country, and even more so across the EU 28.

The price of a given biowaste at the facility gate will depend upon the nature of their characteristics, how fit these characteristics with the existing valorization route, the local competition (demand), haulage costs, specific materials in the context of seeking a specific feedstock mix, use of long-term contracts, etc.¹³

In the EU, over 20 million tons of ABPs emerge annually from slaughterhouses, plants producing food for human consumption, dairies and as fallen stock from farms. ABPs can spread animal diseases (e.g. BSE) or chemical contaminants (e.g. dioxins) and can be dangerous to animal and human health if not properly disposed of. EU rules regulate their movement, processing and disposal.

ABPs are categorised according to their risk using the basic principles in Regulation (EC) 1069/2009 and Commission Regulation (EU) 142/2011. ABPs are categorised in three categories (categories 1, 2 and 3) which reflect the level of risk to public and animal health arising from those animal by-products. This Regulation lays down public health and animal health rules for animal by-products and derived products, in order to prevent and minimise risks to public and animal health arising from those products, and in particular to protect the safety of the food and feed chain.

ABP category 3 can be transformed into biogas

ABP category 2 can be transformed into biogas:

- (i) following processing by pressure sterilisation and permanent marking of the resulting material; or
- (ii) in the case of manure, digestive tract and its content, milk, milk-based products, colostrum, eggs and egg products which the competent authority does not consider representing a risk for the spread of any serious transmissible disease, following or without prior processing;

¹³ ASSESSMENT OF THE OPTIONS TO IMPROVE THE MANAGEMENT OF BIO-WASTE IN THE EUROPEAN UNION ANNEX E: Approach to estimating costs. 2009.
http://ec.europa.eu/environment/waste/compost/pdf/ia_biowaste%20-%20ANNEX%20E%20-%20approach%20to%20costs.pdf

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