OPTIPOLYGEN

TRAINING MATERIAL
in
POLYGENERATION
in
the FOOD INDUSTRY

WP5 Derivable

Work Package Leader: Instituto Superior Técnico

Work package partner: Technical Institute of Serres

Intelligent Energy Europe

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CHAPTER 1 – Polygeneration in the Food Industry

1.1 What polygeneration stands for?

Polygeneration is the transformation of multiple energy sources into multiple, suitable for use, energy forms using one or more generators working together.

This is a general view on what polygeneration means and can be realized by, *e.g.*, when we use natural gas and biogas to produce heat and electricity or when we use solar energy, wind and natural gas to produce electricity and useful hot water, or any other combination of primary or secondary energy sources to produce any combination of useful forms of energy.

Based on the above approach cogeneration of heat and power (CHP) is a version of polygeneration and the same is valid for trigeneration – cogeneration of power, heat and a cooling medium.

Polygeneration can improve energy supply safety, may also have financial benefits and can improve renewable energy participation in the total energy supply mix. It however demands more complicated energy systems, increased investment costs and needs additional operational and engineering skills.

This text serves as training and educational tool focused on the use of polygeneration in the various food industry plants. It has been created under the partial funding of the IEEA SAVE and ALTENER programs within the OPTIPOLYGEN project.

The use of polygeneration in the food industry can arise from several reasons and can serve multiple objectives, *e.g.*, the use of the energy content of by-products, the energy cost savings, etc. In OPTIPOLYGEN project, polygeneration based either on fossil fuels or on primary energy sources available from the production processes themselves have been considered. As such solar or wind energy was not considered as these are not generated by the food production processes and are not specific to the food industry.

The present material forms the WP5 deliverable of the OPTIPOLYGEN project. It serves the need to introduce consultants and engineers in the evaluation of the potential of polygeneration applications in the various areas of the food industry. It can also be used for educational material in courses where energy efficiency and energy systems are taught.

1.2 Cogeneration and polygeneration: the basics

As mentioned in the introduction, cogeneration forms a version of polygeneration. As cogeneration is more familiar within industry, definitions will be first given for cogeneration and then will be extended to include polygeneration.

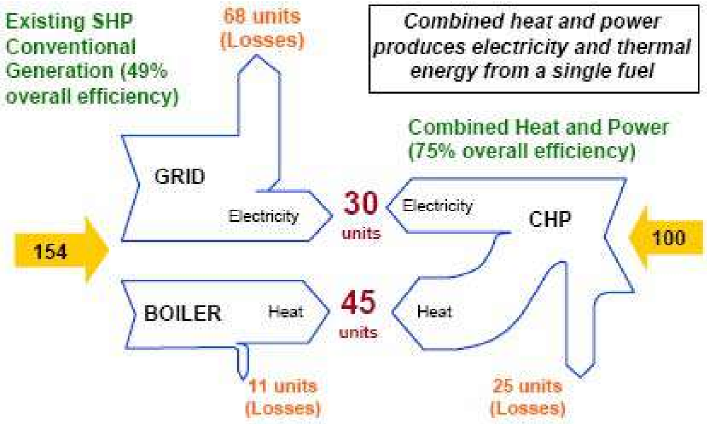
1.3 Cogeneration

Cogeneration is also named as Cogeneration of Heat and Power (CHP).

CHP is the efficient utilization of the heat which is cogenerated with power when thermal cycles are used to produce power.

In conventional thermal power plants the heat cogenerated with the electricity is released in the environment without being used to cover existing thermal needs. As a result the efficiency of a typical plant is relatively low – up to 55% with the modern combined cycle plants.

In CHP the heat cogenerated is used to cover thermal needs as, *e.g.*, space heating or process steam generation, etc. Thus the fuel used in a CHP plant is used normally at a higher total efficiency which can reach even 90% if both electricity and thermal energy use is taken into account. As a result significant primary fuel savings can be realized. The above are shown in figure 1.1.



Note: Assumes national averages for grid electricity and incorporates electric transmission losses.

Source: Tina Kaarsberg and Joseph Roop, "Combined Heat and Power: How Much Carbon and Energy Can It Save for Manufacturers?"

Figure 1.1 CHP versus conventional power and heat generation. Source: [1].

It is obvious from all the above that cogeneration does not form a novel technology and has little to do with the power generating device itself. Even a conventional thermal power plant can be theoretically an efficient CHP plant if we can develop needs which can be met by the low temperature thermal energy released by the plant's cooling towers into the environment. Based on this approach what usually makes a CHP plant efficient is not only the CHP device itself but the methodology which is used to meet efficiently the thermal needs of the process served by the CHP device. Usually the engineering and the realization of this methodology is strongly depended on both the process and the CHP device.

If we take into account that the thermal energy cogenerated with the electricity is useful energy and not losses, total CHP efficiency can reach even 90% based on the lower heating value (LHV) of the fuel used. This results in significant primary energy savings up to, *e.g.*, 30%. Additionally, this corresponds to comparatively high emissions savings and maybe into financial benefits. It is however important to realize that the primary reasons of these important savings are:

- the non renewable nature of the electricity of the grid, *i.e.*, the grid electricity is originating from fossil or nuclear fuels,

- the low efficiency of the thermal power cycles used to generate electricity, and the dissipation of the heat cogenerated,
- the significant grid losses when electricity travels long distances from the large utility thermal/nuclear power plants to the locations of consumption,
- the efficient use of the thermal energy which is cogenerated with the power in the CHP unit.

The equipment used to transform the primary energy into electricity and heat can be of various types such as an internal combustion engine (ICE), a gas turbine combined with a heat recovery boiler (HRB), etc. The main options are analyzed in brief in the subsequent chapters.

Another benefit of CHP is its local character. This is imposed by the need to use efficiently the thermal energy produced. Thermal energy cannot – at least nowadays – be transferred to long distances. As a result, efficient use of the thermal energy means that the plant producing it should be located close to the thermal energy consumption points. This means that electricity is produced also close to the consumption points. This results in significant reduction of the power grid losses which in several countries can be as high as 12% of the total electricity generation of the country. Safety supply is also a significant benefit as one plant can break down while other can still running. All these potential benefits gave rise to the Decentralized Power Generation concept.

1.4 Polygeneration

Usually CHP is realized using a single fuel, *e.g.*, natural gas. When more than one fuel is used then polygeneration arises. In the most general form polygeneration stands for the use of multiple primary energy sources. Using them, multiple useful energy outputs can become available, *i.e.*, electricity, steam, or a cooling medium via absorption chillers. This general polygeneration scheme, which is based on fuels only, is shown in figure 1.2. Additionally other forms of energy can be used as inputs, *e.g.*, wind energy or solar radiation.

Based on the above a definition for polygeneration is

Polyegeneration is the transformation of multiple energy inputs into multiple useful energy outputs.

Theoretically polygeneration can be analyzed using the same parameters as those for cogeneration. The only difference is that primary energy input should be split into several parts one for every specific primary energy source used. In the case that heat is also used to generate a cooling medium then all the parameters used to evaluate the absorption cooling efficiency can be used.

Based on the above general rules polygeneration applications can be analyzed using the following formulas.

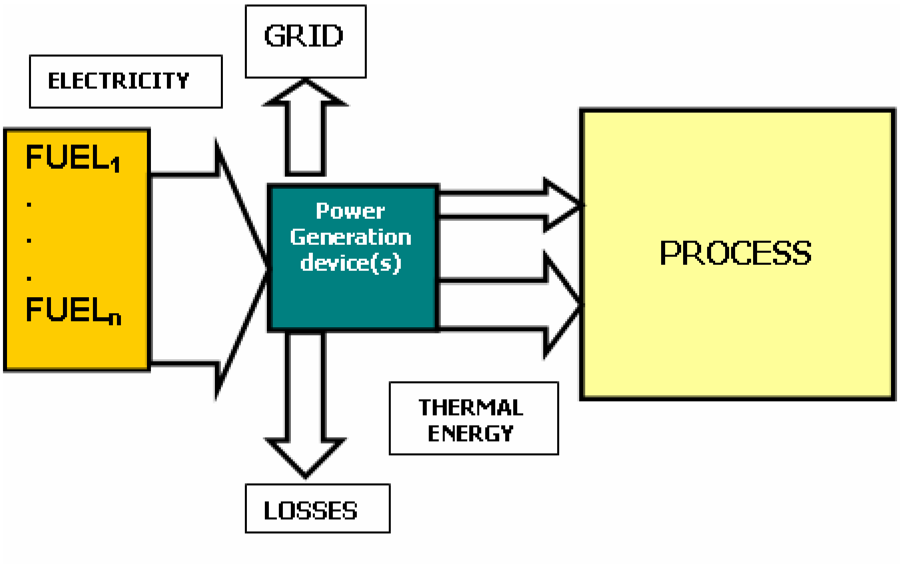


Figure 1.2. A general schematic view of polygeneration where n fuels are used to produce power and useful thermal energy sent to a process.

The total power used in the polygeneration plant is originating from the power of several *n* fuels. Then

$$\dot{Q}_{fuels} = \sum_{i=1}^{n} \dot{Q}_{fn} \qquad [1.1]$$

where

$$\dot{Q}_{fn} = \dot{m}_{fn} \cdot H_{fn} \qquad [1.2]$$

where $\dot{m}_{fn}$ is the mass rate of the fuel n used in the polygeneration plant and H_{fn} is the lower heating value of the fuel n.

Depending on the case, higher heating value (HHV) may be used and this has to be cleared in every related report or calculation. One or more of the fuels can be renewable fuels, *e.g.*, biogas or biomass.

Electrical efficiency

The electrical efficiency of the polygeneration plant can be calculated by

$$n_e = \frac{\dot{W}_e}{\dot{Q}_{fuels}} \qquad [1.3]$$

where $\dot{W}_e$ is the electric power generated by the equipment which uses the fuels n.

In the case that polygeneration plant is consisted by m electricity generating devices using different fuels the total electrical efficiency of the polygeneration plant is:

$$n_e = \frac{\sum_{i=1}^{m} \dot{W}_m}{\dot{Q}_{fuels}} \qquad [1.4]$$

Thermal efficiency

The thermal efficiency of the polygeneration plant can be calculated by

$$n_{th} = \frac{\dot{Q}}{\dot{Q}_{fuels}} \qquad [1.5]$$

where $\dot{Q}$ is the heat generated by the polygeneration equipment which uses the n fuels and is given to the process which demands heat.

It is important to note that $\dot{Q}$ is the usefull heat given to the process and not the heat as denoted in several texts. The extend at which $\dot{Q}$ is usefull depends, also, on the process efficiency, a parameter which only partially depends on the power generating device(s) themselves – polygeneration devices.

In the case that usefull thermal energy is generated by μ different devices using the n different fuels of the polygeneration, then the total thermal efficiency of the system is :

$$n_{th} = \frac{\sum_{i=1}^{\mu} \dot{Q}_{\mu}}{\dot{Q}_{fuels}} \qquad [1.6]$$

Based on the above thermal and electric efficiencies the total energy efficiency of the polygeneration system can be expressed as:

$$n_{\mathrm{tot}} = n_e + n_{th} = \frac{\sum_{i=1}^{m} \dot{W}_m + \sum_{i=1}^{\mu} \dot{Q}_{\mu}}{\dot{Q}_{fuels}} \qquad [1.7]$$

Using this approach the exergetic efficiency of the polygeneration plant is

$$J = \frac{\sum_{i=1}^{m} \dot{W}_m + \sum_{i=1}^{\mu} \dot{\mathrm{E}}_{\mu}}{\dot{\mathrm{E}}_{fuels}} \qquad [1.8]$$

where E_{μ} is the exergy of the thermal energy produced by the μ different devices and E_{fuels} is the total amount of exergy included in the n fuels mixture used.

The total primary energy savings (PES) of polygeneration application can be calculated using the formula:

$$PES = 1 - \frac{\dot{E}_{fuels}}{\frac{\sum_{i=1}^{m} \dot{W}_{m}}{n_{eGRID}} + \frac{\sum_{i=1}^{\mu} \dot{Q}_{\mu}}{n_{thboiler}}} \qquad [1.9]$$

In this formula n_{eGRID} is the total electrical efficiency of the grid which supplies electricity to the user where polygeneration is installed and operate. This efficiency is calculated by the ratio of the electricity consumed by the user in kWh by the primary fuel used to generate this electricity on the thermal power plant site, *i.e.*, n_{eGRID}= electricity consumed by the user/primary energy used to generate this electricity.

It is obvious that before calculating the above figures we have first to define our reference area, to determine the utility plants which exist there and the electricity mix they produce and send to the users where polygeneration is applied. In the cases where the electricity send to the user is not produced by only fossil fuels but rather using a mixture of power plants and renewable energy power stations then n_{eGRID} is calculated using formula [1.4] as follows. First the total grid electricity is split into two parts: i) electricity generated by renewables, *i.e.*, wind or PV's or biomass, $\dot{W}_{RES}$ and ii) electricity generated by fossil fuels, *i.e.*, natural gas, $\dot{W}_{F}$. Then

$$\dot{W}_{RES} + \dot{W}_{F} = \dot{W}_{total} \qquad [1.10]$$

and

$$n_{eGRID} = \frac{1}{\dot{W}_{total}} \times \left(\frac{\dot{W}_F^2}{\dot{Q}_{fuels}} + \dot{W}_{RES} \right) \quad [1.11]$$

Note that $n_{thboiler}$ in formula [1.9] is the thermal efficiency of the boiler used to generate the heat send to the user. In the case that there is no boiler then this parameter can be the normalized thermal efficiency of the processes used in the plant which is to be served by the polygeneration unit. Again, formula [1.6] can be used to calculate this total plant thermal efficiency when more than one thermal processes with different efficiencies are to be served. It is again evident how important is to define the boundaries of the thermodynamic system under consideration.

Heat over power ratio

If we consider the power generated by the polygeneration unit and the thermal energy which is produced then the ratio of these two unit outputs gives the heat over power ratio.

$$\text{Heat over power ratio} = \frac{\text{rate of heat generated by the unit}}{\text{rate of electricity generated by the unit}} \quad [1.12]$$

The heat over power ratio can be used for fast first stage calculations mainly for potential orientation of the project when initial sizing of the unit is performed. In no case should this be used for the final sizing or feasibility studies.

1.5 References and bibliography

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CHAPTER 2 – Technology Overview

2.1 Introduction

As already mentioned polygeneration is usually related with power generation via thermal cycles. Polygeneration can also combine power generation based on thermal cycles together with power generation based on, *e.g.*, wind turbines or photovoltaic, *i.e.*, with technologies other than thermal power cycles. This report is focused only on thermal cycle based polygeneration (TCBP).

The equipment used for TCBP consists mainly of

- Gas turbines,
- Steam turbines,
- ICE,
- Other (Fuel Cells, stirlings, etc.).

The equipment which is mainly used today is shown in table 2.1. The table summarizes the main characteristics and advantages/disadvantages of each technology used as polygeneration driver. Fuel cells and stirling engines are not often used and thus they are not included in the table. The interested can find summarized and detailed information for this equipment in several textbooks and reports, *e.g.*, [1-3].

Technology	Steam Turbine only-not the boiler-	Combined Cycle Gas Turbines (2)	Gas Turbine-Open Cycle	Internal Combustion Engine - ICE-	Micro ICEs	Micro turbines
FUELS						
Fuel Used	Any steam inputs (1)	Gas, Biogas, Gasoil, LFO, LPG, Naphtha	Gas, Biogas, Gasoil, LFO, LPG, Naphtha	Gas, Biogas, Gasoil, LHO, Naphtha	NG, biogas, propane	NG, biogas, LPG
THERMODYNAMIC PARAMETERS						
Energy Range (MWel) or Size	0.5 - 500	5 - 300+	0.25 - 50+	0.2 - 20	0-0,2	0,03-0,2
Heat : Power Ratio	3 : 1 - 10 : 1	1 : 1 - 3 : 1	1.5 : 1 - 5 : 1	0.5 : 1 - 3 : 1	usually at the range of 2:1	usually at the range of 2,5:1
Electrical Efficiency	7 - 20%	35 - 55%	20 - 38%	35 - 45%	25-35%	25-32%
Unit thermal output	steam at various conditions (LP-HP). The higher the steam pressure and temperature the higher the electrical efficiency.	Depends on the part of the steam used in the steam turbine. Can be Medium Grade Steam and/or High/low temperature hot water	450 - 550 deg C exhaust gas, (up to 1000 deg C with supplementary firing), Micros with recuperators produce hot exhaust gases at about 270oC +, hot water (>140 deg C), LP-HP steam (8-18 bar) (5)	Hot water (from cooling system 85 deg C) and Steam (<15 bar from exhaust gases) or only hot water (100 deg C, suplimenting cooling system water temp with exhaust gases), hot air	hot water	hot gases from 250oC - 500oC depending on manufacturer
Thermal Efficiency	depends on the use of the termal output. Can reach 50%	Depends on the use of the thermal output.	Depends on the use of the thermal output.	Depends on the use of the thermal output.	Depends on the use of the thermal output.	Depends on the use of the thermal output.
Overall Efficiency	Depends on the use of the thermal output of the unit. With proper design can reach more than 80% for all types of drivers					
COSTS & MAINTENANCE						
Unit Cost by Size (Euro/kWh). Only the Polygeneration driver-not the whole polygeneration plant.	300 - 900 Euro/kWe (8)	1500 - 1000 Euro/kWel	500 - 1000 Euro/kWel	300 - 1000 Euro/kWel (1)	1000-1300 Euro/kWel	1000-1300 Euro/kWel
Maintenance Costs	2-3 Euro/MWhel	2,5 - 3,0 Euro/Mwhel	2,5 - 3,0 Euro/Mwhel	7,5-10 Euro/kWhel	7,5-10 Euro/kWhel	2,5 - 3,0 Euro/Mwhel
operating hours to overhauls	>50.000	20-30.000	20-30.000	15-25.000	10-15.000	15-20.000
Lifespan	175.000 hours	up to 130.000 hours	up to 130.000 hours	up to 100.000	expected about 80.000	expected about 80.001
OPERATION						
Start-up time	1hr -1 day	1hr-1 day	10 mins	1 min	1 min	1min
sensitivity to frequent star-ups	significant. If more than 1 per week not suitable	significant. If more than 1 per week not suitable	usually not more than 1 per day. Some require 1 per week	no sensitivity	no sensitivity	no sensitivity
power density -kW/m2-	>100	50-80	20-500	35-50	ususally 2-30	ususally 5-70
reliability	high	high	high	good	not yet available	not yet available
partial load behaviour	good	good	moderate	very good	very good	moderate
ENVIRONMENTAL PARAMETERS						
Emission levels -kg Nox /MWhel-	no emmissions	0,11	0,11	0,36	0,4	0,06
Noise	high	high	moderate	high	high	moderate

(1)should preferably be high pressure and high temperature e.g. 42 bar/400 deg C or 63 bar/480 deg C. Lower pressure/temperature result in lower electrical efficieny

(2) Includes all the power plant I.e. Gas turbine, Heat Recovery Steam Boiler -HRSB-, steam turbine.

(3) Includes only the gas turbine.

Table 1.1. Main characteristics and advantages/disadvantages of each technology used as polygeneration driver.

2.2 Steam turbines

Steam turbines are one of the most versatile and oldest drivers still in use. Power generation using steam turbines has been in use for more than about 100 years, when they replaced reciprocating steam engines due to their higher efficiencies and lower costs.

Most of the conventional power plants around the world are based on steam turbines. The capacity of steam turbines can range from 50 kW to several hundred MWs for large utility power plants. Steam turbines are widely used for combined heat and power (CHP) applications although their applications are limited to relatively large scale CHP at the range of more than 5-10 MW_e.

In steam turbine applications exergy of the fuel is turned into steam exergy, a part of which is then used to generate power. The most common approach to fulfil this power generation approach is the Rankine cycle. On the other hand gas turbines produce power from the exergy contained in the fuel combustion gases without steam as intermediate medium. This cycle is sometimes named as Brayton cycle.

In steam turbine cycles the energy is transferred from the boiler to the turbine through overheated steam that in turn powers the turbine and the generator. The use of the fuel in the boiler and not in the turbine enables steam turbine systems to operate with all variety of fuels which can be used in boilers, such as natural gas, solid wastes, all types of coal, wood, wood waste, and agricultural by-products (sugar cane, bagasse, fruit pits, and rice hulls). In CHP applications, steam at lower pressure is extracted from the steam turbine and used directly or is converted to other forms of thermal energy.

Steam turbines offer a wide array of designs and complexity to match the desired application. Usually steam turbines aimed at industrial CHP applications are of much simpler design than those of utility plants.

While steam turbines themselves are competitively priced compared to other prime movers, the costs of complete boiler/steam turbine CHP systems are relatively high on a per kW_e of capacity basis. This is because of their low power to heat (P/H) ratio, the costs of the boiler, fuel handling, overall steam systems, and the custom nature of most installations. Thus, steam turbines are well suited to medium- and large-scale industrial applications where inexpensive fuels, such as coal, biomass, various solid wastes and by products (*e.g.*, wood chips), refinery residual oil, and refinery gases are available. Because of the relatively high cost of the whole system, high annual capacity factors are required to enable a reasonable recovery of invested capital. Sometimes a retrofit application of steam turbines into existing boiler/steam systems is often an economic option.

In case where natural gas or other high quality fuels are to be used then even for high annual capacity factors the option of gas turbines operating with heat recovery steam generator (HRSG) should be examined.

More details on the technical, maintenance, investment and emission aspects of the steam power generation in CHP can be found in several textbooks and reports, *e.g.*, [1-3].

2.3 Gas turbines

Gas turbines were first developed in the early 1900s, and began to be used for stationary electric power generation in the late 1930s.

In CHP gas turbines can be used in a simple cycle (Brayton cycle), where gas turbine exhaust gases are sent to a heat recovery heat exchanger which recovers the heat in the turbine exhaust and converts it to useful thermal energy usually in the form of steam or hot water. Sometimes the hot turbine exhaust gases can be used directly in thermal processes or in combined cycle operation in which high pressure steam is generated from recovered exhaust heat and used to create additional power using a steam turbine. This last case, although often use in utility power plants, may result in reduced total cycle efficiency in CHP's if exhaust steam turbine heat is too low and does have useful temperature. Gas turbines are available in sizes ranging from 30 kW – micro turbines – to 250 MW.

Gas turbines are one of the cleanest means of generating electricity, with low emissions of oxides of nitrogen (NO_x) achieved either with catalytic exhaust cleanup or lean pre-mixed combustion.

Overall CHP efficiency generally remains high under partial load conditions. The decrease in electric efficiency from the gas turbine under partial load conditions results in a relative increase in heat available for recovery under these conditions. This can be a significant operating advantage for applications in which the economics are driven by high thermal demand.

Several technology advances have been incorporated in gas turbine technology over the years, *e.g.*, supplementary firing, recuperators, inlet air cooling, etc. Good overview of these technologies and their effect in gas turbine and CHP/polygeneration system performance can be found in [1-3]. In the same reports several data on the economics of gas turbines and the capital cost of turbine based CHP systems can be found [1-3].

Micro turbines with electrical power output of less than 0.2 MW_e became also available in the last years. Their principles of operation are the same as for the normal gas turbines although several characteristics are significantly different – higher rotational speed, standard recuperator, gas compressor included as standard in the package, etc. Very good reports on the micorturbine characteristics can be found in [2].

2.4 Reciprocating/internal combustion engines

Reciprocating internal combustion engines are a widespread and well-known technology. Reciprocating engines are available for power generation applications in sizes ranging from a few kilowatts to over 5 MW.

There are two basic types of reciprocating engines – spark ignition (SI) and compression ignition (CI). Spark ignition engines for power generation use natural gas as the preferred fuel, although they can be set up to run on propane, gasoline, or landfill gas. Compression ignition engines (often called diesel engines) operate on diesel fuel or heavy fuel oil, or they can be set up to run in a dual-fuel configuration that burns primarily natural gas with a small amount of diesel pilot fuel. Diesel engines have historically been the most popular type of reciprocating engine for both small and large power generation applications.

Current generation natural gas engines offer low first cost, fast start-up, proven reliability when properly maintained, excellent load-following characteristics, and significant heat recovery potential.

Electric efficiencies of natural gas engines range from 28% LHV for small stoichiometric engines (< 100 kW) to over 40% LHV for large lean burn engines (> 3 MW).

Waste heat recovered from the hot engine exhaust and from the engine cooling systems produces either hot water or low pressure steam for CHP applications. Overall CHP system efficiencies (electricity and useful thermal energy) of 70 to 90% are achieved with natural gas engine systems.

Reciprocating engines are well suited to a variety of distributed generation applications. Reciprocating engines start quickly, follow load well, have good partial load efficiencies, and generally have high reliabilities. In many cases, multiple reciprocating engine units further increase overall plant capacity and availability. Reciprocating engines have higher electrical efficiencies than gas turbines of comparable size, and thus lower fuel-related operating costs. In addition, the first costs of reciprocating engine gensets are generally lower than gas turbine gensets up to 3-5 MW in size. Reciprocating engine maintenance costs are generally higher than comparable gas turbines, but the maintenance is generally less demanding in terms of specialized personnel and equipment, can often be handled by in-house staff or provided by local service organizations.

The technical details of the ICEs together with their operating, maintenance, cost and environmental characteristics can be found in several reports e.g [1-3].

2.5 References and bibliography

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[2] EDUGOGEN, The European Educational Tool on Cogeneration, 2nd edition, December 2001 (www.cogen.org).

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CHAPTER 3 – Trigeneration

3.1 The principles of trigeneration

Trigeneration is the use of part or all of the heat which is produced by thermal power cycles to generate a cooling medium suitable for cooling or chilling processes.

Trigeneration, which is also named as cogeneration of heat, cooling and power (CHCP), is an extension of a typical CHP by incorporating mainly an **absorption cooling cycle** for cooling-refrigeration generation. In this way part or all of thermal energy produced by the CHP plant is converted into cooling-refrigeration, depending on the process needs. Absorption cooling cycles are particularly important in internal combustion engines (ICE) based CHP plants, where low grade heat is produced during engine’s water cooling. This heat can be used by the absorption cooling cycle to produce useful cooling, especially during summer.

The main advantage of trigeneration against cogeneration is the fact that CHCP extends the useful operational period of the CHP plant over the year, which reduces, under certain circumstances, the pay back period of the CHP plant. Additionally the use of trigeneration may allow the increase of the size of the cogeneration system thus improving the potential benefits of the cogeneration for the user.

Trigeneration can be also beneficial for CHP applications in industrial processes where refrigeration demands are more constant (especially in low temperature applications between -15 to -55 ºC) than heating loads.

Typical trigeneration applications exist in the food industry, chemical and petroleum industry, large air conditioning installations and in any application where large heating and/or refrigerating loads are needed on a 12 month basis per year, together with power needs. The energy flow in a trigeneration application is compared to the conventional energy supply to a plant as shown in figure 3.1

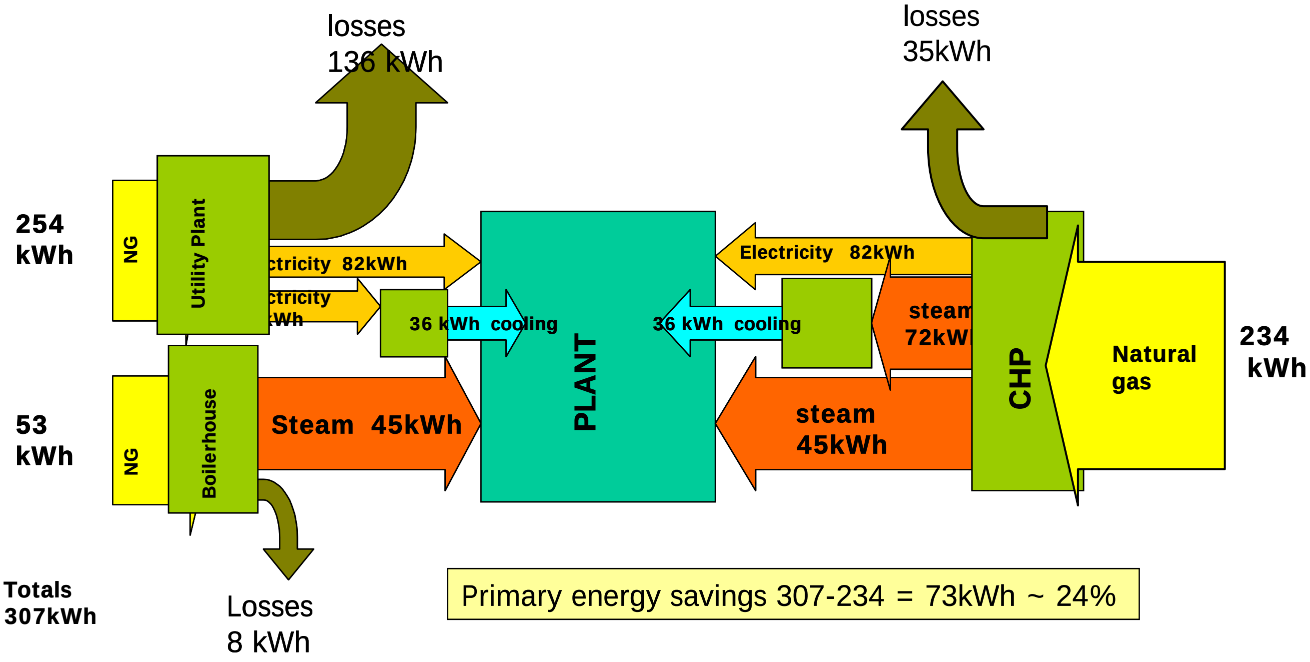

Figure 3.1. Trigeneration compared to typical plant operation requiring electricity, steam and cooling mediums.

One other advantage of trigeneration applications could be the reduction of the peak power demand which may take place in industrial plants and residences during the summer. In several countries special tariffs, usually higher, are applied during the summer time in an attempt of the utility companies to reduce the significant peak power demand which take place during the summer mainly because of the increased electricity demand due to compressor based air conditioning operation.

As mentioned above trigeneration is based on the use of absorption cycles to cool a suitable cooling medium. Some analysis of these cycles is presented in the following paragraphs.

3.2 The principles of absorption cooling/freezing

Absorption freezing cycle (AFC) is based on certain thermodynamic properties of two particular fluids' system. One is the refrigerant and the other the absorbent, forming the “working pair” of the cycle. Many pairs have been proposed through the years but only two of them have been widely used:

- ammonia (refrigerant) together with water (absorbent),
- water (refrigerant) together with a solution of lithium bromide in water (absorbent).

The ammonia-water pair is mostly found in refrigeration applications, with low evaporation temperatures, below 0 ºC. The water-lithium bromide pair is widely used for air conditioning applications, where it is not necessary to cool below 0 ºC. The pressure levels in the ammonia-water machine are usually above atmospheric pressure (up to 12 bar, depending on the evaporation temperature), while the water-lithium bromide machines generally operate in partial vacuum.

In what follows it is supposed that the reader is familiar with the operation and the thermodynamics of the typical compressor based cooling-freezing cycle.

In every cooling cycle the cooling effect is a result of the evaporation of the refrigerant which takes place at a temperature lower than the temperature of the area which should be cooled. During the evaporation the refrigerant absorbs some heat from the surrounding area to support its evaporation thus cooling down these surroundings.

In compression based cycles there is a need for different pressures to perform this process. The refrigerant evaporates at low temperatures and pressures. Then a compressor increases the pressure of the evaporated refrigerant, thus creating the possibility to be condensed at a higher temperature which is the environmental temperature. Then the liquid refrigerant expands to the lower pressure of the evaporator where it has the possibility to evaporate again sucking heat from the surroundings. Schematically this process is shown in figure 3.2.

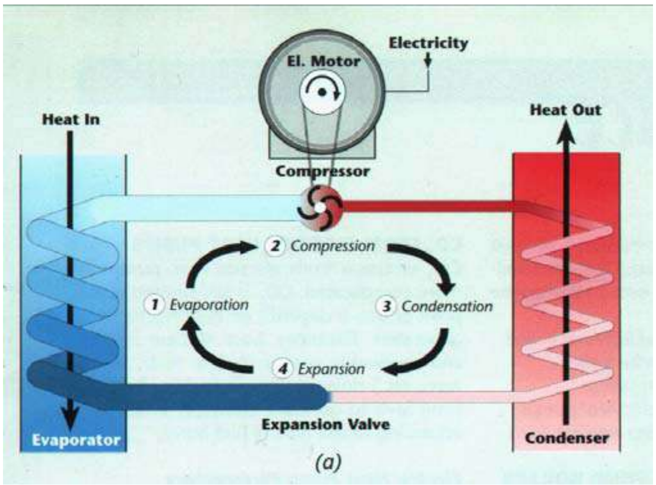

Figure 3.2 Schematic view of the typical compression cycle. Source: [2].

The thermodynamic changes of this process can be drawn on a pressure-enthalpy chart like the one in figure 3.3.

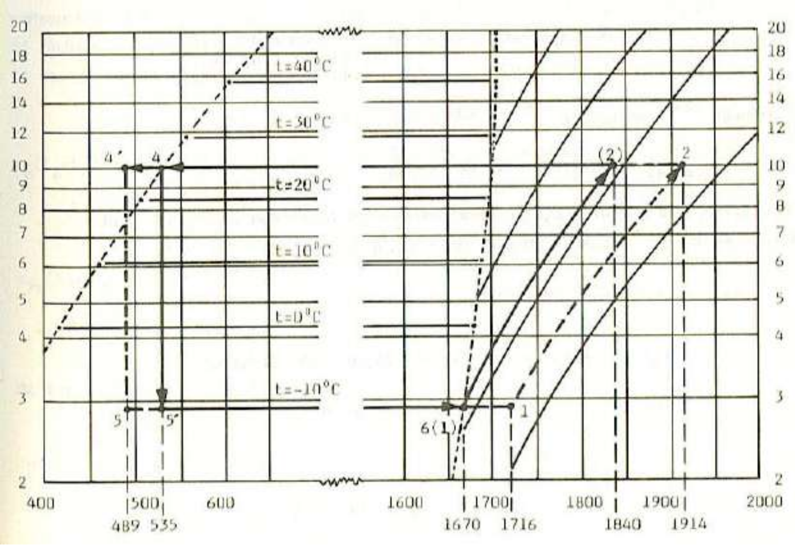

Figure 3.3. The typical ammonia compression cooling cycle on a pressure-enthalpy chart.

Another option to perform this evaporating cooling effect would be the use of the different evaporation temperature of solutions based on a pair of substances. This comes out from the fact that a solution of, *e.g.*, ammonia and water has different boiling, *e.g.*, evaporation temperatures at different water content, *i.e.*, at 1 bar pressure, solution of 0% water content, *i.e.*, pure ammonia boils at -33 ºC while 100% water content, *i.e.*, pure water boils at 100 ºC. Absorption cycle realizes a process where solutions of the same pair of solvents at different percentages are exposed to the proper temperatures – cooling chamber and environment. A schematic view of an absorption cycle is shown in figure 3.4.

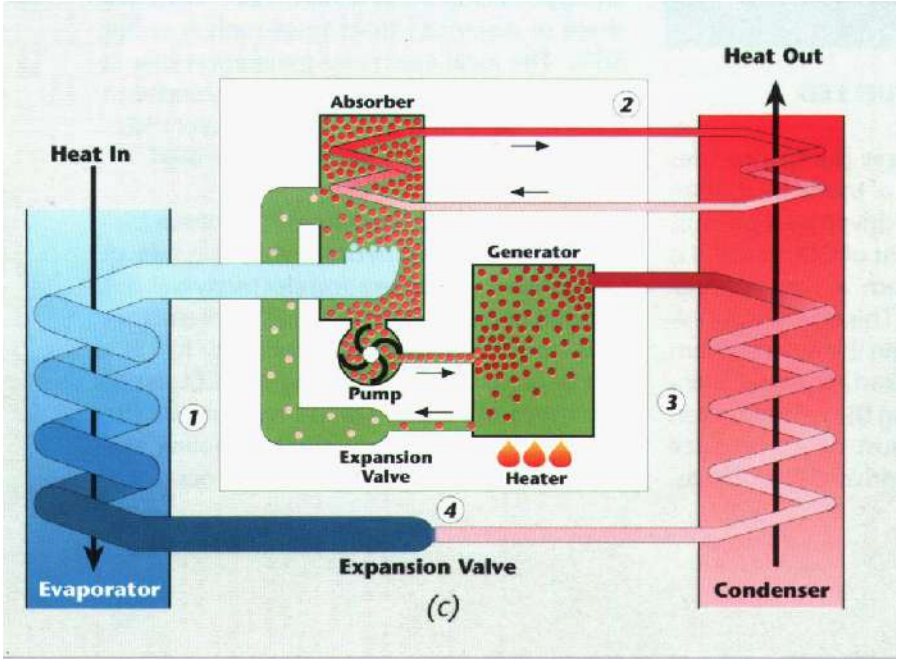

Figure 3.4. Schematic view of the absorption cycle. Source: [2].

It is obvious that the compressor has now been replaced by a piece of equipment suitable to change the contents and the pressure of the solution. This piece of equipment is shown under 2 in figure 3.4 and consists of:

- the absorber,
- the desorber (generator),
- the heater,
- a pump,
- an expansion valve,
- occasionally a distillation column.

In the absorber the vapour of the refrigerant – ammonia – is absorbed by the solvent – water. The resulting solution which is now reached in ammonia is driven by the pump to the higher pressure tank. There with the help of external heat the temperature is kept high and the refrigerant – ammonia – is separated under boiling conditions from the solvent – water. Thus the resulting solution is now poor in ammonia and is sent back to the lower pressure absorber to absorb ammonia and perform the same cyclic operation. The evaporated refrigerant – ammonia – in the desorber, becomes now liquid in the condenser draining its heat into the environment. This liquid refrigerant – ammonia – is guided to the expansion valve where it expands to the lower pressure of the evaporator. There it absorbs the heat from the cooling chamber thus creating the cooling effect and reaches the absorber where it enriches the poor in ammonia water coming from the desorber. The cyclic operation has been fulfilled.

As shown before this system needs heat to evaporate the ammonia from the water-ammonia solution in the desorber-generator. This heat can be provided by steam of by hot flue gases or another heating means. If this heat originates from the heat which is cogenerated from a thermal power cycle then this is trigeneration. The thermodynamic view of this process can be drawn on a pressure-temperature diagram where the lines of the different solution percentages have been drawn. This is shown in figure 3.5.

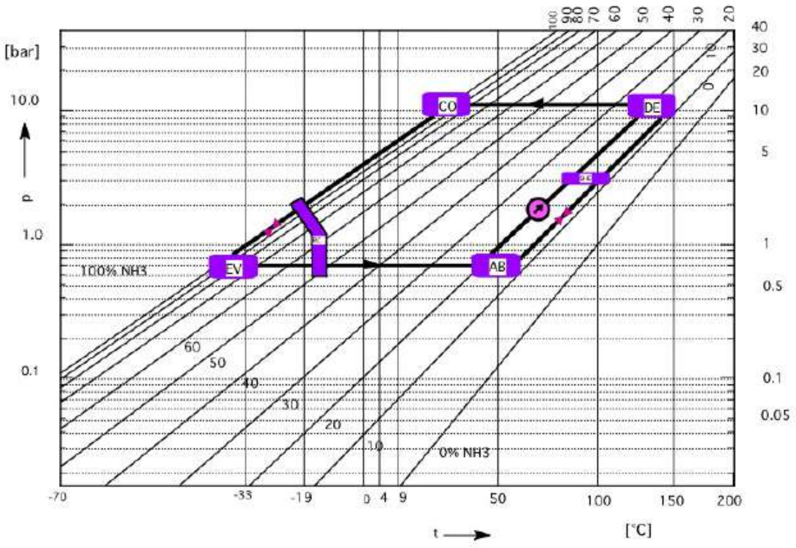

Figure 3.5. View of the ammonia-water absorption cycle in a pressure-temperature chart. Source: [2].

In practice the absorption cooling system can be realized as shown in the figure 3.6.

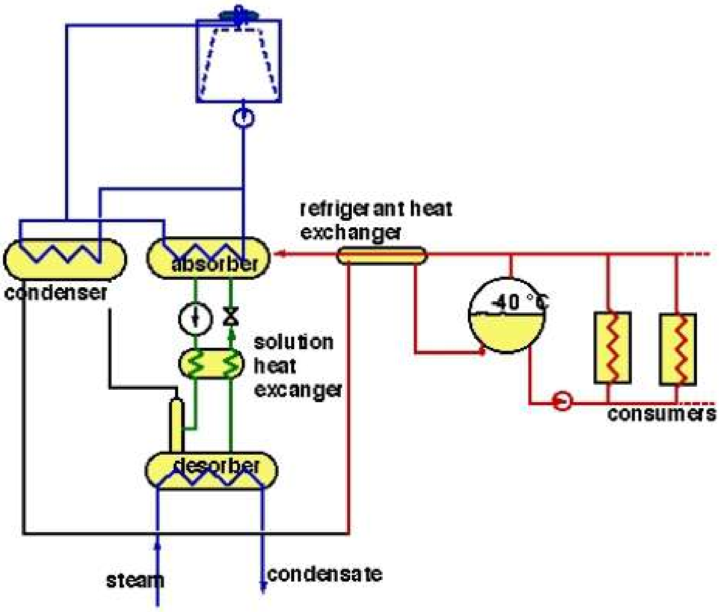

Figure 3.6. Schematic view of a typical ammonia absorption freezing cycle with direct expansion. Source: [2].

In the AFC, thermal energy is given to the solution of the two fluids (*e.g.*, water and ammonia) in a heat exchanger (HE) called **desorber or generator**, so the vapour evaporates from the solution and achieves the higher condensation pressure. Only a small amount of mechanical energy (1-2% of the cooling capacity) is used for pumping of the two fluid solutions.

The rest parts of AFC are:

- high pressure refrigerant vapour (ammonia) is cooled in condenser and condensated (by cooling tower),
- then is adiabatically expanded (through an expansion valve) giving freezing load,
- low pressure refrigerant vapour after expansion, returns to the **absorber** where is diluted (absorbed) in the liquid (water),

- absorption is exothermic and the solution is cooled (by cooling tower) to maximize absorption process.
- cooled solution is pumped to the **desorber** where heat is added to evaporate and pressurize the ammonia vapour (thermal compressor),
- liquid returns back by the higher **desorber** pressure (via a flow control valve) to the **absorber**.

To optimize the **Coefficient of Performance (COP)** of the cycle, several intermediate heat exchangers (HE) are used between the two fluid streams, to exchange heat. This is a result of thermodynamic analysis (*e.g.*, pinch analysis), and technical experience.

A well designed absorption freezing system using ammonia-water pair can reach COP's which range between 0.65 down to 0.35 for evaporator temperatures from 0 down to -40 ºC.

Naturally COP's depend on the temperature which can be achieved in the desorber, the temperature of the condenser and the evaporator. Figure 3.7 gives the relationship of these temperatures in typical applications. Of course this relation depends also on the ammonia content of the solutions. Guidelines should always be requested from the manufacturer of the absorption chiller before detailed engineering of the trigeneration application is to be performed. In ammonia-water pair, during evaporation within desorber, water also evaporates with ammonia, so a distillation column is used on top of the desorber to separate ammonia from water.

The energy balance of AFC is given in figure 3.8 and helps in understanding the AFC operation.

$$Qc + Qa = W + Qd + Qf \qquad [3.1]$$

The COP of the cycle is

$$COP = Qf/(Qd + W) \qquad [3.2]$$

As the mechanical energy W for pumping the solution from absorber to desorber is negligible in comparison to the Qf (for ammonia-water pair, typically 0.5-2% of Qf), equation [3.2] may be written as

COP = Qf/Qd [3.3]

Typical values of COP for ammonia-water pair are 0.2-0.65.

For the water-lithium bromide pair, typical COP values are 0.7-1.2, depending on single or double stage operation, and the whole cycle operates under vacuum.

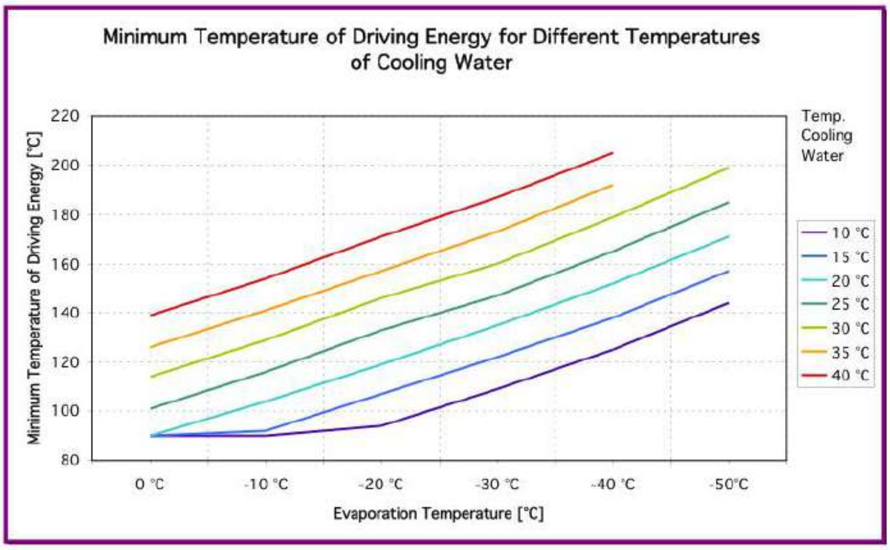

Figure 3.7. Relationship between the main temperatures of typical absorption equipment. Source: [2].

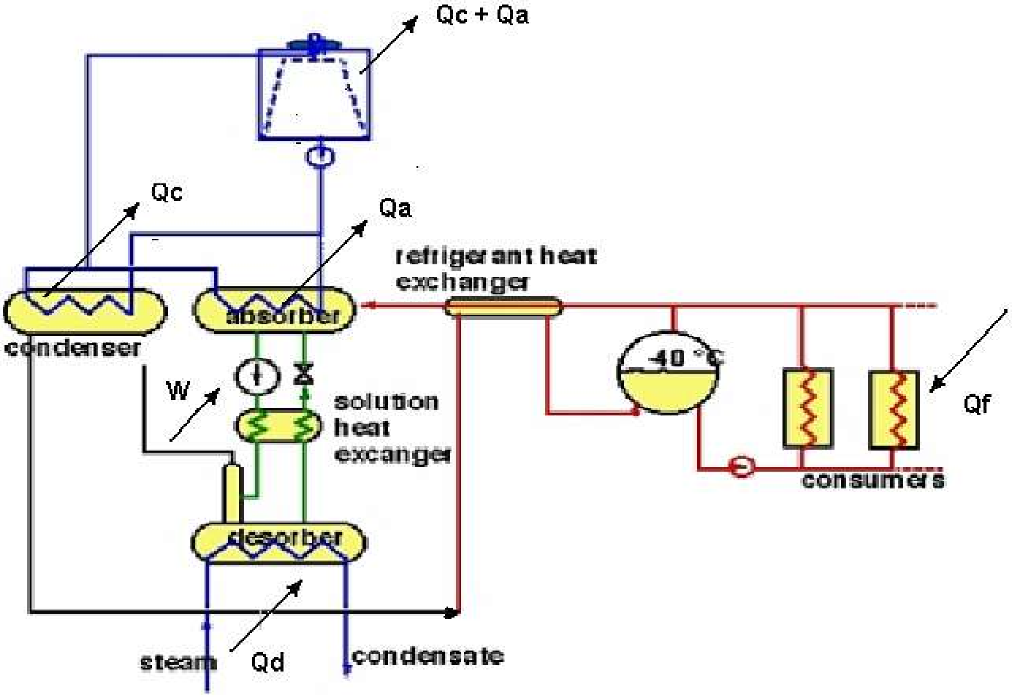

Figure 3.8. Ammonia absorption freezing cycle energy balance. Source: [2].

Figure 3.9 shows the water-lithium bromide pair operation cycle and figure 3.10 the energy balance.

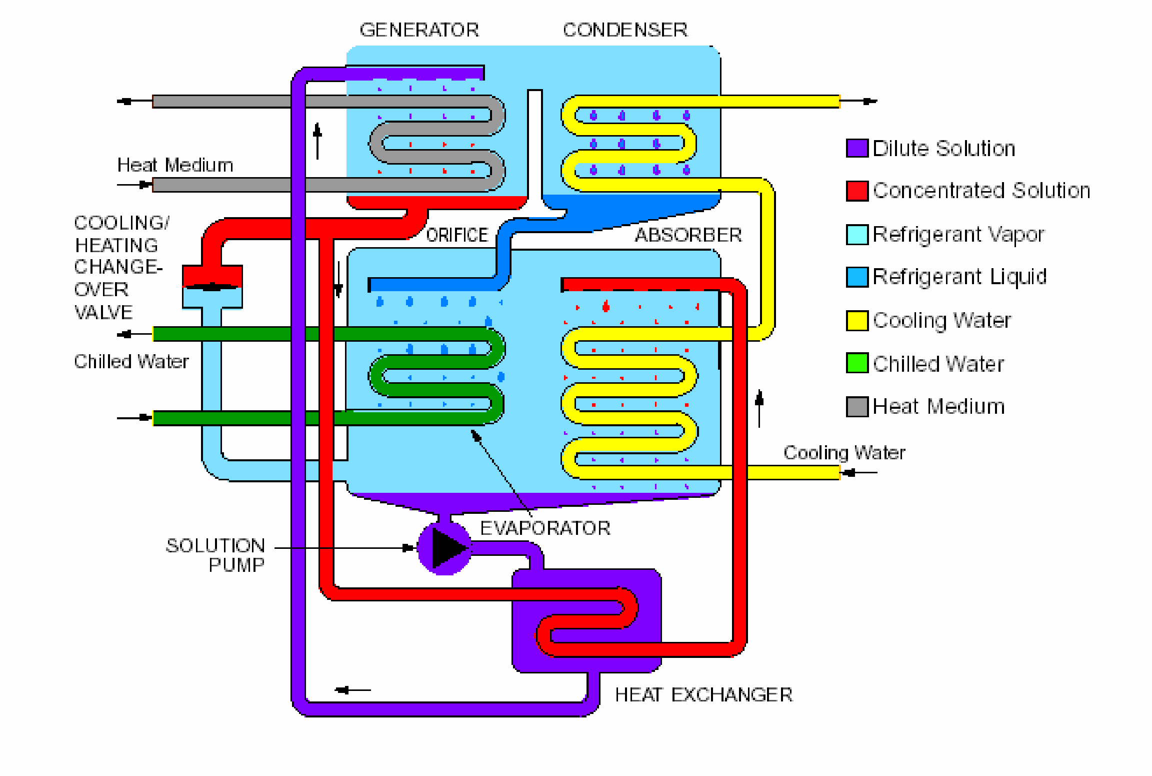

Figure 3.9. Lithium bromide absorption cycle.

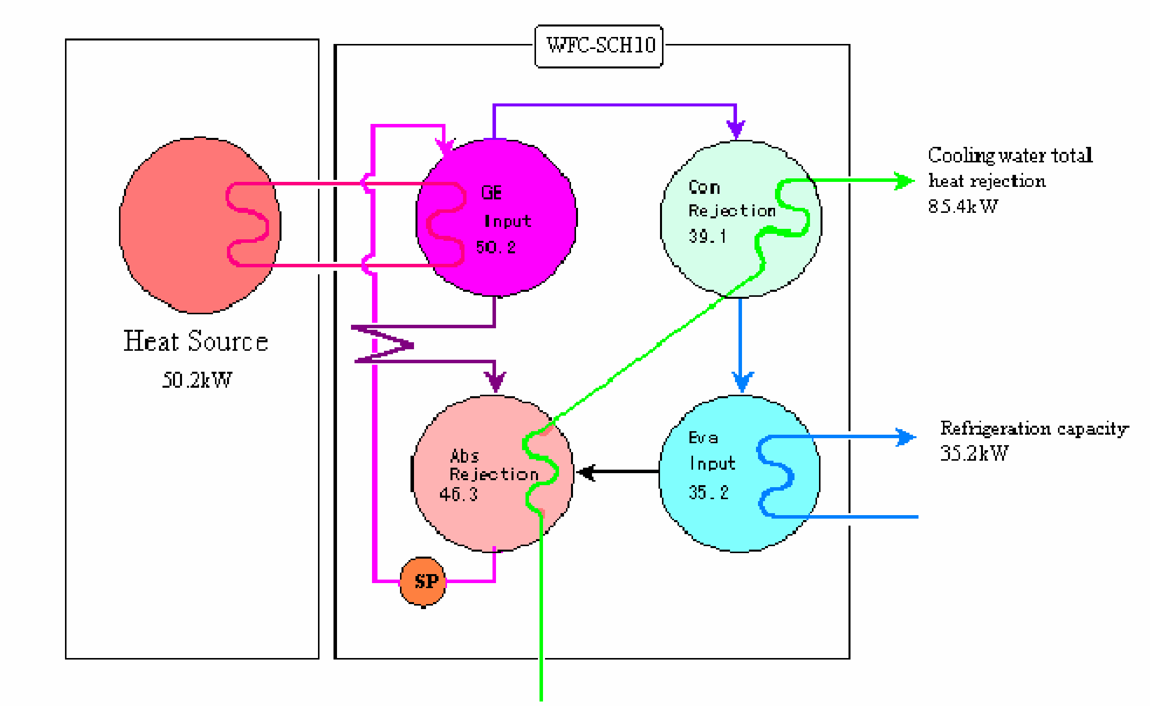

Figure 3.10. Lithium bromide absorption cycle energy balance.

The AFC diagram on an enthalpy-concentration chart can be found in standard refrigeration handbooks for both working pairs [3, 4]. These diagrams are useful and necessary for accurate calculations and equipment design.

3.3 Typical absorption equipment in use

The technology of AFC plants has been used for cooling/freezing for over a hundred years. AFC plants have been always used in situations of low cost heat available, to compensate the more expensive electrical energy. Due to this fact, they represent nowadays the minority in cooling. Two types of AFC working pairs are currently available in absorption equipment: LiBr and water, ammonia and water.

During the last 15 years, AFC equipment demand has been increased because of:

- improved technological level,
- lower capital cost,
- expansion of decentralised power generation policy, through CHP and trigeneration.

Absorption coolers/freezers are classified according to

- the working pair (ammonia, lithium bromide)
- heating medium available: hot water (down to 75 ºC), steam, direct fuel firing, flue gases, diathermic oil, etc.

Absorption coolers operating with LiBr and water are used in large scale air conditioning installations (temperatures down to +4 ºC). Typical market sizes of equipment range from 35 kW up to 5000 kW.

Absorption coolers operating with ammonia and water are used in industrial refrigeration installations (temperatures down to -60 ºC). Typical market sizes are from 250 kW up to 2500 kW, operating at one or two stages, depending on the application.

While LiBr absorption coolers are constructed under standard capacity ranges, ammonia coolers are custom made to match the particular application.

Ammonia absorption coolers consist mainly of heat exchangers. The only moving parts are these of the liquid solution pump. This is the reason that this equipment is of highest reliability with lowest maintenance cost, in comparison with compression ammonia coolers. Ammonia absorption freezers are traditionally used in sectors of high reliability demand, like instant coffee freeze drying plants at -55 ºC.

The main differences between AFC and CFC coolers are listed below.

AFC coolers

- Are driven by heat. If heat is of low cost, very low operating costs.
- Efficiency increases at partial load.
- Low maintenance costs and high availability.
- Use of ammonia-water solution, requires safety specifications
- Relatively high capital cost.

CFC coolers

- Are driven by electrical energy, with high operating costs.
- Efficiency decreases at partial loads.
- Relatively high maintenance costs. High availability requires high capital cost.
- Alternative refrigerants are available, with no safety specifications.
- Relatively low capital cost in comparison with absorption coolers.

3.4 Typical processes suitable for absorption freezing

Almost any industrial process requiring minimum freezing load of 250 kW from 0 to -60 ºC can be served by absorption freezing with ammonia-water cycle. Typical examples in the food industry include:

- Meat and fish processing (refrigeration and deep freezing).
- Vegetables (freeze drying, frozen products).
- Dairy and ice cream industry (freeze drying, refrigeration and deep freezing).

- Instant coffee industry (freeze drying).
- Cooked meals processing (refrigeration and deep freezing).
- Bakery, pastry and confectionery (deep freezing, freeze drying and refrigeration).

Building and industrial air conditioning sector is the application field of LiBr-water absorption equipments. Typical equipment capacities are between 35 and 5000 kW at temperatures down to +6 ºC.

In a **trigeneration system**, the AFC plant is the technical link between the CHP plant and the user's process. It uses the heat coming from the CHP plant, as the driving energy, and produces cooling for the process. In most cases heat comes from the exhaust gases of a turbine or an engine. Depending on the user heating and/or cooling demands and peak loads, there are different possibilities of AFC plant connection to the CHP plant.

Indirect connection.

The exhaust gases of the CHP plant are used to produce steam or hot water in a standard boiler. The steam is then used in the AFC plant to produce cooling. The advantage of this system is that steam or hot water can be used not only in the AFC plant, but additionally or alternatively for other purposes. In processes with fluctuations in steam consumption, the AFC plant can form a buffer where excess steam from CHP can be used. In this way CHP can operate at steady load, even during fluctuating steam demands.

Direct connection

Exhaust gases from CHP plant are used directly to AFC plant, entering the desorber. The desorber will be similar to a conventional steam boiler and can be designed according to the specifications of the turbine or engine. The advantage of this system is that there is no need for extra boiler, which makes the trigeneration plant more compact and cheaper in capital and maintenance costs. These consequences are stronger in small capacity trigeneration plants than in large ones.

On the user side of AFC plant, depending on the cooling demands and peak loads, there are also different possibilities of connections.

If there is an existing ammonia CFC plant, AFC plant has to be connected in parallel and designed to cover base load, while CFC plant covers peak loads. This connection should be indirect, as ammonia from CFC plant contains oil from compressors, and ammonia from AFC plant contains water from distilation column of desorber. This kind of connection is illustrated in figure 3.11.

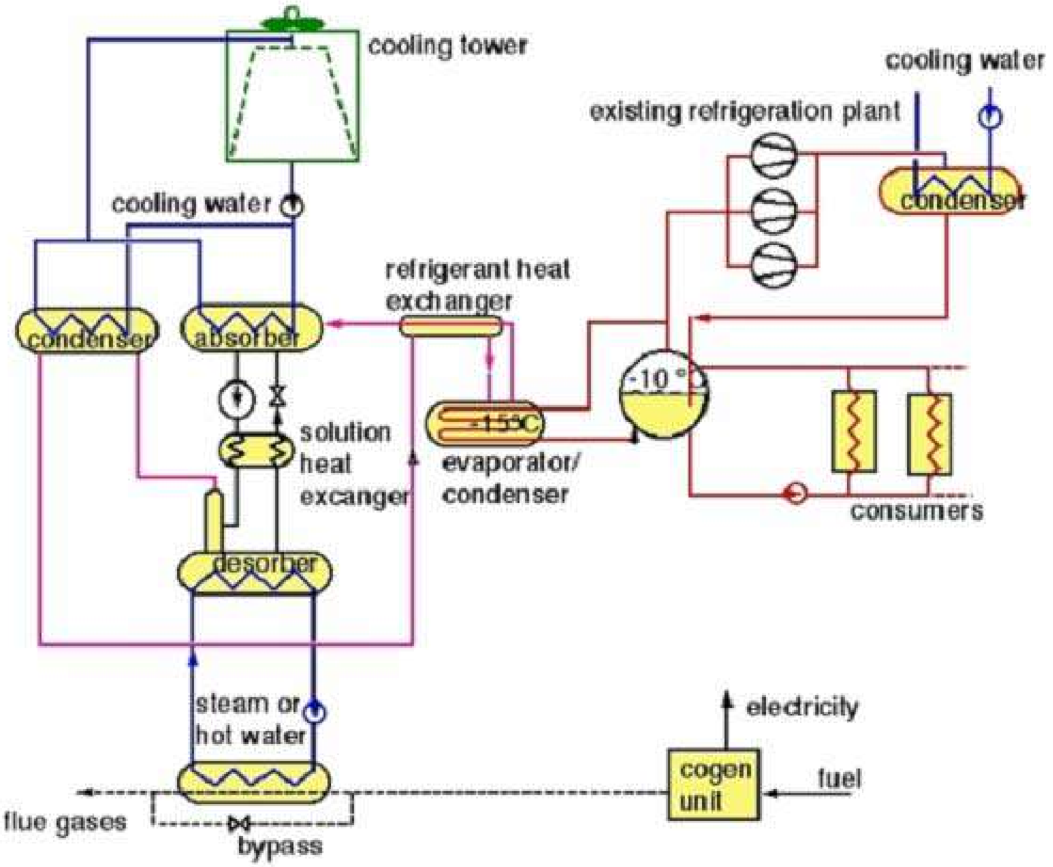

Figure 3.11. Ammonia AFC in parallel connection with CHP plant. Source: [2].

In cases where cooling fluctuations are significant, the AFC plant operation can be normalized using an ice buffer connection to the process. This kind of connection is illustrated in figure 3.12.

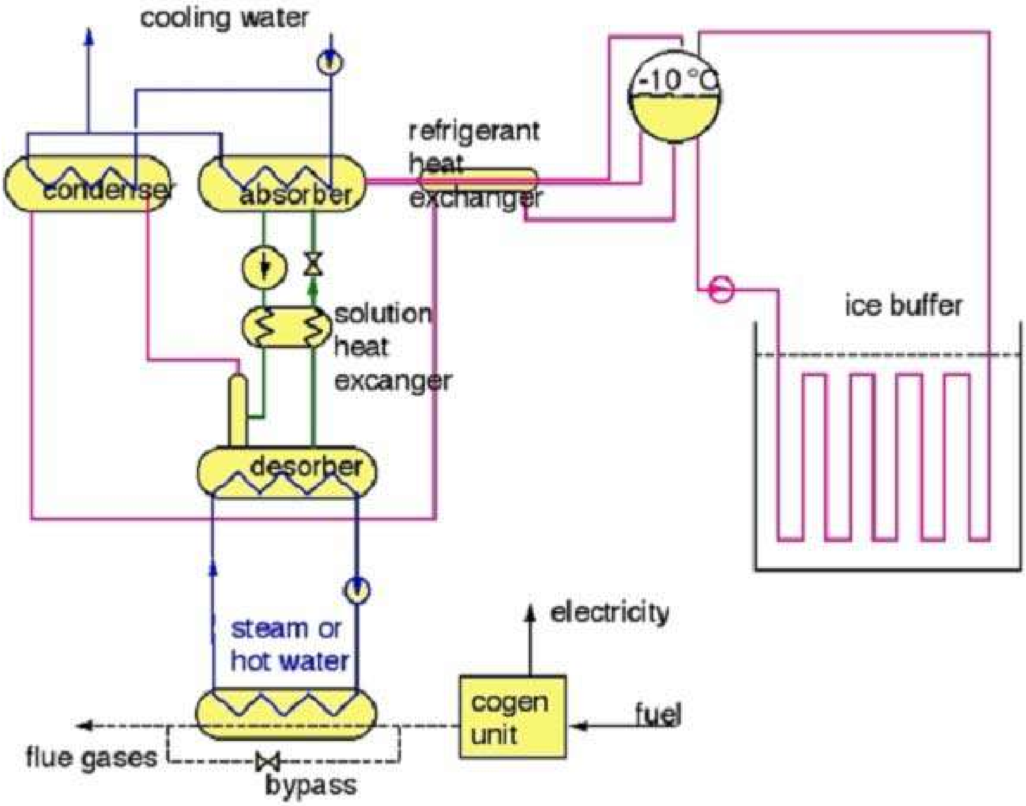

Figure 3.12. Ammonia AFC connected via an ice buffer with process. Source: [2].

3.5 Typical application example with calculation of the basic components

All AFC equipment manufacturers provide standard selection diagrams for easy equipment sizing and selection. They provide also correction factors for performance estimations during different operational conditions. In this way, the rather complicated analytical estimation from thermodynamic charts is by-passed.

Example 1

In a frozen vegetable plant an ammonia-water AFC for 1000 kW cooling, at evaporation temperature of -15 ºC, uses saturated steam of 5 bar, operates at one stage, rejects heat with a cooling tower at *w.b.* 20 ºC. It requires 1800 kW steam and pumping mechanical work is 10 kW.

From equation [3.1] the total heat rejected from cooling tower is

$Qc + Qa = W + Qd + Qf$

$Qc + Qa = 10 + 1800 + 1000$

$Qc + Qa = 2810$ kW

This is almost double than that rejected from an equivalent conventional water cooled CFC.

From equation [3.2] the COP is

$COP = 1000/1810 = 0.552$

If we neglect the mechanical work and use equation [3.3]:

$COP = 1000/1800 = 0.555$

For the equivalent conventional water cooled CFC, the mechanical work is about 800kW.

3.6 Are there benefits? Prices and ranges

Economical benefits of absorption coolers have to be seen in combination with trigeneration application, and low cost thermal energy availability. Absorption cooler by itself is a large energy conversion equipment that transforms low cost thermal energy into low temperature refrigeration with a higher economic value. Trigeneration plants, like cogeneration plants, are profitable in the following situations:

- Low availability of electrical energy.
- High electrical energy cost.
- Inefficient use of fossil fuels.
- Availability of low cost thermal energy.

A comparison between AFC and CFC will clear up the possible benefit margin. If we refer to the example of the previous paragraph, the ratio of the thermal to electrical power needed for the same cooling power (1000 kW) is:

AFC/CFC = 1800 kW_{th}/800 kW_e = 2.25

This means that if electricity cost is 2.25 times or more higher than thermal energy available then there is a benefit margin for AFC application.

Capital cost is also paid back by the above margin.

Indicative capital cost for the ammonia absorption cooler of example 1 is 500 000 €. For a double capacity cooler (2000 kW) the cost would be 800 000 €. For a 1000 kW absorption cooler at -55 ºC, would require 11 bar saturated steam and at one stage operation would cost 1 200 000 €.

If the electricity cost of 65 €/MWh would be compared with zero cost thermal energy available –e.g. thermal energy currently rejected- , the annual benefit from the ammonia absorption cooler of example 1 would be (8000 hr operation):

(8000*1800/2.25)*65/1000 = 416 000 €

and the simple pay back period would be

500 000/416 000 = 1.2 years.

In most cases thermal energy is not of zero cost. In these cases the thermal energy cost should be taken into account to calculate the benefit of absorption cycle against compression cycle freezing application.

In the case that there is no rejected heat and absorption chiller should operate with extra steam to be generated by the boiler then we have to calculate the cost of the MWh of heat to be used in the absorption cooling equipment. If this cost is about 25Euro/Mwh – a typical cost for steam generated in a high efficiency boiler based on typical natural gas prices in 2006- , then the profit of applying absorption cooling is:

Electricity cost for compression cooling/operating hour = 800*65/1000 = 52 Euro/hour

Steam cost for absorption cooling /operating hour = 1800*25/1000 = 45 Euro/hour

In this case the profit margin reduces to 7 Euros/operating hour. This means that 71.000 operating hours i.e. 8,9 years are needed to pay back the equipment costs.

For a full financial consideration on the Absorption cooling benefits, one should take into account other parameters as well e.g. the maintenance costs, the peak load operation etc. All these parameters should related to an hourly cost. In this way financial appraisal of trigeneration is possible – see chapter 6-.

3.7 Effects on pollutant and CO_2 emissions

The effect on pollutant and CO_2 emissions of AFC equipments depends directly on the origin of heat that is used.

AFC equipments that use rejected heat or heat from RES (solar, biogas, etc.), save CO_2 emissions equivalent to those emission generated by the electricity they replace.

If trigeneration with fossil fuels (natural gas) is considered (heat from CHP plant is used), then a double effect on CO_2 emission reduction should be considered: CO_2

emissions are saved because of replaced electricity and also because of the electricity cogenerated at a higher efficiency compared to the utility plants.

Finally, if heat directly from fossil fuels is used (*e.g.*, steam boiler operating with natural gas), then CO_2 emissions are generated based on those which occur because of the fossil fuels used.

3.8 References and bibliography

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[2] www.Colibri-bv.com

[3] Cube von, H.L., Lehrbuch der Kältetechnik, v.I & II, C.F. Müller Verlag, 1981.

[4] Altenkirch, E., Absorptionskältemaschinen, VEB Verlag, 1954.

CHAPTER 4 – Biogas Generation and Use

4.1 The basics of anaerobic digestion

Anaerobic digestion is the biological degradation of organic material without the presence of oxygen, which results in the production of biogas, a valuable (energy containing) product. The biogas can be used as fuel in engine-generators to produce electricity or as boiler fuel to produce steam.

Biogas produced during anaerobic digestion is primarily composed of methane (CH_4) and carbon dioxide (CO_2), as shown in table 4.1.

Matter	%
Methane, CH_4	55-75
Carbon dioxide, CO_2	25-45
Carbon monoxide, CO	0-0,3
Nitrogen, N_2	1-5
Hydrogen, H_2	0-3
Hydrogen sulfide, H_2S	0,1-0,5
Oxygen, O_2	Traces

Table 4.1. Typical composition of biogas. Source: [5].

Methane is also the main component in natural gas and contains most of the energy value of the biogas. Figure 4.1 shows the variation of the low heating value (LHV) of biogas for different percentages of methane content.

Anaerobic digestion is not only a way of producing energy. It is also a technology that provides residues pre-treatment, as it is able to reduce the initial content of organic matter present on the residue.

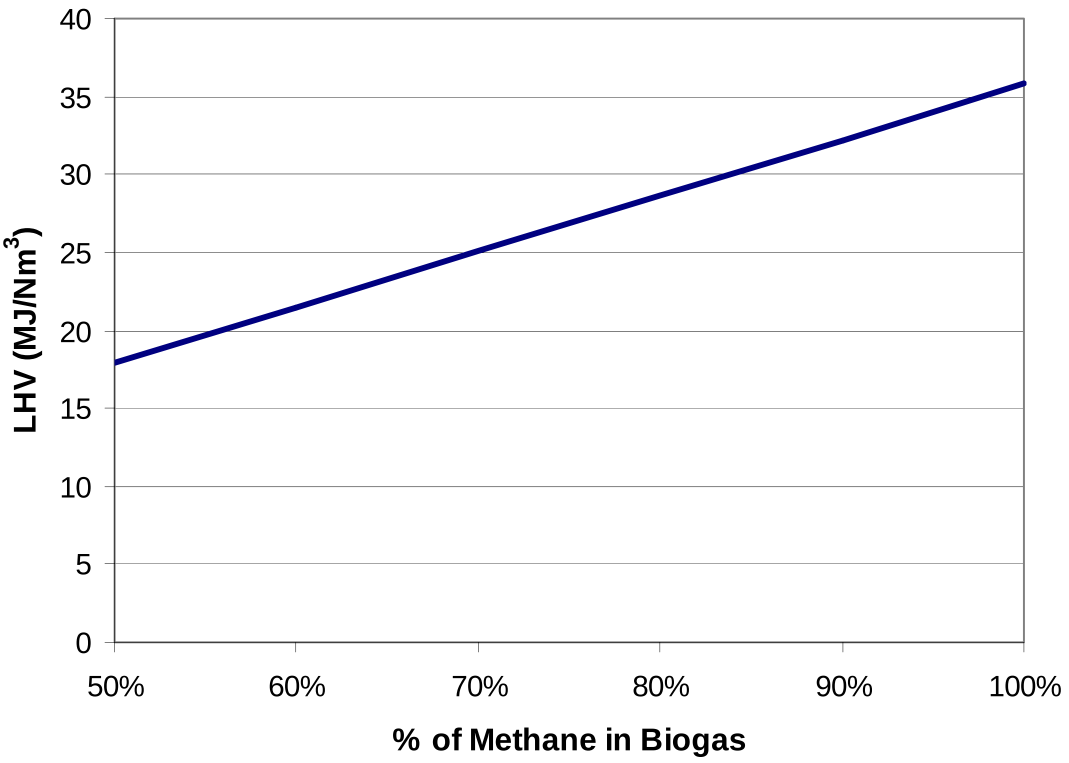

Figure 4.1. LHV of biogas for different percentages of methane.

Table compares the characteristics of biogas with other common gaseous fuels.

Parameter	Unit	Natural gas	Town gas	Biogas*
LHV	MJ/m^3	36,14	16,1	21,48
Density	kg/m^3	0,82	0,51	1,21
Wobbe index (lower)	MJ/m^3	39,9	22,5	19,5
Max. ignition velocity	m/s	0,39	0,7	0,25
Theoretical air requirement	m^3 air/m^3 gas	9,53	3,83	5,71
Dew point	ºC	59	60	60-160

* Biogas with 60% of CH_4, 38% of CO_2 and 2 % of other constituents.

Table 4.2. Characteristics of different fuels. Source: IEA (2000).

4.2 The feed in waste and biomass. Characteristics and their relation to biogas generation

Any biodegradable organic material can in principle be used as input for processing inside the digester. However, for economic and technical reasons, some materials are more attractive than others [5].

Anaerobic techniques are generally utilised in those industries where there is a high level of soluble and readily biodegradable organic material and strength of the waste water, expresses in COD[1], is generally greater than 1500-2000 mg/l. In the food industry sector, the application of anaerobic waste water treatment is largely confined to relatively heavily polluted waste water with COD between 3000 and 40000 mg/l, *e.g.*, in the sugar, starch, fruit, vegetable and alcoholic drinks sectors. There has been recently some success in using certain anaerobic systems even for less heavily polluted waste water with COD between 1500 and 3000 mg/l, *e.g.*, in breweries, dairies, fruit juice, mineral water and the soft drinks sector [3].

All waste constituents are not equally degraded or converted to gas through anaerobic digestion. Anaerobic digestion does not degrade lignin and some other hydrocarbons. An important parameter to evaluate the quality of the residue is the relationship between the amount of carbon and nitrogen present in organic materials – expressed in terms of the Carbon/Nitrogen (C/N) ratio. A C/N ratio ranging from 20 to 30 is considered optimum for anaerobic digestion. If the C/N ratio is very high, the nitrogen will be consumed rapidly by methanogens bacterias in order to meet their protein requirements and will no longer react on the left over carbon content of the material. As a result, gas production will be low. On the other hand, if the C/N ratio is very low, nitrogen will be liberated and accumulated in the form of ammonia (NH_3). Ammonia will increase the pH value of the content in the digester, and affect negatively the methanogenic population. Table shows the C/N ratio for some residues that can be found in the food industry.

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[1] Chemical oxygen demand (COD) is the amount of potassium dichromate, expressed as oxygen, required to chemically oxidise at approximately 150ºC substances contained in waste water.

Organic product	C/N
Pig manure	20
Pig manure: solid fraction	10 – 16
Bovine dung	14 – 20
Oat straw**,** barley straw, rape straw, straw from corn	60 – 70
Rye straw	77
Grape marc	20 – 25
Olive oil cake	16 – 32
Sewage sludge	13
Cow dung	25
Chicken manure	25
Slaughter house wastes	3 – 4

Table 4.3. C/N ratio for various organic products. Source: various.

Although there is always a need to previously evaluate the conditions of biodegrability of the digester feed, since it could be necessary to correct some characteristics, the values listed in table 4.4 can be used for estimating the potential biogas production per kg of organic matter.

It is also reasonable to estimate the quantity of the biogas produced without an exact determination of the waste composition. The main tool for these estimation is the theoretical quantity of methane produced per one kg of organic matter destroyed, which is 0.35 m^3 CH_4/kg COD at 0 ºC and 1 atm.

Industry	Nm^3 of biogas per kg of organic matter
Dairies	0,6
Vegetables	0,6
Fruit	0,55
Slaughterhouse	0,45
Meat processing	0,5
Soup processing	0,4
Sugar	0,65
Cereals	0,4
Coffee and tea	0,6
Wine	0,4
Beer	0,5
Mushroom processing	0,6

Table 4.4. Estimations of biogas production from organic matter in some food industry sectors. Source: [10].

Some concentrated residues or by-products from the food industry have specific production of biogas as function of its content in volatile solids (VS). Table presents data for the estimation of the biogas production from some concentrated residues and by-products of the food industry sector.

The waste characteristics may be altered by simple dilution. Water reduces the concentration of certain constituents such as nitrogen and sulphur that produce products like ammonia and hydrogen sulphide that are inhibitory for the anaerobic digestion process. High solids digestion creates high concentrations of end products that have a negative impact on anaerobic degradation.

Residue type	VS (%)	Nm^3 CH_4/kg of VS	Nm^3 CH_4 /t
Stomach content and entrails from bovine stock	9,6	0,4	38,4
Stomach content and entrails from swine stock	9,6	0,46	44,2
Waste from slaughterhouse	4,0	0,54	21,6
Sludge from fish industry	3,2	0,25	8,0
Fish oil	81	0,8	648
Sorus	4,5	0,33	14,9
Concentrated sorus	9	0,35	31,5
Soyabean oil and margarine	85,5	0,8	684
Alcohol	38	0,4	152
Distillation residues	-	0,5	-
Used vegetable oils	-	1,05	-

Table 4.5. Estimation of the biogas production from some concentrated residues and by-products of the food industry sector. Source: [10].

4.3 The culture needed. What the starting point is?

Anaerobic digestion is carried out by a group, or consortia of bacteria, working together to convert organic matter into a gas. The biological anaerobic degradation of organic matter can be divided into four steps, as shown in figure 4.2.

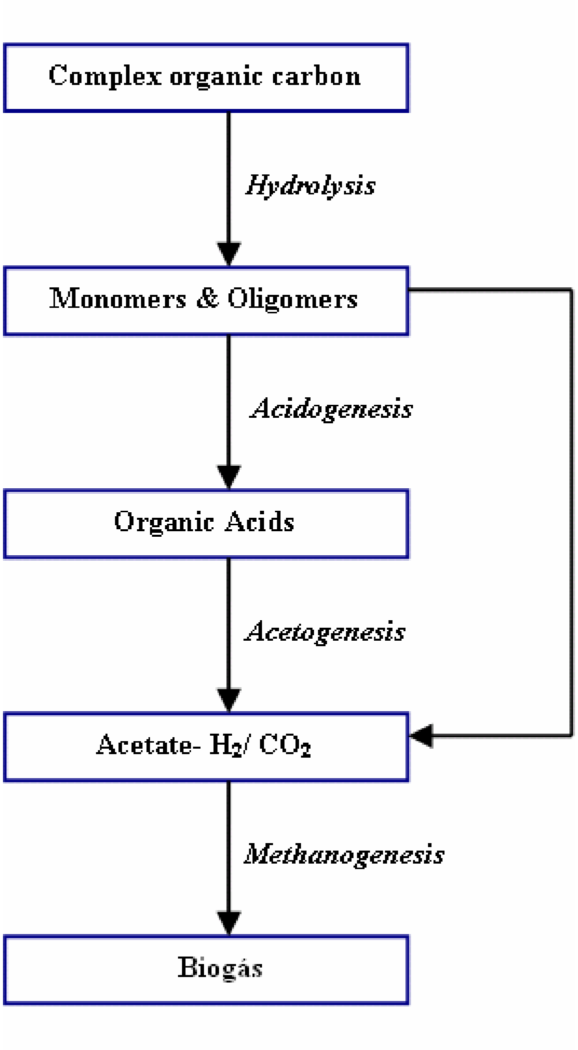

Figure 4.2. Steps of the anaerobic digestion process.

There are several groups of bacteria that perform each step once different species are needed to degrade completely a heterogeneous stream. Table shows the bacterial groups that act in each step.

Bacterial Group	Process
Fermentative	Hydrolysis and Acidogenesis
Acetogenic	Acetogenesis
Methanogenic	Methanogenesis

Table 4.6. Bacterial groups involved in the anaerobic digestion process.

4.3.1 Hydrolysis

In hydrolysis, high weight organic molecules (e.g., proteins, carbohydrates, fat, and celluloses) are broken down into smaller molecules such as sugars, amino acids, fatty acids and water.

4.3.2 Acidogenesis

Acidogenesis is the further breakdown of these smaller molecules into organic acids, carbon dioxide, hydrogen sulphide and ammonia.

4.3.3 Acetogenesis

In acetogenesis, the products from the acidogenesis are used for the production of acetates, carbon dioxide and hydrogen. In this process, two types of acetogenic bacteria may be distinguished, namely the hydrogen producing bacteria and the hydrogen consuming bacteria.

- **Hydrogen producing bacteria**

This bacteria promotes the anaerobic oxidation of the volatile fatty acids in acetates (acetic acid). The reactions are not spontaneously, since they only occur when the partial pressure of hydrogen is in reduced levels. The reactions and the variation of Gibbs free energy[2] (ΔGº) are shown in table 4.7.

Substrate	Reaction	ΔGº (kJ)
Ethanol	$CH_3CH_2OH + H_2O \rightarrow CH_3COOH + 2H_2$	+ 9,7
Proponic acid	$CH_3CH_2COOH + 2H_2O \rightarrow CH_3COOH + 3H_2 + CO_2$	+ 76
Butyric acid	$CH_3CH_2CH_2COOH + 2H_2 \rightarrow 2CH_3COOH + 2H_2$	+ 48

Table 4.2. Some reactions of the hydrogen producing bacteria. Source: [10].

For the common substrates used by the acetogenic bacteria it is possible to see that the oxidation of the proponic acid is the most difficult one, since the value of ΔGº is higher.

- **Hydrogen consuming bacteria**

This type of bacteria is able to produce acetate from CO_2 and H_2, contributing for the maintenance of the desirable hydrogen partial pressure in the system. The reaction is spontaneous as it is shown in Table .

Substrate	Reaction	ΔGº (kJ)
$CO_2 + H_2$	$CO_2 + 4H_2 \rightarrow CH_3COOH + 2H_2$	-95

Table 4.8. Reaction of the hydrogen consuming bacteria. Source: Santos (2000).

4.3.4 Methanogenesis

This is the final producing step, the one that leads to the production of methane, carbon dioxide and water. These products are produced from the acetates, carbon dioxide and hydrogen (products of acidogenesis and acetogenesis), as can be seen in

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[2] The lower the value of the Gibbs free energy the more favourable the reaction is. A spontaneous reaction is a reaction that has a negative value since it releases energy.

table 4.9. Contrarily to the other bacterial groups, the methanogenic ones grow in the absence of oxygen.

The methane production bacteria grows slower (approximately five times) than the acetogenic ones.

Substrate	Reaction	ΔGº (kJ)
Acetic acid	$CH_3COOH \rightarrow CH_4 + CO_2$	- 31
Hydrogen	$4H_2 + CO_2 \rightarrow CH_4 + 2H_2O$	- 131

Table 4.9. Reactions promoted by the methanogenic bacteria. Source: [10].

4.4 Important parameters

Due to the diversity of the micro-organisms involved in the anaerobic digestion process, the efficiency of the process depends on the type and stability of the environmental conditions.

4.4.1 Temperature

The temperature is one of the factors that highly influence the anaerobic digestion process. In all biological processes, the activity of the bacteria strains is increased up to a certain limit as a result of an increase in temperature. Signs of this are an increase in the growth rate and the specific nutritional requirement of the bacteria. There are three main temperature ranges in anaerobic reactors operation as follows:

Psychrophilic	20 – 25 ºC
Mesophilic	32 – 37 ºC
Thermophilic	55 – 60 ºC

Both mesophilic and thermophilic strains are normally used for biogas generation. Figure 4.3 shows that the optimum range for the mesophilic strains is 30°C – 35°C, while for the thermophilic ones is located around 50°C – 60°C.

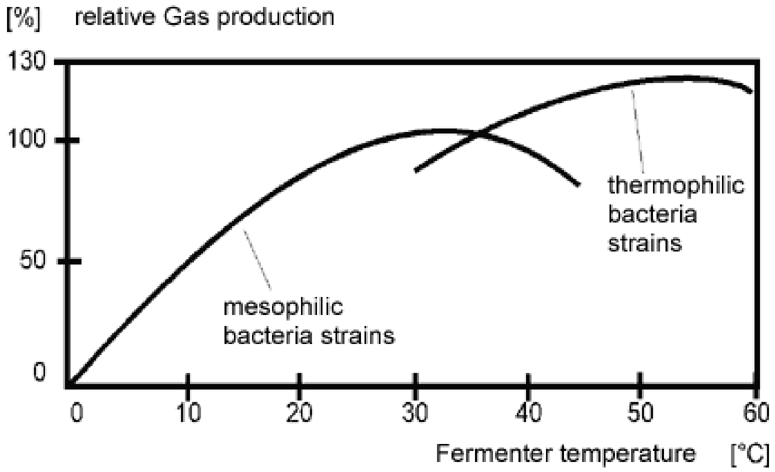

Figure 4.1. Influence of the temperature in the gas production. Source: [2].

Figure 4.3 also reveals that excessively high temperatures may damage the strains of bacteria, and ultimately kill off the biogas producing bacteria. The experience has shown that a temperature between 32 °C and 35 °C is more efficient for stable and continuous production of methane [2]. Biogas produced outside this range of temperatures will have a higher percentage of carbon dioxide and other gases.

As normally the residue is not in this temperature range, a heat supply is normally required. For this purposes, anaerobic digesters are usually equipped with a heating system and a proper thermal isolation in order to reduce thermal losses. The desirable heat can be obtained using an internal (figure 4.4) or an external heat exchanger (figure 4.5)

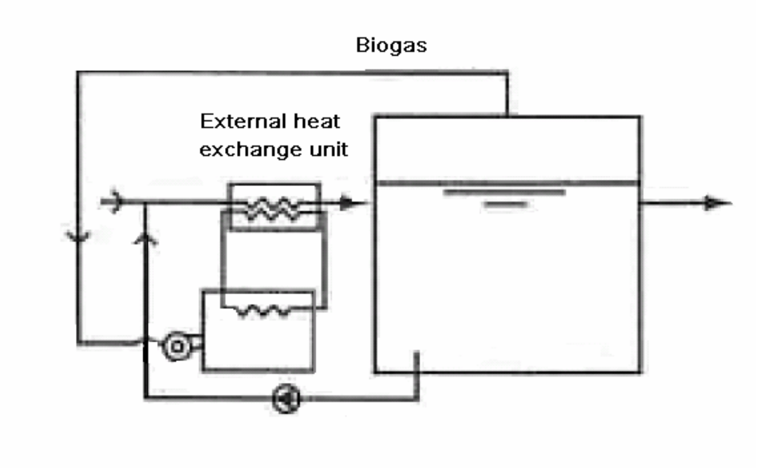

Figure 4.4. Heating of the digester using an external heat exchange unit. Source: [10].

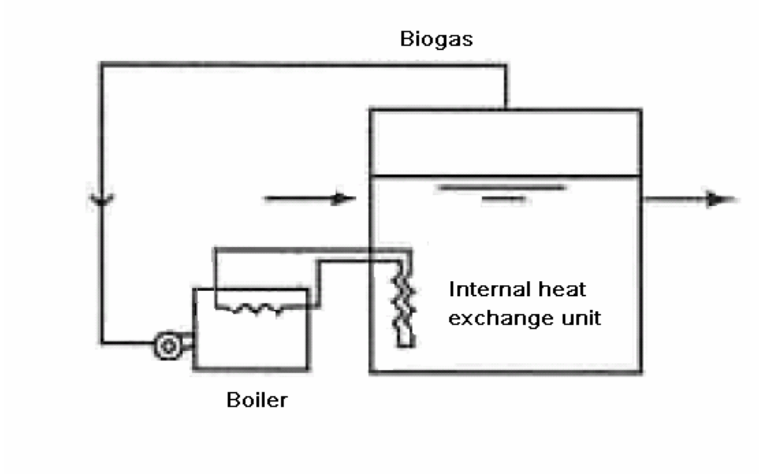

Figure4.5. Heating of digester using an internal heat exchanger unit. [10].

Generally 30 to 40 % of the total energy produced in the form of biogas is used to maintain the temperature in the mesophilic regime [10].

4.4.2 Total solids content

In principle, three ranges of total solids (TS) content may be distinguish as follows:

Low solid content	< 10% TS
Medium solid content	15 - 20 % TS
High solid systems	22 - 40 % TS

The literature indicates that greater efficiencies occur at concentrations of approximately 6 to 7 % of total solids.

4.4.3 Mixing and agitation

The mixing and agitation of the digester content is a factor of great importance, since influences directly the global performance of the digester. The following factors are promoted by an efficient mixing rate:

- Temperature homogeneity in all the mass that is in digestion;
- Elimination of inactive zones in the digester.

For mixing/agitation purposes one of the following strategies is normally used:

- Biogas recirculation (figure 4.6);
- Mechanical agitation (figure 4.7);
- Effluent recirculation (figure 4.8).

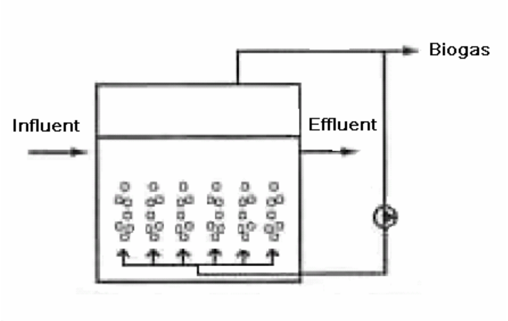

Figure 4.6. Biogas recirculation. Source: [10].

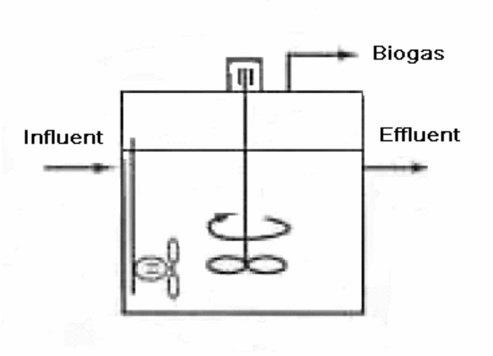

Figure 4.7. Mechanical agitation. Source: [10].

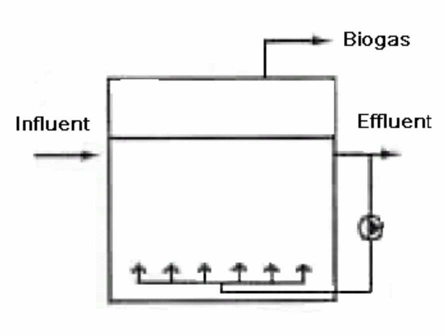

Figure 4.8. Effluent recirculation. Source: [10].

When using mechanical systems some technical problems may arise, such as corrosion of all the metallic components, wear and tear promoted by sand and other inert materials, fouling and interferences caused by coarse materials.

4.4.4 Hydraulic retention time

The hydraulic retention time (HRT) is a measure of the amount of time the digester liquid remains in the digester. For a reactor with a volume of V and an effluent volumetric flow rate of Q, the HRT is defined as:

$$\mathrm{HRT} = \frac{V}{Q} \qquad [4.1]$$

HRT is the parameter that controls the anaerobic system performance, although its degree of influence depends on the reactor type and influent flux. The retention time is crucial because if the feed does not stay in the reactor long enough, for the entire digestion process to take place, biogas will not be produced. The retention time should be at least higher than the time for the duplication of the bacterial population in the digester. Table 4.10 shows typical HRT values for reactors working in the mesophilic regime.

Process	Input COD (mg/l)	Hydraulic retention time (h)	Organic loading (kg COD/m^3 per day)	Efficiency (%)
Contact	1500-5000	2-14	0.5-5.3	75-90
UASB	5000-15000	4-12	2-12	75-85

Table 4.3. Some parameters of digesters working in the mesophilic regime. Source: [3].

4.4.5 Solids retention time

The solids retention time (SRT) is the most important factor controlling the conversion of solids to gas. It is also the most important factor to maintain the digester stability. Although the calculation of SRT is often improperly stated, it is the quantity of solids maintained in the digester divided by the quantity of solids wasted each day [4].

In a conventional, completely mixed, or plug flow digester, HRT is equal to SRT. However, in a variety of retained biomass reactors SRT is bigger than HRT. As result, the retained biomass digesters can be much smaller while achieving the same solids conversion rate.

4.4.6 Organic load and efficiency

The organic load applied to a digester is the quantity of organic compost per unit of reactor volume and time. For a volume of residue of Vresidue with a concentration C, introduced into a reactor with a volume V during the time t, the organic load is:

$$\text{Organic Load} = \frac{CV_{\text{residue}}}{V\ t} \qquad [4.2]$$

For residues with constant concentration, the organic load can be calculated using the HRT as follows:

$$\text{Organic Load} = \frac{\text{C}}{\text{HRT}} \qquad [4.3]$$

The unit of the organic load is kg COD m^{-3} day^{-1} or kg VS m^{-3} day^{-1}.

The COD removal efficiency is a measure of the digester performance. This parameter reveals the fraction of organic matter in the influent that is converted to products of the digestion process, being defined as follows:

$$\text{Efficiency}(\%) = \frac{\text{COD}_{\text{inf uent}} - \text{COD}_{\text{effluent}}}{\text{COD}_{\text{inf luent}}} \qquad [4.4]$$

As stated before, the anaerobic digestion process is able to remove between 40 to 90% of the organic matter present in the residue, so it can be also considered an attractive way of reducing the deposition of organic matter in landfills.

4.4.7 pH value

The optimal pH values for the acidogenesis and methanogenesis stages are different. During acidogenesis, acetic are formed and, thus, the pH falls. Low values of pH can inhibit acidogenesis and pH values below 6.4 can be toxic for methane-forming bacterial (the optimal range for methanogenesis is between 6.6 and 7). An optimal range for all pH is between 6.4 and 7.2 [9].

4.5 Equipment and systems used

The main component of the biogas production process is the reactor or anaerobic digester. The reactor is essentially a closed tank, where the micro-organisms are in contact with the residue or substrate in conditions of total absence of oxygen (anaerobic conditions).

There are two main types of reactors: continuous and batch. Batch is the simplest one, with the biomass added to the reactor at the beginning and sealed for the entire duration of the process. In the continuous process, which is the most common type, organic matter is constantly added to reactor and the end products constantly removed, resulting in a much more constant production of biogas.

Table 4.11 shows the digester types normally used in the food industry. From a technological viewpoint, the biological process can also be carried out in more than one reactor, which has some implications, mainly economical implications.

Industry	Contact	UASB	Hybrid Process
Sugar	38	21	-
Vegetables	11	43	-
Fruits	2	3	-
Starch	12	22	1
Meat	32	5	4
Beverages	28	141	12
Yeasts	7	12	2
Dairies	7	13	4
Total	137	260	23

Table 4.4. Biogas digesters used in the food industry. Source: [8].

4.5.1 Complete mix digester

Figure 4.9 shows a complete mix digester, also known as continuous stirred tank reactor (CSTR). The CSTR is the most often used digester. Usually, a CSTR can be described as a reactor where the contact between the residue and the micro-organisms are promoted by an efficient mixing of the digester content.

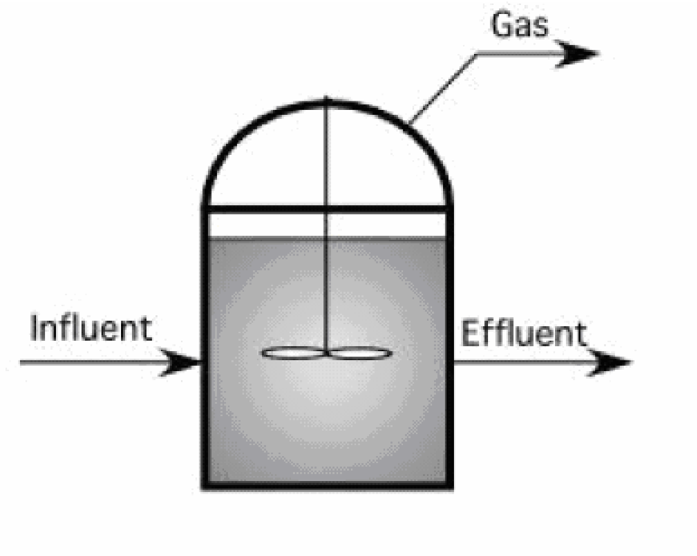

Figure 4.2. Complete mix digester. Source: [4].

Typically, the residence time for the substrate in the digester is maintained as high as possible in order to achieve a satisfactory degradation of the materials that have slower decomposition rates.

Owing to its characteristics and limitations, this type of digester is normally used for concentrated residues, with high solids content. The main advantages of this digester are as follows:

- High level of experience with technology;
- Suitable for use in any climate;
- Waste heat from the boiler can be used to heat the slurry;
- Can be used with a wide range of influent total solids;
- Reasonable conversion of solids to gas.

The main disadvantages of this digester are as follows:

- Expensive to construct;
- Expensive to operate and maintain;
- Mechanical mixing required.

4.5.2 Plug flow

Figure 4.10 shows a plug flow digester. This type of digester is suitable for ruminant animal manure that has a solids concentration between 11% and 13%. A typical design for a plug-flow system includes a manure collection system, a mixing pit and the digester itself. The digester is a long, rectangular container, usually built below-ground, with an airtight, expandable cover. In the mixing pit, the addition of water adjusts the proportion of solids in the manure slurry to the optimal consistency.

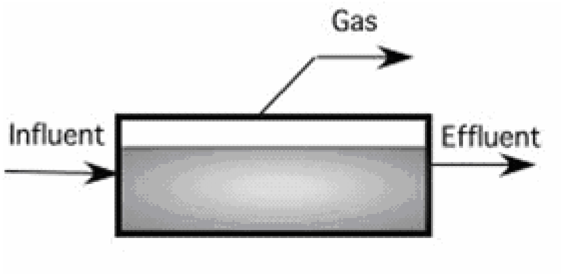

Figure 4.3. A plug flow digester. Source: [4].

The new material is added to the tank at one end and pushes older material to the opposite end. In ruminant manure, coarse solids form a viscous material as they are digested, which limits the solids separation in the digester tank. As a result, the material flows through the tank in a plug.

A flexible, impermeable cover on the digester traps the gas and the pipes beneath the cover carry the biogas from the digester to the engine generator set.

The waste heat from the engine generator can be used to heat the digester by using pipes inside the digester. The hot water heats the digester in order to maintain the temperature between 25 °C and 40 °C, a temperature range suitable for the methane producing bacteria. Another way of getting this extra heat is by burning the digester gas directly in a boiler.

In this kind of digester the retention time is normally higher than in the CSTR model. This is due the need of achieving the same biogas production. The main advantages of this digester are as follows:
Good track record with dairy manure;

- Suitable for any climate;
- Minimal maintenance required;
- Waste heat from generator can be used to heat the digester**.**

The main disadvantages of this digester are as follows:

- Requires high solids manure (11 – 14%);
- Requires regular shutdown and cleaning due to sediment build up.

4.5.3 Up flow anaerobic sludge blanket (UASB)

Anaerobic granular sludge bed technology refers to a special type of reactor concept for the high rate anaerobic treatment of wastewater. The concept was initiated with upward-flow anaerobic sludge blanket (UASB) reactor. Figure 4.11 shows a UASB digester.

From a hardware viewpoint, at first appearance an UASB reactor is nothing more than an empty tank. Waste water is distributed into the tank at appropriately spaced inlets. The waste water passes upwards through an anaerobic sludge bed where the micro-organisms in the sludge come into contact with waste water substrates. The sludge bed is composed of micro-organisms that naturally form granules (pellets), with diameters between 0.5 and 2 mm, which have a high sedimentation velocity and thus resist wash-out from the system even at high hydraulic loads. The resulting anaerobic degradation process is responsible for the production of biogas. The upward motion of the released gas bubbles causes hydraulic turbulence that provides reactor mixing without any mechanical parts. At the top of the reactor, the water phase is separated from sludge solids and gas in a three-phase separator (also known as the gas-liquid-solids separator). The three-phase-separator is commonly a gas cap with a settler situated above it. Below the opening of the gas cap, baffles are used to deflect gas to the gas-cap opening [11].

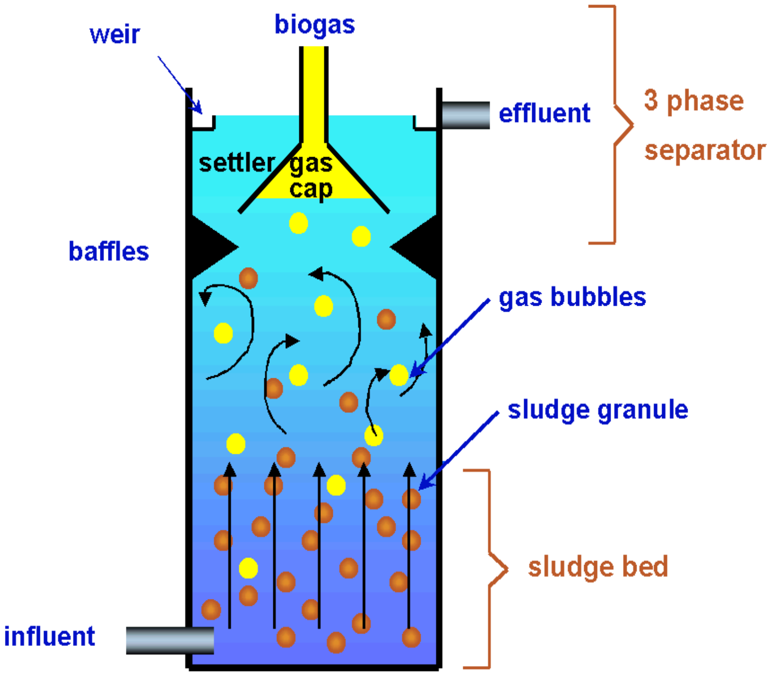

Figure 4.11. An UASB digester. Source: [11].

This technology needs constant monitoring when put into use to ensure that the sludge blanket is maintained, and not washed out (thereby losing the effect). The heat produced as a by-product of electricity generation can be re-used to heat the digestion tanks.

Up flow anaerobic sludge blanket UASB reactors are typically suited to dilute waste water streams with 3% of solids with particle size lower than 0.75 mm. The main advantages of this type of digester are as follows:

- Low energy consumption;
- Small space requirement;
- Variable and intermittent load capacity;
- Low nutrient requirement;

- Surplus sludge suitable for longer storage;
- No noise or odour nuisance**.**

The main disadvantage of this type of digester is the complexity of its operation.

4.5.4 Anaerobic contact process

Figure 4.12 shows an anaerobic contact digester. In an anaerobic contact digester, the active solids mass necessary for biological stabilization of the incoming organics is settled in a separate clarifier and recycled back to the reactor.

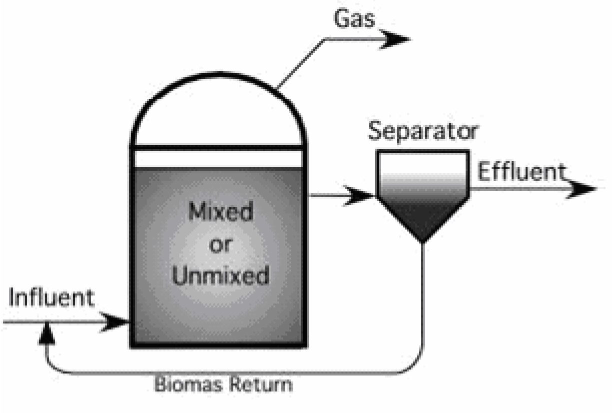

Figure 4.12. An anaerobic contact digester. Source: [4].

The contact digester is suited to treat high strength, readily biodegradable, soluble organic wastes. The contact process has found favour in the treatment of sugar beet waste waters where calcium concentrations are high. Internal calcium carbonate fouling of the reactor components is less of a concern than in an UASB reactor. However, it is noted that the latter processes have been used successfully for sugar beet factory waste water treatment; generally, in these cases, steps have been taken to minimize calcium concentrations in the waste streams.

The main advantages of this digester are as follows:

- Good odour control;
- Not limited by solids concentration;

- Stability;
- Flexibility.

The main disadvantage of this digester is its complexity.

4.5.5 Covered lagoon digester

A covered lagoon digester, as the name suggests, consists of a manure storage lagoon with a cover (figure 4.13). The cover traps the gas produced during decomposition of the manure.

Covering a manure storage lagoon is a simple form of digester technology suitable for liquid manure with less than 3% of solids. For this type of digester, an impermeable floating cover of industrial fabric covers all or part of the lagoon. A concrete footing along the edge of the lagoon holds the cover in place with an airtight seal. Methane produced in the lagoon collects under the cover. A suction pipe extracts the gas for use. Covered lagoon digesters require large lagoon volumes and a warm climate. Covered lagoons have low capital cost, but these systems are not suitable for locations in cooler climates or locations where a high water table exists.

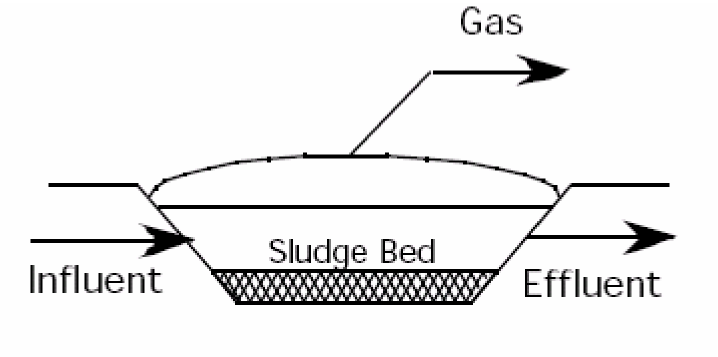

Figure 4.13. A covered lagoon digester. Source: [4].

The main advantages of this digester are as follows:

- Cheap;
- Low technology and easy to construct**.**

The main disadvantages of this digester are as follows:

- Warm climate required;
- Cover maintenance and limited life;
- Solids and nutrients accumulate, therefore periods for cleaning are required,
- Low energy production.

4.5.6 Hybrid process

A number of hybrid processes have been developed and applied to many different types of waste materials. The hybrid process incorporates a combination of the previously described configurations.

4.6 The Output from the process

4.6.1 Available routes

Biogas can be used for all applications designed for natural gas, subjected to some further upgrading, as not all appliances require gas with the same quality standards [6].

Application	H_2S	CO_2	H_2O
Boiler	< 1000 ppm	No	No
Kitchen stove	yes	No	No
Stationary engine (CHP)	< 1000 ppm	No	no condensation
Vehicle fuel	Yes	Recommended	Yes
Natural gas grid	Yes	Yes	Yes

Table 4.5. Requirements to remove gaseous components according with the application. Source: [6].

Food industry is a thermal energy intensive user. Biogas can be used for heating using boilers. Boilers do not have a high quality gas requirement. It is preferable to remove the hydrogen sulphide because it forms sulphurous acid in the condensate which is highly corrosive. It is also recommended to condense the water vapour in the raw gas, once the water vapour may cause problems in the gas nozzles. Removal of water will also remove a large proportion of H_2S [6].

Combined heat and power (CHP) is also an attractive way of using biogas produced by anaerobic digestion. But gas engines do not have the same quality requirements as boilers. In biogas engines, NO_x emissions are usually low because of the high CO_2 content of the gas. CO emissions are often more problematical, once catalysts to reduce CO are difficult to use because of the presence of the H_2S in the gas. However, from an environmental point of view, CO is a minor problem when compared with NO_x, since it is rapidly oxidise to CO_2 which makes part of the carbon cycle [6].

4.6.2 Gas upgrading technologies

A number of gas upgrading technologies have been developed for treatment of natural gas, landfill gas and town gas. However, not all of them are recommended for application with biogas because of the price and/or environmental concerns [6].

Carbon dioxide removal

At the present time, there are four different methods commercially available to achieve good CO_2 removal efficiencies. They are:

- Water scrubbing;
- Polyethylene glycol scrubbing;
- Carbon molecular sieves;
- Membranes separation.

Water scrubber: Water scrubbers (see figure 4.14) are used to remove carbon dioxide and hydrogen sulphide, since these gases have higher water solubility than methane. The absorption process is purely physical. Usually the biogas is pressurised and fed to the bottom of a packed column where water is fed on the top and so the absorption process is operated counter-currently. The water used can be regenerated and recirculated but the most efficient method is to use cheap water such as water from a sewage treatment plant and, thus, there is no need to recirculate it [6].

Polyethylene glycol scrubbing: This uses also a physical process like water scrubbing. The difference is that carbon dioxide and hydrogen sulphide are more soluble in this solvent and, therefore, smaller quantities of scrubbing media are required. In addition, water and halogenated hydrocarbons are also removed when scrubbing biogas with polyethylene glycol. This scrubbing is always done with recirculation [6].

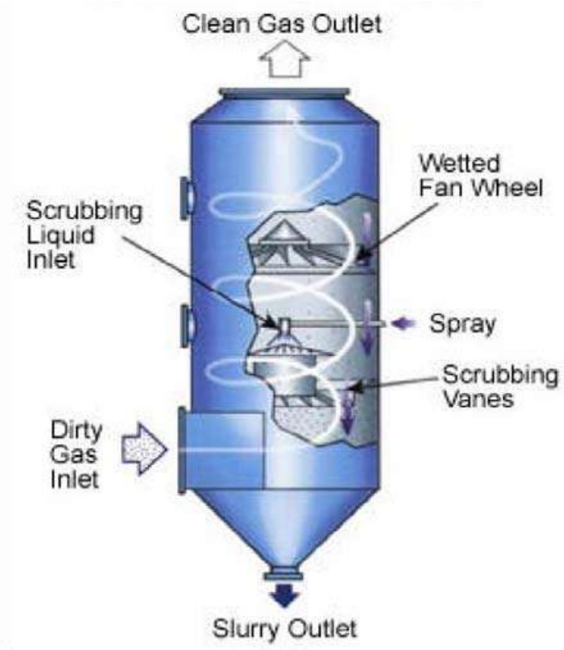

Figure 4.14. Example of a wet scrubber. Source: [9].

C**arbon molecular sieves**: molecular sieves are excellent products to separate specifically a number of different gaseous compounds in biogas. Thereby the molecules are usually loosely adsorbed in the cavities of the carbon sieve but not irreversibly bound. The selectivity of adsorption is achieved by different mesh sizes and/or application of different gas pressures. When the pressure is released the compounds extracted from the biogas are desorbed. The process is therefore often called pressure swing adsorption (PSA). To enrich methane from biogas the molecular sieve is applied which is produced from coke rich in pores in the micrometer range. The pores are then further reduced by cracking of the hydrocarbons [6].

Membranes separation: there two basic gas purification membrane systems: a high pressure gas separation and a low-pressure gas liquid absorption separation. The high pressure gas separation uses gas on both sides of the membrane. The membranes (made of acetate-cellulose) separate the small polar molecules such as carbon dioxide, moisture and hydrogen sulphide. In the low-pressure gas liquid adsorption separation, a liquid absorbs the molecules diffusing through the membrane. The essential element in these systems is a hydrophobic microporous membrane, which has the function of separating the gaseous from the liquid phase. The molecules from the gas stream, flowing in one direction, which are able to diffuse through the membrane, will be absorbed on the other side by the liquid flowing in counter-current [6].

Hydrogen sulphide removal: hydrogen sulphide is always present in biogas, although concentrations vary with the feedstock. It has to be removed in order to avoid corrosion in compressors, gas storage tanks and engines. Hydrogen sulphide is extremely reactive with most metals and the reactivity is enhanced by concentration and pressure, the presence of water and elevated temperatures. Experience has also shown that two of the most commonly used methods for hydrogen sulphide removal are internal to the digestion process:

- Air/oxygen dosing to digester biogas
- Iron chloride dosing to digester slurry

Air/oxygen dosing to biogas: The simplest method of desulphurisation is the addition of oxygen or air (normally 2% to 6% of air) directly into the digester or in a storage tank serving at the same time as gas holder. Depending on the temperature, the reaction time, the amount and place of the air added, the hydrogen sulphide concentration can be reduced by 95% - to less than 50 ppm. Measures of safety have to be taken to avoid overdosing of air in case of pump failures, since biogas in air is explosive in the range of 6 to 12%, depending on the methane content. In steel digesters, without rust protection, there is a small risk of corrosion at the gas/liquid interface [6].

Iron chloride dosing to digester slurry: this method consists in feeding iron chloride directly to the digester slurry or in a pre-storage tank. It reacts with produced hydrogen sulphide to form iron sulphide salt (particles). This is a very effective method in reducing high H2S levels but less effective to attain low and stable levels such as for vehicle fuel demands [6].

It is also possible to use scrubbers for desulphurisation by using water scrubbers. Water scrubbing is a purely physical absorption process, described before, which can be used for selective removal of hydrogen sulphide. The cost for selective removal has not yet been shown to be competitive with the other hydrogen sulphide removal methods. Thus water scrubbing probably only will be considered for the simultaneous removal of carbon dioxide in order to meet vehicle fuel demands on biogas quality [6].

Halogenated Hydrocarbon Removal: halogenated hydrocarbon may cause corrosion on CHP engines, in the combustion chamber, at spark plugs, valves, cylinder heads, etc. For this reason CHP engine manufacturers claim maximum limits of halogenated hydrocarbons in biogas. They can be removed by pressurised tube exchangers filled with specific activated carbon. Small molecules like CH4, CO_2, N_2 and O_2 pass through while larger molecules are adsorbed. The size of the exchangers is designed to purify the gas during a period of more than 10 hours [6].

Siloxanes Removal: organic silicon compounds are occasionally present in biogas which can cause severe damages to CHP engines. During incineration they are oxidised to silicon oxide which deposits at spark plugs, valves and cylinder heads abrading the surfaces and eventually causing serious damage. Particularly, in Otto engines this might lead to major repairs. Dual fuel engines are less susceptible because the temperature of the entire motor body is much higher than with Otto engines [6].

Siloxanes may be removed by absorption on a liquid medium, a mixture of hydrocarbons compounds with a special ability to absorb the silicon compounds with a special ability to absorb the silicon compounds. The absorbent is after regenerated.

4.6.3 EC legislative constrains

If biogas production from biodegradable by-products onsite a food factory is considered, it is important to be aware of different regulations, and therefore, of different investment needs, depending on what type of waste shall be processed. When the raw materials to be fed into the biogas reactor contain only vegetable ingredients, there are no restrictions. But if also animal ingredients are included, the EC statute on animal by-products not intended for human consumption must be followed – this concerns all EU countries[3]. This statute categorizes animal by-products unfit for human consumption into three classes. The first class contains items that pose the highest risks on human health and it is not allowed to process them in a biogas reactor. The second class contains items that need to be made hygienic – except manure – by heating them at 133 °C and 3 bar for 20 minutes before feeding into the reactor. The third class items (includes food waste and animal by-products from food industries) can be used as such. Thus, if animal by-products only from the food factory itself are going to be fed into the reactor, there are no problems. But if also animal waste from outside the food factory is planned to be processed in the reactor, the situation is more complicated: proper commercial documents must accompany every single waste delivery to the biogas reactor plant, stating the class of the delivered waste; and if class 2 waste, in addition to class 3 waste, is desired to be processed in the reactor, then the facility for heat treatment of the class 2 waste must be build onsite as well – unless only heat treated class 2 material is accepted.

The EU emission trading scheme (ETS) is one of the policies being introduced across Europe to tackle emissions of carbon dioxide and other greenhouse gases and combat the serious threat of climate change. The scheme commenced on 1 January 2005. The first phase runs from 2005-2007 and the second phase will run from 2008-2012 to coincide with the first Kyoto Commitment Period. Further five-year periods are expected subsequently. The scheme will work on a cap and trade basis. EU Member State governments are required to set an emission cap for all installations covered by the scheme. Each installation will then be allocated allowances for the particular commitment period in question. The number of allowances allocated to each installation for any given period (the number of tradable allowances each installation will receive), will be set down in a document called the National Allocation Plan.

ETS concerns only installations that have thermal power above 20 MW. Thus, only large food factories can benefit from emission reductions by using ETS. However, the EU ETS Directive allows that also smaller installations can be accepted into ETS (so

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[3] REGULATION (EC) No 1774/2002 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL laying down health rules concerning animal by-products not intended for human consumption.

called Opt-in option). Unfortunately, only few countries have utilized this opportunity.

4.7 Effects on pollutant and CO_2 emissions

There are multiple environmental benefits of producing biogas from wastes, including:

- Reduce landfill waste and associated issues;
- Protection of water quality;
- Reducing green house gases emissions**.**

The extent to which one or more of these occur depends on the specific system design and location, and on the boundaries used in the analysis.

Conservation of natural resources is a common objective. When a company starts producing biogas, a reduction on the use of non-renewable resources is achieved while maintaining the quality of resources, and reusing them.

Biogas is considered to be a source of renewable energy (figure 4.15). This is because the production of biogas depends on the supply of biomass, which usually grows back each year. By comparison, the natural gas used in most of our homes is not considered a form of renewable energy. Natural gas formed from the fossilized plant residues and animal wastes in a process that takes millions of years. These resources do not grow back in a time scale that is meaningful for humans.

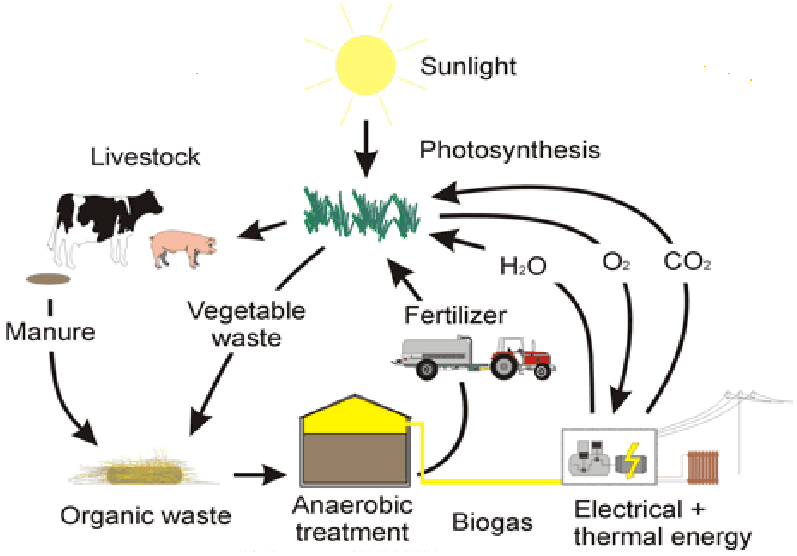

Figure 4.15. Biogas in the nature cycle. Source: [2].

The current patterns of energy use, and associated links to emissions of greenhouse gases and climate change, are some of the major global concerns. The substitution of fossil fuels is a key role of renewable energy, leading to greenhouse house gas (GHG) emissions reduction, or further increases being avoided. Renewable energy systems should avoid fossil fuel intensive processes and materials to optimise the carbon balance and the energy ratio.

When organic wastes are sent to landfills, production of methane occurs from the decomposition of biomass. Methane is also considered a GHG with a global warming potential (GWP) near 23 times bigger than that of the CO_2 considering a time period of 100 years [7]. Acid gas emissions are quite small since the sulphur content on biogas is almost inexistent. Particulate emissions are minimised with modern burner designs and the CO_2 present in biogas composition helps to reduce the formation of NO_x.

4.8 Typical application example

The centralised co-digestion plant in Blåbjerg in Denmark was built in 1995-96 and started up in March 1996. The plant is owned by Blåbjerg Biogas, whose members are the slurry-supplying farmers. The plant was established with the aim of supplying Nørre Nebel town with renewable energy, as well as to contribute to a better distribution of excess manure from the intensive animal husbandry in the area. The biogas plant receives cattle and pig slurry from 49 suppliers. The slurry is mixed and co-digested with organic waste from food processing, fish processing, dairy, medicinal industry and sewage sludge. The biomass mixture is heated up to the process temperature through a heat exchanger system. The Blåbjerg plant concept includes some new solutions, attempting to make the plant more adaptable to various feedstocks and to the environmental protection requirements. Through a combination of buffer tanks and pumping sequences, the biomass has retention times of 8 hours at 53.5 °C. This ensures effective pathogen reduction and allows the plant to treat sewage sludge. After digestion, the fibre fraction is separated and used in a Combined Heat and Power (CHP) unit for heat production, being the liquid fraction returned to the farmers as a nutritionally, well defined fertiliser. The biogas is utilised in two gas engines (3740 kW) at the new CHP plant in Nørre Nebel. The heat is distributed through the district heating system to 550 consumers within the town, being the electricity sold to the grid [1].

The data for this plant is as follows:

Animal manure	222 tons/day
Alternative biomass	87 tons/day
Biogas production	3.1 millions Nm^3/year
Digester capacity (2 × 2500 m3)	5000 m^3
Process temperature	53.5 °C
Sanitation	8 hours at 53.5 °C
Gas storage capacity	4000 m^3
Utilisation of biogas	CHP plant
Transport vehicle	2 × 20 m^3 vacuum tankers
Average transport distance	5 km

• Investment cost	44.1 million DKK
• Government grants	11.5 million. DKK
• Contractor	BWSC Ltd.

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CHAPTER 5 – Biomass

5.1 The main routes for energy from biomass

The word biomass is a very broad term which is used to describe material of recent biological origin that can be used as a source of energy. As such, it includes trees and other plants, as well as agricultural and forest residues. It also includes many materials that are considered as wastes by our society, including food and drink industry effluents, sludge, manures, industrial (organic) by-products and the organic fraction of the household waste. Due to this large variety of sources, biomass may exist in many forms and can also be converted readily into solid, liquid or gaseous fuels. But it can also further be divided into more specific terminology, with different terms for different end uses: heating, power generation or transportation [11].

Figure 5.1 shows the different ways for converting biomass into electricity and heat. In general, the term bioenergy is used for biomass energy systems that produce heat and/or electricity and biofuels for liquid fuels for transportation.

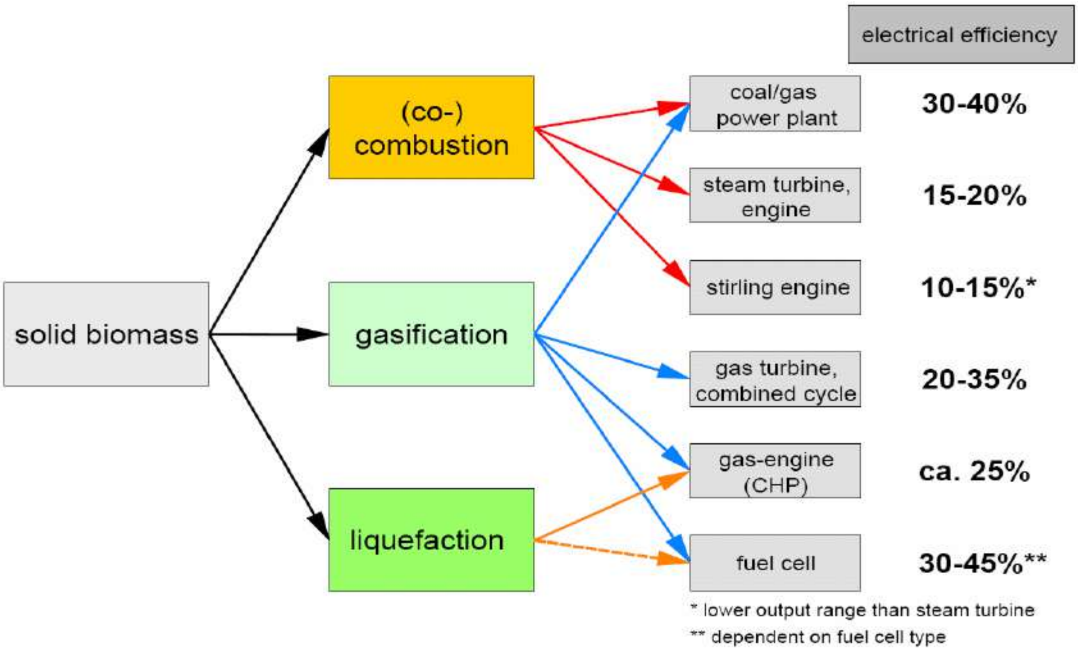

Figure 5.1. The main routes for energy from biomass.

Enormous quantities of a wide variety of biomass fuels, or biofuels, exist in European countries. Food industries generally produce these fuels. The technology for harvesting/collecting, preparation/storage, and transportation/delivery of these fuels are technically proven and commercially available.

Fossil fuels (natural gas, petroleum, and coal), which are marketed by large energy companies, provide a consistent and standardized fuel that has usually undergone considerable upgrading. On the other hand, most of the so-called biomass fuels are provided as produced, with little refinement and no recognized standards. Biomass fuels are typically locally generated, often by small independent contractors or brokers, and long-term supply may not be guaranteed. Care is required to ensure that several options exist to secure a reliable supply [7].

5.2 Principles of biomass conversion technologies

5.2.1 Combustion

Direct combustion of biomass is the most common way of converting biomass to energy – both heat and electricity – and, worldwide, it already provides over 90% of the energy generated from biomass. It is a well understood, relatively straightforward, commercially available, and can be regarded as a proven technology. Compared to other thermo chemical conversion technologies (gasification, pyrolisys, …), it is the simplest and most developed technology, and it can be easily integrated within existing infrastructures [11].

Combustion can be defined as the rapid chemical combination of oxygen with the combustible elements of a fuel. There are just three combustible chemical elements of significance: carbon, hydrogen and sulphur. Sulphur is usually of minor importance as source of heat [3].

Carbon and hydrogen, when burned to completion with oxygen, are transformed to CO_2 and H_2O according to the following reactions:

$$C + H_2O \rightarrow CO_2 \qquad [5.1]$$

$$2H_2 + O2 \rightarrow 2H_2O \qquad [5.2]$$

Air is the usual source of oxygen for boiler furnaces. These combustion reactions are exothermic and the heat released is about 32 800 kJ/kg of carbon burned and 142 700 kJ/kg of hydrogen burned. The energy of a fuel cannot be calculated by the sum of energy from the hydrogen and carbon content alone, as the chemical energy of molecular formation also needs to be taken into account. Also sulphur and other elements in the fuel contribute to the energy release. As water is released in a gaseous form during combustion, the water content of a fuel reduces the heat transferable to the steam generator [3].

The objective of a good combustion is to release all of this heat whilst minimising losses from combustion imperfections and superfluous airflows. The combination of the combustible elements and compounds of a fuel with the oxygen requires a temperature high enough to ignite the constituents, good mixing or turbulence and sufficient time for complete combustion [3].

5.2.2 Gasification

The essence of the gasification process is the conversion of solid carbon fuels into carbon monoxide by a thermochemical process. Biomass gasification breaks solid carbohydrate materials in to basic building block chemicals (CO, H_2, CO_2, H_2O and CH_4) by first thermally depolymerising the biomass particles (devolatilization) followed by hydrocarbon reforming and carbon reforming reactions [10].

The gasification process requires heat and an oxidant such as oxygen. Heat addition can occur directly by partial oxidation of the fuel or indirectly using a high rate indirect heat transfer. The gasification of solid fuel is accomplished in air sealed, closed chamber, under slight suction or pressure relative to ambient pressure.

The product of gasification – producer gas – can, after appropriate treatment, be burned directly for heat supply or it can be used in secondary conversion technologies such as gas turbines and engines for producing electricity or mechanical work. Producer gas is a mixture of combustible and non-combustible gases, as shown in table 5.1. The quantity of gaseous constituents of the producer gas depends upon the type of fuel and operating conditions. The heating value of the producer gas commonly varies from 4.5 to 6 MJ/m^3 depending upon the quantity of its constituents.

Electricity production from gasification is a more complex process than using the direct combustion/steam cycle process, resulting in biomass gasification power systems having higher investment costs. However, the advantage of the gasification is that it can achieve considerably higher efficiencies: most small and medium combustion power plants have overall efficiencies in the range of 15-20%, while their gasification counterparts can achieve overall efficiencies of around 35% [10].

Constituent	Value (%)
Nitrogen (N_2)	45-60
Carbon Monoxide (CO)	15-30
Hydrogen (H_2)	10-20
Carbon dioxide (CO_2)	5-15
Water (H_2O)	6-8
Methane (CH_4)	2-4

Table 5.1. Typical composition of producer gas. Source: [2].

5.2.3 Pyrolysis

Pyrolysis is the thermal decomposition occurring in the absence of oxygen, and it is also the first step in combustion and gasification processes where it is followed by total or partial oxidation of the primary products. The goal of the pyrolysis is to produce a liquid fuel, termed bio-oil or pyrolysis oil, which can be used as a fuel for heating or power generation. The produced oil is composed of a very complex mixture of oxygenated hydrocarbons, and like crude fossil oil can be used in refining to produce a range of chemicals, fuels and fertilisers. The main benefit of the pyrolysis process, when compared to combustion and gasification, is that a liquid fuel is easier to transport than either solid or gaseous fuels.

The pyrolysis reaction is relatively complex and results in non-equilibrium products, making their properties hard to predict. The properties are dependent on the process temperature, the period of heating, ambient conditions, the presence of oxygen, water and other gases, and the nature of the feedstock. In general, lower process temperature and longer heating periods result in the production of char, high temperature and longer heating periods increase the biomass conversion to gas, and moderate temperature and short heating periods are optimum for producing liquids [11].

As compared with combustion and gasification, pyrolysis technology is in the early state of development and thus the development costs are still very high and not well established, but this also means that there is considerable scope for cost reduction.

Current trends in the research and development of pyrolysis are also focused on the so-called fast pyrolysis [11]. Fast pyrolysis is a high temperature process in which the feedstock is rapidly heated in the absence of air, vaporises and condenses to a dark brown mobile liquid which has a heating value of about half that of conventional fuel oil [6]. The essential features of a fast pyrolysis process are [6]:

- Very high heating and heat transfer rates that requires a finely ground biomass feed;
- Carefully controlled temperature of around 500 ºC;
- Rapid cooling of the pyrolysis vapours to give the bio-oil product.

The main product, bio-oil, is obtained in yields of up to 80% (mass basis) on dry feed, together with by-product char and gas which is used within the process so there are no waste streams [6].

5.3 Biomass combustion

Unlike conventional fuels, some physical and chemical properties of biomass complicate their processing and combustion. These properties may include high moisture content, low bulk density, low melting point of the ash and high content of volatile matter. Table 5.2 shows the proximate and ultimate analyses of some biomass residues that can be found in the food industry sector comparing them with wood residues, sewage sludge, brown coal, peat and bituminous coal.

Fuel	Proximate Analyses				Ultimate Analyses[1]				
	Moisture	**Volatile**	**FC[2]**	**Ash**	**C**	**H**	**O**	**N**	**S**
Sunflower Husk	9.1	69.1	19.9	1.9	51.4	5.0	43.0	0.6	0.0
Cotton husk	6.9	73.0	16.9	3.2	50.4	8.4	39.8	1.4	0.0
Mustard husk	5.6	68.6	22.0	3.9	46.1	9.2	44.7	0.4	0.2
Palm fibre	36.4	46.3	12.0	5.3	51.5	6.6	40.1	1.5	0.3
Pepper waste	9.7	58.4	24.4	7.4	45.7	3.2	47.0	3.4	0.6
Soya husk	6.3	69.6	19.0	5.1	45.4	6.7	46.9	0.9	0.1
Groundnut shell	7.9	68.1	20.9	3.1	50.9	7.5	40.4	1.2	0.02
Coconut shell	4.4	70.5	22.0	3.1	51.2	5.6	43.1	0.0	0.1
Sewage sludge	6.9	44.6	7.0	41.5	52.0	6.3	32.1	6.3	3.1
Coffee (mbuni) husks	11.4	64.6	20.0	4.1	43.9	4.8	49.6	1.6	0.1
Coffee (parchment) husks	10.2	72.0	17.0	0.9	46.8	4.9	47.1	0.6	0.6
Wood	40.0	46.7	12.8	0.5	50.7	5.9	43.1	0.2	0.04
Peat	37.0	41.0	17.7	4.3	57.1	5.9	43.1	2.3	0.8
Bituminous coal	7.5	34.0	53.6	4.9	88.0	6.0	4.0	1.2	0.8

[1]Water and ash free, [2]FC: fixed carbon.

Table 5.2. Proximate and ultimate analyses for some fuels used in combustion. Source: [16].

5.3.1 Parameters affecting biomass combustion

Moisture content

In most cases, the moisture content of the residues from the food industry are quite low (see table 5.2), since they are determined by the process of separating the residues from the crop product. For example, during primary processing of coffee, the coffee berries are dried to a moisture content of less than 12 % (mass basis) before the hulling process, where the coffee beans are separated from the husks. In the same way, rice, coconuts, and oilseeds must be dried before the husks are removed. Therefore these husks have relatively low moisture contents.

For residues, which have high moisture content, some problems may be encountered during firing [7]:

- **Increased costs:** the mass of water contributes to the cost of handling and transportation, but does not produce any energy;
- **Loss of efficiency:** the heating of the water and its conversion to steam requires heat which is taken from the heat generated by the biomass combustion; heating systems using high moisture content fuels will have a slower response time to increased heat demand;
- **Higher emissions:** for systems with small capacities, moisture affects the oxidation of the fuel, leading to high emissions of carbon monoxide and unburned hydrocarbons;
- **Increased environmental hazards:** wet fuels are subject to biological activity that can cause oxygen depletion in closed storage areas, release of spores and heating that can lead to spontaneous combustion; on the other hand, very dry fuels create a dust hazard during handling and can pose a fire hazard.

Volatile matter

Compared with coals, food industry residues are characterized by higher content of volatile matter (see table 5.2). This indicates that the residues are easier to ignite and to burn, although the combustion is expected to be rapid and difficult to control. The high volatile matter contents are also expected to affect the overall combustion process. Experiences with the combustion of sewage sludge showed that the high volatile matter contents significantly affect the combustion process [16]. The implication of this is that the design and operation principles normally adopted for coal combustion systems, may not be applied for the combustion of food industry residues. Care must be taken to achieve complete combustion of the volatiles to ensure higher combustion efficiency and low emissions of CO, hydrocarbons and polychlorinated aromatic hydrocarbons [16].

Ash content

The non-combustible inorganic (mineral) content of the biomass is generally referred to as ash. It can be either inherent, i.e., deposited within the biomass during plant growth, or contaminant, i.e., mixed with the biomass from external sources [7].

Generally, however, the ash contents of most food industry residues are quite low, except for sewage sludge (see table 5.2). For the combustion of residues with high ash contents consideration must be given to incorporate efficient ash removal equipment from the flue gas to eliminate or reduce particulate pollution, just like in the case of coal combustion.

A peculiar ash problem, which is normally experienced during the combustion of some residues, is the low melting properties of the ash. This is due to the presence of very high contents of potassium oxide (K_2O) in some residues. The problems attributed to low melting temperatures of the ashes from these residues are bed agglomeration in fluidized bed as well as fouling, scaling and corrosion of the heat transfer surfaces [16].

5.3.2 Combustion: equipment and systems used

The choice of a combustion technology is dependent of factors such as thermal output, fuel flexibility and operation and regulating requirements (*e.g.*, emission restrictions), among others. Figure 5.2 shows a small scale combustion plant.

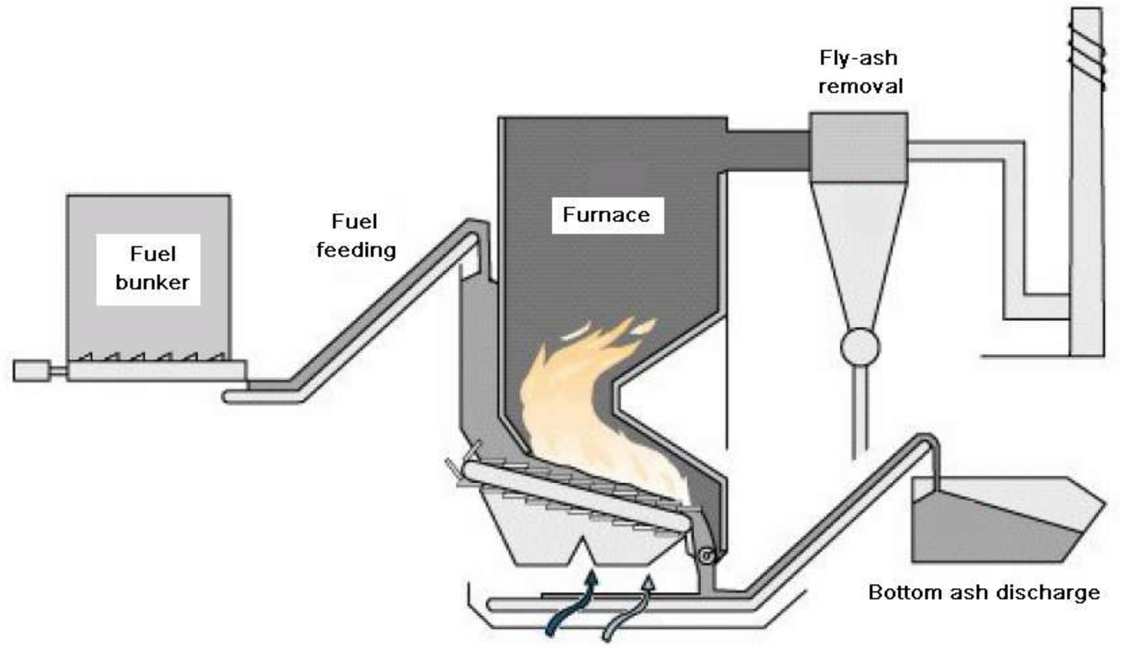

Figure 5.2. A small scale combustion plant. Source: [8].

The desire to burn uncommon fuels gave rise to the development of new technologies, with improved efficiencies, decreased costs and reduced emission levels. Currently, there are a wide range of technologies available, but it is possible to differentiate three main types [11]:

- Grate furnaces;
- Fluidised bed furnaces;
- Suspension burners.

Grate furnaces

Grate firing is the oldest firing principle used in boilers. It was the most popular firing system in small boilers until the beginning of the 1980s, when fluidised bed combustion started to become more popular, largely replacing grate firing. Today, most new solid fuel-fired boilers with a fuel input of over 5 MW are fluidised bed boilers. However, grate firing in this size rage is somewhat more popular in some countries (*e.g.*, Sweden and Denmark) and with some special fuels (*e.g.*, wood pellets, straw, plywood and chipboard waste, and domestic waste) [3].

Before entering in a grate furnace (see figure 5.2), fuel is normally triturated to peaces with different sizes. After the triturating step, the fuel is feed into the grate by the feeding system (*e.g.*, belt conveyor). Along the grate, the fuel is then subjected to an upward air flow, in which drying, gasification and char combustion takes place. In mostly of these systems only a part of the air is used for this propose (primary air) and another air injection is made above the grate, in order to assure the burn of volatile matter. In these boilers type the combustion rate is basically controlled by the air flow rate.

The transport of the fuel over the grate has to be as smooth and homogeneous as possible in order to keep the bed of embers calm and homogeneous, to avoid the formation of holes and to avoid the elutriation of fly ash and unburned particles as much as possible. A good and well controlled grate is designed to guarantee a homogeneous distribution of the fuel and the bed of embers over the whole grate surface. This is very important in order to guarantee an equal primary air supply over the various grate areas. Inhomogeneous air supply may cause slagging, higher fly-ash amounts, and may increase the excess oxygen needed for a complete combustion [11].

There are various grate furnace technologies available:

- Fixed grates;
- Moving grates;
- Travelling grates;
- Rotating grates;

- Vibrating grates**.**

The grates may also be water or air cooled. New grate systems are water-cooled to avoid slagging and to extend lifetime. Figure 5.3 shows a water cooled grate furnace, called Biograte, which was designed specially to burn biomass fuels with moisture content lower than 65%.

Figure 5.3. The Biograte technology patented by Wärtsilä.
Source: Wärtsilä (2006).

Grate-firing systems have some specific advantages [16]:

- They are able to handle heterogeneous fuels with large particle and high moisture content (up to 65%);
- The investment and maintenance costs for plants with a capacity lower than 10 MW_{th} are relatively low;
- Good burnout of fly ash particles;
- Low dust load in the flue gas;
- Good at partial load.

The disadvantages of grate furnaces are [16]:

- Efficient NOx reduction requires special technology.
- Combustion conditions are not as homogenous as on fluidized bed

Fluidised bed furnaces

Within a fluidised bed furnace, biomass fuel is burned in a self-mixing suspension of gas and solid-bed material into which combustion air enters from below. A fluidised bed consists of a cylindrical vessel with a perforated bottom plate filled with a suspension bed of hot, inert, and granular material. The common bed materials are silica sand and dolomite. The bed material represents 90-98% of the mixture of fuel and bed material. Primary combustion air enters the furnace from below through the air distribution plate and fluidises the bed so that it becomes a seething mass of particles and bubbles. The intense heat transfer and mixing provides good conditions for a complete combustion with low excess air demand. The combustion temperature has to be kept low (usually between 800-900 °C) in order to prevent ash sintering in the bed. This can be achieved by internal heat exchanger surfaces, by flue gas recirculation, or by water injection [11].

The major advantages of fluidized bed combustors are [16]:

- Uniform temperature distribution due to intense solid mixing (no hot spots even with strongly exothermic reactions);
- Large solid-gas exchange area by virtue of the small solids grain size;
- High heat transfer coefficients between bed and the heat exchanging surfaces;
- The intense motion of the fluidized bed makes it possible to burn a wide range of fuels having different sizes, shapes, moisture contents and heating values. The fuel supplied can be either wet or dry and either a paste or a solid;
- The high heat capacity of the fluidized bed permits stable combustion at low temperature (≈ 850 ºC), so that the formation of thermal and prompt nitrogen oxides can be suppressed;
- No moving parts in the combustion chamber.

Set against these advantages are the following disadvantages [16]:

- Solid separation or gas purification equipment required because of solids entrained by fluidizing gas and the high dust load in the flue gas;
- Erosion of internals resulting from high solids velocities;
- Possibility of defluidization due to agglomeration of solids;
- Partial load operation requires special technology.

Depending on the fluidisation velocity, bubbling fluidised bed and circulating fluidised bed combustion can be distinguished.

Bubbling fluidized bed furnaces

In bubbling fluidized bed (BFB) furnaces, a bed material is located in the bottom part of the furnace (see figure 5.4). The primary air is supplied over a nozzle distributor plate and fluidises the bed. The bed material is usually silica sand of about 1 mm in diameter and the fluidisation velocity of the air varies between 1 and 2.5 m/s. The secondary air is introduced through several inlets in the form of groups of horizontally arranged nozzles at the beginning of the upper part of the furnace (called freeboard) to ensure a staged-air supply in order to reduce NO_x emissions.

In contrast to coal-fired BFB furnaces, the biomass fuel should not be fed onto, but into, the bed by inclined chutes from fuel hoppers because of the higher reactivity of biomass in comparison to coal [11].

The advantage of BFB furnaces is their flexibility concerning particle size and moisture content of the biomass fuels. Furthermore, it is also possible to use mixtures of different kinds of biomass or to co-fire them with other fuels. One big disadvantage of BFB furnaces is the difficulties they have at partial load operation, which is solved in modern furnaces by splitting or staging the bed [11].

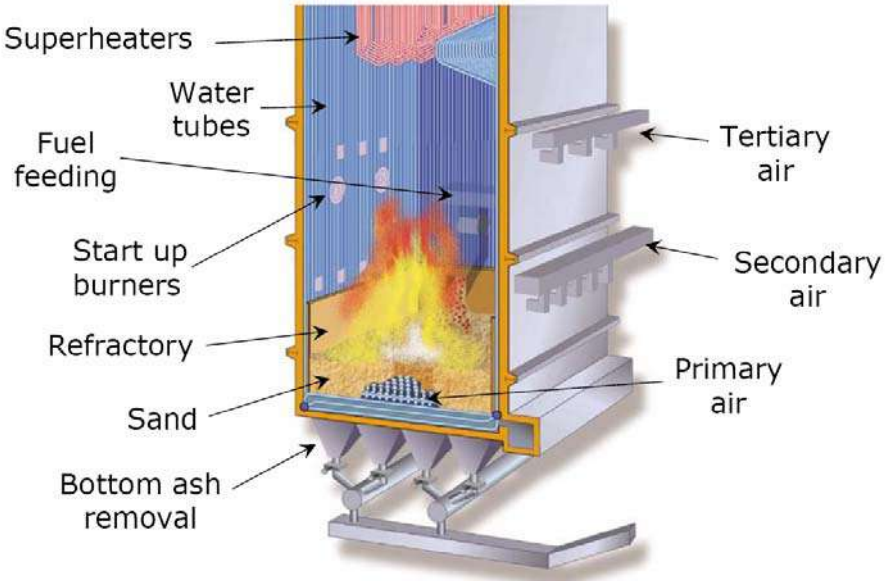

Figure 5.4. A bubbling fluidized bed boiler.

Circulating fluidized bed furnaces

By increasing the fluidising velocity to 5 to 10 m/s and using smaller sand particles (0.2 to 0.4 mm in diameter) a circulating fluidized bed (CFB) system is achieved. The sand particles will be carried with the flue gas, separated in a hot cyclone or a U-beam separator, and fed back into the combustion chamber (figure 5.5). The bed temperature (800 to 900 °C) is controlled by external heat exchangers cooling the recycled sand, or by water-cooled walls [11].

The higher turbulence in CFB furnaces leads to a better heat transfer and a very homogeneous temperature distribution in the bed. This is an advantage for stable combustion conditions, the control of air staging, and the placement of heating surfaces right in the upper part of the furnace.

The disadvantages of CFB furnaces are their larger size and therefore higher price, the even greater dust load in the flue gas leaving the sand particle separator than in BFB systems, the higher loss of bed material in the ash, and the small fuel particle size required (between 0.1 and 40 mm in diameter), which often causes higher investments in fuel pre-treatment. Moreover, their operation at partial load is problematic. In view of their high specific heat transfer capacity, CFB furnaces start to be of interest for plants of more than 30 MW_{th}, due to their higher combustion efficiency and the lower flue gas flow produced (boiler and flue gas cleaning units can be designed smaller), [11].

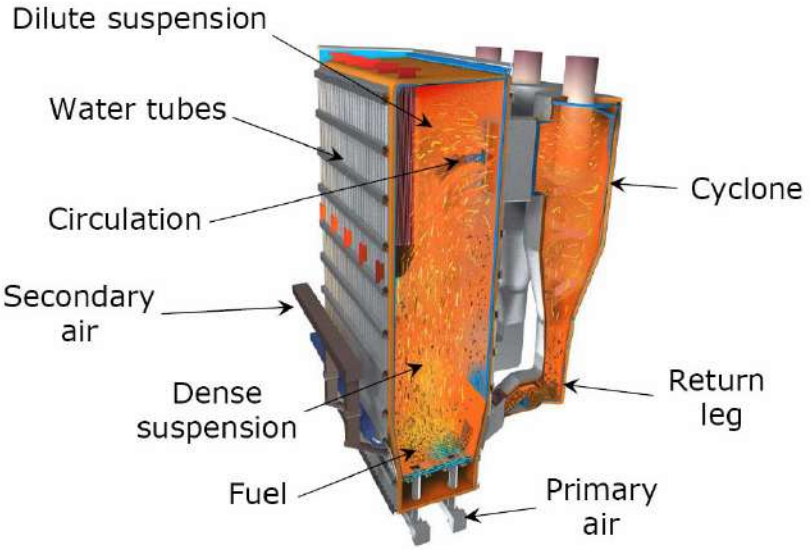

Figure 5.5. A circulating fluidized bed boiler.

Suspension burners

To burn food industry residues in suspension burners it is required that they are dry (e.g., less then 15 wt % of moisture content) and finely pulverised (*e.g.*, particle size below 2 mm). Therefore, a more extensive fuel preparation is necessary. Suspension burners may be installed if appropriately prepared fuel is naturally available (*e.g.*, sander dust). Such combustors may also be equipped with hammer mills and pulverisers for fuel size reduction operations. Fuels with small dimensions are pneumatically injected into the furnace, while the transportation air is used as primary air. Fuel quality in dust combustion systems has to be quite constant and the fuel moisture content should normally not exceed 20% (mass basis).

Due to possible explosion, like gasification of the fine and small biomass particles, the fuel feeding needs to be controlled very carefully and forms a key technological unit within the overall system. Fuel/air mixtures are usually injected tangentially into the cylindrical furnace muffle to establish a rotational flow (usually a vortex flow). The rotational motion can be supported by flue gas recirculation in the combustion chamber.

Since there is a high energy density at the furnace walls and high combustion temperature, the muffle should be water-cooled. Fuel gasification and char combustion take place at the same time because of the small particle size. Combustion takes place while the fuel is in suspension, and gas burnout is achieved after secondary air addition.

The main disadvantages of suspension burners are [16]:

- Inability to accomplish staging;
- All particulates necessarily end up in the fly ash;
- Suspension burning results in higher fuel nitrogen conversion to NO_x than pile burning or spreader-stoker firing.

Suspension burners fired with such forms of agricultural residues, such as rice hulls, have experienced both slagging difficulties and NO_x problems [16]. However this technology is rarely used for biomass residues, since plants are normally too small for achieving feasibility conditions.

5.4 Biomass gasification

Almost any biomass fuel can be gasified under experimental or laboratory conditions. However to achieve a reliable gas producer that can also be economically attractive to the customer it is required an evaluation on the fuel characteristics and the gasification process.

The producer gas is affected mainly by the biomass source but it is also a function of the gasifier design and thus the same fuel may give different calorific value as when used in two gasifiers. Table 5.3 shows approximate values of the producer gas quality for different fuels. In order to illustrate the effect of the gasifier type it is also shown in the table the difference between updraft and downdraft charcoal gasification.

Fuel	Gasification method	Volume percentage					Calorific value (MJ/m^3)
		CO	H_2	CH_4	CO_2	N_2	
Charcoal	Downdraft	28-31	5-10	1-2	1-2	55-60	4.6-5.65
Charcoal	Updraft	30	19.7	-	3.6	46	5.98
Corn cobs	Downdraft	18.6	16.5	6.4	-	-	6.29
Pelleted Rice hulls	Downdraft	16.1	9.6	0.95	-	-	3.25
Cotton stalks cubed	Downdraft	15.7	11.7	3.4	-	-	4.32
Wood with 12-20% moisture	Downdraft	17-22	16-20	2-3	10-15	55-60	5-5.86
Wheat straw pellets	Downdraft	14-17	17-19	-	11-14	-	4.50
Coconut husks	Downdraft	16-20	17-19.5	-	10-15	-	5.80
Coconut shells	Downdraft	19-24	10-15	-	11-15	-	7.20
Pressed sugarcane	Downdraft	15-18	15-18	-	12-14	-	5.30

Table 5.3. Composition of some producer gas from various fuels. Source: [14].

Many manufacturers claim that a gasifier is available to process any fuel. There is no such thing as a universal gasifier. A gasifier is very fuel specific and it is tailored around the fuel characteristics [14].

Thus a gasifier fuel can be classified as good or bad according to the following parameters:

- Energy content of the fuel;
- Bulk density;
- Moisture content;
- Dust content;
- Tar content;
- Ash and slagging characteristic.

5.4.1 Parameters affecting producer gas quality

Energy content and bulk density of the fuel

The higher the energy content and bulk density of biomass fuel, the similar is the gasifier volume since for one charge one can get power for longer time [14].

Moisture content

In most biomasses there is a little choice in moisture content since it is determined by the type of residue, its origin and treatment. It is however desirable to use biomass with low moisture content, because heat loss due to its evaporation before gasification is considerable and the heat balance of the gasification reaction is impaired. For example, for a residue at 25 ºC and raw gas exit temperature from gasifier at 300 ºC, 2875 kJ/kg must be supplied by fuel to heat and evaporate moisture [14].

Besides impairing the gasifier heat balance, high moisture content also puts load on cooling and filtering equipment by increasing the pressure drop across these units because of condensing liquid. Thus in order to reduce the moisture content of the biomass fuel some pre-treatment is required. Generally desirable moisture content for biomass should be less than 20% [14].

Dust content

All gasifier biomass fuels produce dust. This dust is a nuisance since it can clog the internal combustion engine and hence has to be removed. The gasifier design should be such that it should not produce more than 2-6 g/m^3 of dust [14]. The higher the dust produced, more load is put on filters necessitating their frequent flushing and increasing maintenance.

Tar content

Tar is one of the most unpleasant constituents of the gas as it tends to deposit in the intake valves causing sticking and deficient operation. The physical property of tar depends upon temperature and heat rate and the appearance ranges from brown and watery (60% water) to black and highly viscous (7% water). There are approximately 200 chemical constituents that have been identified in tar so far [14].

Very little research work has been done in the area of removing or burning tar in the gasifier so that relatively tar free gas comes out. Thus the major effort has been devoted to cleaning this tar by filters and coolers. A well-designed gasifier should put out less than 1 g/m^3 of tar. Usually it is assumed that a downdraft gasifier produces less tar than other gasifiers. However, because of localized inefficient processes taking place in the throat of the downdraft gasifier it does not allow the complete dissociation of tar. More research effort is therefore needed in exploring the mechanism of tar breakdown in downdraft gasifiers [14].

Ash and slagging characteristics

The mineral content in the fuel that remains in oxidized form after complete combustion is usually called ash. The ash content of a fuel and the ash composition has a major impact on trouble free operation of gasifier.

Ash basically interferes with gasification process in two ways [14]:

- It fuses together to form slag and this clinker stops or inhibits the downward flow of biomass feed;

- Even if it does not fuse together it shelters the points in fuel where ignition is initiated and thus lowers the fuel's reaction response.

Ash and tar removal are the two most important processes in gasification system for its smooth running. Various systems have been devised for ash removal. In fact some fuels with high ash content can be easily gasified if elaborate ash removal system is installed in the gasifier.

Slagging, however, can be overcome by two types of operation of gasifier [14]:

- Low temperature operation that keeps the temperature well below the flow temperature of the ash;
- High temperature operation that keeps the temperature above the melting point of ash.

The first method is usually accomplished by steam or water injection while the latter method requires provisions for tapping the molten slag out of the oxidation zone. Each method has its advantages and disadvantages and depends on specific fuel and gasifier design.

Table 5.4 lists the characteristics of some fuels in the food industry. Most of the results presented where made in laboratory scale units. More research as still to be in order to make gasification systems running on these fuels on a large scale [14].

Fuel	Treatment	Bulk density (kg/m^3)	Moisture content (%)	Tar produced (g/m^3)	Ash content (%)	Experience
Alfalfa straw	Cubed	298	7.9	2.33	6	No slagging, some bridging
Bean straw	Cubed	440	13	1.97	10.2	Severe slag formation
Coconut shell	Crushed (1-4 cm)	435	11.8	3	0.8	Excellent fuel. No slag formation
Coconut husks	Pieces 2-5 cm	65	65	Insignificant	3.4	Slag on grate but no operational problem
Corn cobs		304	11	7.24	1.5	Excellent fuel. No slagging
Corn fodder	Cubed	390	11.9	1.43	6.1	Severe slagging and bridging
Cotton stalks	Cubed	259	20.6	5	17.2	Severe slag formation
Peach pits	Sun dried	474	10.9	1.1	0.9	Excellent fuel. No slagging
Prune pits	Air dried	514	8.2	0	0.5	Excellent fuel
Rice hulls	Pelleted	679	8.6	4.32	14.9	Severe slagging
Safflower	Cubed	203	8.9	0.88	6.0	Minor slag formation
Sugarcane	Cutted 2-5 cm	52		Insignificant	1.6	Slag on hearth ring. Bridging
Walnut shell	Cracked	337	8	6.24	1.1	Excellent fuel. No slagging
Wood blocks	5 cm cube	256	5.4	3.24	0.2	Excellent fuel
Wood Chips		166	10.8	6.24	6.26	Severe bridging and slagging

Table 5.4. Gasification characteristics of various fuels in downdraft gasifiers.

Source: [14].

5.4.2 Gasification: equipment and systems used

Updraft or counter current gasifier

The simplest type of gasifier is the fixed bed counter current gasifier (see figure 5.6). In this gasifier type biomass is fed at the top of the reactor and moves downwards. The air intake is at the bottom and the gas leaves at the top. The biomass moves in counter current to the gas flow, and passes through the drying zone, the distillation zone, the reduction zone and the hearth zone [9].

In the drying zone the biomass is dried. In the distillation or pyrolysation zone the biomass is decomposed in volatile gases and solid char. The heat for pyrolisation and drying is mainly delivered by the upwards flowing producer gas and partly by radiation from the hearth zone.

The major advantages of this type of gasifier are its simplicity, high burn-out and internal heat exchange leading to low gas exit temperatures and high gasification efficiencies. Because of the internal heat exchange the biomass is dried in the top of the gasifier and therefore it is possible to use fuels with high moisture content [9].

Furthermore this type of gasifier can even process relatively small sized fuel particles and accepts some size variation in the fuel feedstock. Major drawbacks are the high amounts of tar and pyrolysis products, because the pyrolysis gas is not burned. This is of minor importance if the gas is used for direct heat applications, in which the tars are simply burnt. In case of the gas being used in engines, extensive gas cleaning is required [9].

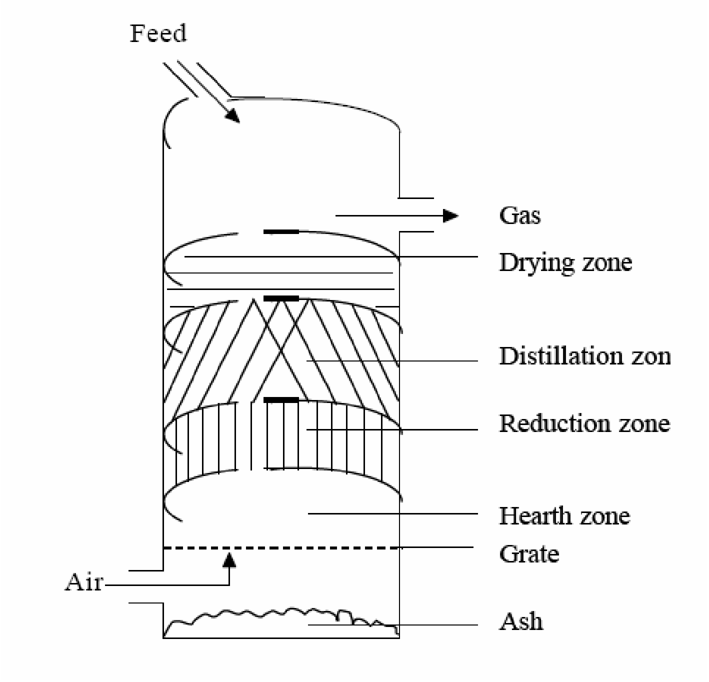

Figure 5.6. A counter current gasifier. Source: [9].

Downdraft or co-current gasifier

In a downdraft reactor biomass is fed at the top and the air intake is also at the top or from the sides. The gas leaves at the bottom of the reactor, so the fuel and the gas move in the same direction (see figure 5.7). The same zones can be distinguished as in the updraft gasifier, although the order is somewhat different. The biomass is dried and pyrolised in the drying and distillation zone, respectively. These zones are mainly heated by radiation (and partly convection) heat from the hearth zone, where a part of the fuel is burnt. The pyrolysis gases pass also through this zone to be burnt as well. The extent to which the pyrolysis gases are actually burnt depends on design, the biomass feedstock and the skills of the operator. After the oxidation zone the remaining fuel and the combustion products carbon dioxide and water vapour pass to the reduction zone where the reduction reactions take place forming CO and H_2 [9].

Hence the main advantage of a downdraft gasifier is the production of a gas with a low tar content which is nearly suitable for engine applications. In practice, however, a tar-free gas is seldom if ever achieved over the whole operating range of the equipment. The main reason seems to be that not all gases pass through the hottest zones and that their residence time in the combustion zone might be too short. In each particular design other features are included to realise a high conversion rate of the pyrolysis gases [9].

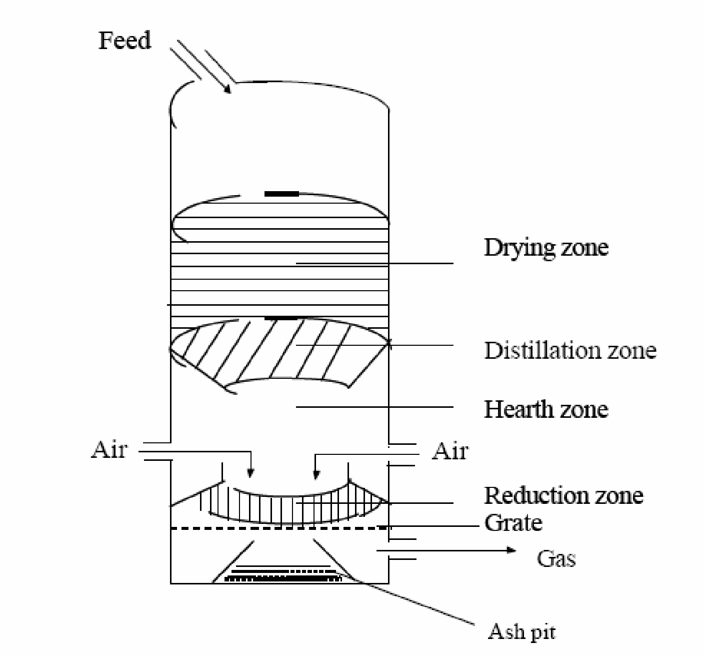

Figure 5.7. A co-current gasifier. Source: [9].

The main drawbacks of the downdraft gasifier are [9]:

- The high amounts of ash and dust particles in the gas due to the fact that the gas has to pass the oxidation zone collecting small ash particles;
- The relatively strict requirements on fuel which has to be uniformly sized in the range of 4-10 cm to realise regular flow, no blocking in the throat, enough "open space" for the pyrolysis gases to flow downwards and to allow heat transport from the hearth zone upwards; therefore pelletization or briquetting of the biomass is often necessary;
- The moisture content of the biomass must be less than 25%;
- The relative high temperature of the leaving flue gases resulting in lower gasification efficiency.
- This type of gasifiers is used in power production applications in a range from 80 up to 500 kW_e or more.

Fluidised bed gasifiers

Fluidised bed gasification was originally developed to solve the operational problems of fixed bed gasification related to feedstock with a high ash content and, principally, to increase the efficiency [1].

These gasifiers are in general suitable for systems with a capacity larger than 10 MW_{th}. The features of fluidised bed gasification are comparable with those of fluidised bed combustion. Compared to fixed bed gasifiers the gasification temperature is relatively low (750-900 °C).

Fluidised bed reactors are gasifier types without different reaction zones. The fuel is fed into a hot (sand) bed which is in a state of suspension (bubbling fluidised bed) or circulating (circulating fluidised bed). The bed behaves more or less like a fluid and is characterized by high turbulence [1].

Fuel particles mix very quickly with the bed material, resulting in a fast pyrolysis and a relatively large amount of pyrolysis gases. Because of the low temperatures the tar conversion rates are not very high.

The main advantages of fluidised bed reactors in comparison with fixed bed reactors are [9]:

- Compact construction because of high heat exchange and reaction rates due to the intensive mixing in the bed;
- Flexible to changes in fuel characteristics such as moisture and ash content;
- Ability to deal with fluffy and fine grained materials with high ash contents and/or low bulk density;
- Relatively low ash melting points are allowed due to the low reaction temperatures.

The main drawbacks are [9]:

- High tar and dust content of the produced gas;
- High producer gas temperatures containing alkali metals in the vapour state;

- Incomplete carbon burn out;
- Complex operation because of the need to control the supply of both air supply and solid fuel;
- Power consumption is required for the compression of the gas stream.

A schematic representation of a fluidised bed gasifier is shown in figure 5.8. In this figure steam or pure oxygen are mentioned as fluidising and gasifying agent instead of air. If the gasification is done with pure oxygen the caloric value of the producer gas will be higher because of the absence of nitrogen in the producer gas. However, production of oxygen is expensive and therefore it is only feasible in large scale applications [9]:

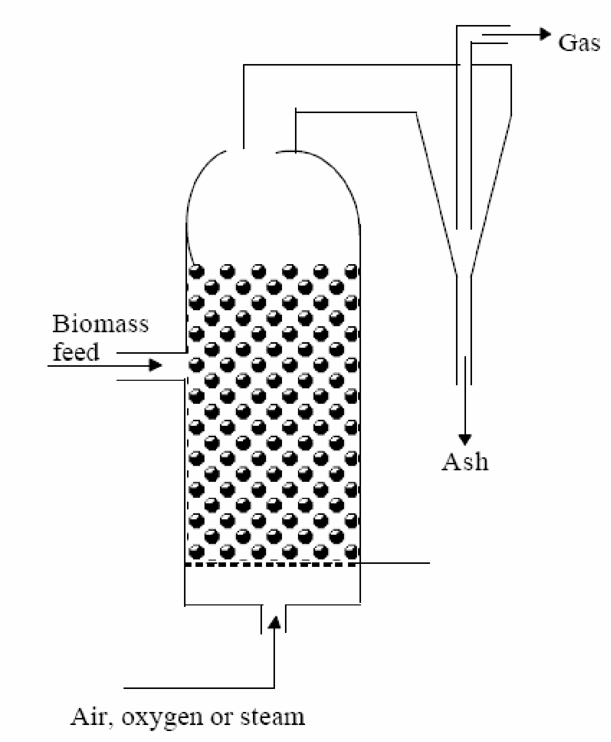

Figure 5.8. A fluidised bed gasifier.

Source: [9].

5.5 Pyrolysis

The elemental and chemical composition of pyrolysis oils is very much dependent on the conditions under which they are produced. Maximum yields are obtained at temperatures in the range 450 to 550 ºC and residence times of 0.5 to 5 s depending on the particular process. In this case the oil is highly oxygenated, indeed being not very different in composition from the feedstock [5]. Table 5.5 compares bio-oil with heavy fuel oil, while table 5.6 shows the composition of both oils.

Physical Property	Bio-oil	Heavy fuel oil
Moisture content (wt %)	15-30	0.1
pH	2.5	-
HHV (MJ/kg)	16-19	40
Viscosity (at 50ºC) (Pa s)	0.040-0.1	0.180
Solids (wt %)	0.2-1	1

* Moisture free basis.

Table 5.5 Characteristics of bio-oil and heavy fuel oil.

Source: [17].

Elemental composition (wt %)	Bio-oil	Heavy fuel oil
C	54-58	85
H	5.5-7.0	11
O	35-40	1.0
N	0-0.2	0.3
Ash	0-0.2	0.1

Table 5.6. Elemental composition of bio-oil and heavy fuel oil.

Source: [17].

Typical characteristics of fast pyrolysis liquid (table 5.7) can vary considerably according to the feed material and its characteristics, the pyrolysis process parameters and the liquid collection parameters of which temperature of liquid collection system and method of collection are particularly important.

5.5.1 Parameters affecting pyrolysis oil quality

The complex interaction of time and temperature on liquid product quality has not been explored yet, at least partly because the characteristics of pyrolysis oil for different applications have not been defined and there is no standard pyrolysis liquid. It is this definition of oil quality requires to be defined by potential users and may differ by application. While there are set standards and methods of measurement for conventional fuels, analogous standards and methods have not yet been defined for biomass pyrolysis liquids. Density, viscosity, surface tension and heating value are known to be typical key properties for combustion applications in boilers, furnaces and engines; but other characteristics such as particle size and ash content may have a major effect

Bio-oil has a number of special features and characteristics which require consideration in any application including production, storage, transport, upgrading and utilisation. These are summarised in section 5.5.2.

Characteristic	Effect	Solution
Suspended char	Erosion, equipment blockage, combustion problems from slower rates of combustion, “sparklers” can occur in combustion leading to potential deposits and high CO emissions.	Hot vapour filtration, liquid filtration, modification of the char for example by size reduction so that its affect is reduced, modification of the application.
Alkali metals	Deposition of solids in combustion applications including boilers, in turbines the damage potential is considerable particularly in high performance machines with, for example, coated blades.	Hot vapour filtration, processing or upgrading of oil, modification of application, pre-treat feedstock to remove ash.
Low pH	Corrosion of vessels and pipe work.	Careful materials selection, stainless steel and some olefin polymers are acceptable
Incompatibility with polymers	Swelling or destruction of sealing rings and gaskets.	Careful materials selection.
High temperature sensitivity	Liquid decomposition on hot surfaces leading to decomposition and blockage, adhesion of droplets on surfaces below 400 ºC.	Recognition of problems and appropriate cooling facilities, avoidance of contact with hot surfaces above 500 ºC.
High viscosity	High pressure drops in pipelines leading to higher cost equipment and/or possibilities of leakage or even pipe rupture.	Careful low temperature heating, and/or addition of water, and/or addition of co-solvents such as methanol or ethanol.
Water content	Complex effect of viscosity, heating value, density, stability pH, homogeneity, etc.	Recognition of problem, optimisation with respect to application.
In-homogeneity	Layering or partial separation of phases, filtration problems.	Modify or change process, modify pyrolysis parameters, change feedstock to low lignin, additives, and control water content.

Table4.7. Characteristics of bio-oil and methods for modification. Source: [4].

5.5.2 Pyrolysis: equipment and systems used

A fast pyrolysis system consists of an integrated series of operations starting with a roughly prepared feedstock such as whole tree chips from short rotation coppice, energy crops, or agricultural residues such as straw. A conceptual fluidised bed fast pyrolysis system is shown in figure 5.9 indicating the main components that are discussed below.

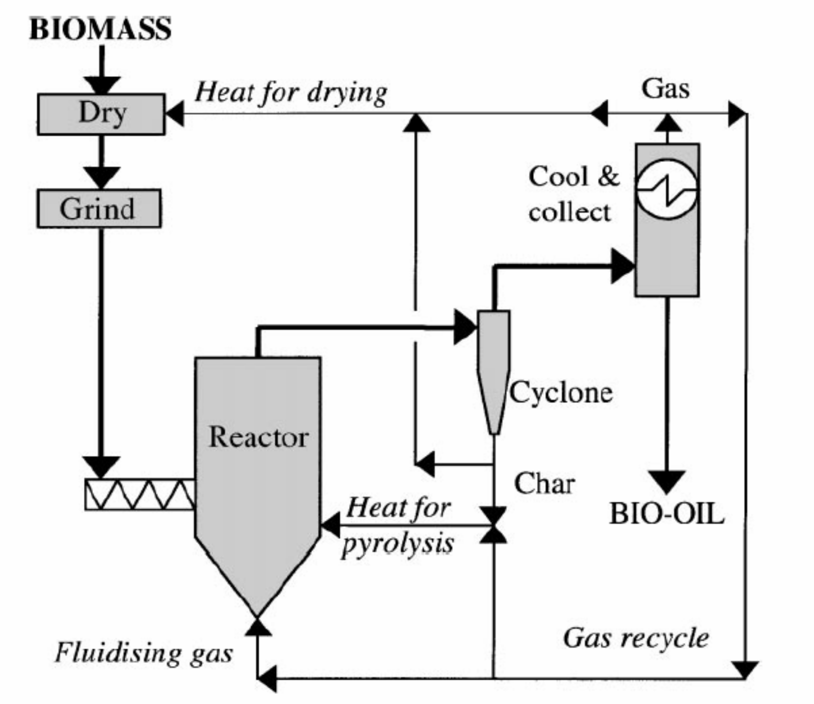

Figure 5.9. A fluidised bed fast pyrolysis system. Source: [6].

Reception and storage

It is always necessary to provide for reception and handling and some storage of feed material. Low capacity systems of up to around 3 t/h feed can consist of a concrete pad for tipping delivered feed and a front end loader to move it between steps. As plants get larger, increasingly sophisticated reception, storage and handling systems will be required analogous to those employed in pulp and paper mills. This will include a weighbridge, tipping units, conveyors, bunker storage and reclamation [6].

Feed drying

Unless a naturally dry material is available, drying is usually essential as all the feed water is included in the liquid product. Low grade process heat would usually be employed, for example flue gases from by-product gas [6].

Grinding

Particles have to be very small to fulfil the requirements of rapid heating and to achieve high liquid yields. Feed specifications range from less than 200 mm for the rotating cone reactor to less than 2 mm for fluid beds and less than 6 mm for transported or circulating fluid beds. Ablative reactors can utilise whole tree chips as the mechanism of heat transfer is different. Size reduction becomes increasingly expensive as size reduces and reactors using larger particles have an advantage in this respect [6].

Reactor configuration

A wide range of reactor configurations have been investigated so there is a considerable diversity and innovation in meeting the basic requirements of fast pyrolysis. The best method is not yet established with most processes giving between 65 ± 75% liquids based on dry feedstock input. The essential features of a fast pyrolysis reactor are: very high heating and heat transfer rates; moderate and carefully controlled temperature; and rapid cooling or quenching of the pyrolysis vapours. Commercial operation is currently only being achieved from a transport or circulation fluid bed system that are used to produce food flavourings. Fluid beds have also been extensively researched and are an ideal R&D tool. Fluid beds have been scaled up to pilot plant size with plans in hand for demonstration in several locations. Substantial developments can be expected in performance and cost reduction in coming years [6].

Bubbling fluid beds

Bubbling fluid beds, usually referred to as just fluid beds as opposed to circulating fluid beds (see section 0) have the advantages of a well understood technology that is simple in construction and operation, good temperature control and very efficient heat transfer to biomass particles due to high solids density. A typical configuration is shown in figure 5.10 with electrostatic precipitators that are more widely used in laboratory systems. Commercial plants may try to rely on a series of collection stages including de-misters although aerosol capture is notoriously difficult [13].

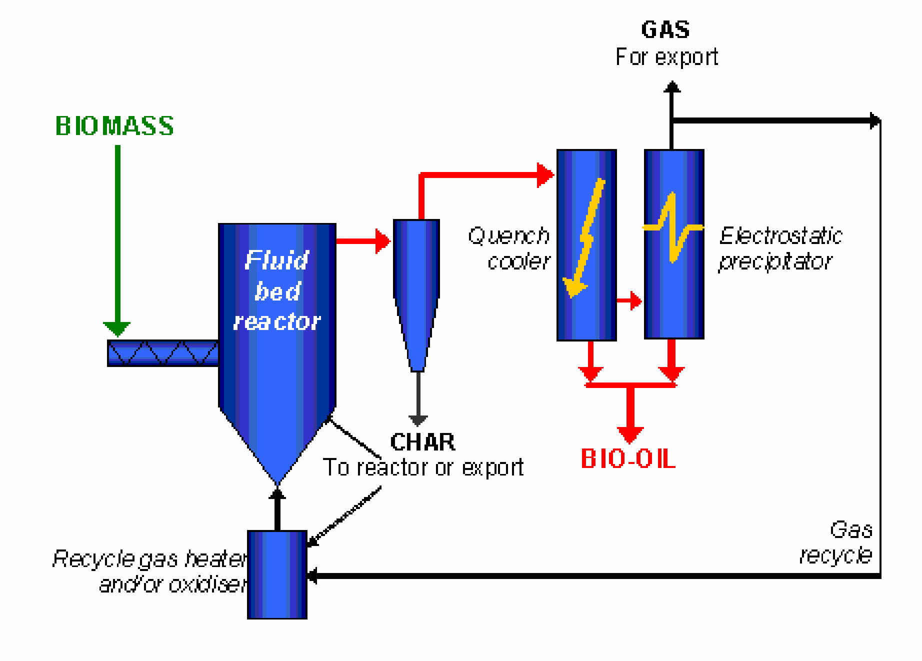

Figure 5.10. A bubbling fluid bed reactor. Source: [13].

Fluid bed reactors give good and consistent performance with high liquid yields of typically 70-75 wt % from wood on a dry feed basis. Small biomass particle sizes of less than 2-3 mm are needed to achieve high biomass heating rates, and the rate of particle heating is usually the rate limiting step [13].

Residence time of solids and vapours is controlled by the fluidising gas flow rate and is higher for char than for vapours. As char acts as an effective vapour cracking catalyst at fast pyrolysis reaction temperatures, rapid and effective char separation/elutriation is important. This is usually achieved by ejection and entrainment followed by separation in one or more cyclones so careful design of sand and biomass/char hydrodynamics is important [13].

Circulating fluid beds and transported bed

Circulating fluid bed (CFB) and transported bed reactor systems, shown in figure 11, have many of the features of bubbling beds described above except that the residence time for the biomass is almost the same as for vapours and gas [13].

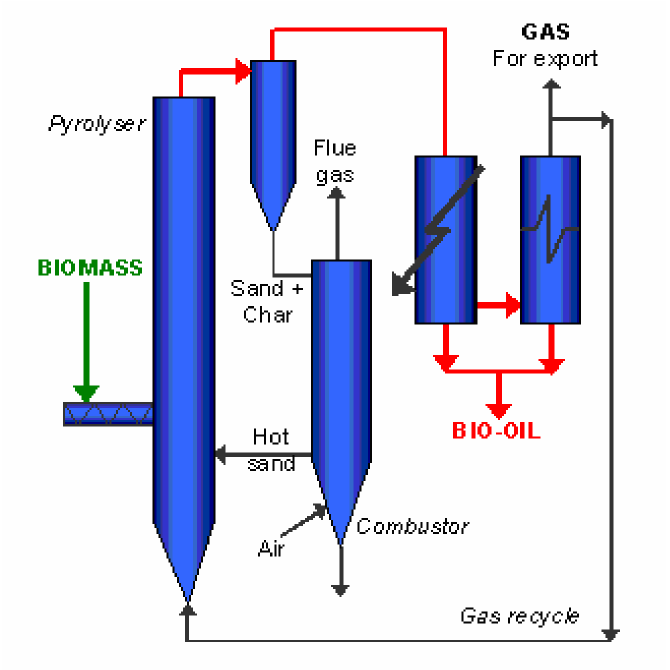

Figure 5.11. A circulating fluid bed reactor. Source: [13].

An added advantage is that CFB are suitable for very large throughputs even though the hydrodynamics are more complex. Heat supply results from recirculation of heated sand from a secondary combustor, which can be either a bubbling or circulating fluid bed. In this respect the process is similar to a twin fluid bed gasifier except that the reactor (pyrolyser) temperature is much lower and the closely integrated combustion in a second reactor requires careful control to ensure that the temperature and heat flux match the process and feed requirements.

The rotating cone reactor has many similarities except that the sand and biomass transport is affected by centrifugal forces operating in a rotating cone [13].

Ablative pyrolysis

Ablative pyrolysis is substantially different in concept compared to the other methods of fast pyrolysis. In all these other methods, the rate of reaction is limited by the rate of heat transfer through a biomass particle, which is why small particles are required.

In ablative pyrolysis heat is transferred from the hot reactor wall to melt. The pyrolysis front thus moves unidirectionally through the biomass particle. As the biomass is mechanically moved away, the residual oil film both provides lubrication for successive biomass particles and also rapidly evaporates to give pyrolysis vapours for collection in the same way as other processes. The rate of reaction is strongly influenced by pressure, the relative velocity of biomass on the heat exchange surface and the reactor surface temperature.

The key features of ablative pyrolysis are therefore as follows [13]:

- High pressure of particle on hot reactor wall, achieved due to centrifugal force or mechanically;
- High relative motion between particle and reactor wall;
- Reactor wall temperature less than 600 °C.

As reaction rates are not limited by heat transfer through the biomass particle large particles can be used, and in principle there is no upper limit to the size that can be processed. The process in fact is limited by the rate of heat supply to the reactor rather than the rate of heat absorption by the pyrolysing biomass as in other reactors. There is no requirement for inert gas, so the processing equipment is smaller, and the reaction system is thus more intensive. However the process is surface area controlled so scaling is more costly and the reactor is mechanically driven so is thus more complex. Table 5.8 summarizes the main features of the reactors described before.

Reactor type	Main Features
Ablative	• Accepts large size feedstock's • Very high mechanical char abrasion from biomass • Compact design • Heat supply problematical • Heat transfer gas not required • Particulate transport gas not always required
CFB	• High heat transfer rates • High char abrasion from biomass and char erosion • leading to high char in product • Char/solid heat carrier separation required • Solids recycle required; Increased complexity of system • Maximum particle sizes up to 6 mm • Possible liquids cracking by hot solids • Possible catalytic activity from hot char • Greater reactor wear possible
BFB	• High heat transfer rates • Heat supply to fluidising gas or to bed directly • Limited char abrasion • Very good solids mixing

	- Particle size limit <2 mm in smallest dimension - Simple reactor configuration

Table 5.8. Main features of pyrolisys reactors. Source: [4].

Char and ash separation

Some fine char is inevitably carried over from cyclones. Unless removed by a hot vapour filter, which is still under development, it will collect in the liquid and can only be removed by liquid filtration using for example cartridge or rotary filters. Almost all of the ash in the biomass is retained in the char, so successful char removal gives successful ash removal. Char separation, however, is difficult and may not be necessary for all applications [6].

Char contributes to secondary cracking by catalysing secondary cracking in the vapour phase. Rapid and complete char separation is therefore desirable. Even char in the cooled collected liquid product contributes to the instability problems, accelerating the slow polymerisation processes which manifest as increasing viscosity [6].

Vapour residence time

The time and temperature profile between formation of pyrolysis vapours and their quenching influences the composition and quality of the liquid product. High temperatures will continue to crack the vapours and the longer the vapours are at higher temperatures, the greater the extent of cracking. Although secondary reactions become slow below around 350 ºC, some secondary reactions will continue down to room temperature which contributes to the instability of the bio-oil. The time-temperature envelope that the pyrolysis vapours endure will affect the oil quality. Char also contributes to vapour cracking as described above [6].

Vapour residence times of a few hundred milliseconds are necessary for optimum yields of chemicals and food additives, while fuels can tolerate vapour residence times of up to around 2 seconds. Longer residence times result in significant reductions in organic yields from cracking reactions [6].

Liquid collection

The collection of liquids has been a major difficulty in the operation of fast pyrolysis processes due to the nature of the liquid product which is mostly in the form of aerosols rather than a true vapour. Quenching (*i.e.*, contact with cooled liquid), is effective but careful design and temperature control is needed to avoid blockage from differential condensation of heavy ends. Light ends collection is important in reducing liquid viscosity. Electrostatic precipitation has been shown to be very effective in recovering the aerosols. In fluid bed type systems the vapour/aerosol concentration can be very low, further increasing the difficulty of product separation due to the low vapour pressure [6].

5.6 Effects on pollutant and CO_2 emissions

Table 5.9 shows some of the pollutants expected during the combustion of biomass. The pollutant emissions from biomass combustion can be classified in two groups. The first group consists of the unburned pollutants, which are mainly influenced by the combustion equipment and process. The other group consists of pollutants which are mainly influenced by the fuel properties [16].

Origin, fuel	Emissions
Unburned pollutants (all biomasses)	CO, HC, tar, PAH[1], unburned char particles
Oxidized pollutants (all biomasses)	NO_x, N_2O
From biomass containing Cl and S	HCl, SO_2, salts (KCl, K_2CO_4 , NH_4Cl
Ash (all biomasses)	Particles
From biomass containing heavy metals	Pb, Zn, Cd, Cu, Cr, Hg etc.
From fuel biomass containing high Cl	PCDD[2] and PCDF[3]

[1]Polychlorinated aromatic hydrocarbons, [2]Polychlorinated dibenzo-dioxins, [3]Polychlorinated dibenzofurans.

Table 5.9. Sources of pollutant emissions from biomass combustion. Source: [16].

The unburned pollutants include CO, HC, tar, PAH, C_xH_y and char particles. These pollutants are usually due to poor combustion which is a result of low combustion temperature, insufficient mixing of fuel with combustion air and too short residence time of the combustible gases in the combustion zone. They can be expected from all biomass fuels depending on the furnace design and the operation conditions of the firing systems.

Generally lower emissions of unburned pollutants can be realized by conducting the combustion such that higher burnout efficiency is achieved. This requires efficient mixing of the combustion air with the combustibles (*i.e.*, char and volatiles). It also requires that high combustion temperatures and adequate residence time of the combustibles is maintained in the hot zone [16].

Staged combustion has also been found to be an effective way of ensuring high combustion efficiency and consequently low emissions of the unburned pollutants. Because of the reduced volume of combustion air in the primary stage, the flue gas leaves at a lower superficial velocity thus carrying away less combustible particles from the fuel bed. The injection of secondary air above the fuel bed may be used to create an intense mixing of combustion air with the volatiles, thus enhancing gas phase combustion reactions [16].

Ash is also a potential pollutant. The quantity of ash, carried with the flue gas from the furnace is governed largely by the feed rate of the fuel, its ash content, the excess air ratio and the distribution of the combustion air. Here too staged combustion has been found to be effective for low particulate emissions. The particulate emissions from biomass-fired boilers have different physical characteristics with the size ranging from sub-micron to 2 mm. The solids loading of the flue gas may range from 30 to 100 mg/m^3 [16]. The physical characteristics of the ash of each waste should be known for the selection of suitable particulate control equipment.

At temperatures below 1000 ºC, which are recommended for agricultural residues and especially for those with high contents of alkali oxides and salts, NO would be expected to be originate mainly from the fuel nitrogen. As the content of N is relatively low for agricultural residues low emissions of NO_x and N_2O may be expected. However, for NO_x and N_2O emissions, other parameters, apart from the fuel nitrogen contents, are important. For example, due to the low contents of fixed carbon in agricultural residues as well as the insignificant content of CaO in some residues, the catalysing effects of char and CaO on the reduction of NO_x will be negligible. Consequently, agricultural residues may emit higher concentrations of NOx than coals of comparable nitrogen contents. Where the emissions of these pollutants are too high, NO_x emission reduction techniques (*e.g.*, staged combustion and SNCR[4]) which have been found useful during the combustion of wood or related biomass may be applied to the combustion of agricultural residues [16].

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[4] SNCR: selective non-catalytic reduction.

The combustion of carbon based fuels (which include fossil fuels like oil, coal and gas, but also biomass) releases carbon dioxide to the atmosphere, which acts as a greenhouse gas and its increased concentration results in global warming and climate change [11].

The crucial difference between fossil fuels and biomass lies in the time frame over which carbon dioxide is released. Burning fossil fuels releases the carbon that has been locked up for millions of years. Burning biomass, however, can be a part of the natural process called the carbon cycle (figure 5.12): plants take up carbon dioxide when they grow, to construct the organic biological molecules that make up the bulk of their dry mass, and when the plants are eaten, burned or decomposed, the carbon is released again and is returned to the pool of carbon dioxide in the atmosphere [11].

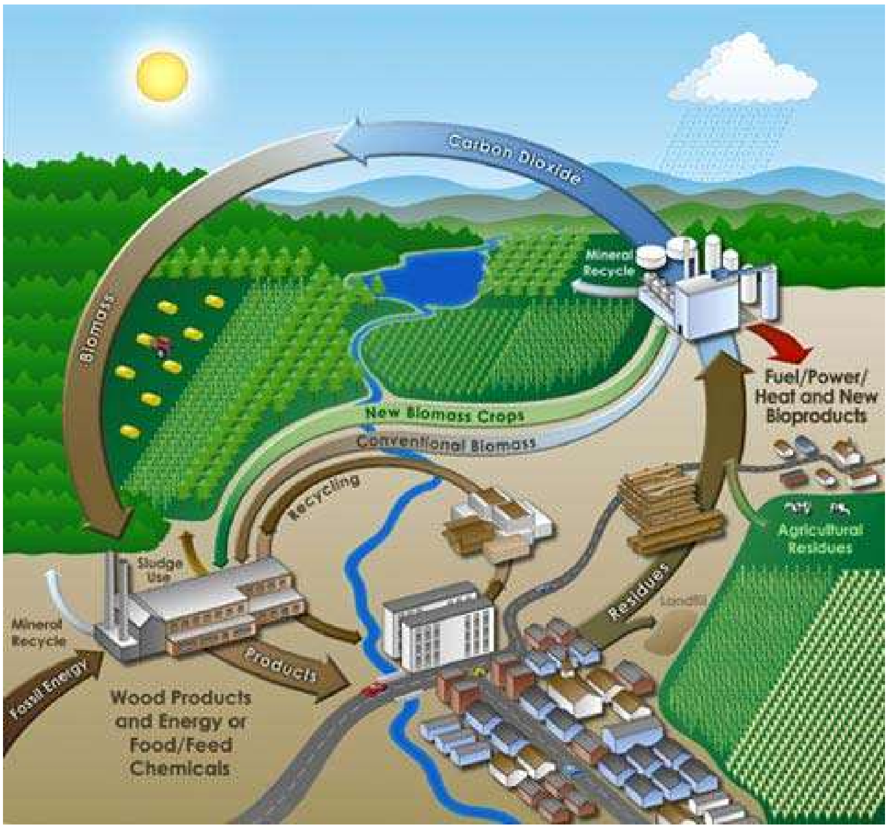

Figure 5.12. Biomass in the carbon cycle. Source: [11].

5.7 Typical application example

A Spanish high-tech olive-oil industry waste-to-energy plant is in operation in the town of Villanueva de Algaidas in Málaga. The new plant represents an important step forward that could streamline the oil-olive industrial activity throughout the zone. This is due to three main features [12]:

- It burns all of the waste produced in the olive-oil industry;
- It optimises the process thus reducing environmental impact;
- It features high energy efficiency in an interesting combined-cycle cogeneration plant (Olextra), and biomass-fuelled electricity generation plant (Extragol).

The facilities were developed by Valoriza Energía (Sacyr-Vallehermoso Group) and Extractora Algaidens, and designed and built by Iberese. On a 200 000 m^2 lot, the company Oleoliva, an olive-oil producer in operation for over fifty years, has the necessary facilities to process the production of all of the olive orchards in the zone. Its oil-mill comprises two lines of twelve presses each and six latest-generation continuous lines, to grind 900 000 kg of olives per day. The biomass employed is the olive pulp and stone mash left after the second stage of the oil extraction process is completed. It also occasionally includes the prunings from the Oleoliva olive orchard. The two plants operate separately but share certain elements (such as the steam turbine room, cooling towers, electricity evacuation system and regulation and control systems). This arrangement serves to rationalise the project and enhance operating efficiency [12].

The Extragol facility is formed basically by a rocking-grate steam boiler that burns crushed and dried olive pulp and pits, and a condensing steam turbo generating set.

The plant can operate in three different inter-connection modes [12]:

- Parallel with the grid;
- As power island;
- Without power generation plant input (only fed by the grid).

The main operating parameters are [12]:

Olive waste availability	64 000 t/year
Operating hours	8 000 h/year
Fuel consumption	30 800 t/year
Turbine electric power	9 150 kW
Auxiliaries average power	600 kW
Gross efficiency	24.7%
Net efficiency	23.0%

The biomass boiler was designed, built and supplied by the Danish company KEM, specialised in this type of equipment. The boiler is conceived specifically to burn crushed olive pulp and stones. The water-tube type boiler has the following main specifications [12]:

Fuel consumption	3 850 t/h LCV
Steam production	41 600 kg/h
Working pressure	42 bar
Steam temperature	403 ºC
Feed-water temperature	105 ºC
Efficiency	89.4%

By means of an automatic fuel supply system, fuel can be sent to the grate from the storage facility, comprising the following main elements [12]:

- Warehouse with three unloading zones and a main storage space;
- Ten-tonne loading crane;
- Chain conveyor belt;
- Fuel doser for feeding the hearth.

Before being released into the atmosphere through the stack, the flue gases are cleaned in a bag filter facility, consisting of eight independent units [12].

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CHAPTER 6 – Financial / economic appraisal of polygeneration applications

6.1 General principles

Typically the term financial/economic appraisal is used to distinguish between the engineering part of an energy conversion application with the financial one. The engineering part include all the actions (calculations, drawings, definition of equipment, building of the plant etc.) and the equipment which physically is used to convert the energy into useful forms with the lowest possible environmental impact. To achieve this goal the engineer should take into account several parameters related with the physical laws and one parameter which is not related with physical phenomena but with capital appraisal: the financial benefit over the capital needed to achieve the goal of energy conversion. The analysis of this parameter is the goal of the financial appraisal of the energy projects.

In the next paragraphs financial appraisal will be presented for polygeneration applications. The reader is supposed to be familiar with the basic financial terminology which can be found in related textbooks, e.g. [1].

6.2 Polygeneration: where the profit is coming from?

6.2.1 General remarks

The definition of Polygeneration developed in chapter 1 can help to understand the sources of the potential financial profits when applying polygeneration.

Polygeneration is the transformation of multiple energy sources into multiple, suitable for use, energy forms.

Profit exists if the energy sources used in the polygeneration plant are cheaper or can be used more efficiently i.e. consume less, compared with the conventional ones currently used.

Based on the above there are only two ways to generate profits from a polygeneration application:

-Use cheaper primary energy sources e.g. renewables which are usually free.

-Use primary energy source more efficient i.e consume less energy e.g. cogeneration of CHP or trigeneration.

6.2.2. When are we going to expect benefits from polygeneration applications?

The goal of any energy analysis before polygeneration installation has the goal to secure energy savings, environmental benefits and financial profits. As such the answer cannot be given before finalising a detailed feasibility study of the potential polygeneration investment. However there are some rules of thumb for initial feasibility checks of a polygeneration investment. These have been detailed in WP4 deliverable -page 10-. The process can be performed in phases to reduce the effort to reach a safe final result.

- **Phase 1**: Go through the *checklist of favorable conditions* (see in the next pargraph) - includes fuel availability, sufficient heating/cooling load, feed-in tariffs or other substantial subsidies, etc. Mark each item in the list with 'OK' or 'NOT OK' as is the case with the food factory in question. If there are enough of OK's then go to the next phase.

- **Phase 2**: Apply *spreadsheet calculations* on the feasibility (see Chapter 3.3 of WP4 deliverable), taking into account investment and maintenance cost, fuel and electricity prices, interest rate, technical parameters of the polygeneration technology, etc. If results are promising then go to the next phase.

- **Phase 3**: Perform detailed analysis using computer programs capable of *hourly simulations* (see Chapter 3.4 of WP4 deliverable). This results in reliable and detailed backup information for investment decisions, as well as for postponing or canceling planned investments.

A list for initial feasibility checks

This list can help newcomers separate important from less important parameters when planning a Polygeneration investment.

Criteria	**OK**	**NOT OK**
1. Sufficient heating or cooling load – average load ($MW_{heating}$ or $MW_{cooling}$) of the food factory exceeds the threshold of a chosen technology (see Chapter 2)		
2. Suitable fuel available for the chosen technology, or suitable (waste) heat source, in the case of absorption cooling		
3. Price of electricity clearly higher than price of fuel – preferably at least twice as high		
4. Part(s) of the factory energy system (which includes cooling devices) at the end or close to the end of their lifespan		
5. Room available onsite the food factory for additional energy device(s)		
6. Heating loads of the factory can be covered with hot air, hot flue gases, hot water or steam (polygeneration integration into the factory energy system and interfacing with the food processing easy)		
7. Access to electricity grid as a seller		
8. Buyer of surplus heat exists (additional heat consumer nearby / district heat company – confirmation always needed in both cases!)		
9. Substantial subsidies become available if polygeneration onsite is started		
10. Thermal and electrical loads occur mainly simultaneously, and the heat/electricity load ratio then is close to the heat/power ratio of the chosen CHP technology (to answer this question reliably requires real time measurements of both electrical and thermal loads (use e.g. fuel consumption), or at least a complete list of major energy consuming devices in the factory and their power/heat consumption and schedule of running)		

6.3 Methodology to extract the cost figures for the financial appraisal.

If at least half of the issues in the checklist above are answered OK, then the case is promising enough to take the feasibility study to the next level, spreadsheet calculations (phase 2). If ALL answers are OK, one may even jump directly to the detailed analysis, for hourly simulations. Results will then be used in step 3 below. Moreover one can go ahead to perform the financial analysis following the steps described below.

Step 1. Define your application area.

The first step is to define the area which will participate in the financial calculations i.e. the control volume. This control volume should be identical with the control volume used for the thermodynamic considerations developed in chapter 1.

This means that if polygeneration application is sought for a food processing plant then both energy consumption and financial calculations should be done for this same plant.

Step 2. Get data & prices for current energy consumption.

Current energy consumption is of great interest as this defines the base line for any improvements which might arise by any polygeneration application. The total cost of energy use should be also calculated. This total cost should include the cost for the fuels , the electricity and all other costs related with the maintenance or the operation of the energy system installed in the area under consideration e.g. personnel, lubricants, spare parts, environmental cost, etc. This is usually done at a yearly basis.

Step 3. Calculate the energy consumption of the polygeneration energy mix.

Next step is to calculate the energy consumption after applying the polygeneration approach. Accurate estimation of this energy consumption could be a demanding task and is based on the thermodynamic principles. Using the unit prices of every form of energy participating in the polygeneration mix the total energy and operational cost is calculated usually on a yearly basis. All the cost parameters should be taken into account.

Step 4. Calculate the polygeneration profit.

The difference between the cost figures resulted from steps 2 and 3 is the potential profit from polygeneration compared with the current situation. If this is positive then the steps towards financial appraisal can be performed. If not then there is no financial benefit from polygeneration application and the approach stops. The output of this step is a figure indicating the polygeneration profit in currency units per year e.g. Euro/year.

Step 5. Estimate the cost of the polygeneration plant.

The final step before financial appraisal is to estimate the cost of the polygeneration plant in currency units e.g. Euro. The more detailed the project cost knowledge the better. However often only project costs estimations are available and because of this the figures of the unit costs presented in chapter 2 are used. The higher accuracy of the project cost estimation the better for the financial appraisal of the polygeneration investment.

6.4 Financial appraisal of polygeneration investments

As far as the output of steps 4 and 5 is known then financial appraisal of the polygeneration investment can be done using all the methodologies developed for financial appraisal of investments. There are excellent textbooks which treat this subject thoroughly and the interested can get there all the necessary information. In the energy investment practice 2 parameters are the more often used;

-the simple pay-back period and

-the Internal Rate of Return –IRR-

Simple –pay back period.

Is the ratio of total polygeneration investment cost with the yearly polygeneration profit. Result is a figure representing years. It is the time needed in years to get back the capital used for developing the polygeneration investment. In several industry sectors this period should be lower than a figure for an investment to proceed. This parameter does not take into account the time value of money.

Internal Rate of Return –IRR-

IRR takes into account the variation of the value of money within time. An amount FV – Future Value- which is to come after n time periods has a present value which is calculated with the formula,

$PV = FV_n / (1+k)^n$

In this formula, n is the number of time periods and k is the said opportunity cost. Opportunity cost could be e.g. the interest rate one can get by placing FV in a Bank.
A Polygeneration investment could generate every year an inflow. The investment has also a lifetime e.g 20 years. We can construct the following equation:

$$\text{Total investment Cost} - \sum_{n=1}^{n} \frac{FVn}{(1+k)\,{}^\wedge n} = 0$$

The k for which this equation holds is the Internal Rate of Return –IRR-for this investment.
IRR is used often in industry. Investments which exhibit and IRR higher than a specific value are usually accepted for implementation. This bottom –line value depends on the case and the market and economic environment i.e. inflation rates etc. Of course other parameters also hold when evaluating investments. Several of these parameters are subjective and depend a lot on local market and other economic environment conditions.
An excellent in depth analysis of these topics can be found in chapter 5 of [1].

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CHAPTER 7– a case example in the food industry: energy savings and polygeneration in a fish processing plant

7.1 Introduction

This case example refers to a real plant –North Aegean Sea Canneries S.A. - in Greece. The plant receives raw fish from fisheries and produces canned fish food. The plant production is about 4000 tones of cooked canned fish food /year.

7.2 Energy system of the plant before polygeneration installation

To cover the thermal energy needs of the case plant LPG is consumed in the plant's steam boilers. These are three steam boilers with a maximum capacity of 2.500 Kg per hr of saturated steam at 6 barg each. Approximately about 90% of the total thermal energy is consumed to cover the process needs while the rest 10% is used for building heating and domestic hot water –DHW-.

In the next figure 3, the SHANKEY chart shows the current situation in the plant. All the heat flows are shown in MWh/year.

The combustion of LPG in the boilers produces about 6.459 MWh/year -based on -LCV- and steam of about 5.490 MWh. The boilers have relatively high efficiency - measurements showed this to be near 85% -LCV-. A considerable amount of energy - 966 MWh- is released through the boiler chimneys. The rest of the energy added to the energy from the condensate return i.e 5.818Mwh is carried by the steam and consumed in the various equipment in the plant.

Defrosting consumes about 566MWh of live steam. Cooking needs about 2781MWh of steam. In the can sealing process about 250MWh of steam is used to heat up fresh water and detergent to wash up the cans. Then in the sterilization process some 1000 MWh of heat is consumed every year.

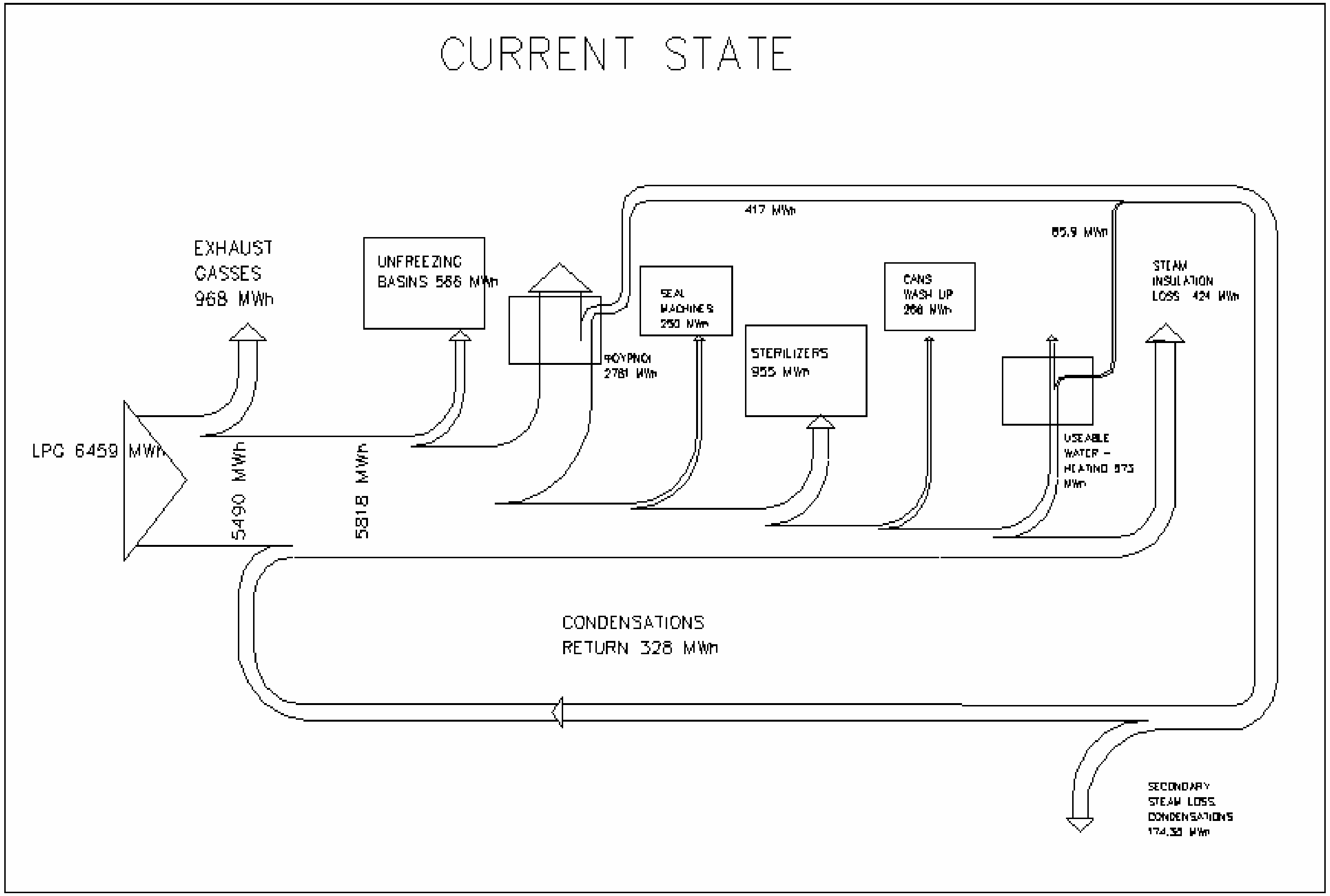


Figure 3: SANKEY flowchart in NASCA.

By-products are generated in several process stages. At the moment these by-products are sent to the Waste Eater Treatment Plant –WWTP- where they are treated aerobically. A significant part of them is removed at the first separation stage –before the sedimentation tank- while the rest of them is removed as sludge. Then these solid wastes are sent to landfill.

Using measurements for periods of about one month the following data on the by-products generation have been retrieved.

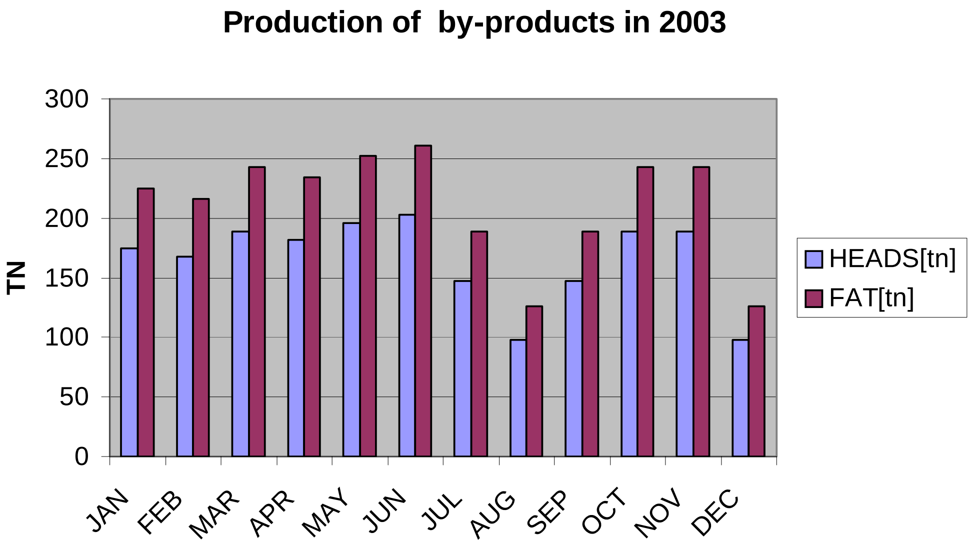


Figure 4: By-products production in 2003.

Figure 4 shows that a total of about 5000 tones per year of solid by-products is generated by the plant.

7.3 Energy system of the factory after polygeneration installation

7.3.1 Energy savings

Energy saving interventions are not described in detail as they are not the primary goal of this work. They are mainly focused to reduce steam consumption in the plant by using the rejected hot streams of water, condensate and flue gases. The energy saving interventions are listed below.

- Heat recovery from the cooling water of the sterilizers
- Heat recovery from water of the sealing and final washing process
- Heat recovery from boiler's exhaust gas
- Recovery and use of secondary steam, condensations return from cooking ovens, steam network insulation

The combined effect of all the energy saving interventions is the 25% reduction of the total fuel consumption.

1.1.2 Anaerobic treatment of the solid wastes

As has already noted many unnecessary parts of the seafood like the head, the tail, the gills are removed during the flash pack stage and the de-frosting. Environmental compatible disposal of the solid wastes is important for NASCA. Disposal of solid wastes could be done more easily if they are treated anaerobically. Annual production of solid wastes is about 5.000 tones –fig.4-.

To evaluate the potential of biogas productivity representative samples of solid waste were taken to examine their ability to produce biogas as well as the composition of the produced biogas -gas potential test-. In brief, 4150tn of sub products/year can produce about 400.000 Nm3 of biogas with a total net calorific value –LHV- of 2.631.000 kWh. Biogas produced by the NASCA solid wastes consist of 65% methane and the rest is mainly carbon dioxide. Part of the heat of the biogas has to be consumed for the heating of the digester in the biogas plant. There is also some electricity consumption for the equipment of the biogas plant.

Comparing the result of the gas potential test and the fuel consumed in the plant it comes out that about half of the plant fuel can be replaced by the biogas produced from the solid wastes of the process if first the proposed energy saving interventions is to be applied.

Figure 5 shows the SANKEY chart after the energy saving and the biogas production are completed.

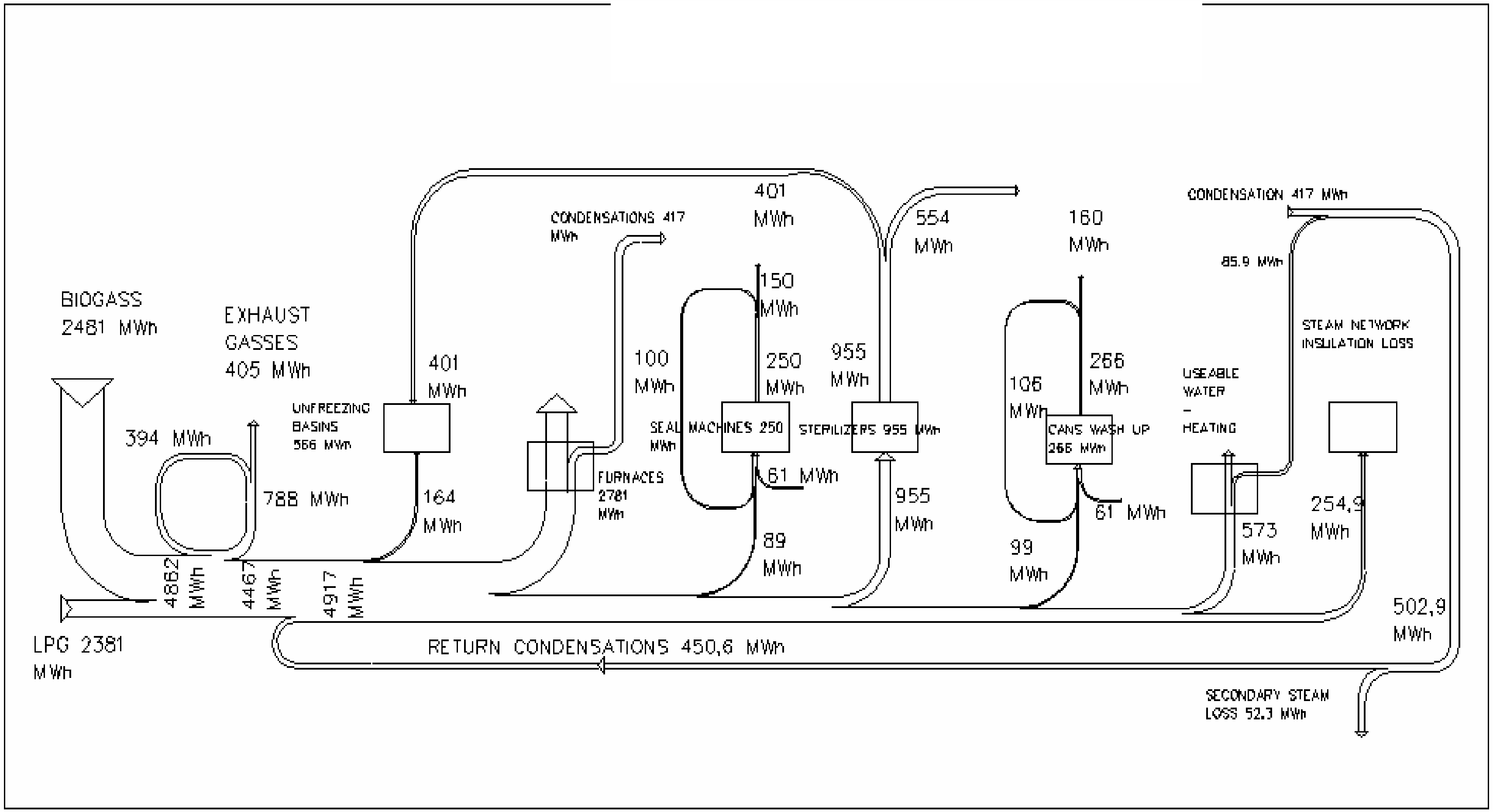


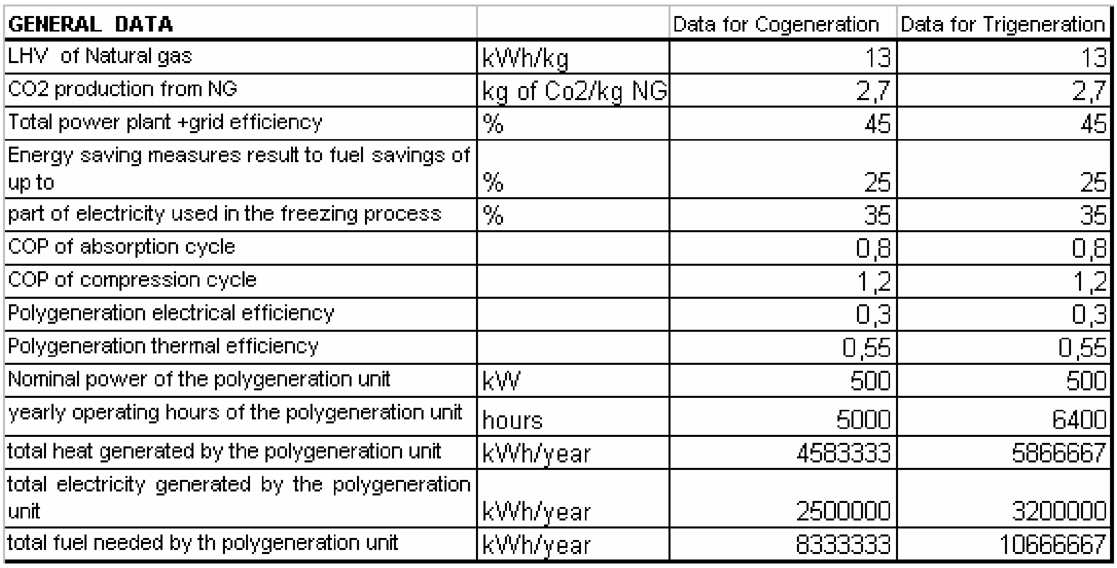
Figure 5: **SANKEY chart after the completion of the suggested interventions in NASCA.**

7.3.3. Trigeneration

A significant part of the electricity consumed annually in the plant is due to the refrigeration. Energy auditing showed that about 40% of the total electricity consumption of the plant is used for the freezing and refrigerating purposes. This means that if using absorption freezing with a mean COP of 0,8 - compared with the electricity driven COP of 1,2 - to replace about 70% of the total freezing load then additional 1.050 MWh/year of heat is needed to replace about 700 MWh el / year of electricity.

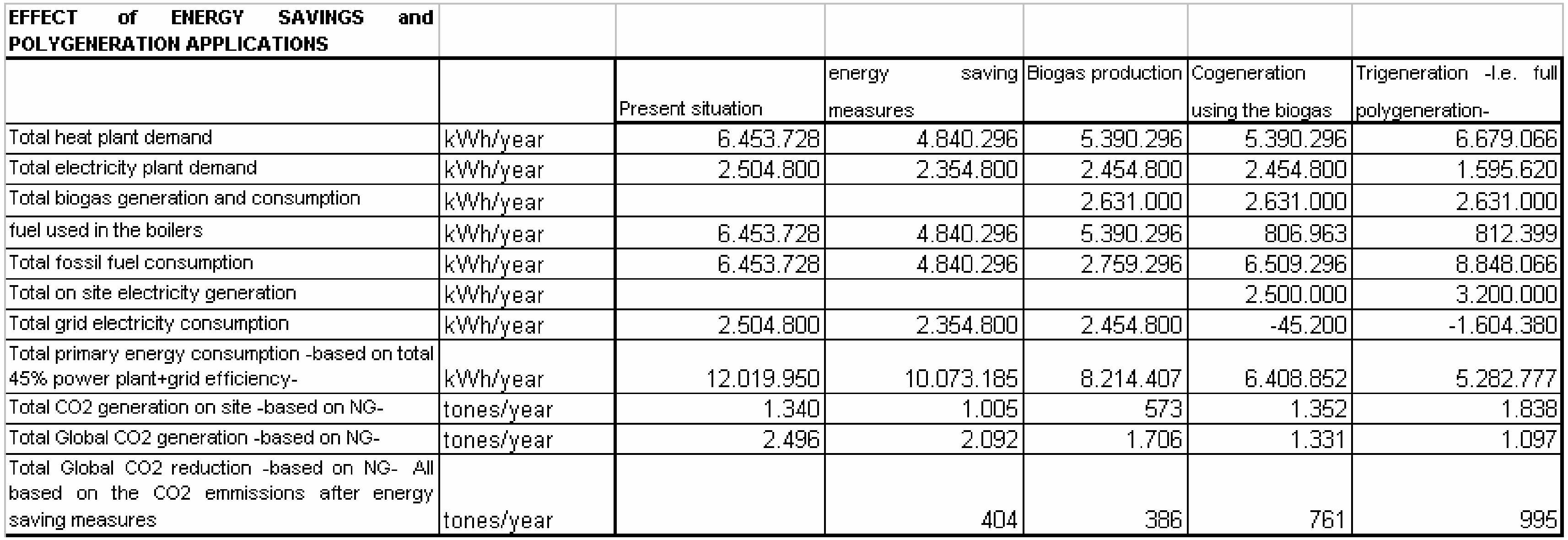
7.3.4. Polygeneration

All the above considerations form the final polygeneration scenario to be applied in NASCA. In table 6 the successive steps for polygeneration application and their impact on the total primary energy consumption of the plant are shown together with the environmental implications in terms of CO2 emissions and savings. The parameters used for the calculations are shown in the next table 5.



GENERAL DATA		Data for Cogeneration	Data for Trigeneration
LHV of Natural gas	kWh/kg	13	13
CO2 production from NG	kg of Co2/kg NG	2,7	2,7
Total power plant +grid efficiency	%	45	45
Energy saving measures result to fuel savings of up to	%	25	25
part of electricity used in the freezing process	%	35	35
COP of absorption cycle		0,8	0,8
COP of compression cycle		1,2	1,2
Polygeneration electrical efficiency		0,3	0,3
Polygeneration thermal efficiency		0,55	0,55
Nominal power of the polygeneration unit	kW	500	500
yearly operating hours of the polygeneration unit	hours	5000	6400
total heat generated by the polygeneration unit	kWh/year	4583333	5866667
total electricity generated by the polygeneration unit	kWh/year	2500000	3200000
total fuel needed by th polygeneration unit	kWh/year	8333333	10666667

Table 5. Parameters used for the calculation of energy and emission consumption from successive application of energy saving and polygeneration in the NASCA plant.



EFFECT of ENERGY SAVINGS and POLYGENERATION APPLICATIONS						
		Present situation	energy saving measures	Biogas production	Cogeneration using the biogas	Trigeneration -I.e. full polygeneration-
Total heat plant demand	kWh/year	6.453.728	4.840.296	5.390.296	5.390.296	6.679.066
Total electricity plant demand	kWh/year	2.504.800	2.354.800	2.454.800	2.454.800	1.595.620
Total biogas generation and consumption	kWh/year			2.631.000	2.631.000	2.631.000
fuel used in the boilers	kWh/year	6.453.728	4.840.296	5.390.296	806.963	812.399
Total fossil fuel consumption	kWh/year	6.453.728	4.840.296	2.759.296	6.509.296	8.848.066
Total on site electricity generation	kWh/year				2.500.000	3.200.000
Total grid electricity consumption	kWh/year	2.504.800	2.354.800	2.454.800	-45.200	-1.604.380
Total primary energy consumption -based on total 45% power plant+grid efficiency-	kWh/year	12.019.950	10.073.185	8.214.407	6.408.852	5.282.777
Total CO2 generation on site -based on NG-	tones/year	1.340	1.005	573	1.352	1.838
Total Global CO2 generation -based on NG-	tones/year	2.496	2.092	1.706	1.331	1.097
Total Global CO2 reduction -based on NG- All based on the CO2 emmissions after energy saving measures	tones/year		404	386	761	995

Table 6. Effect of energy savings and polygeneration in the energy consumption and generated emissions in the NASCA plant.

Results are also shown in the next figures 6 and 7. Application of polygeneration combined with energy saving measures results to up to 50% primary energy reduction and corresponding CO2 reduction. For a plant where energy saving measures have been applied, biogas generation accounts for up to 18% primary energy savings and CO2 reduction while a full polygeneration approach using trigeneration improves this figure to 42%. Simple cogeneration is not capable to harness all the benefits as it lacks about 12% the achievements of polygeneration. It is important to note that full trigeneration improves also the viability of the cogeneration scheme as combined with absorption chilling the yearly operating hours are increased because of the base load nature of the chilling load.

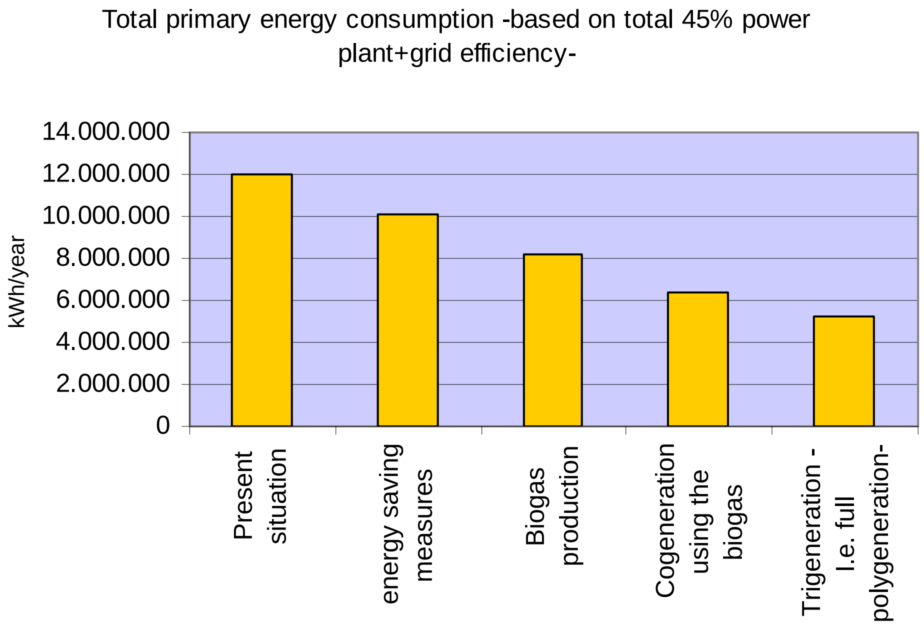
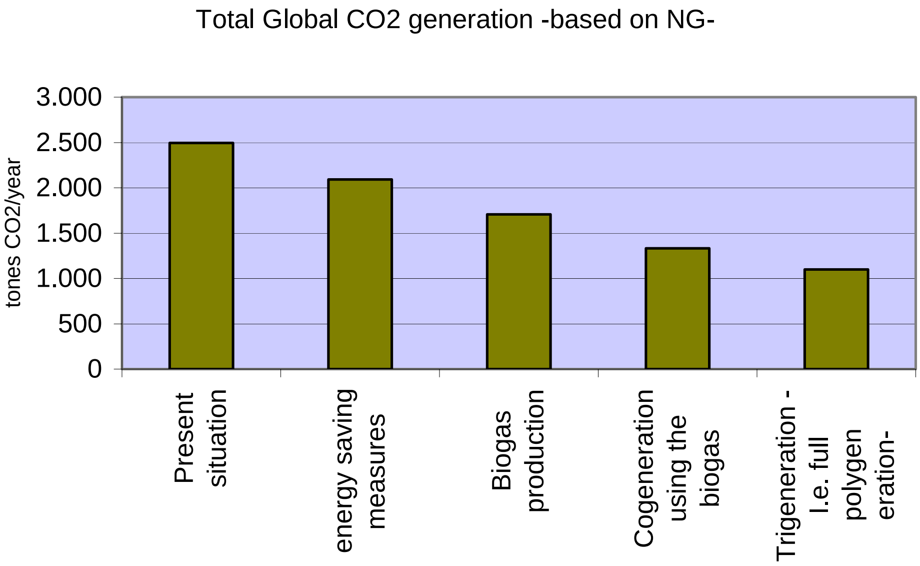
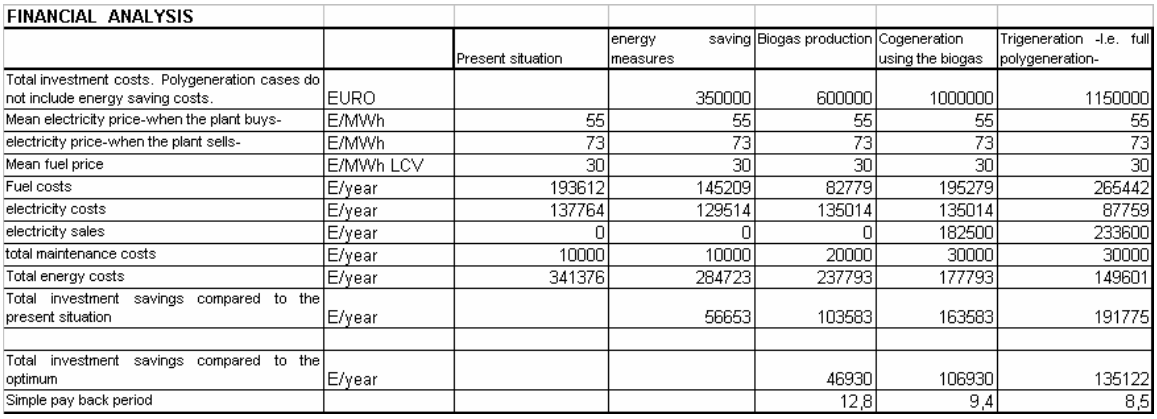


Figure 6 & 7. Effect of successive energy saving and polygeneration measures on the total primary energy consumption and CO2 generation.



7.4. Financial analysis

By using current typical prices for fossil fuel and electricity in Greece, and nominal investment costs the data in the following table are obtainable.



FINANCIAL ANALYSIS						
		Present situation	energy saving measures	Biogas production	Cogeneration using the biogas	Trigeneration -I.e. full polygeneration-
Total investment costs. Polygeneration cases do not include energy saving costs.	EURO		350000	600000	1000000	1150000
Mean electricity price-when the plant buys-	E/MWh	55	55	55	55	55
electricity price-when the plant sells-	E/MWh	73	73	73	73	73
Mean fuel price	E/MWh LCV	30	30	30	30	30
Fuel costs	E/year	193612	145209	82779	195279	265442
electricity costs	E/year	137764	129514	135014	135014	87759
electricity sales	E/year	0	0	0	182500	233600
total maintenance costs	E/year	10000	10000	20000	30000	30000
Total energy costs	E/year	341376	284723	237793	177793	149601
Total investment savings compared to the present situation	E/year		56653	103583	163583	191775
Total investment savings compared to the optimum	E/year			46930	106930	135122
Simple pay back period				12,8	9,4	8,5

Table 7. Simple financial considerations for the NASCA plant.

Data in table 7 show that for any polygeneration application and for the current fuel and electricity prices there is a need for financial subvention to make the investments viable. This support can be direct funding or indirect taking into account the positive environmental impact of the interventions.

APPENDIX

Guidance for the trainers

For more efficient use of the material in training sessions please take into account the following:

Learn about the background of your audience. The participants should normally have some knowledge of thermodynamics, fluid mechanics and energy systems analysis.

You can present first the content of chapter 2 i.e. the drivers. Most of the industry people are familiar with several of this equipment. You can use this to introduce the terms of efficiency, energy transformation etc. Although it is supposed that knowledge of CHP is a prerequisite we found that during training sessions it is useful to cover also the subject of CHP before going ahead into polygeneration.

Chapter 1 should normally be covered before proceeding to chapters 3 and more. We found that if trainees are not familiar with the basic calculations then they perform poor in the more specific topics.

The chapters 3, 4 and 5 can be presented or eliminated according to the needs of the course. You may choose to present first the chapter in biogas and then the one in trigeneration. It is up to you and to the interests of the audience to choose those most useful for their specific application fields.

Chapter 6 assumes that there is some familiarity with financial analysis of investments. If not, the use of the textbook in the references is strongly recommended.

In every chapter there are some examples worked out to help the trainer introduce his/her own examples which might be of interest for the audience. We found extremely useful to permit industry people bring in the course their own questions and examples to work with them. In chapter 7 an overall example of polygeneration application in a food industry plant is presented. This will help trainers and trainees to understand the diversity of the scenarios to be faced when a real industry case is to proceed towards polygeneration.

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