

Biomass Energy Utilization & Environment Protection Commercial Reality and Outlook

Introduction

Rapid rate at which fossil and residual fuels are releasing CO₂ into the atmosphere has raised international concern and has spurred intensive efforts to develop alternative, renewable, sources of primary energy.

Biomass as the solar energy stored in chemical form in plant and animal materials is among the most precious and most promising alternative fuels not only for power generation but also for other industrial and domestic applications on earth.

It provides not only food but also energy, building materials, paper, fabrics, medicines and chemicals. Biomass has been used for energy purposes ever since man discovered fire.



It is important to say, that biomass absorbs the same amount of CO₂ in growing that it releases when burned as a fuel in any form. This means that biomass contribution to global warming is zero. In addition, biomass fuels contain negligible amount of sulphur, so their contribution to acid rain is minimal.

Over millions of years, natural processes in the earth transformed organic matter into today's fossil fuels: oil, natural gas and coal. In contrast, biomass fuels come from organic matter in trees, agricultural crops and other living plant material.

CO₂ from the atmosphere and water from the earth are combined in the photosynthetic process to produce carbohydrates that form the building blocks of biomass. The solar energy that drives photosynthesis is stored in the chemical bonds of the structural components of biomass. If we burn biomass efficiently oxygen from the atmosphere combines with the carbon in plants to produce CO₂ and water. The process is cyclic because the carbon dioxide is then available to produce new biomass.

Typical biomass resources include:

- The forest residues from logging operations and other forest wooden waste
- Waste from wood processing industry sawdust, cut-offs, bark, etc.
- Agricultural waste palm oil residues, rice husks, sugarcane, coconut shells, coffee & cocoa husks, cotton & maize residues, etc.
- Organic waste animal manure, food-processing wastes..
- Urban wood waste wooden pallets, packing material, etc.

Ever since the earliest inhabitants of this planet burned wood in their fireplaces, direct biomass burning has been a source of energy for meeting human needs until the present time.

Direct combustion is a thermochemical conversion process utilizing the following major feedstock:

- ✚ Wood
- ✚ Agricultural waste
- ✚ Municipal solid waste

The energy produced by direct combustion process is heat and steam.

Despite its apparent simplicity, direct combustion is a complex process from a technological point of view. High reaction rates and high heat release and many reactants and reaction schemes are involved.

In order to analyze the combustion process a division is made between the place where the biomass fuel is burned (the furnace) and the place where the heat from the flue gas is exchanged for a process medium or energy carrier (the heat exchanger).

The basic process flow diagram for direct combustion is shown in the following picture

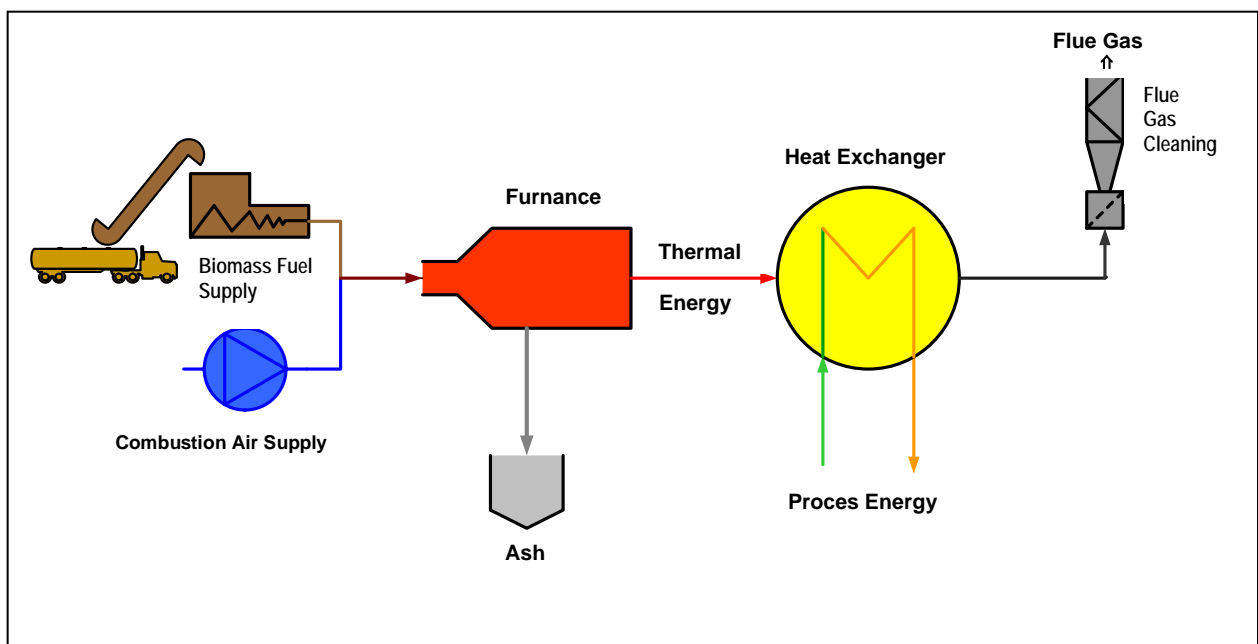


Figure 2
Principal scheme of direct combustion system

Proper designed industrial biomass combustion facilities can burn all type of above listed biomass fuel. In combustion process, volatile hydrocarbons (C_xH_y) are formed and burned in a hot combustion zone. Combustion technologies convert biomass fuels into several forms of useful energy for commercial and/or industrial uses. In a furnace, the biomass fuel converted via combustion process into heat energy.

The heat energy is released in form of hot gases to heat exchanger that switches thermal energy from the hot gases to the process medium (steam, hot water or hot air).

The efficiency of the furnace is defined as follows:

$$\eta_{\text{COMBUSTION}} = \frac{\text{CHEMICAL ENERGY AVAILABLE IN FURNACE EXHAUST GAS}}{\text{CHEMICAL BIOMASS FUEL ENERGY}}$$

Depending on the wet **L**ow **H**eating **V**alue (LHV) of received biomass fuel, typical combustion efficiencies varies in the range of 65% in poorly designed furnaces up to 99% in high sophisticated, well maintained and perfectly insulated combustion systems. In single statement, the combustion efficiency is mainly determined by the completeness of the combustion process (i.e. the extent to which the combustible biomass particles are burned) and the heat losses from the furnace. Direct combustion systems are of either fixed-bed or fluidized-bed systems.

Fixed-bed systems are basically distinguished by types of grates and the way the biomass fuel is supplied to or transported through the furnace.

In stationary or travelling grate combustor, a manual or automatic feeder distributes the fuel onto a grate, where the fuel burns. Combustion air enters from below the grate. In the stationary grate design, ashes fall into a pit for collection. In contrast, a travelling grate system has a moving grate that drops the ash into a hopper.

Very important factor is also acceptable maximum moisture content in supplied biomass fuel. In the following table a comparison between individual systems is made (Table 1).

System	Fuel size mm	Max. Moisture Content in %	Fuel Supply	Ash Removal
Static Grate	Ø 100 x 300	50	Manual/automatic	Manual/automatic
Underscrew	< 40x 30 x 15 >20 x 20 x 10	40	Automatic	Manual/automatic
Through Screw	< Ø 50 x 100	40	Automatic	Automatic
Inclined Grate	< 300 x 100 x 50	50	Automatic	Automatic
Sloping (moving) Bed	< 300 x 100 x 50	50	Automatic	Automatic
Suspension Burning	< 5 x 5 x 5	20	Automatic	Manual/automatic
Spreader-stocker	< 40 x 40 x 40	50	Automatic	Manual/automatic

Table 1
Fixed bed combustion systems

Fluidized-**B**ed **C**ombustors (FBC) burn biomass fuel in a hot bed of granular, non-combustible material, such as sand, limestone, or other.

Injection of air into the bed creates turbulence resembling a boiling liquid. The turbulence distributes and suspends the fuel. This design increases heat transfer and allows for operating temperatures below 970°C, reducing NOx emissions.

Depending on the air velocity, a bubbling fluidized bed or circulating fluidized bed is created. The most important advantages (comparing to fixed bed systems) of fluidized-bed combustion system are:

- ✚ Flexibility to changes in biomass fuel properties, sizes and shapes;
- ✚ Acceptance of biomass fuel moisture content up to 60%;
- ✚ Can handle high-ash fuels and agricultural biomass residue (>50%);
- ✚ Compact construction with high heat exchange and reaction rates;
- ✚ Low NOx emissions;

Low excess air factor, below 1.2 to 1.4, resulting in low heat losses from flue gas. Additional factor that determines the system efficiency is the efficiency of the heat exchanger, which is defined as follows:

$$\eta_{\text{HEAT EXCHANGER}} = \frac{\text{Available Process Thermal Energy}}{\text{CHEMICAL ENERGY AVAILABLE IN FURNACE EXHAUST GAS}}$$

Typical heat exchanger efficiencies based on biomass LHV range between 60% and 95%, mainly depending on design and kind of operation and maintenance. The main losses are in the hot flue gas exiting from the stack.

In the industrial practice, the furnace and heat exchanger form together biomass-fired boiler unit. The boiler is a more adaptable direct combustion technology because the boiler transfers the heat of combustion directly into the process medium. Overall boiler efficiency is defined as follows:

$$\eta_{\text{BOILER}} = \eta_{\text{COMBUSTION}} \times \eta_{\text{HEAT EXCHANGER}}$$

Overall boiler efficiency varies between 50% and 95%.

Very common and most efficient are biomass systems with direct combustion for electrical power generation and co-generation. Such system can achieve an overall efficiency between 30% (power generation systems) and 85% (co-generation systems).

Two cycles are possible for combining electric power generation with process steam production. Steam can be used in process first and then re-routed through a steam turbine to generate electric power. This arrangement is called a bottoming cycle.

In the alternate cycle, steam from the boiler passes first through a steam turbine to produce electric power.

The back-pressure (or extracted) steam from the steam turbine is then used for processes or for heating (or cooling) purposes. This arrangement is called a topping cycle, which the more common cycle.

Typical flow diagram of biomass fired (mixture of wood chips and hay) 11MW power plant with fluidized-bed boiler system, designed by SIEMENS AG is shown in the following picture (Figure 3).

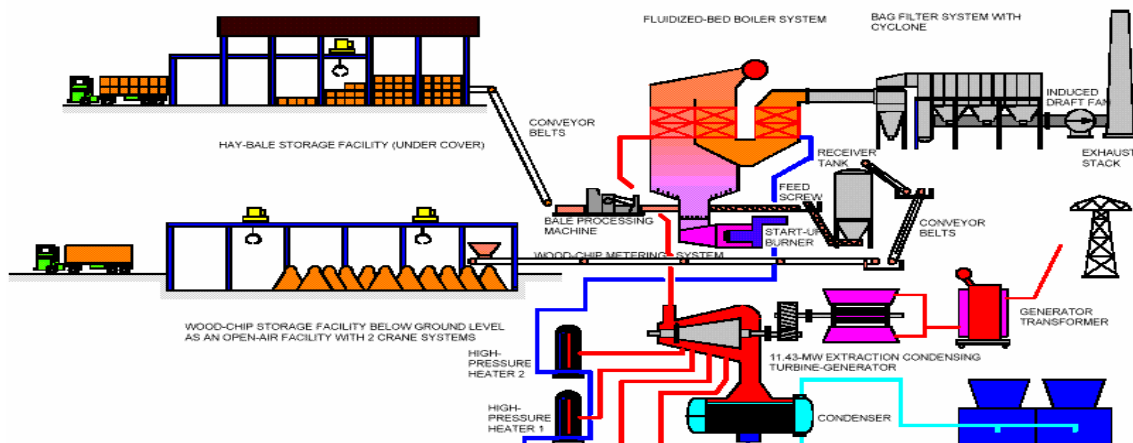


Figure 3
Typical scheme of biomass fired power generation plant

More efficient co-generation system based on above shown steam cycle is very easy to design. Instead of condensing steam turbine a back-pressure steam turbine can be applied, delivering steam at required process conditions. Another possibility is a combination of condensing steam turbine with controlled steam extraction facilities. This alternative offers maximum flexibility, i.e. during low process steam demand period maximum electric power can be generated.

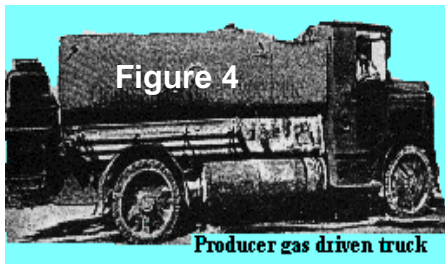
Up to the present time, many biomass fired co-generation power plants have been built worldwide, replacing low efficient heat-only boilers.

Biomass Gasification Systems

Gasification, production of combustible gas from carbon containing materials, is already an old technology. The first record of its commercial application origins from so called dry distillation (or pyrolysis – heating of feedstock on absence of O_2 , resulting in thermal decomposition of fuel into volatile gases and solid carbon) origins from year 1812 (Gas Company in London).

The first commercial gasifier for continuous air-blown gasification of solid fuels was installed in 1839. Later, gas industry producing gas from coal and biomass was established.

The first attempt to use producer gas to fire the internal combustion engine was carried out in 1881. In 1920's gasification systems were being implemented to operate lorries



and tractors. However, operation of vehicles and stationary engines on this fuel did not survive competition of the new petroleum-driven engines. Biomass gasification was reintroduced during the 2nd World War as the consequence of unavailability of petroleum. More than a million of gasifier-powered vehicles (Figure 4) were in operation during that time in Europe.

They ran on wood or charcoal. After the end of the war gasifier systems were substituted with engines driven by liquid fossil fuels again. It was not before the 1970s energy crisis when gasification won its come-back for the third time through its history.

Biomass gasification is other thermochemical conversion process utilizing the following major feedstock:

- ▶ Wood
- ▶ Agricultural waste
- ▶ Municipal solid waste

Chemical process of gasification means the thermal decomposition of hydrocarbons from biomass in a reducing (oxygen-deficient) atmosphere. The process usually takes place at about $850^{\circ}C$. Because the injected air prevents the ash from melting, steam injection is not always required. A biomass gasifier can operate under atmospheric pressure or elevated pressure.

If the fuel gas is generated for combustion in the gas turbine (Figure 5) the pressure of gasification is always super-atmospheric.

The resulting gas product, the syngas, contains combustible gases – hydrogen (H₂) and carbon monoxide (CO) as the main constituents.

By-products are liquids and tars, charcoal and mineral matter (ash or slag). Reducing atmosphere of the gasification stage means that only 20% to 40% of stoichiometric amount of oxygen (O₂) related to a complete combustion enters the reaction.

This is enough to cover the heat energy necessary for a complete gasification. Say in other words, the system is autothermic.

It creates sensible heat necessary to complete gasification from its own internal resources. Prevailing chemical reactions are listed in Table 2, where the following main three gasification stages are described.

Stage I ⇒ Gasification process starts as autothermal heating of the reaction mixture. The necessary heat for this process is covered by the initial oxidation exothermic reactions by combustion of a part of the fuel (refer to Table 2).

Stage II ⇒ In the second – pyrolysis stage, combustion gases are pyrolyzed by being passed through a bed of fuel at high temperature. Heavier biomass molecules distillate into medium weight organic molecules and CO₂, through reactions (8) and (9). In this stage, tar and char are also produced.

Stage III⇒ Initial products of combustion, carbon dioxide (CO₂) and (H₂O) are reconverted by reduction reaction to carbon monoxide (CO), hydrogen (H₂) and methane (CH₄).

These are the main combustible components of syngas. These reactions, not necessarily related to reduction, occur at high temperature. Gasification reactions (10-13), most important for the final quality (heating value) of syngas, take place in the reduction zone of the gasifier.

Heat consumption prevails in this stage and the gas temperature will therefore decrease. Tar is mainly gasified, while char, depending upon the technology used, can be significantly "burned" through reactions (10) and (11), reducing the concentration of particulates in the product.

Gasification Stage	Reaction formula	(Reaction number) / Reaction type	Reaction heat kJ/kmol
Stage I Oxidation and other exothermic reactions	$C + \frac{1}{2}O_2 \rightarrow CO$	(1) Partial oxidation	+110,700
	$CO + \frac{1}{2}O_2 \rightarrow CO_2$	(2) CO oxidation	+283,000
	$C + O_2 \rightarrow CO_2$	(3) Total oxidation	+393,790
	$C_6H_{10}O_5 \rightarrow xCO_2 + yH_2O$	(4) Total oxidation	>>0
	$H_2 + \frac{1}{2}O_2 \rightarrow H_2O$	(5) Hydrogen oxidation	+241,820
	$CO + H_2O \rightarrow CO_2 + H_2$	(6) Water-gas shift	+ 41,170
	$CO + 3H_2 \rightarrow CH_4 + H_2O$	(7) Methanation	+206,300
Stage II Pyrolysis	$C_6H_{10}O_5 \rightarrow C_xH_z + CO$	(8) Pyrolysis	<0
	$C_6H_{10}O_5 \rightarrow C_nH_mO_y$	(9) Pyrolysis	<0
Stage III Gasification (Reduction)	$C + H_2O \rightarrow CO + H_2$	(10) Steam gasification	-131,400
	$C + CO_2 \rightarrow 2CO$	(11) Boudouard reaction	-172,580
	$CO_2 + H_2 \rightarrow CO + H_2O$	(12) Reverse water shift	- 41,170
	$C + 2H_2 \rightarrow CH_4$	(13) Hydrogenation	+ 74,900

Table 2

Three main successive stages of biomass gasification.

Source: J.B. Jones & G.A. Hawkins: Engineering Thermodynamics, 1986, p. 456

Gasification is accompanied by chemical reactions that proceed at high temperature with gasifying agent and (occasionally) with steam as moderating agent.

In general, the gasifying agent can be air, oxygen (O₂) or oxygen-enriched air. For biomass gasification, air is normally used as oxidant (oxygen as the oxidant agent is preferred in high-capacity fossil fuel gasification systems).

The net product of air gasification can be found by summing up the partial reactions, as follows:



Reactions labelled in Table 2 with positive value of reaction heat are exothermic (chemical energy is converted to sensible heat). Reactions with the negative sign are on contrary endothermic (heat is consumed in favour of chemical energy).

Gasifiers are designed according to the origin and quality of fuel and the method in which the fuel is brought to contact with the oxidant. According to the fuel gas end use, the gasifier types can be divided into

- ▶ heat gasifiers - used for fuelling external burners in boilers or dryers; and
- ▶ power gasifiers - coupled to gas turbine or internal combustion engine for power generation

Additionally, apart from being categorized according to heat or power generation purposes, gasifiers can be classified as

- ▶ entrained bed
- ▶ fluidised bed
- ▶ fixed bed

Entrained Bed Gasifiers (EBG) are high-capacity design apparatuses. They require perfect atomisation of feedstock (0.1mm) and therefore are not suitable for biomass gasification.

Fluidised Bed Gasifiers (FBG) can be divided into **Bubbling (BFBG)** and **Circulating (CFBG)** gasifiers. BFBG give a good temperature control and high conversion rates, good scale-up-potential, possibility of in-bed catalytic processing.

They are not sensitive to particle size and to fluctuations in feed quantity and moisture. Product gas generated by BFBG has low tar content. Their drawback is high content of particulates.

CFBG are suitable for fuel capacity higher than 10 MWth. Compared to BFBG, they have the additional advantage of giving high gas quality.

Fixed bed gasifiers are the most suitable for biomass gasification. Three possible designs of fixed bed gasifiers exist, namely

- ▶ Down-draft (or co-current)
- ▶ Updraft (or counter-current)
- ▶ Crossdraft (or cross current)
- ▶ Open core (open current)

All gasifiers have strict fuel requirements to size, moisture and ash content. The typical characteristics of some biomass fuels can be summarised as presented in the Table 3.

Biomass Fuel	Moisture % wet	Ash % dry	Volatile Matter % dry	Bulk density kg/m ³	Average HHV MJ/kg dry
Charcoal	2-10	2-5	5-30	200-300	30
Wood	20-40	0.1-1.0	70-80	600-800	20
Rice Husks	3-5	15-25	60	100	15
Coconut Shells	25	0.8	79	not available	20

Table 3
Typical characteristics of biomass fuels for gasification

A generalised overview of the most important fuel requirements for different type of gasifiers, are presented in Table 4.

Gasifier Type	Updraft	Downdraft	Open Core	Cross draft
Fuel	Wood	Wood	Rice Husks	Charcoal
Size, mm	20-100	5-100	1-3	40-80
Moisture, %	<25	<60	<12	<7
Ash, %	<6	<25	Approx. 20	<6

Table 4
Fuel requirements for different gasifier types

The biggest advantage of gasification is the variety of feedstocks as well as products. The produced syngas can be utilized not only as the fuel for power generation but also as the feedstock for chemical industry.

Final products of synthesis can be various chemicals, hydrogen, ammonia, methanol, as indicated in Figure 5.

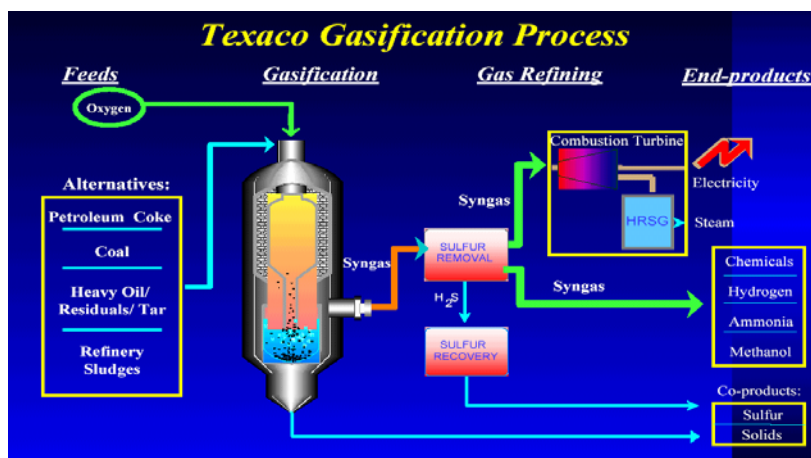


Figure 5

Downdraft entrained-flow Texaco gasifier. Gasification process is versatile in the feedstock choice as well as the end-product spectrum following from further processing of syngas.

A typical diagram of a biomass gasification process combined with power and heat generation is shown in Figure 6.

In this example, biomass (bagasse) is first dried and then injected in to the gasifier. The resulting biogas is purified in the **H**ot **G**as **C**lean-up (HGC) system.

The purified biogas is then utilized in the conventional **G**as **T**urbine **C**ombined **C**ycle (GTCC) power plant, to produce electricity and steam.

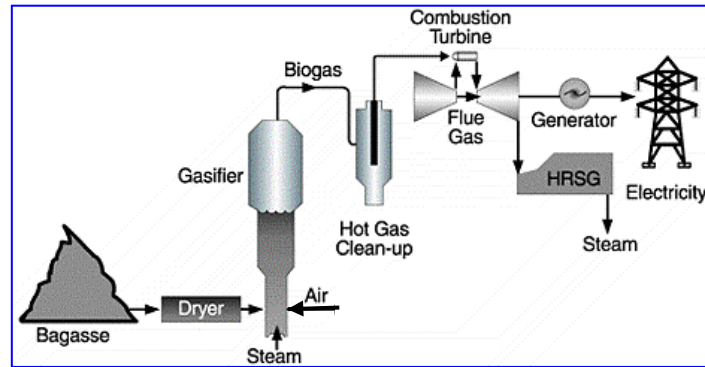


Figure 6

A simplified flowsheet for the bagasse gasification process integrated with GTCC

Advanced integrated biomass gasification and combined heat and power concepts are promising but still not fully demonstrated. The main difficulties are the requirements set by gas turbine manufacturers in adapting gas turbines to low BTU gases and to fulfil the gas quality specifications applicable for syngas utilization in gas turbines.

Anaerobic Digestion – Biogas & Landfill Gas

As per records biogas was first discovered by Alessandro Volta in 1776 and Humphery Davy was the first to pronounce the presence of combustible gas Methane in the Farmacyard Manure in as early as 1800.

Anaerobic digestion is other biochemical conversion process utilizing the following major feedstock:

- Solid & liquid animal manure
- Agricultural plant waste
- Waste from agricultural products processing industry
- Organic components in town waste
- Waste waters
- Landfills

Biogas occurs naturally, hence its name, amongst others in swamps and lakes when conditions are right. Anaerobic digestion can be used to produce valuable energy from waste streams of natural materials or to lower the pollution potential of a waste stream.

The biogas-production will normally be in the range of 0.3 - 0.45 m³ of biogas per kg of solid substances for a well functioning process with a typical retention time of 20-30 days. The lower heating value of this gas is about 22 MJ/m³.

Biogas plant has a self-consumption of energy to keep the sludge warm. This is typically 20% of the energy production for a well designed biogas plant. For example if the biogas is used for power and co-generation, the available electricity will be 30-40% of the energy in the biogas, the heat will be 40-50% and the remaining 20% will be said self-consumption.

Anaerobic digestion is a complex biochemical reaction carried out in a number of steps by several types of micro-organisms that require little or no oxygen to live. During the process a biogas, principally composed of approximately 65% methane (CH₄) and about 30% carbon dioxide (CO₂), is produced.

The amount of biogas produced varies with the amount of organic waste fed to the digester and temperature influences the rate of decomposition.

Several different types of bacteria work in stages together, to break down complex organic wastes, resulting in the production of biogas. Controlled anaerobic digestion requires an airtight chamber, called a digester.

To promote bacterial activity, the digester must maintain a temperature of at least 20°C (ideal 25°C - 35°C). Higher digester temperatures, above 50°C - 65°C, shorten processing time, allowing the digester to handle a larger volume of organic waste.

A mixture of CH₄ with CO₂ is making up more than 90% of the total biogas composition. The remaining gases are usually smaller amounts of H₂S, N, H₂, methylmercaptans and O. The biogas energy content depends on the amount of CH₄ it contains. Biogas CH₄ content varies from about 55% to 80%. Typical biogas, with a CH₄ concentration of 65%, contains about 22 MJ/Nm³ of energy which is equivalent to 0.55 kg of light diesel oil.

The process of biological anaerobic digestion occurs in a sequence of steps involving distinct types of bacteria as illustrated in Figure 7.

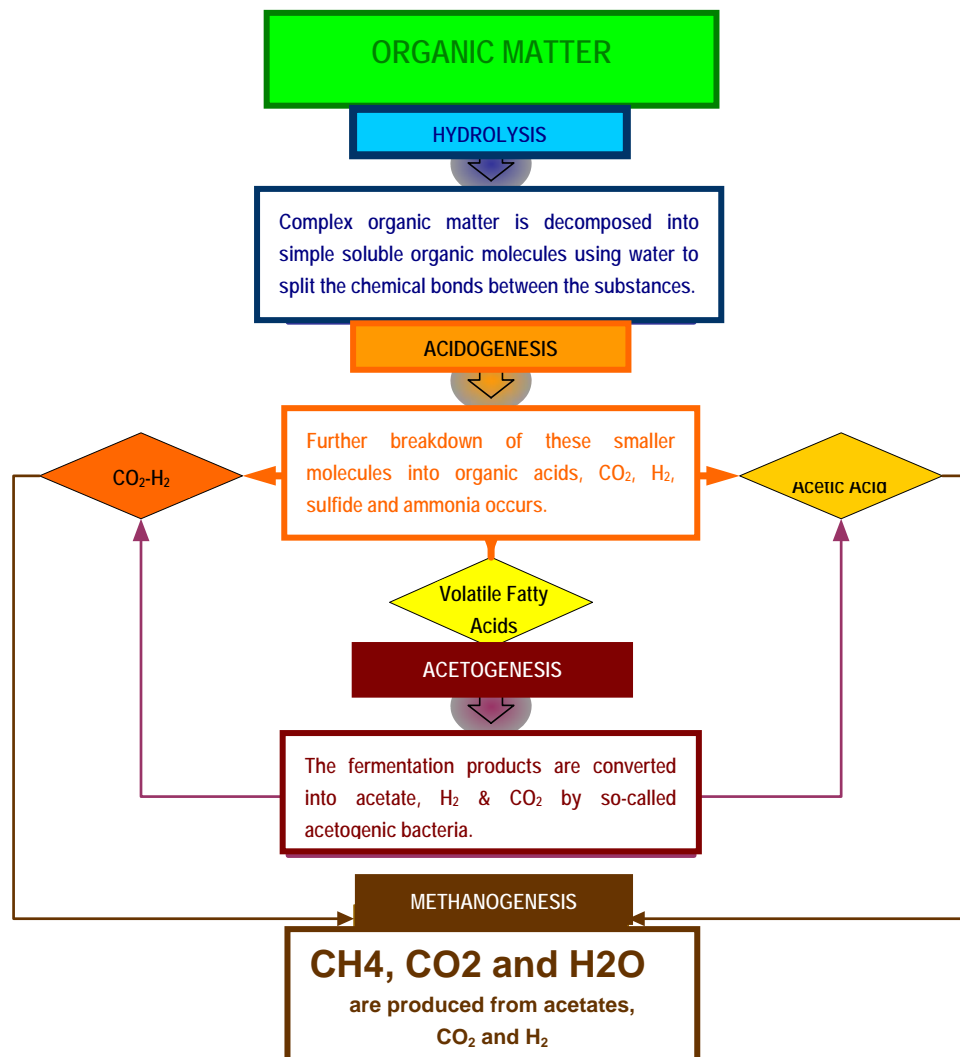


Figure 7
Sequential steps of biogas production

The acetogenic bacteria grow in close association with the methanogenic bacteria during the last stage of the process.

The reason for this is that the conversion of the fermentation products by the acetogens is thermodynamically only possible if the hydrogen concentration is kept sufficiently low. This process only takes place under strict absence of oxygen.

The combustion of biogas can supply useful energy in the form of steam, hot water or hot air. After filtering and drying, biogas is suitable as fuel for an internal combustion engine.

Future applications of biogas may include electric power production from gas turbines or fuel cells.

Biogas can substitute for natural gas or propane in space heaters, refrigeration equipment, cooking stoves or other equipment. Compressed digester gas can be used as an alternative transportation fuel.

Comparison of various anaerobic digestion process parameters is shown in the Table 5.

Digestion Process	Description	Advantages	Disadvantages
Dry	Dry solids content of > 25-30%	Compact, lower energy input, better biogas quality (<80% CH ₄), maintenance friendly	Restricted mixing possibilities
Wet	Dry solids content of < 15%	Better mixing possibilities	Higher energy input, larger reactor
Mesophilic	Digestion temperature between 25°C and 35°C	Longer process time, slower rate	Low energy input
Thermophilic	Digestion temperature between 50°C and 70°C	Shorter process time, higher degradation, faster rate	Higher energy input
Batch	Substrate in closed reactor during whole degradation period	Suitable for small plants with seasonal substrate supply	Unstable biogas production
Continuous	Reactor is filled continuously with fresh material	Constant biomass production through continuous feeding	

Table 5
Anaerobic digestion process parameters

Other very important factors for proper anaerobic digestion process are the residence time and acidity (pH-value).

Residence time has to be well balanced and optimized. The longer a substrate is kept under proper reaction conditions the more complete its degradation will become.

But the reaction rate will decrease with increasing residence time. Longer residence time requires automatically larger reactor for a given amount of substrate to be treated.

Shorter residence leads to a higher production rate per reactor volume unit, but a lower overall degradation.

Acidity (pH-value) is other very important factor for bacteria digestion process. It is important to balance the acidity in reactor in such way that the bacteria become most productive.

Unfortunately, for the different groups of bacteria the optimum acidity is not the same. The complexity of the entire system is increased by the fact that the intermediate

products of the digestion have a tendency to lower the acidity, making the later steps in the process more difficult.

The same anaerobic digestion process that produces biogas occurs naturally underground in landfills.

Most landfill gas results from the decomposition of cellulose contained in municipal and industrial solid waste.

Unlike above motioned anaerobic digesters, which control the anaerobic digestion process, the digestion occurring in landfills is an uncontrolled process of biomass decay.

The efficiency of the process depends on the waste composition and moisture content of the landfill, cover material, temperature and other factors.

The biogas released from landfills, commonly called "landfill gas," is typically 50% CH₄ and 45% CO₂. Remaining 5% are usually other gases like H₂S, N, H₂ and O.

In theory, the lifetime yield of a good site should lay in the range 150-300 m³ of gas per tonne of wastes. This suggests a total energy of 5-6 GJ per tonne of waste, but in practice yields are much less.

Capturing landfill gas before it escapes to the atmosphere allows for conversion to useful energy.

The gas is collected by an array of interconnected perforated pipes buried at depths up to 20 metres in the waste. In new sites this pipe system is constructed before the wastes start to arrive, and in a large well-established landfill there can be several miles of pipes, with as much as 1000 m³ an hour of gas being pumped out. A landfill must be at least 12m deep and have at least one million tons of waste in place for landfill gas collection and power production to be technically feasible.

Combination of landfill gas capturing with power generation, landfill gas to energy system, is shown in Figure 8.



Figure 8

A piping system connects the wells and collects the gas. Dryers remove moisture from the gas, and filters remove impurities.

The gas typically fuels a boiler to produce heat (steam, hot water, etc.) or gas turbine to produce electricity. Further gas cleanup improves biogas to pipeline quality, the equivalent of natural gas. Reforming the gas to hydrogen would make possible the production of electricity using fuel cell technology.

Another source of biogas is hidden in organic waste and municipal sewage.

Biomass that is high in moisture content, such as sewage, animal manure and food-processing wastes, is suitable for producing biogas using anaerobic digester technology.

Many municipal wastewater treatment plants use anaerobic digestion to reduce the volume of the biomass sludge in sewage.

Sludge digestion produces biogas containing between 60% and 70% HC₄, with an average energy content of about 22 MJ/m³.

Average digestion retention time is 80 days at 20°C and 20 days at 50°C, i.e. proper waste heat utilization from the process to warm the slurry in the digester reduces retention time considerably.

Ethanol

Starch content of Biomass feedstocks like corn, potatoes, beets, sugarcane, wheat, barley, and similar can be converted by fermentation process into alcohol (ethanol).

Fermentation is the biochemical process that converts sugars into ethanol (alcohol). In contrast to biogas production, fermentation takes place in the presence of air and is, therefore, a process of aerobic digestion.

Ethanol producers use specific types of enzymes to convert starch crops such as corn, wheat and barley to fermentable sugars. Some crops, such as sugar-cane and sugar beets, naturally contain fermentable sugars.

Ethanol may also be used as a hydrogen source for fuel cells. Because ethanol is easier to transport and store than hydrogen, fuel reforming (using a chemical process to extract hydrogen from fuel) may be a practical way to provide hydrogen to fuel cells in vehicles or for remote stationary applications.

Latin America, dominated by Brazil, is the world's largest production region of bioethanol.

Alcohol fuels have also been aggressively pursued in a number of African countries currently producing sugar - Kenya, Malawi, South Africa and Zimbabwe. Others with great potential include Mauritius, Swaziland and Zambia.

In developing countries interest in alcohol fuels has been mainly due to low sugar prices in the international market, and also for strategic reasons. In the industrialized countries, a major reason is increasing environmental concern, and also the possibility of solving some wider socio-economic problems, such as agricultural land use and food surpluses. As the value of bioethanol is increasingly being recognized, more and more policies to support development and implementation of ethanol as a fuel are being introduced.

Methanol

Production of methanol (wood alcohol) from biomass is a thermochemical conversion process. Potential feedstock includes wood and agricultural residues.

However, nearly all methanol produced today is made from natural gas, thus, will not be considered in this paper.

In addition, there is a growing consensus that methanol does not have all the environmental benefits that are commonly sought for oxygenates and which can be fulfilled by ethanol.

Commercial Aspects

Direct combustion, gasification as well as anaerobic digestion systems are commercially available. Direct combustion most advanced concepts based on fluidized bed combustion are technically proven.

Even though that gasification systems are also commercially available, they are less reliable and need more supervision in comparison to direct combustion. The further development should be directed towards improving their performance and reliability.

Anaerobic digestion is very wide used common method for biogas generation, mainly from sewage, landfills and from waste produced in medium and large farms.

The economy of a biogas plant consists of large investments costs, some operation and maintenance costs, mostly free raw materials, and income from sale of biogas or electricity and heat. Sometimes can be added other values e.g. for improved value of sludge as a fertilizer.

A comparison between all three technologies is shown in the following Table 6.

Type	Technology	GT Power Output MWe	ST Power Output MWe	Fuel Input Ton/hour	Specific Costs US\$/kW
FBC	Fluidized Bed Combustion	0	5	5-10	2600
FBG	Fluidized Bed Gasification	3.3	1.7	4-8	2800
ADB	Anaerobic Digestion-Biogas	<1.0	<0.9 ¹⁾	2.5 ²⁾	3000-4500

¹⁾ 0.9 MW_{th} (Net Available Heat Energy) ... ²⁾ Assumptions: Biomass LHV=8 MJ/kg, 35% Power / 45% Heat Generation / 20% Internal Consumption

What can not be seen from the above comparison is the production of by-products like additional heat energy extracted from direct combustion and gasification process as well as fertilizer produced from anaerobic digestion process.

Depending on system design and optimization, both systems, combustion and gasification, can produce hot water or hot air for process, heating and also cooling purposes.

Additional to 1.3 MW_{th} heat energy, typical 1 MWe aerobic digestion plant produces annually more than 20'000 tons of valuable fertilizer.

Due to biomass fuel relatively low energy content and low bulk density of the fuel, which prevents, from economic point of view, transportation of fuel over long distances, power plants Type FCB & FBG (Table 1) shall have an optimal size of 5 – 10 MWe.

Lower size will improve the fuel supply logistics, but it will considerably increase total installation costs. For example specific costs (US\$/kW) for 1 MWe power plant will be approximately 30% higher than specific costs for 5 MWe power plant and this will be again around 20% higher than 10 MWe power plant.

Biomass fired power plant larger than 10 MWe is recommendable where the biomass fuel can be secured not only in sufficient quality and quantity but during the whole expected operational time period.

Due to high ratio between fuel demand and generated electric power and size of anaerobic digestion equipment the biogas fired power plants are sized between couple of kW and 1 MW.

Summary – Conclusions

Disposal of any kind of waste will become ever more constraining, due to environmental regulations and legislations.

Modern biomass utilization technologies, mainly the gasification and anaerobic digestion, give the advantage of separating the toxic substances and providing clean gas for combustion.

Additionally, the internal combustion engines fuelled by syngas and biogas have the less emissions compared to petroleum derivatives fuelled engines. Sulphur dioxide and NO_x are, normally, absent in syngas and biogas.

Plantation of electrical energy generation based on gasification and anaerobic digestion technologies is beneficial for world's environment and its inhabitants.

In fact, the investment cost for rural electrification based on classical centralised power plants, is related to an erection of long electricity grids to connect the areas to be electrified to the power plants, far away.

Biomass technologies, such as biomass gasification and anaerobic digestion, that use locally available resources, would enable poor rural areas to access the electricity produced in a decentralised power plants.

Locally limited availability of biomass leads to the conclusion that small scale power plants with respectable efficiency will be preferred.

In order to increase the thermal efficiency of small systems, development works with steam cycles aims to downgrade large steam cycle (as already done for GT cycles) to ranges between 1 and 10 MWe.

The International Energy Outlook 2001 projections indicate a continued growth in worldwide energy demand that is supposed to increase by 59% the present World Energy Consumption by 2020 and, the emissions of CO₂ (one of the GHG that contribute for Global Climate Change) in the same period are almost going to double.