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TECHNOLOGY CATALOGUE FOR BIOMASS TO ENERGY

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CONTENTS

Abbreviations

ATEX	EU Directive 94/9/EC (Appareils destinés à être utilisés en ATmosphères EXplosibles)
BFB	Bubbling Fluidized Bed
BFW	Boiler feed water
BIGCC	Biomass Integrated Gasification Combined Cycle
CAPEX	Capital expenditure
CCMEP	Mexican Danish Cooperation on Climate Change Mitigation and Energy
C&I	Control and instrumentation
CFB	Circulating Fluidized Bed
CHP	Combined Heat and Power
CH4	Methane
CO	Carbon Oxide
CSP	Concentrated solar power
DAC	Direct Air Cooling
DB	Dry Bulk
DCS	Distributed Control System
DMC	Dry Matter Content
ESIA	Environmental and Social Impact Assessment
ESP	ElectroStatic Precipitator
EU	European Union
GHG	Green House Gases, e.g. CO_2 and CH4
GJ	Giga Joule
HMI	Human Machine Interface
HRSG	Heat recovery steam generator
K	Potassium
Kg	Kilogram
LCOE	Levelised cost of electricity
LPG	Liquefied Petroleum Gas
Mg	Magnesium
MJ	Mega Joule
Mn	Manganese
MW	Megawatt
MWe	Megawatt electrical energy
MWh	Megawatt hour
MWth	Megawatt thermal energy
NO_X	Nitrogen Oxides
OECD	Organisation for Economic Co-operation and Development
O&M	Operations and Maintenance
OPEX	Operating expenses
ORC	Organic Rankine Cycle
P	Phosphorus
PE	Project Emissions
PV	Photovoltaics
R&D	Research and Development
S	Sulphur
SCR	Selective Catalytic Reduction
SLD	Single-Line-Diagram
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur dioxide

1 Biomass to Energy

1.1 Introduction

Biomass is a sustainable resource and can, using the right technologies, with benefits replace fossil fuels in power plants and can be a back-up energy production for intermittent renewables (solar, wind and hydro).

Decentralised, biomass fuelled power plants may also reduce the load on an already challenged electricity grid and replace costly fossil fuels as oil, coal and gas utilized in rural industries in Mexico.

The Mexican Danish Cooperation on Climate Change Mitigation and Energy (CCMEP) presents this catalogue as a tool for developers and investors in biomass to energy projects to aid in the assessment of the technical and financial feasibility of the different biomass to energy options available to their businesses and industry.

1.1.1 Acknowledgement

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Further thanks to the companies and organisations, who have contributed with information on Mexican plants:

AB Energy México

INCO RENOVABLES S.A.P.I DE C.V.

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Experto independiente (preliminar)
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Monterrey Intelectual
Grupo MC
Ecotec
TecnoEcor
Renova Atlatec, S. A. de C. V.
Lorean Energy Group, S. A. P. I. de C. V.
ECOSYS III S.A. de C.V.
Compañía Agroeléctrica de Yucatán, S. de R. L. de C. V.
Egreentech, S. A. de C. V.

The technology catalogue cannot replace feasibility studies for individual projects and nothing in this technology catalogue shall be construed as containing any recommendations of any of the technologies and solutions mentioned.

1.1.2 Background

In COP21, in Copenhagen, collaboration between Denmark and Mexico was initiated with the Mexican Danish Cooperation on Climate Change Mitigation and Energy (CCMEP). The aim of CCMEP was to aid Mexico in their ambitious target of reducing 22 % of GHG and 51 % of Black Carbon in 2030 compared to 2013.

A way to achieve the target of reduction of GHG and Black Carbon is increased utilization of biomass for power production and introduction of limits on emission for new and existing biomass combustion plant, combined with enforcement of emission control measures.

This technology catalogue is developed as a method of ensuring that key technical and emission parameters for renewable energy technologies used by different stakeholders are consistent, and thereby contribute to timely adaption of new low carbon technologies.

This catalogue gives an overview of energy generation with renewable resources in Mexico, a general overview of the biomass resources in Mexico from the agricultural, forestry and industry sectors and describes the commercial combustion and biogas technologies, suitable for either solid or liquid biomass fuels, in high-efficiency and low-emission conversion systems. The catalogue features a section on technology selection, aiding to describe which technologies might be used, depending on the quality of the biomass. This catalogue describes only the electricity production of the combustion technologies in detail, only mentioning heat production where relevant. Finally, the technology perspective for Mexico and related opportunities and obstacles are outlined.

Utilizing biomass for power generation with emission control measures reduces the consumption of fossil fuels and thereby greenhouse gas (GHG) emissions to the atmosphere. This catalogue encourages the use of secondary or tertiary biomasses, which are resources not suitable as human food, as there are several ethical obstacles in regards to combusting primary biomasses, biomasses which are suitable as human feedstock. In principle, agro and forest based industries in developing and emerging countries produce sufficient volumes of biomass residues to provide a stable fuel supply chain for a power plant.

It must be highlighted, that combusting biomass with emission control measures will produce small amount of GHGs and Black Carbon, but these emissions are not comparable to those produced from fossil fuels. The difference lies in the timespan in which the CO_2 has been removed from the atmosphere. CO_2 originating from fossil fuels have been removed from the atmosphere for millions of years whereas CO_2 originating from biomass has only been removed from the atmosphere within a lifetime, and is part of the natural Carbon Cycle. Furthermore, if left on the fields the biomass will eventually produce methane, an even more harmful GHG, compared to CO_2.

The development of a biomass project involves a high level of complexity in technical, economic, environmental and potential social aspects, and requires careful preparation.

1.1.3 Scope

The purpose of this catalogue is to assist in the strategic planning of Mexico's commitment to reduce CO_2 and black carbon emissions by 2030. The catalogue equips project developers in Mexico with a standardised approach and methodology for developing a biomass to energy project. The catalogue furthermore aims to ensure that appropriate technologies are used for different biomasses, in order to reach the full potential of the biomass.

To assess the quality of the biomasses, this catalogue includes a characterization of the most common types of biomass available in Mexico. The biomasses included in this catalogue are primarily agricultural waste products, such as straw, wood chips and bagasse.

Based on international studies and field experience, three types of commercial technologies, with numerous reference plants worldwide, are assessed in this catalogue, providing the project developer with insight, enabling him to evaluate a biomass to energy project. The technologies are:

- Combustion plants using a water/steam boiler.
- Combustion plants using Organic Rankine Cycle (ORC) technology.
- Biogas technology using a gas engine.

As biomass to energy projects are subject to significant economies of scale, this catalogue distinguishes between following plant sizes.

- Small: 1-5 MWe
- Medium: 5-10 MWe
- Large: 10-40 MWe

It shall be noted, that plants with a generating capacity below 0,5 MWe due not require CRE approval.

Table 1 illustrates which technologies are applicable for the different capacities.

Table 1: Overview of technologies and plant sizes

Technology/Range	1-5 MWe (4-20 MWth)	5-10 MWe (20-40 MWth)	10-40 MWe (40-160 MWth)
Combustion plants using a water/steam boiler	X	X	X
Combustion plants using ORC technology	X	(X)	N.A.
Biogas productions using a gas engine	X	N.A.	N.A.

1.1.4 Types of biomass covered

The origin of biomass is classified in three classes: - primary, secondary and tertiary biomass. By primary, we refer to energy crops harvested solely for the purpose of energy generation. Secondary crops refer to by-products used for energy production. As such, the main crop harvested (e.g. grain for food and feed) is not used for energy generation, but any residues (e.g. straw, husks, shells) are.

Tertiary sources refer to end-of-life materials, e.g. discarded wood products or household waste and other biological waste. This is illustrated in the figure below.

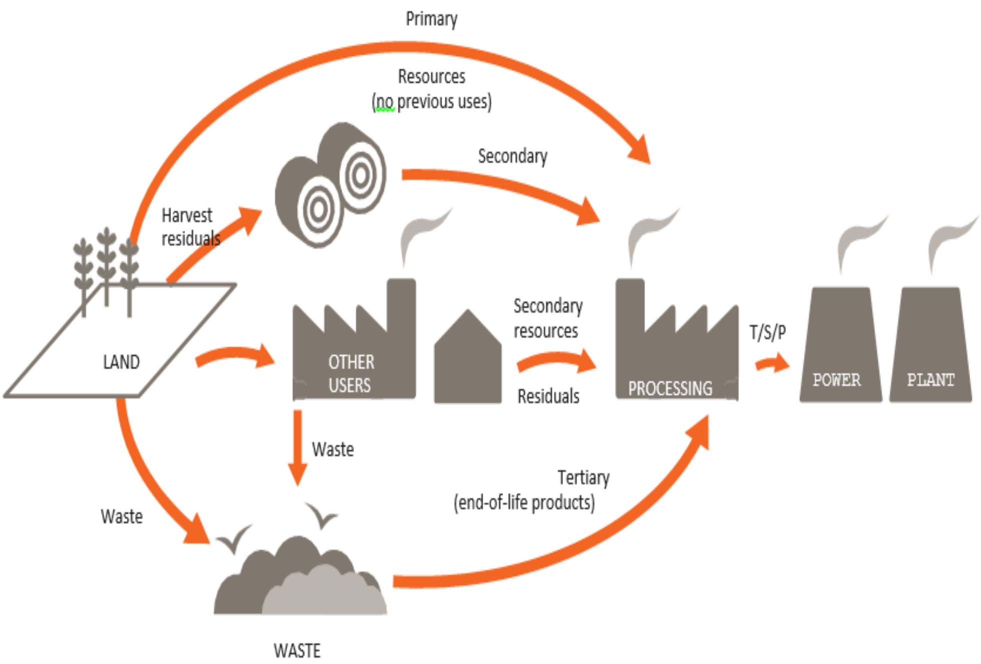


Figure 1: Biomass resources in Mexico - From field to plant

The origin of the biomass determines the project environmental and social viability in terms of direct and indirect land use changes which could affect GHG emissions and food prices. In this context, the social and environmental risks associated with utilizing primary biomass for energy purposes are significantly higher than for secondary and tertiary bio-residues. The present guide therefore focuses on technologies for utilization of secondary and tertiary biomass for energy production.

1.1.5 Biomass types relevant for energy production in Mexico

A general overview of the biomass resources in Mexico from the agricultural, forestry and industry sectors is provided in the figure below.

Figure 2: Biomass resources in Mexico

Sector	Primary	Secondary	Tertiary
Agriculture	- Annual crops (grains, maize, alfalfa) - Perennial crops (coffee, cocoa) - Grasses (sugar cane)	- Crop residues (straw, husks, stalks) - Sugarcane harvest residues, agave leaves - Other harvest residues (e.g. vegetables, perennials)	- Manure (bovine, pig, poultry)
Forestry	- Lumber - Roundwood	- Stumps - Thinnings and increment - Logging residues - Wood chips	- Forestry industry waste (sawdust, cut-offs) & Paper industry waste - In-forest harvest waste materials (twigs, branches) - End-of-life wood / waste wood
Industry	- Food production	- Food production residues - Various processing residues - Bagasse (sugarcane, agave)	- Wastewater sludge - Slaughterhouse & food industry waste - Vinasse from distilleries /breweries/dairies - Municipal and other organic waste

In Mexico, the existing utilization of biomass to power production is highly concentrated to the sugar industry, who use bagasse in back-pressure steam boilers, and to production of biogas from manure in lagoon plants. Outside these areas, there are very limited utilization of biomass to energy. The table below shows the number of permits given by CRE in April 2016 to plants generating electricity.

Biomass	Number of permits	Total capacity (MW)	Sugar sector share	-1 MW	1-5 MW	5-10 MW	10-40 MW	40- MW
Bagazo de Caña	57	944	67%		6	19	24	8
Biogás	34	128	6%	4	25	2	3	
Biogás y Gas Natural	5	118	100%	2	1		1	1
Residuos Orgánicos	1	0,5	100%	1				
Residuos Solidos	2	60	100%				2	
Residuos Sólidos Urbanos	3	116	100%				2	1
Vapor	3	69	100%			1	1	1
Total	105	1436		7	32	22	33	11

PERMISOS DE GENERACIÓN E IMPORTACIÓN DE ENERGÍA ELÉCTRICA ADMINISTRADOS AL 30 DE ABRIL DE 2016, CRE

A biomass resource screening has been completed under CCMEP, evaluating the biomass types relevant for energy production in Mexico. It was concluded that a large amount of biomass residues is available, suitable as fuel for power production. The key sources of biomass include bagasse, corn stalks from maize, straw from wheat and sorghum and forestry residues in the form of wood chips. The resource screening is summarized in Table 2 to 5 below.

Table 2: Biomass screening in Mexico – key agricultural crops with residuals relevant for combustion

AGRICULTURAL RESIDUAL		Wheat	Sugar cane	Sorghum	Maize	Agave	Sugar cane
Residual feedstock		Straw	Harvest residue	Straw	Stalks	Bagasse	Bagasse
Production (crop)	tons	4,445,540	55,400,870	5,195,389	24,694,046	1,846,345	55,400,870
Residue to production (ratio)		1.17	0.07	1.00	1.00	0.60	0.24
Residual amount (unit)	tons	5,023,460	3,878,061	5,870,790	28,892,034	1,107,807	13,296,209
Theoretical potential	TJ	93,623	46,537	77,931	345,717	11,078	185,039
Unused residual ratio		0.10	1.00	0.10	0.10	0.5	0.80
Unused residual amount	tons	2,600,641	3,878,061	2,597,695	12,347,023	55,390,352	8,864,139
Energy content in various biomasses	GJ/ton	18.0	12.0	15.0	14.0	10.0	16.7
Technical potential	**GJ**	**502,346**	**3,878,061**	**587,079**	**2,889,203**	**553,904**	**10,636,967**

Table 3: Biomass screening in Mexico – forestry residuals relevant for combustion

FOREST RESIDUAL		Forestry - timber	Forestry	Forestry	Harvest residues	Waste wood	Garden waste
Residual feedstock		Roundwood	Wood chips	Saw dust	Wood chips	Wood chips	Wood chips
Production (crop)	tons	2,897,729	2,897,729	2,897,729	2,897,729	394,151	2,957,711
Residue to production (ratio)		1.00	0.30	0.15	0.70	1.00	1.00
Residual amount (unit)	tons	2,897,729	869,319	434,659	2,028,410	394,151	2,957,711
Theoretical potential	TJ	109,720	32,916	15,192	32,916	7,686	57,675
Unused residual ratio		0.05	0.10	0.40	0.90	0.95	1.00
Unused residual amount	tons	56,267	168,800	337,599	151,919,774	37,444,367	2,957,711
Energy content in various biomasses	GJ/ton	19.5	19.5	18.0	19.5	19.5	19.5
Technical potential	**GJ**	**144,886**	**86,932**	**173,864**	**1,825,569**	**374,444**	**2,957,711**

Table 4: Biomass screening in Mexico – biomass residuals from agriculture relevant for biogas production

AGRICULTURE RESIDUAL	Unit	Poultry	Cattle Dairy	Swine	Slaughter-house waste	Slaughter-house water	WWTP municipal
Residual feedstock		Manure	Manure	Manure	Slaughterhouse waste (blood and liquids)	Sludge	Sludge
Production	tons	534,692,610	2,457,683	16,364,459	8,973,539	8,973,539	1,751,879,189

Residue to production (ratio)		N/A	N/A	N/A	0.05	0.06	0.006
Manure per year	Tons/po-pulation unit	0,002	23,400	0,500	N/A	N/A	N/A
Residual amount - theoretical	tons	1,288,609	57,509,782	8,182,230	448,677	1,596,530	10,511,275
Unused residual ratio	%	80%	90%	80%	50%	90%	90%
Unused residual amount - technical	tons	386,583	11,501,956	6,545,784	224,338	1,436,877	9,460,148
Biogas potential	**GJ/ton**	**1**	**0.4**	**0.4**	**1.41**	**0.32**	**0.32**
Biogas potential	**GJ**	**368,583**	**4,600,782**	**2,618,313**	**316,316**	**459,800**	**3,027,247**

Table 5: Biomass screening in Mexico – biomass residuals from food processing relevant for biogas production

FOOD PROCESSING RESIDUAL	**Unit**	**Coffee**	**Vinasse (tequila)**	**Wholesale market**	**Municipal Food Waste**	**Agricultural residues (stubbles from vegetables)**
Residual feedstock		Pulp	Vinasse	waste	Food waste	Vegetable Residues
Production	tons	1,026,252	1,763,000	26,608,837	8,062,758	32,251,030
Residue to production (ratio)		0.436	10	0.025	1	0.05
Manure per year	Tons / population unit	N/A	N/A	N/A	N/A	N/A
Residual amount - theoretical	tons	447,446	17,630,000	665,221	8,062,758	1,612,552
Unused residual ratio	%	100%	100%	40%	80%	10%
Unused residual amount - technical	tons	447,446	17,630,000	332,610	6,450,206	161,255
Biogas potential	GJ/ton	1.4	1	1.60	4.74	2.22
Biogas potential	**GJ**	**626,424**	**17,630,000**	**532,176**	**30,573,976**	**357,986**

1.2 Overview of technologies

A number of technologies are available for converting biomass to power. The most common commercial technologies are biomass combustion using grate technology or fluidized bed and biogas plants.

In this catalogue, only commercial technologies are suggested. Commercial technologies, opposed to emerging technologies, have been proved in large-scale plants and have reached a state of maturity, allowing limited developments or improvements. Choosing a commercial technology ensures no unforeseen obstacles, in regards to the technology.

1.2.1 Commercial technology

To ensure the viability and robustness of the project, along with securing the financial plan, proven and commercial technologies must be chosen. The technologies considered proven and commercial in this catalogue are:

- Biomass combustion plant using grate technology combined with a water/steam boiler
- Biomass combustion plant using bubbling fluidized bed (BFB) technology combined with a water/steam boiler
- Biomass combustion plant using circulating fluidized bed (CFB)technology combined with a water/steam boiler
- Biomass combustion plant using Organic Rankine Cycle (ORC) technology
- Biogas plants (anaerobic digestion + gas engine)

The selected technologies have numerous reference plants worldwide along with extensive operation experience.

1.2.2 Emerging technologies

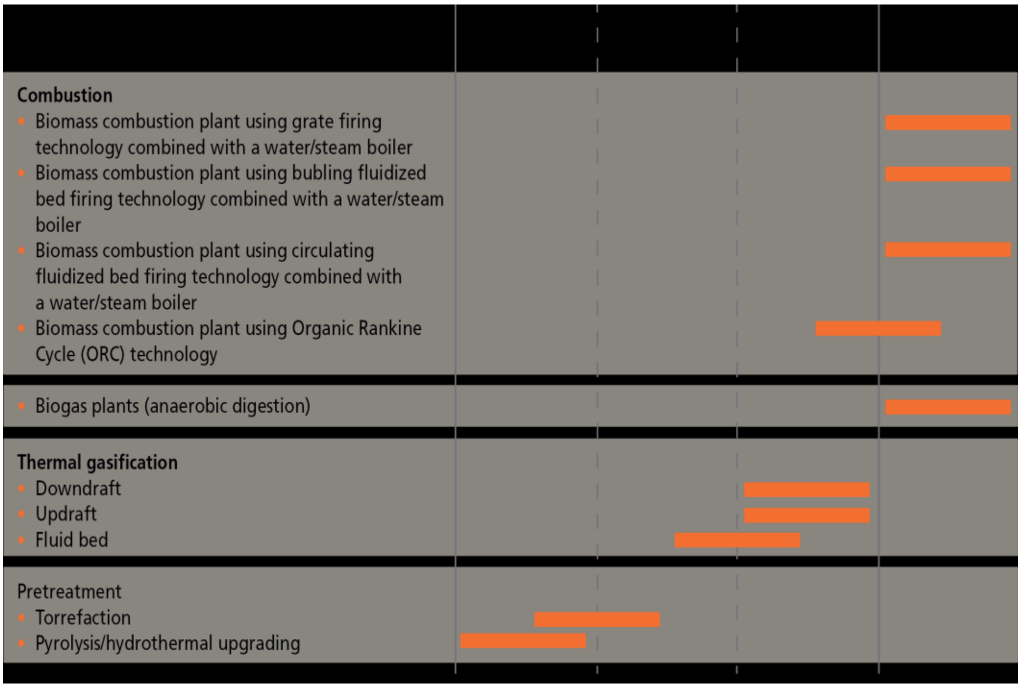
Some promising emerging technologies are presented briefly in Section 5. These technologies are:

- Thermal gasification
- Torrefaction
- Pyrolysis/hydrothermal upgrading

These emerging technologies are currently not considered relevant options for biomass to energy projects in Mexico.

In figure 3, an overview of biomass conversion technologies and their current development status is shown.

Figure 3: Overview of biomass conversion technologies and their current development status [10]



1.3 Technology selection

Once choosing a technology type of biomass, fuel flexibility, load ramping capability, investment cost, plant size, etc. must all be considered. The most important criteria is, however, the moisture content of the biomass. If the moisture content is above 60-65 %, the calorific value of the biomass is too low for beneficial combustion whereas anaerobic digestion in a biogas plant would be the advantageous technology, not being influenced by the high moisture content. Drying may be considered in some projects, but usually renders economically unsustainable.

In Mexico, generation capacity is distinguished as:

- 5 kW to 0.5 MW: Distributed generation, low voltage
- 0.5 MW – 5 MW: Partially distributed generation, medium voltage with transport by the national grid to several points of load
- 5 MW – 50 MW: For the wholesale power market or for qualified users within a node, medium or high voltage
- Above 50 MW, for wholesale electrical market or qualified users, high voltage.

For the scope of this report, the focus are on plant size from 1 to 40 MW, which are international standard commercial scale generation from biomass and, at the same time, relevant in a Mexican context.

The selected technologies are described in three approximate size ranges: 1-5 MWe, 5-10 MWe and 10-40 MWe as indicated in Table . There is no clearly defined distinction between the size ranges and overlaps might occur. Combustion plants with water/steam cycles are also applicable for plant sizes above 40 MWe.

Table 6: Steam cycle technologies according to size

Technology	1-5 MWe	5-10 MWe	10-40 MWe
Grate technology	X	X	X
BFB technology		X	X
CFB technology			X

Some selected biomass residues are listed with their respective appropriate technologies in table 7.

Table 7: Selection of technology based on biomass

Biomass	Typical humidity	Technology selection
› Manure from animals › Organic waste material from food industries › Sludge from flotation plants › Vegetables and fruit waste from agriculture › Other organic waste materials from industries	Higher than 65 %	Biogas technology
› Wood › Various straw › Rice straw and husk › Other	Lower than 60%	Combustion technology

2 Combustion technology

In figure 4, the systems making up a biomass combustion plant are shown. These systems are more or less standardised and may be supplied by numerous suppliers.

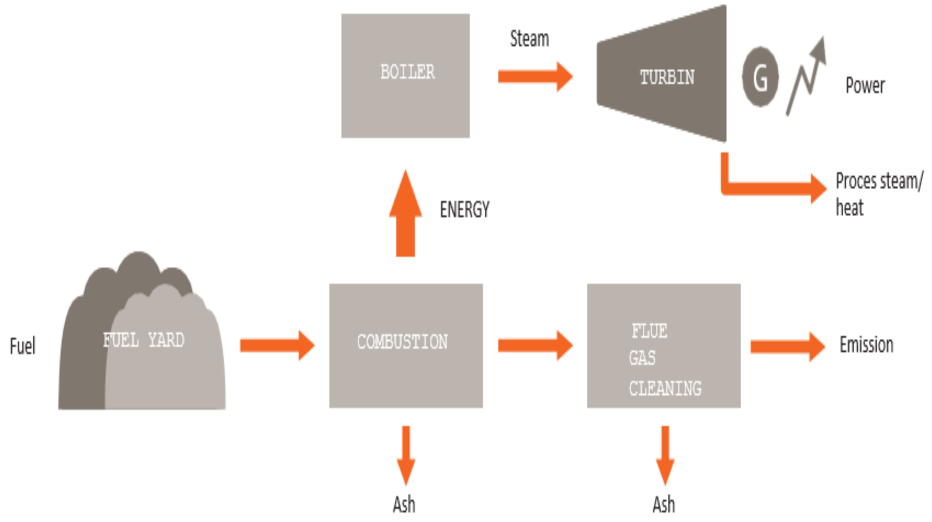


Figure 4: The biomass combustion plant

The initial system, the fuel yard, is where the fuel is received and stored. Next is the combustion system in which the fuel is fed and combusted by a chosen technology. Following the combustion is the boiler, where the energy from the hot flue gases are turned into high-pressure steam. The turbine system then converts the high-pressure steam into electricity and process heat. The final system is the flue gas cleaning in which harmful elements are removed from the gas before emitted to atmosphere. All systems are described in detail in the following sections.

2.1 Fuel yard

Fuel yards differ in handling, storage and preparation of the biomass, depending on the type and quality of the biomass. Wood chips require different storage and handling systems than that for instance baled wheat straw. To ensure proper fuel handling, following must be considered:

- Fuel reception, including weighting, quality and moisture control.
- Storage, including fuel yard management.
- Preparation of the biomass fuel, including drying, shredding, and grinding.
- Fire risk and strategy, including explosion risk and fire extinguishing means.

- Environmental issues, such as dust, fungi spores, noise, odour, etc.
- Boiler feeding.
- Flexibility in terms of handling various fuel.

2.1.1 Biomass Fuel Reception

Quality control is always performed on the biomass received at the power plant.

The quality control is of the outmost importance once receiving fuel from an external fuel supplier. The weight and moisture content determines the energy contents of the load and normally sets the payment to the supplier. Weight may be registered on a scale, normally a weigh bridge or by a scale installed on a crane. The moisture content may be measured with portable instruments, radar sensors or other on-line equipment using microwaves, radioactivity, light absorption, etc. The moisture content may also be determined via manual sampling, and following drying of the sample at 103 °C for a minimum of 17 hours. The difference in weight between the initial sample and the dried sample represents the moisture content. This test is convenient in small facilities. In general, biomasses have a great variance in moisture content and the correct method must therefore always be selected.

Random visual inspections discourages suppliers from attempting to deliver a quality not in accordance with the contract. It is recommended to conduct such visual inspections especially in the first years operation of the power plant.

It is important that rejection criteria are clearly conveyed to the fuel supplier in the fuel supply contract, to avoid receiving biomass of an inadequate quality.

2.1.2 Biomass Fuel management and storage

The fuel management depends on the security of supply from the biomass supplier. If unreliable, a fuel yard corresponding to up to 2 weeks of capacities might have to be established. If the fuel yard is covered by either a roof or wall, it influences the costs of the fuel yard significantly.

The logistics and management of the large biomass quantities necessary is a very important issue that must be considered carefully during the project development.

2.1.3 Fuel preparation

Proper fuel preparation benefits the combustion and as a result the energy efficiency. Fuel preparations may include:

- Drying
- Pelleting
- Shredding, chipping or grinding.

Wet fuels, above 60 %, may be difficult to combust and must therefore be dried. Common for all drying processes is the high cost. As a result, wet fuels should only be utilized in combustion plants if the excess heat can be utilized at a nearby industry, as the evaporation of the moisture in the biomass will otherwise reduce the efficiency of the plant.

Pelleting is, like drying, costly and is not normally required at new power plants

To reduce the fuel size in order to fit the feeding equipment at the power plant, shredding or chipping may be necessary.

If the boiler requires pulverized fuel, milling is required by equipment such as hammer mills. Co-firing on existing coal fired power plants often require this despite the high electricity consumption and maintenance requirement of the milling process.

Common for both shredders and hammer mills are the high noise levels and extensive precautions implemented to avoid personnel injuries.

2.1.4 Fire and explosion risk

Different biomasses, both with high and low moisture contents, may pose a potential fire and explosion risk. The dry biomasses, such as straw and bagasse, may cause dust explosions, whereas wet biomasses will undergo a microbial degradation during storage causing very high local temperatures and the risk of spontaneous combustion. Necessary precautions must be imposed to avoid serious fire and explosion risks with potential personnel injuries and production stop.

Sprinkler systems above conveyors and handling/un-loading areas may be used as fire and explosion protection. In case the town water system is insufficient, a fire water storage with a corresponding fire water pump is required.

When handling dry fuels, ATEX classifications of equipment and instruments should be evaluated to reduce the fire and explosion risk.

2.2 Combustion technologies

This chapter describes three combustion technologies that are commonly used for biomass to energy plants. The first part describes the grate technologies, including an introduction to the most common types of grates. The second part introduces Bubbling Fluidized Bed (BFB) and Circulating Fluidized Bed (CFB).

2.2.1 Grate firing technologies

Grate fired combustion, also named "fixed bed" technology, is applicable for fuels with a high moisture content, high ash content and varying particles sizes, however with a lower limit for fine particles. The grate fired technology is used on biomass fired power plants up to 50 MWe.

The actual type and size of grate and combustion technology will depend on the biomass type, woody or herbaceous fuels, combustion behaviour, moisture content, ash melting point and particle size.

To ensure an efficient combustion, the fuel must be well distributed on the grate. The fuel feeding system should be designed to control this.

In grate fired boilers, the same process takes place in and above the fuel bed:

- Drying of moisture
- Pyrolysis and combustion of volatile matter
- Combustion of char particles.

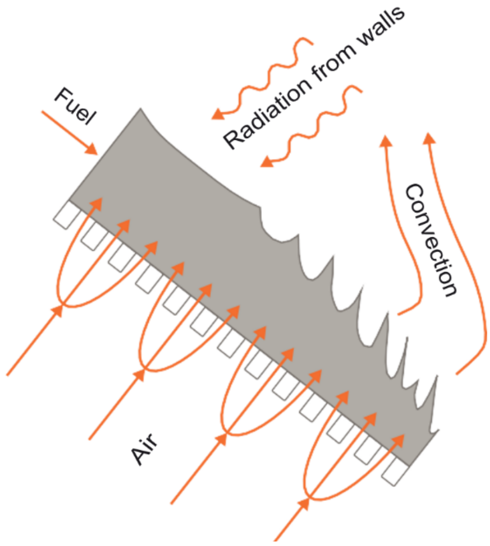


Figure 5: Combustion process on a sloping grate

The primary air has the purpose of drying the fuel and supplying oxygen for pyrolysis and char burn out. The primary air is supplied from underneath the grate, where it is distributed across the grate into sections. Heated primary air will boost the drying of wet fuels. In figure 5, combustion on a sloping grate is shown.

Secondary air has the purpose of burning out volatiles and fuel dust particles, and is supplied to the combustion above the grate.

Tertiary air has the purpose of reducing NO_X emissions by ensuring complete combustion of the gases and is supplied to the upper part on the combustion chamber.

The purpose of supplying primary, secondary and tertiary air is to optimize the stoichiometry at the lower part of the combustion bed and thereby obtain the thermodynamically optimal temperature.

When deciding the type of grate firing, the biomass size must be considered. The larger particles requires time to burn out before it is removed as ash at the end of the gate and the smaller particles can cause a high amount of unburned particles in the fly ash and CO-emissions.

The operation of the grate must consider the melting temperature of the ash in the fuel, the ash content and the combustion temperature. Severe slag-accumulation in the char burn-out zone can be caused by a combination of high gas temperatures and low ash melting temperatures.

Considering all of the above, an appropriate grate technology can be chosen, ensuring a continuous and trouble free operation.

The most commonly used grates are:

- Travelling grate
- Vibrating grate
- Step grate.

Travelling grates are advantageous for small, biomass fired boilers of >1 MWe, fed with a homogenous fuel, ensuring ignition and burn-out within a short distance. Travelling and vibration grate boilers can have a capacity of up to 50 MWe.

Vibrating grates are beneficial for loose density biomass fuels such as straw and blends of fuels with different densities. Different parts of the sloping grate are vibrated successively.

Step fired boiler is advantageous when using "difficult" biomasses such as waste wood and solid waste. It is equipped with a step-like grate alternating back and forth to move the fuel through the combustion zone.

Travelling grate

A travelling grate fired boiler unit is illustrated in figure 6. The fuel is moved continuously from the fuel inlet to the ash outlet on a belt with "hinged" cast iron grate bars attached to chains. Screw conveyors supplies fuel to the grate in an evenly distributed manner.

Travelling grates are advantageous for combustion of wet biomass fuels, high ash fuels and blends of fuels with different sizes.

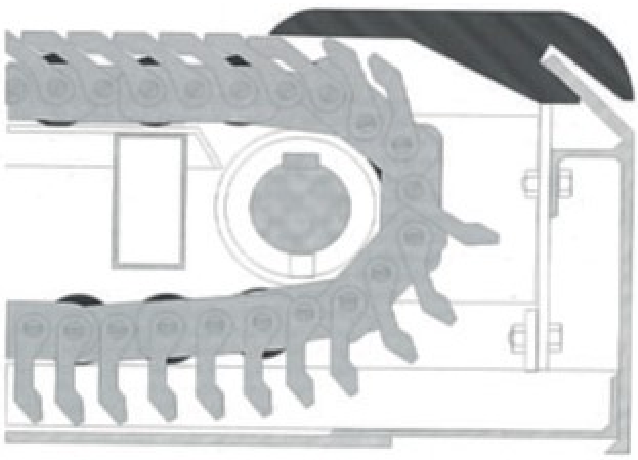


Figure 6: Travelling grate principle [2]

The bars are cleaned for ash and slag at the ash outlet. The returning bars are cooled by primary air to the grate.

To ensure a complete burn-out of the char, without slagging or overheating the grate, the height of the bed layer, the grate velocity and the combustion air are controlled. The fuel bed layer shall be distributed across the grate ensuring that no primary air "leaks" directly in to the combustion chamber. Causing a faulty stoichiometric in the fuel bed.

The maintenance costs for a travelling grate are considered high, as the moving chain requires regular maintenance.

Vibrating grate

A vibrating grate is illustrated in figure 7. Vibrating grates are a cost effective solution for combusting loose biomasses such as wood chips, loose straws or blends of fuels with different densities. Straw bales may be conveyed to the boiler feeding system, where the twines are cut and straw shredders loosen the fuel before feeding the straw onto the grate. Vibrating grates may be constructed with capacities of up to 50 MWe.

The grate can consist of one or more sections, each designed as a membrane wall with air nozzles in the fins. The grate cooling water, protecting the grate against overheating, is integrated with the boiler water/steam system. A vibrating grate can also be designed with cast iron grate bars, attached to a frame that vibrates on an alternating basis.

Figure 7: Vibrating grate

To regulate the combustion, the grate sections are vibrated consecutively in cycles. The vibrations causes the fuel ash and slag to gradually move down the grate before ending up in the ash conveyor.

Like for a travelling grate, primary air is supplied from underneath the grate and secondary and tertiary air is supplied above the grate directly into the combustion chamber.

The maintenance cost for a vibrating grate are considered low, as a result of the lack of moving parts inside the combustion chamber.

Step grate

A step grate is shown in figure 8. Step grates are commonly used for "difficult" biomasses such as waste wood and solid waste. Moving step grates may be built with a capacity of 10-20 MW fired capacity.

Step fired boilers have the fuel fed at the top of the steps. Each step is alternating forth and back moving the fuel through the combustion zone and down to the water-filled ash conveyor. The complete grate can consist of more parallel moving grate sections (lanes).

The grate may either be cooled by primary air, as for travelling grates, or by cooling water as possible for vibrating grates.

Figure 8: Stepgrate [14]

The maintenance costs for a step grate are considered high due to the numerous moving parts inside the combustion chamber.

In table 8, the three grate technologies are summarized.

Table 8: Summary of grate technologies

	Travelling grate	Vibrating grate	Step grate
Fuels	Wet fuels High ash fuels Blends of fuels	Wood chips Loose straw	Waste wood
Cooling options	Primary air	Cooling water	Primary air Cooling water
Maintenance cost	High	Low	High

2.2.2 Fluidized bed technology

Fluidized bed combustion is extensively used for biomass fuels. Two commercial fluidized bed combustion technologies are available; bubbling fluidized bed (BFB) and circulating fluidized bed (CFB). Both boilers are advantageous for fuels with a high moisture and ash content but less used for fuels with a high alkaline content, such as straw.

BFB boilers are advantageous in small-scale plants as a result of the simpler technology whereas CFB boilers are beneficial in larger plants, being more complicated to operate but obtaining a higher efficiency.

Bubbling fluidized bed (BFB)

The BFB technology has the purpose of enhancing the efficiency of the heat transfer from the combusted fuel to production of high pressure steam. The combustion chamber of a BFB boiler features water-cooled walls and bottom. The bottom has a full refractory lining and the lower portion of the water wall is also refractory lined.

The bed, consisting of sand mixed with fuel, is fluidized by primary air fed from the bottom of the bed, creating turbulence with the purpose of mixing the bed and converting the fuel into char. Fluidization of the bed occurs when the air is fed at a velocity sufficient to overcome the particles' gravity force, also referred to as the minimum fluidization velocity. The BFB must be operated in the range between the minimum fluidization velocity and the velocity, at which bed materials will be dragged together with the flue gas into the boiler.

The majority of solid particles shall remain in the fuel bed, whereas smaller particles will be blown up into the freeboard region. Coarse bed material and ash is withdrawn from the bottom of the bed.

To reduce sulphur and chlorine from the flue gas, limestone might be added to the fluidized bed.

Primary air makes up approximately 30 % of the combustion air and is, like for the grate technologies, supplemented by secondary and tertiary air in the upper combustion chamber, enhancing staged combustion.

Cold start-up time is relatively slow, compared to the grate technology. The bed material and the refractory in the combustion chamber requires slow temperature changes during the start-up.

A BFB boiler normally operates in the range of 800 and 950 °C, with 850 °C being a typical bed temperature.

The maintenance and operation costs of BFB boilers are high. The high maintenance costs are caused by the refractory lining in the bed and on the boiler walls, which requires regular maintenance and replacement. During operation, the bed material (sand) is continually replaced. The handling of the sand and the increased amounts of ash residues result in relatively high operation costs.

Circulation fluidized bed (CFB)

A CFB boiler uses the same principal as a BFB boiler, mixing fuel with sand to create a homogenous bed. The difference between the technologies is the velocity of the primary air. A BFB aims to keep the bed material in the bed, whereas a CFB aims to create more turbulence. Because of the higher air velocity in a CFB, the bed material is dragged with the flue gas into the boiler pass where it is separated from the flue gas in a cyclone and returned again to the bed. The primary airflow may have velocities of 4.5-6.7 m/s.

CFB boilers are commonly used in large-scale plants, with capacities up to hundreds of MWe, but may also be used in small-scale plants with fuels that require longer residence time to burn out.

The maintenance and operation costs of a CFB boiler are, like for the BFB, relatively high, due to the frequency of maintenance required on the refractory lining in the bed and on the boiler walls, and due to the sand consumption and increased handling of bed material.

Table 9 compares the grate and fluidized bed combustion technologies with one another.

	Grate technology	Fluidized bed technology
Typical use	Biomass (step and vibrating grate), Municipal solid Waste (step grate), coal (travelling grate)	Biomass and coal
Level of maturity	Proven and matured	Proven and matured
Fuel flexibility	High	High
Start from cold	Quick	Slow
Load ramping capability	High (very limited refractory in the boiler)	Low (covered by refractory)
Low load capability	Good (typically 25-30%)	Limited (basically a base load unit)
Emissions	- Medium NOx (low by Ammonia/Urea injection) - Desulphur using lime in fluegas	- Low NO_x - Possibility to desulphurize in the bed
Consumables	Ammonia/Urea for DeNOx if applicable	Inert bed material (sand)
Residues	Bottom ash + fly ash	Higher amount (bottom ash + bed material + fly ash)
Maintenance requirement	Low	Medium

Table 9: Comparison of grate and fluidized bed technology

The differences between a BFB and CFB, are illustrated in figure 9.

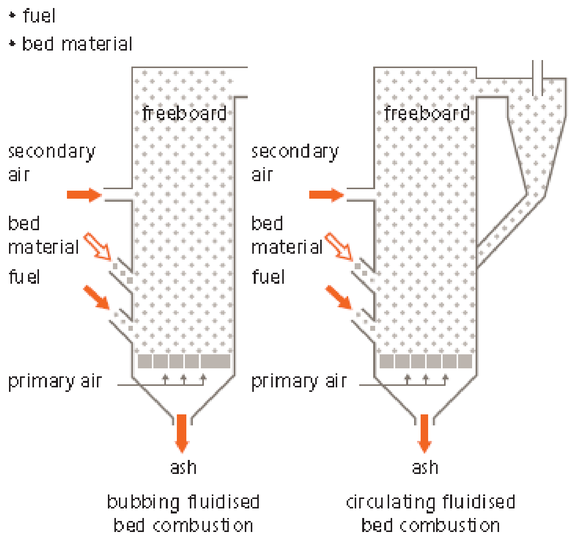


Figure 9: Principle of BFB and CFB

2.3 Boiler technologies

This section describes how the boiler converts the hot flue gas from the combustion to high pressure and high temperature steam. The section introduces the thermodynamic concept of a water/steam cycle and presents the main boiler types.

2.3.1 Boiler

The steam generator, or boiler, converts the high temperature energy from the flue gas into high pressure and high temperature steam. The steam may be used for different purposes, e.g. power generation in a turbine/generator, district heating, industrial processes or combinations hereof.

There are two boiler types, a fire-tube boiler and a water-tube boiler. In a fire-tube boiler, hot flue gases flow inside the tubes surrounded by water whereas in a water-tube boiler, water and steam flows inside the tubes surrounded by hot flue gases. For power generation, which requires high-pressure steam, it is cost advantageous to have the high-pressure water and steam inside pipes with smaller diameters; hence water-tube boilers are the preferred boiler at power plants. In small-scale boilers for heat production fire-tube boilers normally is the less costly solution.

Process

The conversion of energy from the hot flue gases to super-heated steam normally takes place in three steps: an economizer, an evaporator and a super heater. In the economizer, the water is heated to the saturation temperature (boiling temperature of the water), in the evaporator the saturated water is evaporated, and in the super-heater the saturated steam is heated to super-heated steam. In figure 10, a typical boiler arrangement is illustrated.

Feed water is pumped from the feed water tank into the economizer where it is heated to saturation temperature. The economizer is located as the last cooler of the flue gas, to ensure that all heat from the combustion is utilized. From the economizer the saturated water is led to the evaporator.

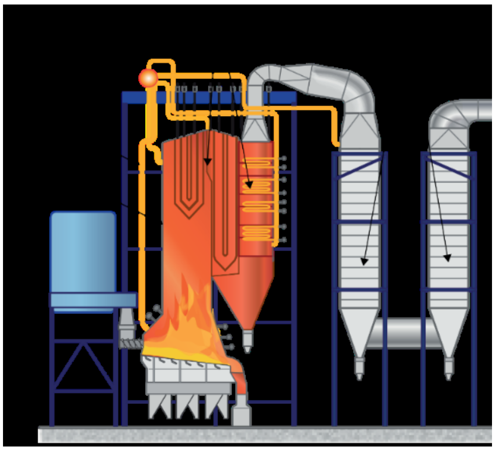


Figure 10: Typical water-tube boiler arrangement

A schematic drawing of an evaporator is illustrated in figure 11. The evaporator consists of a number of down-comer pipes and riser tubes connected in a loop going through a header at the bottom of the boiler and connected to a drum at the top of the boiler. The riser tubes constitute the walls of the combustion chamber, mainly absorbing heat by radiation. The saturated water from the economiser is led to the boiler drum and by gravity led further to the riser tubes/boiler walls. The heat from the flue gas evaporates the water and the steam is led to the drum, where the saturated steam is collected and led to the super-heaters. In the following super-heaters the saturated steam is further heated to the desired temperature that are considered optimal power generation in a steam turbine. The super-heater consists of steam pipes that are placed in the flue gas flow in order to get the steam heated further. Normal steam temperatures at biomass fired boiler vary from 450°C to 530°C.

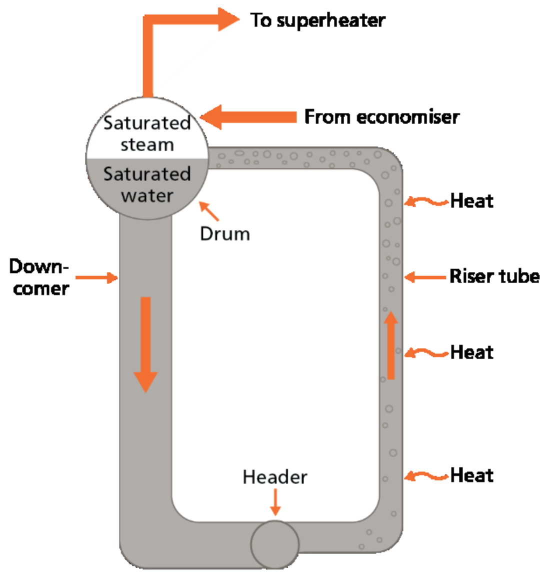


Figure 11: Evaporator circulation system

2.3.2 Water – Steam Cycle

The steam coming from the super-heater is expanded in a steam turbine, which drives a generator producing electrical power. Once the steam has been through the turbine, it is condensed and recycled back to the boiler. A water-steam cycle is the most common technology for the production of electric power. In figure 12 a water-steam cycle, also referred to as a Rankine Cycle, is illustrated.

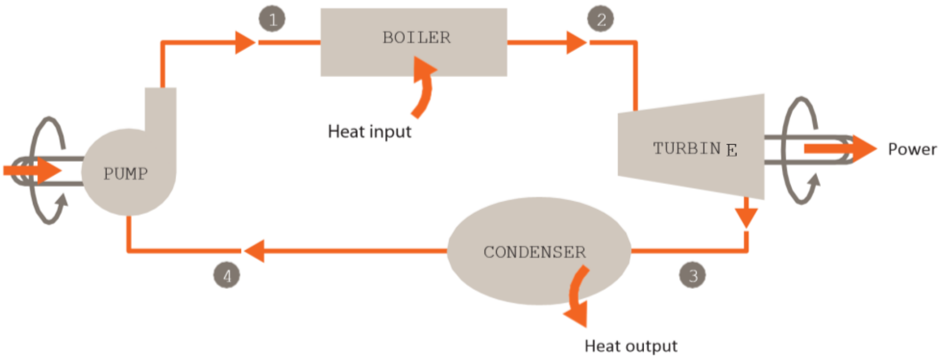


Figure 12: Water-Steam cycle

Step 1-2: The boiler ensures an efficient energy transfer from the combusted fuel and produces super-heated steam as described in the process section above.

Step 2-3: The super-heated steam expands in a turbine, transferring mechanical energy to the generator producing electrical power. Figure 13 illustrates an example of a steam turbine.

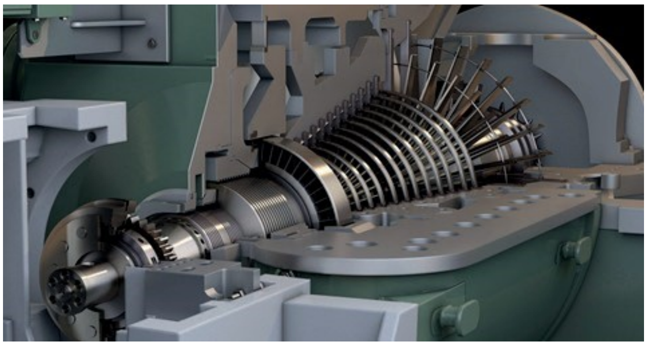


Figure 13: Illustration of a steam turbine [3]

Step 3-4: Once exiting the turbine, the steam is saturated and must be condensed before it can be recycled into the boiler. The condenser can be cooled either with air coolers or cooling water from nearby rivers or lakes. Local demands for process heat may also be met with heat from the condenser. Condensers are further described in Section 2.3.3. Often this excess heat is used as district heating.

Step 4-1: The condensed steam pumped to a feed water tank, from which it is returned to the boiler for steam production by a feed water pump. Feed water pumps are usually multi-stage pumps suitable for handling large pressure heads.

Electrical efficiency

Normal electrical efficiencies in biomass power plants are within the range of 20-30 %, i.e. 20-30 % of the energy from the fuel is converted into electrical power. The electrical efficiency of the steam cycle is highly dependent on the super-heated steam temperature and the condensing temperature. The efficiency will increase with a higher steam temperature and a lower condensing temperature. Higher steam temperatures require more expensive steel alloys in the boiler, steam pipes and turbine, and lower condensing temperature requires the availability of sufficient cooling water.

Combined heat and power plant

When both electrical power and heat is produced from a combustion plant, it is referred to as combined heat and power (CHP) plant. The condenser can produce water at a temperature of 70–100 °C or low-pressure steam. Higher temperatures can be obtained, however this compromises the electrical efficiency. The heated water may be used for district heating or as a supply of process heat in nearby industries. The heat recovered in the condenser is normally 40-60 % of the energy from the fuel.

Heat only boiler

A boiler may be designed to produce only heat and no power.

Numerous suppliers offer standardised boilers of 30-40 MWth, which can combust most common types of biomasses. These boilers may be tailored to meet special requirements and produce different parameters in regards to flow, pressure or temperature of the process heat.

2.3.3 Condenser cooling

The energy released in the condenser when the steam is condensing and further cooled must be removed by a cooling circuit. For the production of this secondary cooling water, four common cooling methods are listed below.

- Natural convection cooling towers
- Dry coolers
- Wet/Dry coolers
- Wet coolers

Natural convection cooling towers

Natural convection cooling towers allow the cooling water to flow across grates. Evaporation occurs and thereby cools the remaining cooling water. The evaporation is aided by the shape of the cooling tower, allowing a cold air inlet at the bottom and a hot air outlet at the top, creating natural convection. As an example from a large power plant, natural convection cooling towers could have a diameter of 100 m and a height of 150 m to supply sufficient condensing power to a 400 MW turbine.

A challenge is that natural convection cooling towers are not normally available for plant sizes of 1-40 MW. Another challenge is the open cooling water circuit allowing contaminations, such as E-coli bacteria, and the bleeds, which must be performed to control accumulation of salts in the cooling water. This bleed must be discharged and treated somewhere.

Because of the evaporation, the resulting cooling water temperature may be lower than that of the ambient air.

Dry coolers

Dry coolers have the advantage of being closed systems, not allowing contaminations to the same degree as in natural convection cooling towers and requires no bleeding as there is no evaporation. Instead, the water flows through tubes cooled by an air flow created by a fan.

In dry coolers, the resulting cooling water temperature is typically around 10 degrees above that of the ambient air.

Wet coolers

Wet coolers cool like natural convection cooling towers in an open system by evaporation, but instead of using the natural convection, a fan supplies the air flow. The wet coolers may be downscaled to smaller power plants, whereas the same challenge is valid as for the natural convection cooling towers, in regards to the open system and built-up of salts, the need for a bleed, and possible bacterial spreading of the cooling air.

Wet/dry coolers

Wet/dry coolers is a combination of wet and dry cooling concepts. Primary cooling is done by direct contact with the air flow, afterwards the air is heated by hot cooling water allowing the air to leave the tower without visible evidence of steam and thus with less risk of spreading bacteria and chemicals. In other respects, the wet/dry coolers are similar to the wet coolers.

Examples of forced convection cooling towers are illustrated in figure 14 and 15.

Figure 14: Cooling tower from Mexican sugar mill

Figure 15: Industrial cooling towers for a power plant

2.3.4 Organic Rankine cycle

The difference between the Rankine Cycle described in Section 2.3.2 and the Organic Rankine Cycle (ORC) is the fluid used in the boiler cycle. The Rankine Cycle as described earlier uses water whereas the ORC uses an organic, high molecular mass fluid with a lower boiling point than water. The lower boiling point allows ORC to produce electricity from a low-temperature heat source such as industrial waste heat, geothermal heat or heat from a relatively simple biomass combustion system.

The temperature of the heat input from biomass combustion to an ORC is 300-350 °C compared to a Rankine Cycle requiring a heat input with a temperature of 500-600 °C. Because of the lower heat input temperature, the ORC has a lower theoretical efficiency than that of a Rankine Cycle.

The CAPEX of an ORC is lower than that of a Rankine Cycle because of the lower design temperatures and pressures, requiring less costly materials, smaller wall thicknesses and comparatively more simple designs.

Using the ORC technology compared to the Rankine Cycle, normally will improve the economic feasibility of small-scale plants, as the lower temperatures and pressures simplifies the operation and maintenance along with the reduced criteria to operating staff.

The basic ORC thermodynamic cycle and the coupling of the main components are illustrated in figure 16.

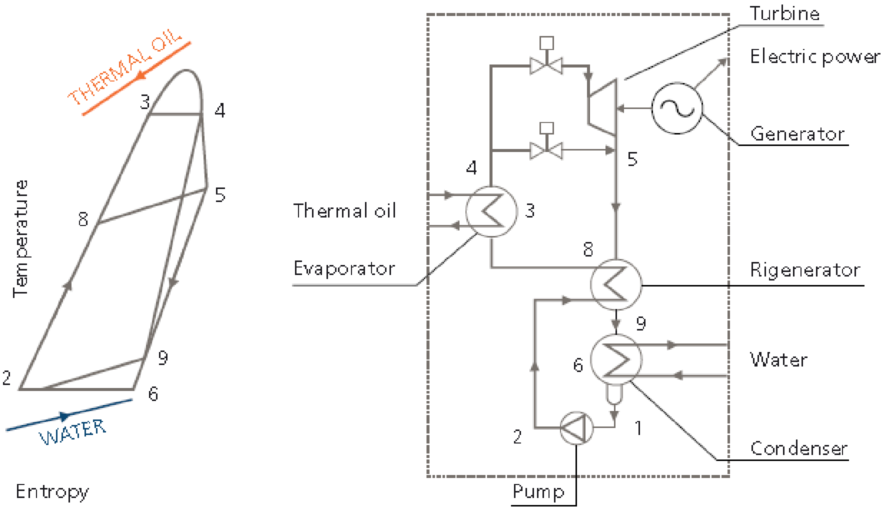


Figure 16: Principle of a typical Organic Rankine Cycle

An oil heat transfer system is often used as an intermediate cycle between the boiler and the ORC unit. This thermal fluid/oil in the heat transfer system has the advantage, over a Rankine Cycle, that it may be designed and operated at much lower pressures, which reduces CAPEX costs. A disadvantage is the flammability of the thermal fluids used, requiring ATEX classification of equipment operating with and located nearby an oil heat transfer system.

Like for the Rankine Cycle, the electrical efficiency depends on the evaporating and condensing temperatures. The higher the evaporating temperature and the lower the condensing temperature, the higher the efficiency. The correlation between condensing temperature and electrical efficiency is as illustrated in figure 17. The same cooling technologies are available for ORC as for the Rankine Cycle.

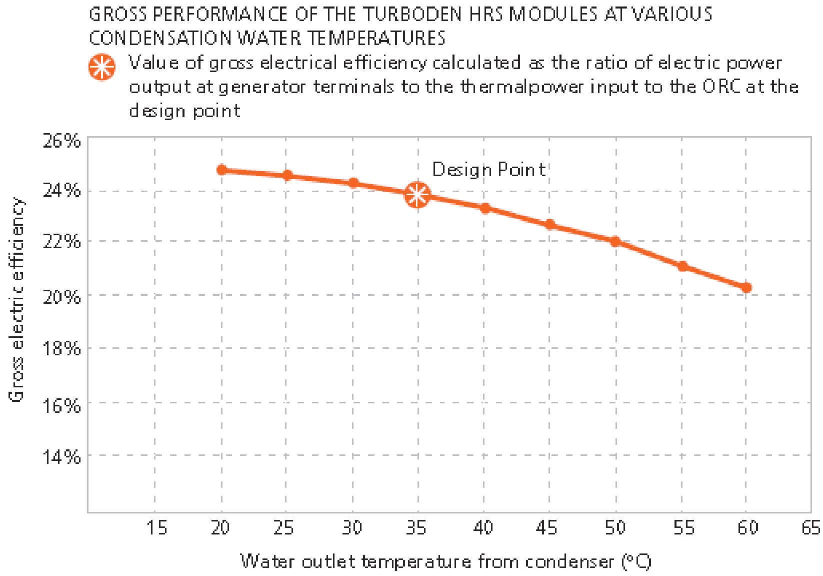


Figure 17: Illustration of the electrical efficiency as a function of cooling water temperature [4]

ORC plants can also be designed as CHP plants, where both power and heat is produced. The electrical efficiency will decrease in a CHP plant as a result of the temperatures required for heat applications being generally higher than the temperatures in the cooling circuit. However, the overall efficiency (electrical and thermal) may be much higher, at 90 %, if all low temperature heat is used.

Similar as for the water/steam cycle, these CHP projects have a stronger economy due to the income streams from both power and heat.

Figure 18: Layout of a 1 MWe ORC unit [4]

Figure 19: A 1 MWe biomass driven ORC unit [4]

ORC plant configurations and layout

Smaller ORC plants, of a few hundred kWe, units are factory assembled, simplifying the on-site installation and commissioning. Larger plants, of 10-15 MWe, are partly factory assembled and transported in modules, requiring final connection and testing to be made on-site. Figure 18, 19 and 20 illustrate examples of ORC unit layouts.

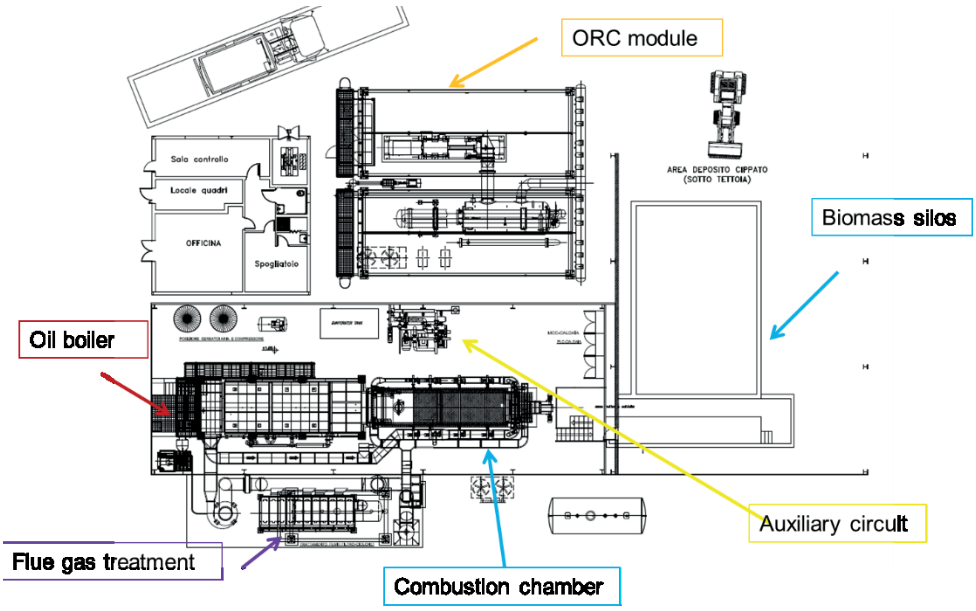


Figure 20: Illustration of the layout of a biomass ORC plant including biomass boiler, fuel silo and some auxiliary systems [4]

During project development of an ORC plant, it is important to consider all systems and utilities, as the ORC may only represent 20-30 % of the total CAPEX. An ORC plant requires the following systems:

- The ORC unit.
- Fuel yard.
- Biomass boiler.
- Flue gas cleaning.
- Ash handling.
- Thermal oil heat transfer system.
- Cooling water system and/or low temperature heat recovery system.
- Internal electricity supply and control system.
- Electrical grid connection.
- Civil works and buildings.

2.3.5 Air emissions and flue gas cleaning

Combustion of fuels produces emissions containing pollutants. This section describes the primary (combustion process integrated measures) or secondary measures (post combustion cleaning), used to reduce the pollutants emitted.

Primary Measures

The primary measures aim at optimizing the combustion and thereby minimizing the production of pollutants. Pollutants may be produced as a result of combustion temperature, biomass composition or incomplete combustion.

A combustion temperature above 850 °C for a minimum of 1.5 seconds ensures a complete combustion. If not obtained, pollutants of complex hydrocarbons, black carbon and CO may be emitted. Pre-heating combustion air and ensuring a moisture content in the fuel below 50-60 %, will normally ensure a sufficient combustion temperature. Sub-stoichiometric combustion may also cause pollutants of un-burnt hydrocarbons and result in CO in the emissions. This may be prevented by implementing staged combustion. Normally, an online analogue CO transmitter is following the CO emission in the chimney just before the flue gas is sent to the atmosphere, and an alarm is generated in case the CO level increases to an unacceptable level, normally defined in the national emission regulations.

Different biomasses contain different amounts of nitrogen from 12 % in hardwood to 2 % in some agricultural waste products. High levels of nitrogen in the biomass potentially may lead to NO_X formation. This tendency may be reduced by applying staged combustion, in which the initial sub-stoichiometric combustion tends to prevent forming NO_X, thus reducing total NO_X emissions.

NO_X emissions may also originate from the oxidation of atmospheric nitrogen. This is however only a risk when operating temperatures exceed 1400 °C and will not be an issue in biomass-fuelled plants, normally operating in the temperature range 900-1200 °C.

Normally, an online analogue NO transmitter is following the NO_X emission in the chimney just before the flue gas is sent to the atmosphere, and an alarm is generated in case the NO_X level increases to an unacceptable level, normally defined in the national emission regulations.

Sulphur and chlorine that are creating the acid flue gases HCl and SO_2 during a combustion are normally not present in biomass fuels in amounts that cause emission problems.

Finally, inappropriate boiler operation may cause pollutants (Particles, NO_X, CO) in the emissions. A control system automatically adjusting the air/fuel ratio according to the operation, considering load changes will prevent this.

Measures to enhance the combustion process are summarized below:

- Fuel quality – uniform size and (low) moisture content.
- Staged combustion – reducing NO_X formation plus VOC and CO from incomplete combustion.
- Combustion temperature > 850 ^{0}C; > 1.5 sec. to secure complete burnout.
- Adequate control system – to adapt to changes in load and fuel quality.

Secondary Measures

Whereas CO, VOC and NO_X are minimized by proper design and operation of the combustion process, dust particles and the acidic constituents are removed by secondary measures. These are defined as flue gas treatment systems, removing pollutants from the flue gas, and they are located between the combustion zone and the chimney.

Sulphur and chlorine generate the acid flue gases HCl and SO_2 during a combustion are normally not present in biomass fuels in amounts that cause emission problems. Hence, flue gas cleaning systems to remove acid gases are normally not installed on biomass power plants.

Ash, dust and particulate removal is the main purpose of flue gas cleaning from biomass combustion. Systems for dust removal are:

- Multi-cyclones
- (Venturi) Scrubbers
- Electrostatic precipitators

- Bag house filters

Multi-cyclone

A cyclone is illustrated in figure 21**Error! Reference source not found.**. A cyclone uses centrifugal forces to separate particles from gaseous streams. Multi-cyclones are batteries consisting of 8 or more single cyclones. The advantages of multi-cyclones are their high temperature tolerance and simplicity, the disadvantage is their low efficiency in regards to small particles. Multi-cyclones are often used for upstream pre-treatment.

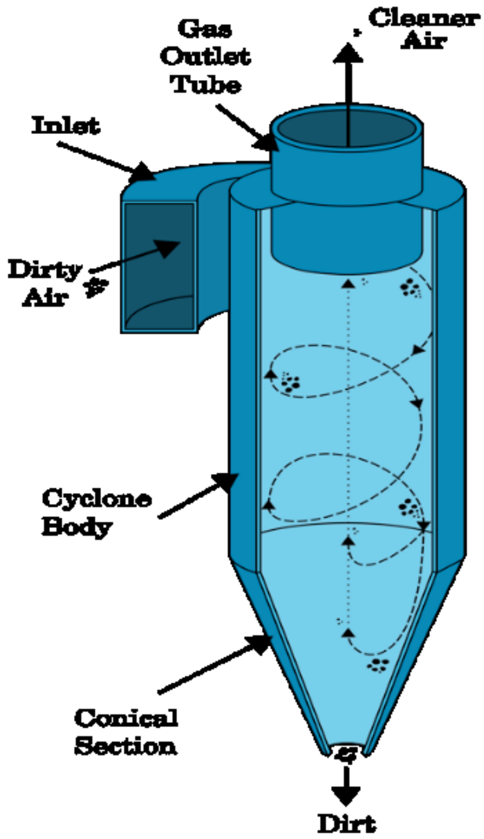


Figure 21: Illustration of a multi-cyclone [15]

Wet scrubber

Numerous types of wet scrubbers are available, among the most efficient are the venturi scrubber, as illustrated in figure 22**Error! Reference source not found.**.

A venturi scrubber consists of three sections: a converging section, a throat section and a diverging section.

The gas stream enters the converging section, in which the area decreases, forcing the gas velocity to increase.

In the throat section droplets are introduced, covering the throat walls. The high velocity gas, shears the liquid off the walls, producing droplets.

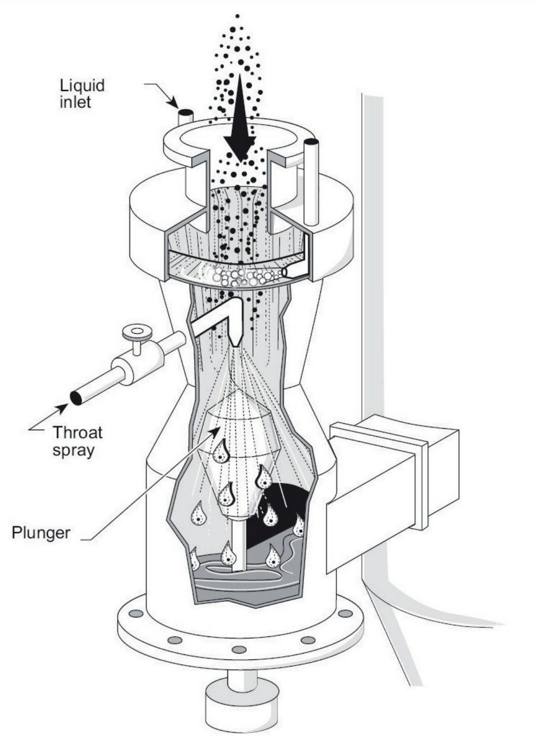


Figure 22: Illustration of a venturi scrubber [16]

In the diverging section, particles are mixed with the droplets, enabling removal of the coagulated particles from the gas stream exiting the venturi scrubber.

Electrostatic precipitators

An electrostatic precipitator (ESP) is a particle removal system using electric forces to separate the particles from the gas stream. A schematic diagram of an ESP is illustrated in figure 23.

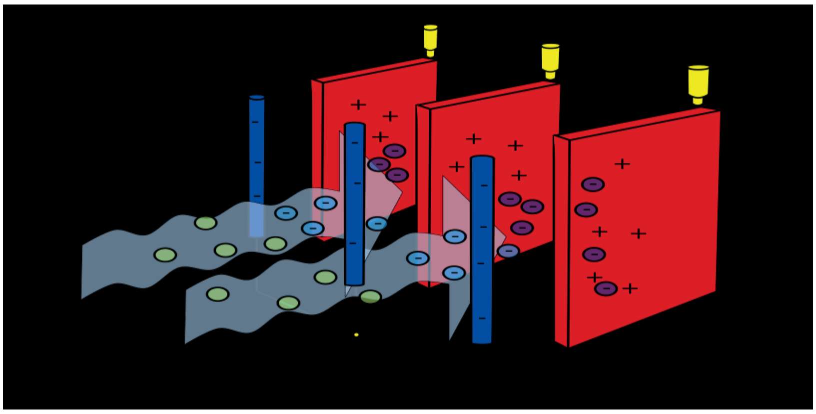


Figure 23: Detail of an electrostatic precipitator [6]

The ash/dust particles from the combustion are charged by the high voltage between the wires and plates as indicated with blue and red in figure 23. An electrical field forces the charged particles to the plates. The particles are removed from the plates by knocking them loose by an automatic hammering system and allow them to slide down into a hopper in which they are collected. This must be done without re-entraining the particles in the gas stream.

The efficiency of the ESP depends on the size distribution and resistivity of the particles. Smaller particles may obtain a lower electric charge compared to larger particles, as a result of the comparatively smaller surface. Smaller particles are therefore removed with a lower efficiency than that of larger particles. An ESP is however still more efficient than multi-cyclones.

The resistivity of the particles should be suitable for an optimal particle removal. If too low, the particles will lose their charge when they contact with the collecting plate and re-entrain into the gas stream. If too high, the particles will not be charged at all.

Bag house filters

A bag house filter is illustrated in figure 24. The filter uses physical restrains to remove particles from the flue gas. The gas passes through bags of textiles or membrane coated textiles retaining all particles above the pore size of the textile.

Cleaning of the filters is done automatically once a certain pressure drop is obtained across the bags. Cleaning has the purpose of releasing the retained particles from the bag and collecting it in the hopper below. Cleaning may be performed by mechanical shaking, reverse air or jet pulses of compressed air.

The advantage of bag house filters is the high particle removal efficiency. The disadvantage is that the flue gas must be dry and the particles non-sticky.

Emission of gaseous substances

Most gaseous pollutants in the flue gas are best handled by primary measures. NO_X emissions may however require additional removal by secondary measures in biomass fuelled plants.

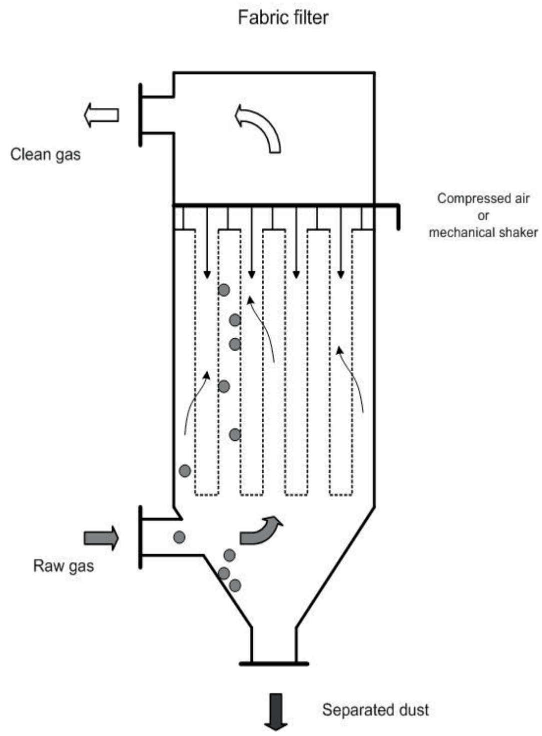


Figure 24: Illustration of a baghouse filter

NO_X may be reduced by selective catalytic reduction (SCR) or non-selective catalytic reduction (SNCR).

The SCR process normally takes place immediately before the economizer where the flue gas has the required temperature for the SCR process catalyst of 320-380 °C. Ammonia and a catalyst are used to convert NO_X to nitrogen gas.

The SNCR process takes place in the boiler by injecting ammonia directly into the flue gas, converting NO_X to nitrogen gas. This process takes place at boiler temperatures of 850-950 °C.

The advantage of SCR over SNCR is the lower ammonia consumption. The advantage of SNCR over SCR is the higher NO_X reductions, the lower investment cost and the high maintenance cost of the SCR. The maintenance cost of the SCR is a result of the high risk of degradation caused by potassium in the flue gas on the catalyst.

Systems/secondary measures for NO_X removal are CAPEX and OPEX intensive and shall only be implemented, if deemed necessary by legislation and by the ESIA outcomes.

Comparison of systems for dust removal

The table below provides a comparison between the performance and cost of the key technologies.

Table 10: Comparison of systems for dust removal

	Multicyclone	Wet Scrubber	Electrostatic precipitator	Baghouse filter
Efficiency	Low efficiency in regards to small particles	Medium efficiency in regards to small particles	High efficiency in regards to larger particles	High/very high efficiency depending on fabric filter
Application	High temperature tolerance	Retrieve energy from condensing the fluegas	Not suitable for all biomass types	Low temperature tolerance
Expected dust emission (mg/Nm³ at 6 % O_2)	200 – 400	50 – 100	10 - 50	2 – 20
Capex	Low	Medium	High	High
Opex	Medium	Medium	Medium	High

Choice of systems for emission control

The investment choices of systems for emission control are largely determined by existing and expected future regulatory requirements.

A new norm for emission from Bagasse fired plants is under development. While the new emission limits have not been finally confirmed, they are expected to enforce installation of flue gas cleaning measures on new and existing plants.

2.4 Residues and their handling

Combusting biomass in designated plants, opposed to leaving it on the fields, removes vital nutrients and acid-buffering capacities from the soil.

These nutrients and acid-buffering substances are concentrated in the ash from biomass fuelled plants. Distributing the ashes onto the fields, replaces all lost nutrients, with the exception of nitrogen, which is combusted to nitrogen gas.

The composition and volume of the ash depends on the biomass type and the amount of residual soil attached to the fuel. Hardwood logs yields the lowest amount of ash whereas straw collected from fields, which has high amounts of residual soil, have the highest amount. Typical ash amounts are 1-4 % of the dry fuel.

Ash recycling can be performed by returning the ash to the fields. Ash should preferably be returned to fields with the same crops as those from which the ash originates from and in amounts corresponding to the biomass removed. A rule of thumb is to recycle less than 3 ton ash/ha.

Annual crops may contain high concentrations of heavy metals such as cadmium, lead and zinc. Ash analysis should therefore be an ongoing procedure, ensuring that the ash complies with local regulation. Ash from biomass plant is separated into bottom ash from the boiler and fly ash from the flue gas cleaning. Fly ash contains the majority of the heavy metals and may be landfilled, whereas the bottom ash may be recycled. If permitted by the local authorities, the fly ash may be also recycled, resulting in a much lower cost.

Furthermore, biomass ash has a high pH, and may cause an uncontrolled pH shock in the fields if recycled immediately. To overcome this obstacle, the ash may be stored for a season allowing atmospheric CO_2 to react and neutralize the ash.

If the ash can neither be reduced nor recycled, it must be deposited in an approved landfill.

2.5 Electrical/DCS

For a 1-40 MWe biomass fuel unit, the main power distribution voltage level is typically given by the turbine generator terminal voltage, e.g. 10 kV AC (AC: alternating current).

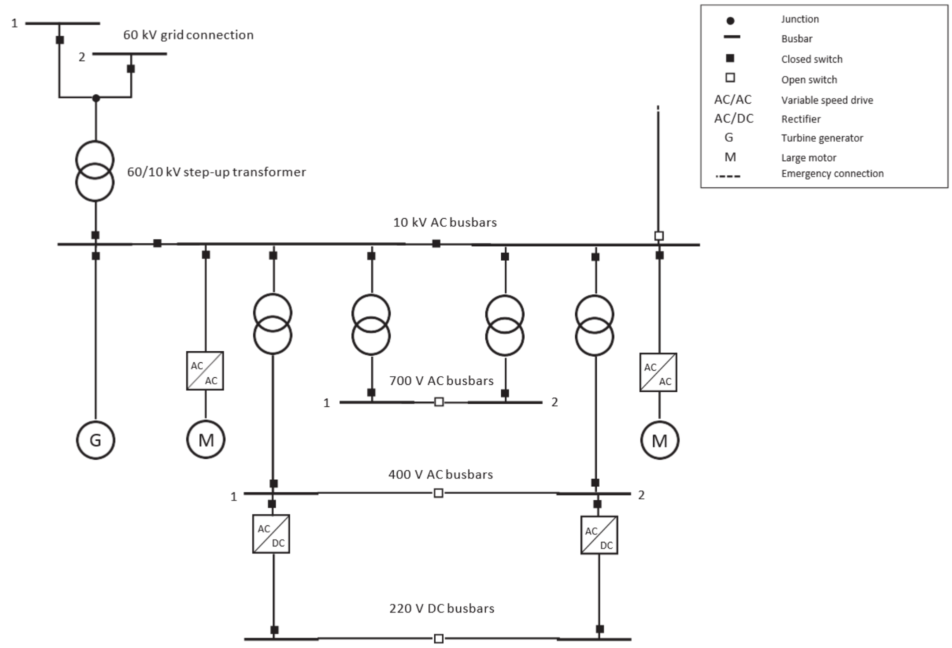


Figure 25: Simplified typical electrical single line diagram for a 35 MWe unit. No consumers are shown on the diagram except two large motors supplied by variable speed drives.

The electrical consumers are normally connected to a 700 V and a 400V system. Bigger consumers as ID fan and feed water pumps are normally connected to the 700V system, the smaller consumers to 400 V AC and 230 V AC. Therefore several distribution transformers must be used to convert from 10 kV AC to 700 V and 400/230 V AC.

In addition to the AC power systems, DC (DC: direct current) power systems are required for critical and uninterruptable services (UPS). Typical consumers are DCS, boiler safety/protection systems, fire detection, emergency lights etc. Furthermore, critical pumps and fans may also be supplied by the DC systems during a power failure, but the power demand must be relatively small. The DC power systems are during normal operation supplied by the AC systems via rectifiers. When a failure occurs in the AC systems, batteries power the DC systems.

The electrical main distribution single-line-diagram (SLD) is a key element when describing and visualizing the concepts and the design of the electrical systems. Therefore, a preliminary SLD should be constructed at the earliest possible stage of the project. The SLD is maintained and developed continuously throughout the project. At hand-over and commercial operation, it should be in an "as-built" version.

Figure 25**Error! Reference source not found.** shows a simplified typical electrical single line diagram for a 35 MWe unit with 10 kV switchgear, transformers, 700 V and 400 V distribution switchboards and rectifiers for 220 V DC systems. No consumers are illustrated in the diagram except two large motors supplied by variable speed drives. Almost all motors in the plant will be supplied via variable frequency drives because of energy efficiency requirements.

2.5.1 Grid connections

The turbine generators used for 1-40 MWe biomass fuel units are typically designed for a terminal voltage of approx. 10 kV. In the lower power range, it may be possible to make a connection directly to the local power distribution networks. In the upper power range there will typically be a need for a dedicated unit step-up transformer connecting the unit to the power distribution networks of 20-160 kV or higher voltage.

In the early project phase, it is necessary to obtain close contact and dialogue with the local grid company. When the maximum electrical power output is known, the grid company will be able to locate a point of connection in the existing networks or advice if new networks are required to absorb the power production.

The grid company's grid connection requirements shall be closely analysed as they often impose design requirements to the steam turbine, the boiler and the protection and control systems. Design of auxiliary systems for the turbine generator, e.g. the excitation system and the relay protection systems are often determined by the requirements given by the requirements from the grid company.

Finally, the requirements from the grid company often prescribes how the grid connection shall be documented and tested. Generally, the grid connection permit is obtained by proving the compliance by both calculations and simulations supported by capability testing during commissioning.

2.5.2 DCS

DCS automation for a 1-40 MWe biomass fuel unit typically consists of control system for fuel handling, control system for steam-turbine and generator, control system for boiler, and control systems for auxiliary systems such as cooling water, ash removal etc. It is preferred that most of the control systems mentioned are in a common DCS (Distributed Control System), if possible all.

Supervision and operation is made from a common control room with HMI (Human Machine Interface) for all control systems, and preferable mainly from a common DCS.

Hardware (input-, output-modules, CPU-units, interface modules, switches, relays, power supply etc.) must be built into cubicles or cabinets with sufficient and suitable cooling, and placed in rooms with sufficient cooling.

Dependent on local regulation, a 1-40 MWe biomass fuel unit may require monitoring of the flue gas and its content of NO_X, dust and maybe other contents.

In addition to DCS system and other control system, DCS Automation for a 1-40 MWe biomass plant includes instrumentation, control valves, dampers, motors and other electrical equipment. All is electrically connected to DCS and MCC (Motor Control Centre). Equipment and cables are exposed to different environments and must be able to resist negative impacts such as ultraviolet (UV) radiation, rodents eating cables, heavy rainfall during monsoon, etc.

If the plant location is far away from airport or other traffic, a remote connection for the supplier to access the DCS and other major control systems is necessary. A remote connection enables the DCS supplier to access the DCS system and assist during maintenance and prepare any major overhaul of the DCS.

However, a remote connection makes the plant vulnerable to attack via the Internet and must therefore include firewalls and other measures to protect against Internet attack.

The fuel handling area might be categorized as ATEX area. Therefore, design of cable trays, components and other electrical installation must be designed to avoid biomass dust to collect and become a source for explosions and fire.

Secondly, fire detection in the whole plant is necessary. Protection systems and interlocks must be made such that they cannot easily be overruled.

Cooling of rooms for electrical and DCS equipment must protect against dust and moisture condensing by a small overpressure. Moisture condensing must be moved away safely to avoid contact with electronic and electric equipment.

3 Co-firing of biomass and retrofit of existing boilers

Biomass

Co-firing of biomass in coal fired power plants or retrofit of existing fossil fuel fired power plants and making them capable of using biomass as a secondary fuel is very common.

The technical options or economic viability cannot be generalised, but will have to be investigated in each case.

Examples of co-firing and retrofit projects are:

- Supplementary co-firing biomass dust in coal fired PF (Pulverized Fuel) boiler
- Coal fired PF boilers converted to 100 % biomass dust firing
- Coal fired PF boilers converted to biomass BFB.
- Coal fired grate boilers converted to biomass grate.
- Natural gas/LPG/light oil fired boilers converted to biogas.

Projects in Europe and the United States, converting large-scale coal fired PF power plants of 600-800 MWe to wood pellets, demonstrate the technical feasibility of the conversion.

A full conversion will normally reduce the plant output, due to an excessively larger flue gas flow with the increased moisture contents in the biomass fuels.

A biomass with a relatively low moisture content should be chosen as substitute

Wood pellets are an expensive substitute, and it is possible to use other form for dry biomass, which then have to be divided and milled to achieve the required small particle size.

As the grinding properties of biomass differs from coal the fuel preparation system will have to be rebuilt. To avoid a reduction in capacity due to the lower calorific value of biomass compared to coal, the fuel feeding system normally will have be modified to handle the larger volumes of fuels. e. Finally, the alkaline content of the biomass should be considered to avoid inexpedient fouling and corrosion of the heating surfaces.

The technical considerations for a conversion project should include:

- New installations for fuel handling and storage.

- New installations or modifications of filters for particle removal.
- New installations or modification of ash handling.

Biogas

Biogas is an appropriate alternative for natural gas, LPG or light fuel oil. The only significant alterations would be change of burners and possibly combustion air systems. Such fuels have low contents of sulphur and ash, requiring no particular flue gas cleaning.

These projects are technical feasible solutions, but are outside the scope of this catalogue, and will not be discussed further in this catalogue.

4 Biogas plants

4.1 Feedstock for biogas production

Any organic material ready for biological degradation is a suitable feedstock for a biogas plant. Possible feedstocks may be divided into the following 5 categories.

1. Manure
2. Food waste
3. Sludge
4. Agricultural waste
5. Plant waste

Ad 1. **Manure** – is defined as manure from mainly livestock and other animals. Manure is a very suitable biomass for production of biogas in a digester. The advantages are

- no pre-treatment is required
- nutrients and hydrocarbons in the manure are available as fertilizer in the digestate after digestion,

The disadvantage is

- that easily digestible organic material have already been absorbed in the intestine of the livestock giving the manure a lower potential biogas yield.

Ad 2. **Food waste** – is defined as the left over organic material from food producing industries such as dairies, breweries, slaughterhouses, fishing industries, and the starch producing industry. This feedstock has a high potential for biogas production as it is very rich in sugars, proteins and fat. The advantage is the high biogas potential and that no pre-treatment is required before being pumped into the biogas plant.

Ad 3. **Sludge** – is defined as the sludge from flotation plants and other types of sludge. Flotation plants are normally used at slaughterhouses and where the sludge is rich in fat and proteins, yielding a very high biogas potential. The advantage of sludge as a feedstock for biogas is that no pre-treatment is required.

Ad 4. **Agricultural waste** – is defined as vegetables and fruit from agriculture. Products like corn, sugar beets, grain and fruit, can be digested in a biogas plant with a high biogas potential. These are referred to as primary biomasses, meaning that it is suitable for human consumption.

In EU the feedstock for biogas plants is limited to residues which cannot be used as food for humans, referred to as secondary biomass. Secondary biomasses have a lower biogas potential than primary biomass and usually needs pre-treatment before being pumped into the biogas plant. It might be necessary to cut these product into pieces and grind them into a pulp.

Ad 5. **Plant waste** – is defined as plant material from different productions such as grass, straw from grain, and fibres from sugar canes, palms and other plants. These biomasses have a lower biomass potential than those rich on starch and fats. They furthermore require pre-treatment before they can be degraded in a biogas plant. Because these biomasses have a strong structure of hemicellulose, this must be opened prior to entering the biogas plant, to obtain the full potential of the feedstock. It will be sufficient to grind the grass into a pulp but straw and fibres must be cut into small pieces and heated or mechanically treated in a mill, extruder or similar. This will open the cellulose to the bacteria in the digester. These types of biomass are difficult and demanding to handle before a biogas production can be obtained.

Several other biomasses might have a good biogas potential, but most will be covered in the five categories described above. An overview of the potential biogas yield from different feedstocks is as shown in **Error! Reference source not found.**.

4.2 Process flow of a biogas plant

Biogas production is the anaerobic (no oxygen) digestion of organic material into mainly CO_2, and methane. The anaerobic digestion is performed by several groups of bacteria working in symbiosis transforming the complex hydrocarbons into their oxidized form. The purpose of the biogas plant is to provide optimal conditions for the bacteria, meaning an anaerobic atmosphere, easy access to food and a temperature of 37-55 °C, depending on whether the process is mesophilic or thermophilic.

Two types of biogas plants are described in this catalogue. One type is a simple low technology biogas plant mainly used in developing countries and another type is a traditional biogas plant which is the most widespread type in the world.

4.2.1 Low-tech biogas plants

The low-tech biogas plants may be established as low cost polyethylene tube digesters. The tube digester is partly underground and partly above the ground level. The lower part of the tube is in a hole in the ground and the biomass use some 75% of the volume of the tube. The upper part of the tube is the gas holder.

In the simplest version, biomass is added in one end of the tube and digistate (digested biomass) is taken out in the other end. Feeding can be done as batch feeding or as continuous feeding. Biogas is taken out on top of the tube through a gas pipe. The tube digester is heated by the sun.

The simplest version of the tube digester is without any mixing. A simple form of mixing is by recirculation of sludge from the bottom of the digester to the top of the digester.

The low technology biogas plants are not as efficient as the traditional biogas plants since optimal and stable conditions for the bacteria cannot be obtained in the low cost biogas digesters.

Figure 26: Lagoon biogas reactor in Puebla, Mexico

The key factors explaining the low efficiency of low technology biogas plants are:

- The feeding of biomass is normally not stable and continuous. This will reduce the efficiency of the bacterial biogas production and result in low gas production.

- Mixing in a digester has two purposes. One is to bring biomass in close contact with the bacteria and the other is to release the produced small biogas bubbles from the biomass. The mixing in a low technology digester, if it is installed, will not be efficient and result in a low gas production in relation to the biomass amount available.

- The temperature in a digester shall be kept stable to obtain an optimal gas production. In the low technology digester this is not obtained since heating comes from the sun. During daytime temperature will be high and during night time the temperature will be low.

Due to the above 3 reasons the low technology biogas plants are not efficient, mainly due to the reasons that there in not sufficient possibilities to control the biogas process.

The investment costs for low technology biogas plants are low, and this might be the main reason why so many low technology plants has been established in countries with a warm climate. The low technology biogas plants do produce biogas which can be used for cooking etc., but if the same amount of biomass is fermented in a traditional and modern biogas plant the amount of biogas produced will be much higher since there are much better control of operation conditions of the digester.

4.2.2 Traditional biogas plants

The process flow of a biogas plant is as listed below.

- Collection and transportation of biomass to the biogas plant
- Storage and pre-treatment
- Anaerobic digestion
- Gas collection and combustion
- Sludge handling

The collection of biomass depends on the type of biomass and respective origin. If the biomass is agricultural waste this must be collected from the fields and transported to the plant, if however the feedstock available is sludge, it would be advantageous to locate the biogas plant nearby the sludge producing industries eliminating transportation.

Many feedstocks, particularly manure, produces odours, which may be reduced by designing an indoor unloading and storage area. Ventilation and cleaning of the air may be necessary. The biomasses, if several feedstocks are chosen, are mixed, and if required pre-treated, into a homogenous mass which is fed to the biogas reactor at an hourly rate of 1/24 part of the daily dose, to provide a stable and continuous feeding of the reactor. A mixer is normally installed in the storage tank.

Biogas reactors are constructed in steel, concrete or in developing countries as a covered lagoon. The lagoon digesters are less effective than the biogas reactors built in steel or concrete. Small units might benefit from being constructed in glass fibre. The reactor is insulated in order to maintain a stable temperature and a mixer is installed ensuring sufficient mixing of bacteria and biomass. The mixer also has the purpose of degassing the liquid and reducing the formation of floating sludge.

The size of the reactor depends on the biomass and temperature chosen. If mesophilic, 37 °C, a retention time of 20-22 is required to digest easily degradable biomass, whereas a retention time of 40-50 days is required for feedstocks like straw. The thermophilic process is faster due to the higher temperature and resulting higher degradation, and may reduce the retention time with 40 %. A heating system is installed to keep a constant temperature in the reactor.

Pressure relief valves are installed on the reactor to prevent damage of the system if a pressure builds up in the tank or to prevent vacuum caused by e.g. fast changes in pumping sludge out of the digester. During maintenance and failure of the gas engine, excess biogas will be burned in a flare.

Biogas is collected from the header of the reactor. The bulk of the H_2S and the water is removed after which the biogases are burned in a gas combustion engine for power and heat production.

Figure 27 illustrates a simple flow chart for a biogas plant.

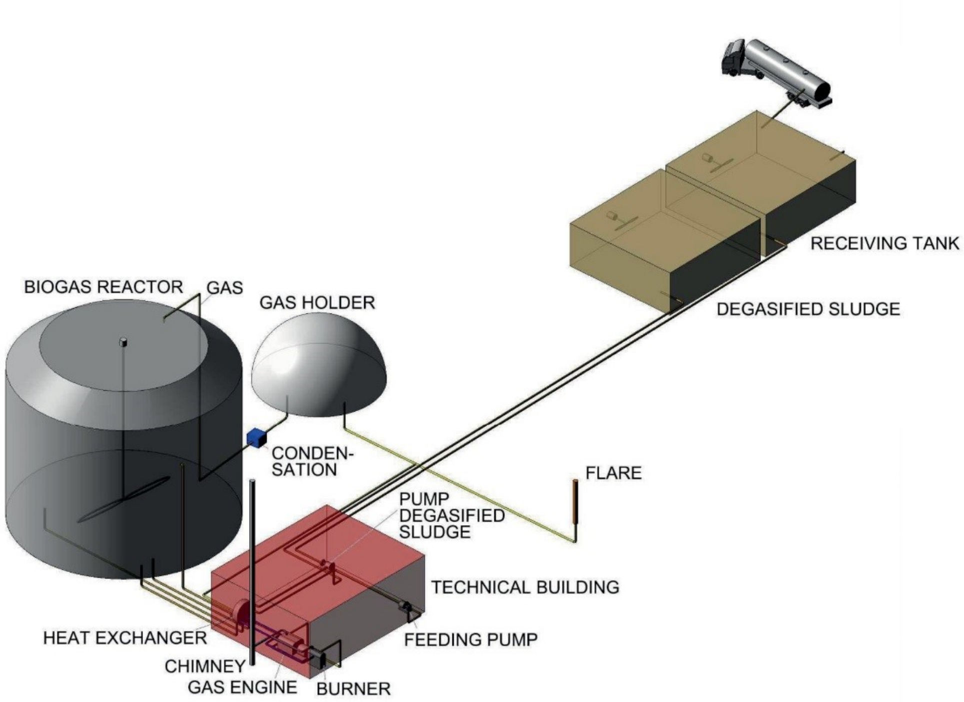


Figure 27: Process flow of a simple biogas plant [8]

A by-product from the biogas plant is the digested sludge, called digestate. The digestate contains all the remaining micro- and macro-nutrients that are not converted to biogas. The micro- and macro-nutrients are components like N, S, K etc. which makes the digestate an excellent substitution for conventional fertilizers. Furthermore, the digestate is advantageous as a fertilizer as the nutrients are more accessible for plants and crops compared to undigested biomass.

4.3 Safety and environmental issues

4.3.1 Safety

An overpressure may be built up in the reactor in cases of no gas offtake. Pressure relief valves is installed on the biogas reactor to avoid damage to personnel and equipment.

Methane, the main component of biogas, is explosive and the area around the tank and related equipment should be ATEX classified accordingly. Open fire, smoking and mechanical sparks are not accepted near the biogas tank and equipment with biogas.

The ATEX directive operate with 3 zones; zone 0 inside the digester; zone 1 on top of the digester; and zone 2 which is normally a 2 -3-meter zone around the digester.

There are two ATEX directions (one for the manufacturer and one for the user of the equipment). It is highly recommended to follow these directives, also on projects outside Europe.

According to the ATEX directive, the mechanical equipment and electronic devices must be protected against sparks, and people working in an ATEX area must follow special safety rules.

4.3.2 Environmental considerations

Using anaerobic fermentation as opposed to leaving the manure, agricultural residues or other potential biogas feedstocks on the fields is an environmental advantage. On the field, the untreated feedstocks will eventually produce methane (CH_4) and emit these to the atmosphere.

Methane is estimated to have a Global Warming Potential of 28–36 over 100 years (CO_2 has a Global Warming Potential of 1). If treated in a biogas plant, the feedstock will also be converted to methane but this is collected and combusted to CO_2, the less harmful GHG, reducing the emissions of methane.

4.3.3 Location of biogas plants

Infrastructure must be considered when locating a new biogas plant, ensuring accessibility for the trucks delivering the biomass.

Odour issues while unloading and handling the biomass must be considered to avoid unnecessary nuisance of neighbours.

5 Emerging technologies

5.1 Gasification

Gasification is a thermochemical process in which a mixture of several combustible gases is produced from biomass. The process partially combust the biomass to form hydrogen gas, CO and CO_2, by applying high temperatures and a limited oxygen supply. The partial combustion supplies the remaining heat. Gasification may convert any dry biomass, whether it is originally dry or has been dried prior to entering the process. A simplified flow diagram is shown in figure 28.

The gas may be used directly in gas engines, to produce electricity, providing a higher efficiency opposed to Rankine Cycles. This is particularly for small-scale plants of 5-10 MWe.

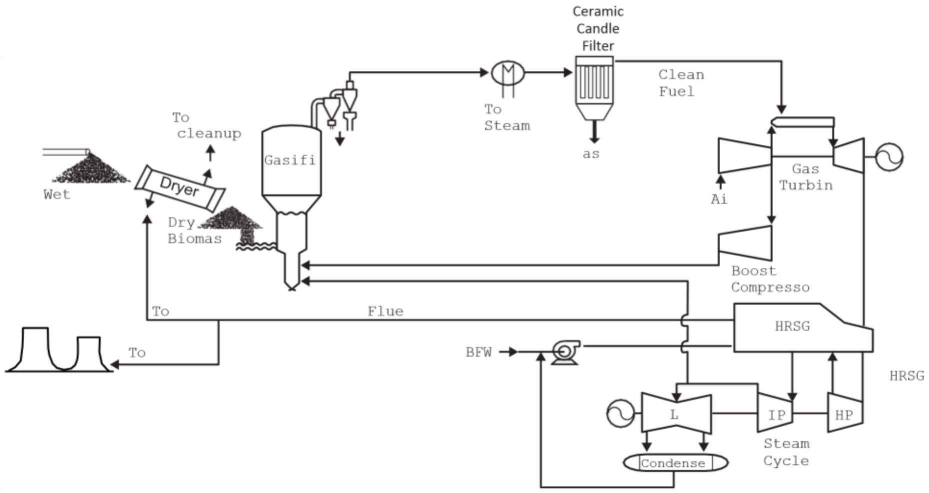


Figure 28: NREL example of biomass gasification power plant. HRSG is heat recovery steam generator and BFW is boiler feed water [9]

Gasification based systems may include heat recovery and a steam turbine (Combined Cycle) yielding a higher efficiency. The efficiency and reliability of biomass to gasification requires some confirmation, but otherwise the Combined Cycle technology, based on natural gas, has been proven.

Numerous projects with gasification as the key stone, such as the Biomass Intergrated Gasification Combined Cycle (BIGCC), is in the pipeline in northern Europe, United States, Japan and India.

5.2 Torrefaction

The torrefaction process is identical to that of conventional charcoal production, with the one difference being that more volatiles remain in the biomass feedstock. The feedstock is heated to 200-300 °C in the absence of oxygen and thereby converted into char. The intermediate products of torrefaction are as described in table 11. The product of torrefaction is black pellets with 25-30 % higher energy density than conventional wood pellets.

Table 11: Wood chips, at different steps towards "black pellets" [10, 11]

Step 1	Step 2	Step 3	Step 4
Unprocessed wood	Dried wood chips	Torrefied wood chips	Final wood pellets
Woods chips are collected and stored, so they can be used as biomass.	Woods chips are dried before they undergo the torrefaction process.	The wood chips are heated using micro wave technology within a rotating drum reactor, creating a charcoal like substance.	The torrefied wood is milled and made into pellets that produce up to 10 % to 20 % more energy than untreated one.

Black pellets may be handled, stored and processed in existing coal plants without modifications. A large-scale torrefaction plant has been demonstrated, with a capacity of 35-60 kton/year. The higher costs of black pellets opposed to wood pellets may be made up for by reductions in capital and operating costs in the combustion plant.

A critical obstacle in torrefaction is the lack of feedstock flexibility, enabling only some types of biomass to be torrefied.

5.3 Pyrolysis/thermal upgrading

Pyrolysis produces charcoal, an oil referred to as bio-oil and a fuel gas, each fraction depending on the temperature and residence time of the process. The pyrolysis process normally heats the biomass to 400-600 °C in the absence of oxygen. Pyrolysis is advantageous for long-distance transporting as it has twice the energy density of wood pellets. A schematic drawing of the pyrolysis process is as shown in figure 29.

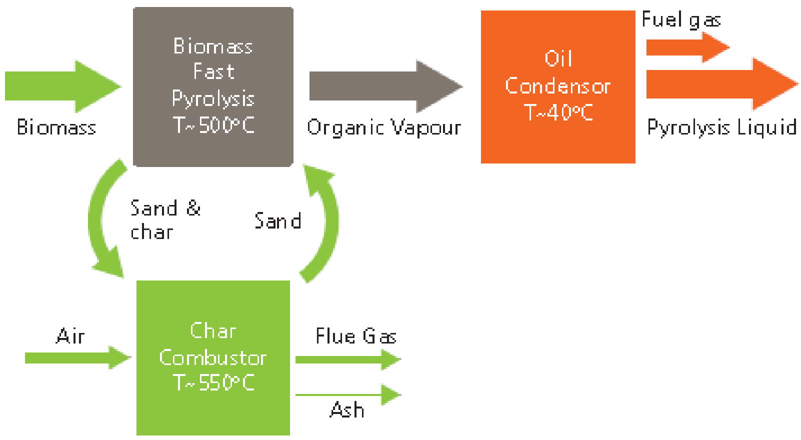


Figure 29: Sketch of a pyrolysis process

The pyrolysis technology is currently in the R&D phase heading towards the demonstration phase as indicated on Figure . The advantages, besides the high energy density, is the applicability in heat and/or power generation units or a potential upgrade to transportation fuel. The disadvantage of the technology is the relatively high content of oxygen, its long-term stability and the financial viability.

6 Technology perspective in Mexico

6.1 Opportunities

Increased use of biomass in the Mexican power supply would not only reduce the consumption of fossil fuels, but also provide a more stable and reliable electricity production compared to the intermittent electricity production from wind or solar power. The technologies described in this catalogue could therefore complement other renewable energies such as wind and solar power with a flexible electricity production.

The sugar industry in Mexico furthermore has good experience with bagasse-fired power plants, which can be utilised when establishing the new biomass power plants.

The biomasses suggested in this catalogue are accessible in Mexico in volumes that should not give significant obstacles to the fuel supply chain.

The technologies suggested in this catalogue are proven, commercial technologies which, in combination with the experience from the bagasse-fuelled power plants, should yield no unexpected obstacles or costs risking the financial security of a potential biomass to energy project.

Besides from phasing out fossil fuels, biomass to energy projects including establishing of the required fuel supply chain will create a new industry resulting in significant job creation.

Examples of the identified opportunities for increased use of biomass in the Mexican power supply are, but not limited to the listed below.

Biomass co-combustion

Co-combustion of smaller amount of biomass in large coal-fired power plants is a fairly simple way to substitute part of the fossil fuel with biomass. Substitution of coal in a PF boiler with 5 – 10 % wood pellets requires only a minor rebuilt of the fuel handling system. Against using wood pellets is the cost of pellets, and the alternative is to use a low cost biomass fuel, which then have to be processed before it can be used in the power plant.

An example of potential biomass co-combustion in Mexico is a recent feasibility study conducted under CCMEP for a 350 MWe unit at the coal-fired Petacalco power plant, where a feasibility study identified the possibility of co-combust up to 5 % processed sugarcane trash, corresponding to a yearly volume of 60.000 tons biomass. Mapping of the biomass resource confirms the availability of the biomass, however, significant transport distances are involved and a long term supply chain will have to be established.

Subject to the establishment of a reliable biomass supply chain, the business case is promising, securing good rate of return even at the competitive prices for CELs during the second long term auction in 2016.

Medium to large scale biomass combustion plants with sale to grid

Projects establishing a new medium to large scale biomass combustions plant 5 – 40 MWe, are more or less limited to areas of intense biomass production or to facilities, where large amount of biomass is handled, like the sugar industry.

The energy production facilities at the sugar mills are typically based on bagasse and are constructed as backpressure plants meaning that the electricity production is linked to the sugar process. A numbers of sugarmills have a surplus of bagasse, which could be utilised in energy production.

A feasibility study conducted under CCMEP at Ameca and El Hico sugar plant concerning new installations designed with extraction/condensing turbines, giving improved electrical efficiency and potential for export of electricity.

The long-term viability of energy sales to the grid are however dependent on the obtainable terms for grid access and sale of power.

Small scale biomass combustion plants for own use of energy

Small scale biomass combustion plants 0,5 - 5 MWe are potential seen established in connection with wood processing facilities, who have residues of sawmill dust, and in rural areas on the country site with poor electrical grids, using locally produced biomass.

Examples of potentials for small scale biomass combustion plants is found in Durango in the wood processing industry, using sawdust, forest residue and/or woodchips to produce heat and power to own purpose. The potential for realization is largest, where biomass is accessible at no or low cost.

The potentials is further described in the forthcoming report under the CCMEP "Biomass roadmap for Mexico: Assessment of potentials".

Biogas plant

There is a large potential for efficient biogas plant utilizing waste from farming or the food industry. An example of a medium size (1 -2 MW) potential biogas plant based on harvest residues, slaughterhouse waste and manure is in Guanajuato.

The potentials are further described in the forthcoming report under the CCMEP "Biomass roadmap for Mexico: Assessment of potentials".

6.2 Challenges and obstacles

The key challenges for utilization of the potential for biomass to energy production in Mexico are:

- Establishment of a biomass supply chain, which ensures long-term access to the needed quantities and quality of biomass at prices which including collection and transport are competitive with other energy sources. A potential upside in relation to the establishment of a biomass supply chain is the creation of significant employment in rural areas.

- Framework conditions for tie-in of power production to the transmission grid. For projects where the economics is dependent on sale of power to the national grid, the combination of cumbersome procedures for grid access, potential cost of capacity upgrade of the nearest substation and adjacent transmission grid, and the fall in CEL and Capacity prices at the auction during the second half of 2016 challenges the project viability. SENER is presently assessing the ability of the current technology neutral auction system to support generation from non-solar PV and wind sources such as geothermal and biomass. Green Economy Board under Economy Ministry, working on supply chains for renewable energy in Mexico, has focused on PV and wind, but are considering to extend the focus to biomass and geothermal energy.

- Ability to reach economics of scale in biogas projects is challenged by regulation limiting the joint collection of manure from several farms.

- Access to external commercial finance for biomass and biogas projects is limited by the above mentioned challenges, as well as weak balance sheets of project developers and unfamiliarity with the related project risks in the commercial banking sector.

6.3 Power plant pricing international

6.3.1 Current cost of biomass-fired power generation and key reference technologies

Investment costs

The study **Renewable Power Generation Costs in 2014** [12] underlines that a range of biomass power generation technologies are mature and that biomass is a competitive power generation option wherever low-cost agricultural or forestry waste is available. Cumulative worldwide installed capacity at the end of 2013 was around 86 GW and is anticipated to reach 130 GW by the end of 2025. Around one-third of the installed capacity is located in Europe, 29 % in the Asia Pacific region and almost 20 % in North America.

The total installed costs of biomass power generation technologies varying between USD 2,000 and USD 6,000/kW in the OECD. Costs are significantly lower in China and India where cheaper, less efficient technologies are more typical and costs range from USD 400 to USD 2,000/kW. This is illustrated in figure 30.

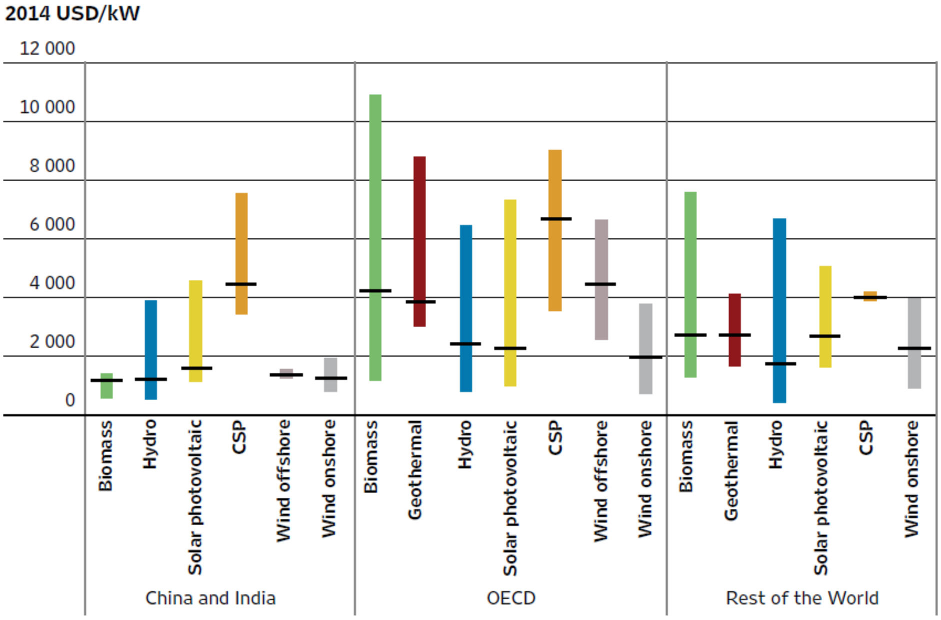


Figure 30: Typical ranges and weighted averages for the total installed costs of utility-scale renewable power generation technologies by region, 2013/2014 [12]

It should however be noted that there is significant economies of scale related to the investment costs as illustrated in the chart below from **Biomass to Energy: A Guide for Project Developers and Investors** (IFC, 2017).

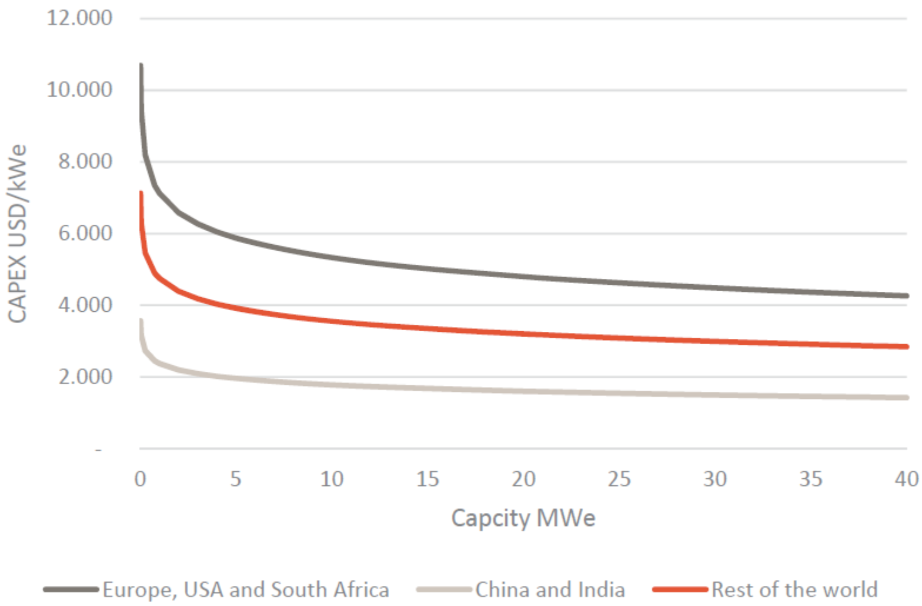


Figure 31: Variations in biomass to energy capacity cost (2016) [13]

We would expect that the technology to be applied on the biomass power plant side will be more like Europe and North America than like India and China.

Cost of biomass

Biomass power plants require sustainably sourced, low-cost, adequate and predictable biomass feedstock supplies. The range of costs for feedstocks is highly variable, from zero for wastes produced as a result of industrial processes to potentially high prices for dedicated energy crops if productivity is low and transport costs are high. More modest costs are incurred for agricultural and forestry residues that can be collected and transported over short distances, or are available at processing plants as a by-product. Collection and transport costs dominate the costs of feedstocks derived from agricultural and forest residues.

IRENA 2015 [12] finds that spot prices for wood chips on the North American markets ranged between USD 5.5 and USD 6.6/GJ in July 2014 and forward prices in the European markets ranged between USD 8.2 and 8.4/GJ in March 2014. Outside Europe and North America, biomass costs for most projects can range from negligible for agricultural or forestry processing residues, up to USD 2.25/GJ. They may sometimes exceed these values and rise to as much as USD 4/GJ where additional feedstocks are purchased to achieve higher capacity factors.

Operations and maintenance costs

Biomass-fired power generation operations and maintenance costs are assessed in IRENA [12].Fixed operations and maintenance costs for biomass power (Stoker/BFB/CFB boilers) are in the order of 2-6 % of CAPEX/YEAR while variable operations and maintenance costs are relatively low in the order of 4-5 USD/MWh.

Capacity factors and efficiency

Biomass-fired power generation capacity factors and efficiency are surveyed in IRENA [12]. Technically, it is possible for biomass-fired electricity plants to achieve capacity factors of 85-95 %. In practice, most plants do not regularly operate at these levels. Feedstocks may be a constraint on capacity factors in cases where systems relying on agricultural residues may not have year-round access to low-cost feedstock and buying alternative feedstocks might make plant operation uneconomical. The assumed net electrical efficiency (after accounting for feedstock handling) of the prime mover (generator) averages around 30 %, but varies from a low of 25 % to a high of around 36 %. In developing countries, cheaper technologies and poor maintenance sometimes result in lower overall efficiencies that can be around 25 %, but many technologies are available with higher efficiencies, with 31 % for wood gasifiers to a high of 36 % for modern well-maintained stoker, circulating fluidised bed (CFB) and bubbling fluidised bed (BFB).

Levelled costs of electricity (LCOE)

Biomass can provide dispatch able baseload electricity at very competitive costs. IRENA [12] shows that the regional or country weighted LCOE ranged from a low of USD 0.04/kWh in India and USD 0.05/kWh in China to USD 0.085/kWh in Europe and North America reflecting a more sophisticated technology with more stringent emissions controls and higher feedstock costs. The average LCOE for the rest of the world is in the order of USD 0.06/kWh.

6.3.2 Cost reduction potential to 2025

Significant reductions in the price for solar PV and wind capacity in the recent years has meant, that these renewables are now the getting increasingly economic competitive to fossil based power generation.

IRENA [12] shows that solar PV module prices in 2014 were around 75 % lower than their levels at the end of 2009 and between 2010 and 2014, the total installed costs of utility-scale PV systems have fallen by 29 % to 65 %, depending on the region. As a consequence, the LCOE of utility-scale solar PV has fallen by half in four years and the most competitive utility scale solar PV projects are now delivering electricity for just USD 0.08 per kilowatt-hour (kWh) without financial support, compared to a range of USD 0.045 to USD 0.14/kWh for fossil fuel power. This is illustrated in figure 32.

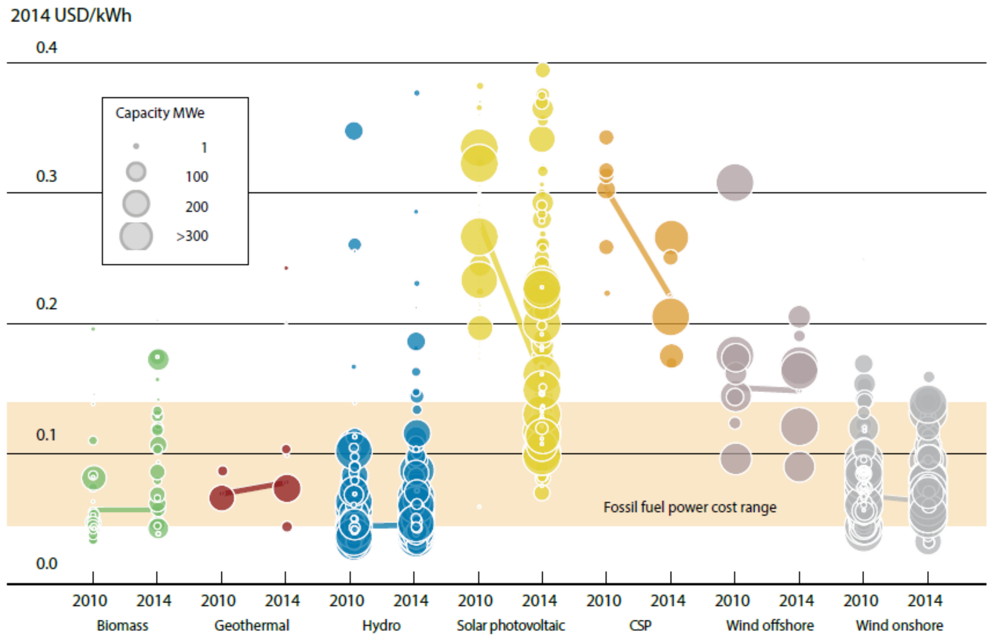


Figure 32: The levelled cost of electricity from utility-scale renewable technologies, 2010 and 2014 [12]

LCOEs of the more mature renewable power generation technologies – biomass for power, geothermal and hydropower – have been broadly stable since 2010. However, where untapped, economic resources remain, these mature technologies can provide some of the cheapest electricity of any source.

Looking forward to 2025, the technologies with the largest cost reduction potential are CSP, solar PV and wind. Hydropower and most biomass combustion and conventional geothermal technologies are mature and their cost reduction potentials are not as large. Figure 33 presents the cost ranges for wind, solar PV, concentrated solar power (CSP), geothermal and biomass today as well as projections for 2025.

For onshore wind, the lower end of the LCOE range does not shift significantly, given the already very competitive costs of today's most competitive projects.

However, depending on where new installed capacity is built, the installed cost reductions projected will significantly lower the weighted average LCOE.

The typical LCOE range for solar PV will decline from between USD 0.08 and USD 0.36/kWh in 2014 to between USD 0.06 and USD 0.15/kWh in 2025.

The potential for reduction in LCOE for CSP is substantial subject to improving the current investment climate and longer-term commitments to policy support measures that can underpin deployment and learning. By 2025, solar towers could be producing electricity for between USD 0.11 and USD 0.16/kWh on average.

Biomass technologies will not see the lower end of their LCOE range shift significantly by 2020, given that today’s cheapest options rely on low capital costs and on very cheap or even free feedstocks. However, for less mature technologies such as gasification, capital cost reductions will drive down the upper end of the range.

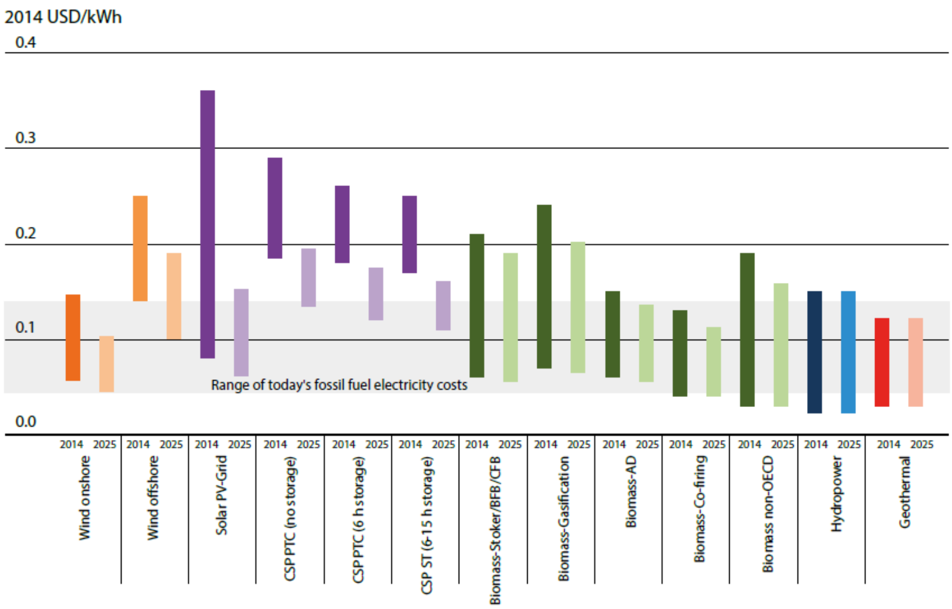


Figure 33: LCOE ranges by renewable power generation technology, 2014 and 2025 [12]

6.4 Datasheets

Datasheets with technical data, emission data and financial data have been developed for different size and type of biomass plant and for reference power production plants, indicating the average values in OECD. These datasheets are enclosed in Appendix 2.

Mexican data have been collected from literature, questionnaires to stakeholders and direct interview with project developers, plant owners and suppliers. It has only been possible to achieve partly information and the cost prediction are done by extrapolation and using known relations of cost and plant size/complexity.

In figure 34 is an overview of newer identified Mexican biomass to energy project references.

Fuel	Sector	Realized /project	Type of plant	Size (MW)	Electrical efficiency (%)	Description	CAP 1
Straw	Agroindustry (palm oil processing)	Under Realization	Condensing /Extraction	3	13	Indian turbine Mexican boiler	1,
Straw		Project	Condensing	2	19	Brazil boiler	4,
Straw		Project	Condensing	40	26	Brazil boiler	2,
Wood	Forest industry	Under Realization	Condensing/ Steam engine	0,5		American boiler	3,
Bagasse	Sugar industry	Realized	Backpressure	5	12		2,
Bagasse	Sugar industry	Under Realization		40		Indian boiler Brazil turbine	1,
Co-firing	Power generation	Project	Condensing	17	35	Sugarcane husk at Petacalco	0,

Figure 34: Mexican biomass to energy project references

Notes:

1) Level of Capex in mill. USD/MWe excluding landprocurement and preparation, gridconnection and cost of finance.

The information for biomass plant is limited, while for reference technologies (natural gas, coal, wind and PV), there are more comprehensive information available for Mexican plants.

Based on the available information for Mexican plant and forecast of development of unit invest cost (CAPEX) a comparison has been made in the figure 35 of the unit investment cost (CAPEX) for energy plants in Mexico with average investment cost in OECD in year 2020.

For biomass plant in the range 1 – 40 MW, the unit investment costs (CAPEX) and operating costs (OPEX) identified for Mexico are significantly lower than the average in OECD.

This mainly reflects a sourcing strategy focussed on investment cost reduction. Such a sourcing strategy yields very competitive unit costs, but may also encourage the installation of plants with lower technical standards than in other OECD countries. A consequence may be lower availability, shorter lifetime, lower fuel efficiency, high level of maintenance and increased emission compared to plants in OECD.

Fuel	Size (MWe)	Type	Mexico	OECD
Straw	1 - 5	Backpressure	3,0	5,0
	5 - 10	Condensing	2,5	4,0
	10 - 50	Condensing	2,0	3,0
Woodchips	1 - 5	Backpressure	3,0	5,0
	5 - 10	Condensing	2,5	4,0
	10 - 50	Condensing	2,0	3,0
Bagasse	1 - 5	Backpressure	3,0	5,0
	5 - 10	Condensing	2,5	4,0
	10 - 50	Condensing	2,0	3,0
ORC, biomass	1 - 5	Backpressure	3,0	5,0
	5 - 10	Condensing	2,5	4,0
Biogas	1 - 5	Reactor	2,5	4,0
Coal	350	Condensing	1,5	2,0
N-gas turbine	5 - 40	Single stage	0,6	0,7
	100 - 500	Combined cycle	0,8	0,9
Wind	3 - 5		1,1	1,1
PV	5 - 40		1,0	1,0

Figure 35: Estimated CAPEX year 2020 in mill. USD/MWe [10]
(Capex excluding land procurement and preparation, grid connection and cost of finance)

For large coal fired power plants and for natural gas turbines, CAPEX and OPEX for Mexico is slightly lower than the average in OECD.

For these plants there is no low-tech solutions, the equipment is from the same international suppliers as used by other OECD countries and the slightly lower CAPEX and OPEX is mainly due to the lower cost level for civil works and staff in Mexico.

For photovoltaic (PV) and wind, CAPEX and OPEX for Mexico is similar to the average in OECD. The equipment is from main international suppliers, and the major part of the plant cost is the equipment.

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Appendix A Biomass characterization

No.	Biomass	Conversion Technology	Net Calorific Value (MJ/kg)	Biogas Potential (Milliliters of methane / grams of volatile solids)	Bulk Density (kg/m³)	Moisture Content (Traded Form) (w–%)
1	Wheat straw	combustion / fermentation	16.6–20.1	240–440	20–40 (loose) 20–80 (chopped) 110–200 (baled) 560–710 (pelletized)	10–30
2	Barley straw	combustion / fermentation	18.9	240–320	20–40 (loose) 20–80 chopped) 110–200 (baled) 560–710 (pelletized)	15 (5–35)
3	Sugarcane bagasse	fermentation / combustion	16.7 (15–19.4)	72–200	130 (120–160)	50 (48–53)
4	Corn cobs	fermentation / combustion	14	330	160–210	8–20
5	Cereal straw	combustion / fermentation	14.8–20.5	245–445	20–40 (loose) 20–80 (chopped) 110–200 (baled) 560–710 (pelletized)	15 (8–25)
6	Logging residues. coniferous	combustion	18.5–20.5	not relevant	300 (270–360)	35–55
7	Chicken manure	fermentation / combustion	9–13.5	156–295	230	6–22
8	Dairy manure	fermentation / combustion	no data	51–500	depending on moisture content	10–75
9	Swine manure	fermentation / combustion	no data	322–449	depending on moisture content	10–85
10	Sewage sludge	fermentation / combustion	7–15	249–464	depending on moisture content	55–96.5
11	Empty fruit bunch	combustion / fermentation	11.5–14.5	264	100–200	61–72

Appendix B Data Sheets

Straw fired boiler 1-5 MWe

Straw fired boiler 5-10 MWe

Straw fired boiler 10-40 MWe

Wood chip fired boiler 1-5 MWe

Wood chip fired boiler 5-10 MWe

Wood chip fired boiler 10-40 MWe

Bagasse fired boiler 1-5 MWe

Bagasse fired boiler 5-10 MWe

Bagasse fired boiler 10-40 MWe

Biomass fired ORC 1-5 MWe

Biomass fired ORC 5-10 MWe

Co-firing at a coal fired power plant

Biogas plant 1-5 MWe

Coal fired power plant

Gas turbine (Single cycle)

Gas turbine (Combined cycle)

Photovoltaic (grid connection system)

Wind turbines