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**RES-FC Market
Status and cost of the technology
options
Final report**

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ECN

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Contents

List of figures	3
1 Introduction	4
2 Methodology	5
2.1 3 Scenarios for H ₂ production to RES-FC Market	5
2.2 Case 1: Biogas to CHP.	6
2.3 Case 2: Biomass and Wind to CHP	7
2.4 Case 3: Only wind to CHP	8
3 Results	10
4 Conclusions	13
Appendix 1 Use of biogas for residential fuel cells	14
Appendix 1.1 The biogas process	14
Appendix 1.2 Conditioning of biogas	20
Appendix 1.3 Reforming of biogas	29
Appendix 1.4 Conditioning of reformat	30
Appendix 1.5 Use of Biogas in Fuel Cells – current situation in Germany	30
Appendix 1.6 References	32
Appendix 2 Technical and Economical description of the combined Methanol and Ethanol Plant	34
Appendix 2.1 Flow-sheet	42
Appendix 2.2 Methanol Consumption for a Region	43
Appendix 2.3 Commercial available methanol reformers/crackers	44
Appendix 3 Description of case 3 (only wind to CHP)	45
Appendix 3.1 Economical information of case 3 (only wind to CHP)	49
Appendix 4 Identification of electrolyser- technologies	53
Appendix 4.1 Electrolyser market, Western and Eastern	57
Appendix 4.2 Barriers: Prices, Efficiency, CE-Marking, Safety	67
Appendix 5 Status on Balance of Plant components.	72
Appendix 6 Memo on near-commercial fuel cell CHP technology	78

List of figures

Figure 1: Case 1 Biogas to CHP.....	6
Figure 2: Case 2 Biomass and wind to CHP	7
Figure 3: Case 3 Only wind to CHP.....	8
Figure 4: Stages of methanogenesis [modified after 10, 15].....	14
Figure 5: General scheme of the biogas production	17
Figure 6: Production of biogas in time delayed operated dry fermentation boxes	19
Figure 7: Exemplary layout of a scrubber under high pressure [5].....	26
Figure 8: Exemplary set-up of a pressure swing adsorption	28

List of tables

Table 1: Content of the technology description from the partners:.....	9
Table 2: Overview of cost and performance of the technology for the different options.	11

1 Introduction

The EU-project "RES-FC Market" aims to define market conditions and identify opportunities to accelerate the introduction of fuel cell household systems (FCHS) for cogeneration of heat and power (CHP) that use energy carriers from renewable energy sources (RES). This concept may help reduce CO₂ and other emissions related to energy use in households. For the market development it is essential that initial customers are identified and that by application of the FCHS the cost of the system decreases. The main objective of the project is to identify an aggregated market of 3000 RES-FCHS units to be realised in the near future. To this end 10 markets in 7 regions will be investigated that have been identified upfront as potentially interesting. "RES-FC Market" aims to accelerate the development and rate of cost reduction of FCHS by combining the initiatives and opportunities in various regional markets so that enough market pull will be generated to get FCHS developers to start producing systems in series.

Work package 2 of the project is divided in two parts:

1. State-of-the-art of RES-FCHS technology
2. Describing potential regional markets

This report forms the first part and describes the state-of-the-art of the renewable energy technologies, the hydrogen production techniques using these renewable energy sources and the fuel cell based CHP units considered in the project.

The report from the second part will describe the status of potential regional markets in Jutland (Denmark), Schleswig Holstein and Baden-Württemberg (Germany), Reykjavík area (Iceland), Coimbra region (Portugal), Navarra and Basque (Spain) and North Friesland (the Netherlands) for the conversion of renewable energy sources (RES) into hydrogen for household fuel cell (FC) applications.

2 Methodology

2.1 3 Scenarios for H₂ production to RES-FC Market

In this project the primary energy sources that will be considered are:

- I. Organic matter suitable for biogas production
- II. Biomass in general
- III. Wind Energy, especially “excess wind”

In order to develop an aggregated market it is important to have some standard procedures and processes to convert the above mentioned energy sources into heat and electricity, and hence the following 3 standardised processes have been suggested:

Case 1: Biogas to CHP (see Figure 1)

Case 2: Biomass and Wind to CHP (see Figure 2)

Case 3: Only wind to CHP (see Figure 3)

In the first project meeting the outline for the fuel cell CHP system was decided. It was decided that the specification for the fuel cell system would be the same for all systems in order to take advantage of the scale effect on the cost reduction to come to an aggregated market. The chosen application was a CHP unit for a single household with a power output comparable to the average electric power demand of the household. The fuel from the system described by case 3 is pure hydrogen and this will be the fuel of choice. The hydrogen product is fed into a standard CHP for households, operating on pure H₂ and delivered by a H₂ grid. Colours are added in the figures for highlighting the activity distribution between partners (Table 2). Due to the high power/heat ratio for fuel cells and the hydrogen as an energy carrier, the hydrogen/fuel cell system is best suited for districts with new houses with a low heating demand.

The starting specification of the fuel cell CHP system is:

Electrical power:	0.5-1 kW _e
Fuel cell type:	PEMFC
Fuel type:	pure Hydrogen
Heating power:	0.5-1 kW _e
Operating temperature:	70-80°C

2.2 Case 1: Biogas to CHP.

Biogas is produced in a biogas plant converting organic matter (manure) into biogas. The biogas is cleaned/upgraded to natural gas standard and mixed into the existing NG-Grid. The biogas/natural gas is transported by the existing natural gas grid to a region containing say minimum 300 households that are or will be equipped with fuel cell systems for combined heat and power supply. The natural gas/biogas is reformed to pure H₂ at a central reforming station located close to a cluster of households. The hydrogen is transported from the reformer station to the household through a new hydrogen grid. The hydrogen is converted to heat and electricity by a fuel cell CHP in the household.¹

Case 1: Biogas to CHP
Responsible: IBBK

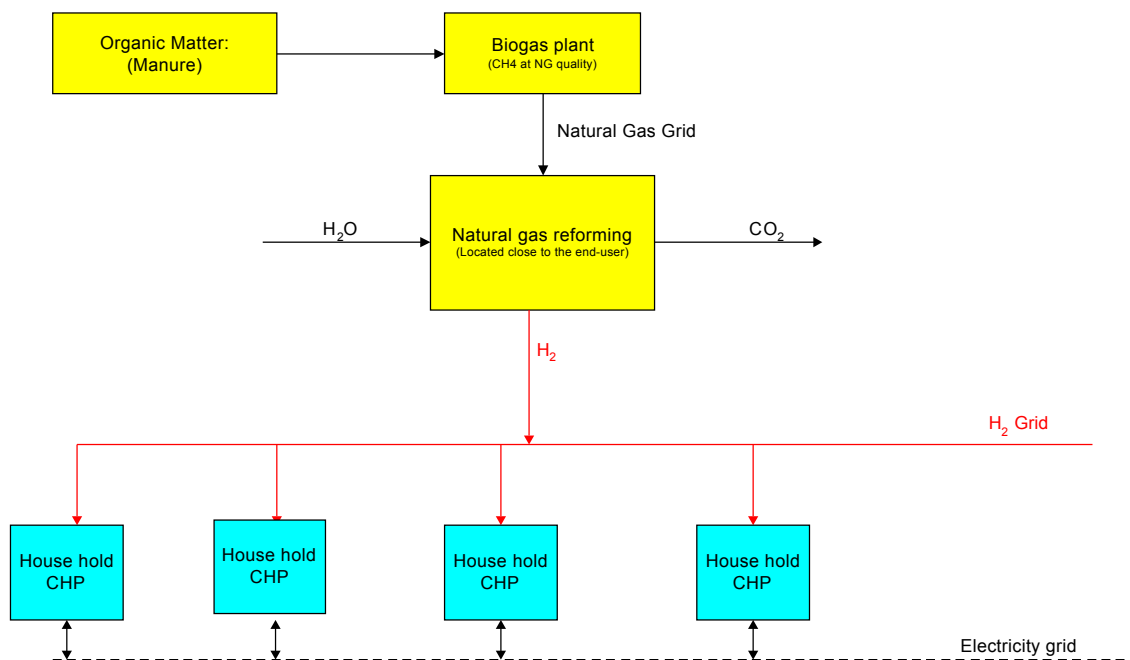


Figure 1: Case 1 Biogas to CHP

¹ In Europe some Sulphur containing compounds are added to the natural gas grid, in order to be able to smell any leakages. This sulphur will most likely deactivate the catalyst used for natural gas reforming, and hence it has to be removed prior to the reforming of natural gas into hydrogen.

2.3 Case 2: Biomass and Wind to CHP

Methanol and ethanol are produced in a plant converting biomass and electricity into methanol and ethanol. The ethanol is produced by fermentation of biomass. The by-product from the fermentation which is called the non-fermentable is gasified with pure O_2 into a mixture of H_2 , CO and CO_2 . The O_2 is delivered by an electrolyser unit². Hydrogen from the electrolyser is mixed into the gas exiting the gasifier. The gas mixture is used to produce methanol, which is stored as a liquid under normal conditions. The methanol is transported by truck to a local storage and reformer station located close to the cluster of households that are or will be equipped with fuel cell systems for combined heat and power supply. The methanol is reformed to pure H_2 . The hydrogen is transported from the reformer station to the household through a new hydrogen grid. The hydrogen is converted to heat and electricity by a fuel cell CHP in the household.

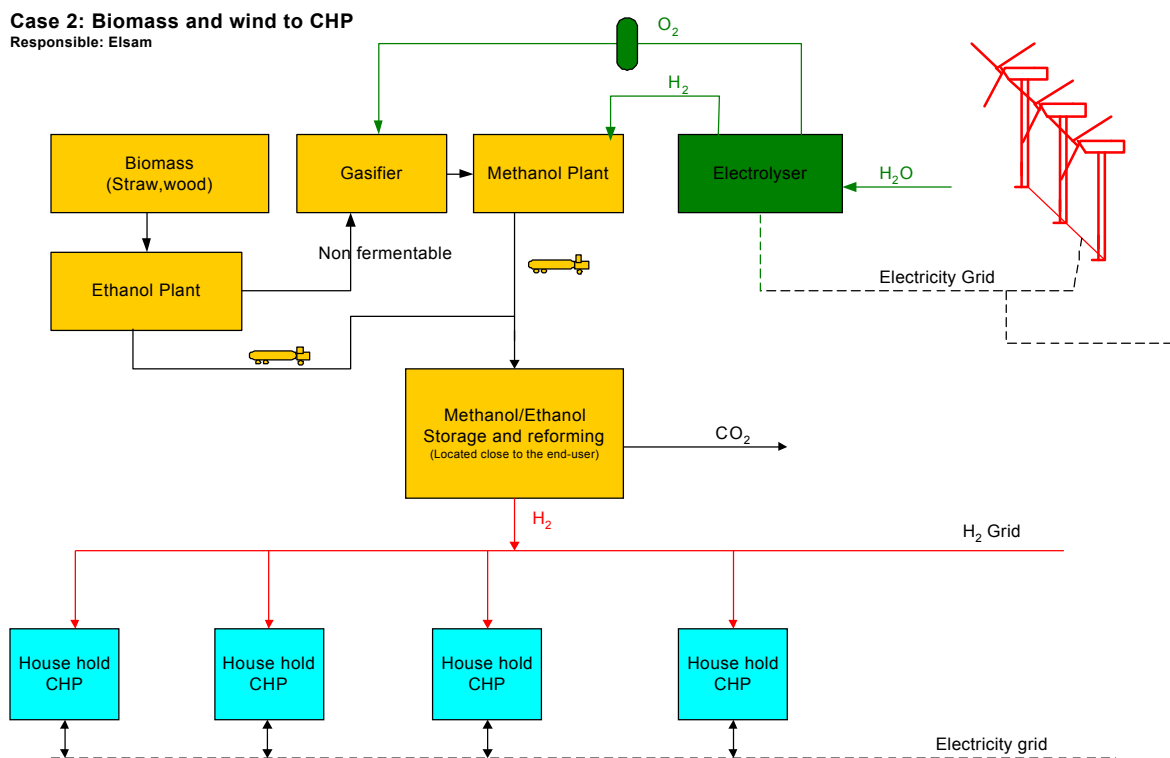


Figure 2: Case 2 Biomass and wind to CHP

² The electrolyser is assumed to operate almost constantly, but will be closed down in the peak hours where the electricity is most expensive. The electrolyser may be used to regulate the electricity grid, and offering a way to integrate/implement more fluctuating renewable energy sources such as wind power in the electricity grid.

2.4 Case 3: Only wind to CHP

Hydrogen is produced from electricity, through an electrolyser unit, located close to a cluster of households that are or will be equipped with fuel cell systems for combined heat and power supply. The electrolyser is assumed to operate almost constantly, but will be closed down in the peak hours where the electricity is most expensive. The electrolyser may be used to regulate the electricity grid, and give room for more fluctuating renewable energy as wind power. The size and type of the hydrogen storage needs to be discussed. (daily / weekly storage). The electrolyser and the fuel cell are not supposed to operate at the same time since that would convert 2/3 of the electrical energy instantaneously into heat. The produced hydrogen is stored in a hydrogen storage located close to the electrolyser. The hydrogen is transported through a new hydrogen grid from the hydrogen storage to the households. The hydrogen is converted to heat and electricity by a fuel cell CHP in the household.

Case 3: Only wind to CHP
Responsible: CENER

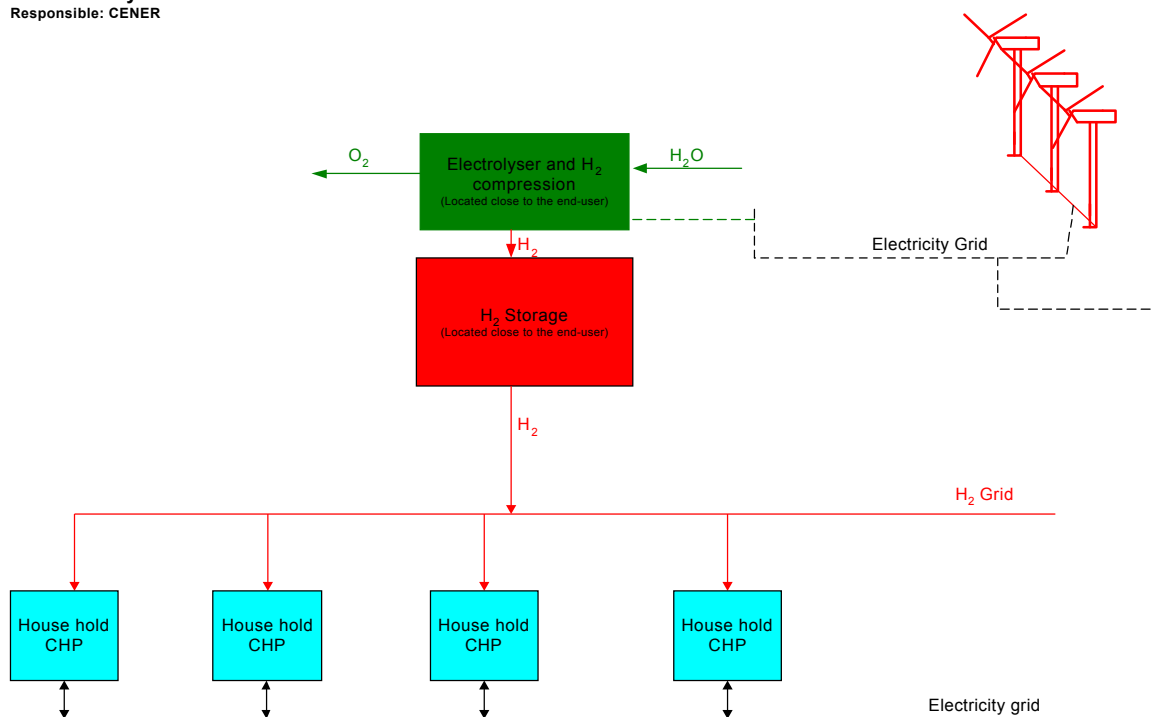


Figure 3: Case 3 Only wind to CHP.

Next to these descriptions, a cost estimation has to be obtained for each of these cases based on an aggregated market. The assumption for the aggregated market for the fuel cell and the fuel cell system are 3000 units of 0.5 to 1 kW_e. The assumption for the first regional markets is 100-500 units per region, giving a sizing for the different cases in the order of 100 kW to 1 MW primary energy input.

Table 1: Content of the technology description from the partners:

Appendix	Activity	Partner
1	Manure collection, Biogas production, Biogas upgrading to a quality sufficient for feeding the biogas into the natural gas grid; Desulphurization Steam reforming of biogas (natural gas); H ₂ separation	IBBK (yellow)
2	Biomass collection (Electrolysis, extensively described in A) Syngas production Methanol production Ethanol production (M) ethanol distribution (M) ethanol steam reforming H ₂ separation	Elsam (orange)
3	Electricity from wind (fluctuations) H ₂ compression H ₂ storage H ₂ grid/distribution	Cener (red)
4	AC/DC conversion Electrolyser Intermittent operation/control	BIC (green)
5	Fuel cell system DC/AC conversion H ₂ safety Heating application Intermittent operation/control	Dantherm (blue)
6	Hydrogen fed fuel cell stack Cathode air preparation Water cooling	IRD (part of blue)

For the cost estimation of the hydrogen produced and for the electricity and heat produced by the fuel cell system, the partners were provided with the questionnaire used as a starting point for gathering the necessary information. If possible, further elaboration of the questionnaire with technical or delivery terms items can be provided in order to be able to make a better comparison between different suppliers.

3 Results

The partners provided the descriptions of the 3 cases for conversion of the renewable energy sources biogas, biomass and wind into hydrogen for fuel cells, and the descriptions of the technology status for the conversion steps. It was difficult to obtain cost information on the technology and especially for the cost projections. An overall view of the cost of the technology options is provided in Table 2. For electrolyzers the cost/kW_e strongly depends on the size of the electrolyser. For ethanol reformers no suppliers could be found.

The renewable pathway of biomass to methanol conversion is still in the development phase, but the cost projections are encouraging. Both Germany and Denmark have pilot plants in operation. Methanol itself can be easily obtained and is an easily distributed fuel. Today, it is primarily made from natural gas, but with increasing need of integration of renewable energy, methanol will gradually be made from this. Methanol reforming will then still be an option, however, cost reduction for methanol reformers are required. Cracking of methanol into hydrogen is, however, a relatively easy process. The producers of FCHS see a potential market for methanol fuelled FCHS in areas with no district heating or natural gas network. Alternatively, in the Netherlands a methanol plant (now BioMethanol Chemie Holding (BV) in Delfzijl) is adapted in order to use glycerine, a by-product from the biodiesel production, as the base material for methanol production. The expected production rate is 800.000 ton of biomethanol per year. Ethanol from biomass is an established process. Ethanol for energy purposes is applied as an additive for gasoline, in order to reach the EU goal of 5.75% renewables in 2010.

The process for obtaining biogas is well known and many units are already installed. The biogas purification and upgrading route to natural gas (NG) quality is feasible, the reforming step is then in principle natural gas reforming, a well-known technology on large scale. Because of the assumption that PEM fuel cells operating on pure hydrogen will be used, the reformat gas will need a hydrogen purification step.

The most common way of utilizing biogas today is to burn it, at the production site, in internal combustion engines. This use of biogas has an efficiency of approximately 40% electricity and roughly 20-25% non process heat, which can be utilized externally through a district heating network. Since the latter route at the moment is significantly cheaper than upgrading and installation of fuel cell systems this route is the obvious choice in locations with district heating networks.

The application "biogas to MCFC fuel cells" without the upgrading of the biogas is also an apparent option in areas with district heating network due to lower number of process steps relative to the PEM route. If this is to be used for household cogeneration, a heat distribution network is necessary since the MCFC units are 250 kW+, much larger than needed in household applications.

The "PEM route" we are investigating in this study has an overall energy efficiency of 0,77 (losses in upgrading) * 0,85 (LT PEM with decentral reforming and heat recovery) which equals a total efficiency of 65% (30% electricity and 35% heat) which is

comparable to the traditional route. However, taking regional perspectives into perspective then there are several areas in Europe with rising biogas production and no district heating - but with natural gas grids - where it is an obvious and energy efficient choice to experiment with biogas upgrading and use of the upgraded gas in FCHS.

Cost reduction and lifetime improvement of reformers for use with biogas/natural gas are still required for commercialisation of the reforming route.

Wind turbines are a mature technology and are important for the increase of renewable energy part of the energy supply chain. For large participation of wind electricity in the electrical network, a solution is needed for the imbalance between the stochastic supply of electricity wind energy and the electrical demand.

Electrolysers are suitable for intermittent operation because they should only operate when electricity is cheap. If customers require “green” hydrogen and are prepared to pay for that “green” hydrogen, or are encouraged by subsidies, the electrolyser industry could grow and cost reductions can then be expected. If also applications for the oxygen can be identified, this can also enhance the use of electrolysers.

Hydrogen storage capacity has to be evaluated for seasonal variation of wind electricity and subsequent hydrogen production from excess wind energy. If on the other hand the hydrogen production is performed at night-time, when low cost electricity hours exist, the storage can be smaller.

For the fuel cell household applications cost reduction and lifetime improvement of the fuel cell are the main items for commercialisation.

Table 2: Overview of cost and performance of the technology for the different options.

Year of reference	2007							
Technology	Power [kW]	Investment [€/kW _{out}]	Lifetime [yr]	Maintenance [% of investment]	Load [% of full load]	Efficiency [% on HHV]	Remark	Reference [-]
Electrolyser	10	10000	20	2	33	70	Alkaline	
Electrolyser	100	5000	20	2	33	70	Alkaline	
Electrolyser	1000	1000	20	2	33	70	Alkaline	
Fuel cell	1	1000					PEMFC	5000 units/yr 2010-2012 2006/2007 price level For 1000 units/year in 2011 operating on H ₂
Fuel cell system	1	10000	5	n/a	n/a	51 for electricity 38 for heat	PEMFC	
Ethanol reformer	n/a							
Methanol reformer	1050	1905		n/a	n/a	81		

Biogas/NG reformer	1	5000 (unit)	5	n/a	n/a	75-80	Price, if 300 units sold, efficiency provided for LHV	WS-Reformer
Biogas/NG reformer	100	n/a	n/a	n/a	n/a	n/a		
Wind turbine	1000	850-1100				100		
Ethanol/Methanol plant	430000	440	20	5	100		Additionally 75 MW electricity is needed	
Biogas plant	500	3800	20	4	92	100	without CHP	
Biogas cleaning/upgrading	500	1900	12	3	92	99	Pressurised scrubber, most simple system	Oral information by Ökobit GmbH, Naturgas GmbH
<hr/>								
Storage	H ₂ [kg]	[€/kg H ₂]						
H ₂ storage	100	500-2000	100					

4 Conclusions

The RES fuel cell household system considered in this project is a hydrogen based low temperature PEM which has a power range of 0.5-1 kW electrical and 0.5-1 kW thermal. In this way an aggregated market with nearly identical units can be obtained. These systems will be preferably located in new dwellings where the heat demand is low.

The report on the conversion of biogas to hydrogen for PEM-FC showed that low temperature fuel cells (although they work with biogas) are not the first choice when biogas should be used in combination with a fuel cell. Too many process steps are needed to refine biogas to the level of natural gas and then transform the biomethane to hydrogen.

The combined ethanol/methanol plant from biomass is still under development and cost projections for the ethanol/methanol as fuel are encouraging. Methanol is a low cost commodity and can be procured from the world market where it is mainly produced from (by-product) natural gas. Methanol production from glycerine, a by-product from biodiesel fabrication, will start in the Netherlands. The methanol from this plant will be used again in the biodiesel production.

The excess wind to hydrogen case lacks understanding of the conditions for optimal operation between electricity production for direct use versus electricity production for conversion into hydrogen in the electrolyser mode. Because electricity is traded on an international level, the use of low cost electricity for operation of the electrolyser is more likely. Since it on a political level has been decided that our future energy system shall contain a larger fraction of fluctuating renewable sources, this will mean more fluctuating electricity prices in the future, and furthermore foster the need for a means of electricity storage to balance the supply and demand of electricity. For that purpose electrolysers and FCHS are a promising technology.

The description on the electrolysers shows that cost reductions are required. This is expected from Eastern Europe manufacturers, but not yet confirmed. The efficiency for hydrogen production of the electrolysers from the Eastern Europe manufacturers should be increased.

The part on the fuel cells and fuel cell CHP systems shows that cost reduction is a very important issue for commercialisation and this is one of the goals for the project. One of the ways to decrease the cost is by increase of the production level. Aggregating the market into standardised systems enhances the possibilities for mass production and cost decrease. The competing household cogeneration technologies also require cost reduction before mass market application can be considered.

The information from this document will be used for the market development plan in WP3 and the cost calculations for the aggregated market in WP4

Appendix 1 Use of biogas for residential fuel cells

By Katrin Pietzsch, IBBK

Appendix 1.1 The biogas process

Biogas is produced when organic matter is broken down by bacteria under anaerobic conditions (i.e. absence of air). It can be produced from sewage sludge, agro-industrial waste, organic household waste and in the agricultural sector from both liquid and solid manure and energy crops. The process consists of several steps that partly run parallel to each other and partly depend on each other. Figure 1 shows the basic stages of the biogas production simplified as a linear process. Acetic acid, hydrogen and carbon dioxides, that are mainly produced in the third stage and are the reactants for the methanogenesis, can to a lower extend also be directly produced from the products of the first stage.

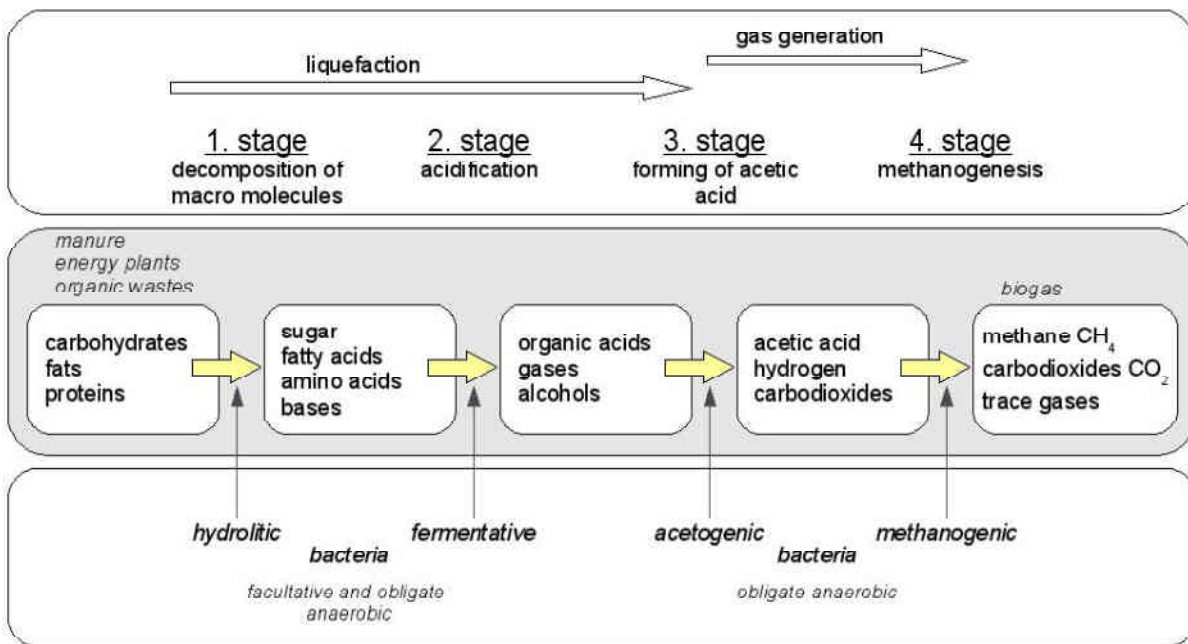


Figure 4: Stages of methanogenesis [modified after 10, 15]

A wide range of bacteria are involved in breaking down the organic matter and converting it into biogas. In this symbiotic relationship two main groups are of interest – bacteria that are responsible for the hydrolysis and bacteria that produce methane (methanogens). Each group of bacteria has distinct demands concerning their environment in terms of temperature, pH value, presence of oxygen, etc. and the task of operating a biogas plant is to meet the demands of the various groups of bacteria. Especially the methanogens are very specialised and, hence, more sensitive towards the environmental conditions. They also have the slowest growth rate³. Three typical temperature ranges exist, in which special strains of methane producing bacteria prosper and gas yield is highest:

- psychrophilic strains favour temperatures below 10...20 °C
- mesophilic strains favour temperatures between 25...45 °C and
- thermophilic strains favour temperatures above 50...70 °C

³ 10-20 days compared to 1-48 hours for hydrolytic and fermentative bacteria

According to the principles of reaction kinetics the speed of reaction increases with rising temperatures [10] and hence, the highest turnover of the substrate happens in the thermophilic temperature range. However, methanogens of the thermophilic range are even more sensitive than the average methane producing bacteria and the whole process can become difficult to handle. Bacteria working in the mesophilic range are usually more robust which results in stable processes. The highest yield of methane is produced by the psychrophilic strains, but the conversion speed is too low and hence high retention time would be necessary. Most agricultural biogas plants run in the mesophilic temperature range. Table 1 shows the relation between temperature ranges and retention time.

Table 1: Temperature ranges for anaerobic digestion [15]

<i>Fermentation</i>	<i>Minimum</i>	<i>Optimum</i>	<i>Maximum</i>	<i>Retention time</i>
Psychrophilic	4-10 °C	15-18 °C	25-30 °C	> 100 days
Mesophilic	15-20 °C	28-33 °C	35-45 °C	30-60 days
Thermophilic	25-45 °C	50-60 °C	75-80 °C	10-16 days

Apart from temperature, pH value and anaerobic conditions parameters such as dry matter content (DM), organic dry matter (oDM) of the substrate and the carbon-nitrogen-ratio (C/N-ratio) play an important role in the digestion process. Bacteria need a moist environment for two reasons:

1. to move around and
2. for the transport of nutrients from the substrate into the bacteria cell where metabolism takes place.

Therefore the dry matter content of the substrate is limited to a maximum of 50 % in dry fermentation processes. Due to a different process engineering in wet fermentation processes the DM content is restricted to approx. 15 %. The C/N-ratio is considered to be favourable within the range of 40:1 and 10:1. A ratio below 8:1 can inhibit the metabolism due to an excessive ammonia content.

The resulting gas mainly consists of methane (CH₄) and carbon dioxide (CO₂) as well as smaller amounts of several trace gases (Table 2).

Table 2: Composition of biogas [4]

<i>Substance</i>	<i>Volume content</i>
Methane - CH ₄	50 – 70 %
Carbon dioxide - CO ₂	35 – 45 %
Hydrosulphide - H ₂ S	20 – 20.000 ppm (0,002 – 2 %)
H ₂ , NH ₃ , N ₂ , Urea, CO, O ₂ und H ₂ O	Trace elements with total volume of < 5,0 %

Methane is the energy carrier and, hence, the aim should be to produce a gas rich in methane and low in sulphides and trace elements. Depending on the further use of the gas it might need to be conditioned in order to avoid and reduce damages and corrosion in the final consuming device.

With respect to using biogas in a low temperature Fuel Cell CHP, conditioning has to focus on producing a gas that has the same properties as natural gas. This means that beyond the elimination of sulphides and trace elements methane has to be enriched to 96-98 %. Methods for conditioning biogas are described after the explanation of the technical processes to produce biogas.

Technologies for producing biogas

Today a wide variety of principles and technologies for producing biogas exist. They can basically be classified according to the *method of feeding* the digester (discontinuous feeding/ batch method, continuous feeding), the *method of mixing* (fully mixed, plug flow, percolation), the *number of process stages* (single stage, two or multi-stage) or the *consistency of the substrate* (pumpable or stackable). For this study the main classification will be according to the consistency of the substrate, as the other criteria can be almost fully applied to both the solid and the liquid process. Regardless of the kind of applied technology basic process steps have to be followed:

- collection and storage of input substrates (manure, energy crops, organic wastes)
- preparation/ conditioning of input substrate
- feeding of digester
- mixing of digester content
- emptying of digester
- post storage and final use or disposal of digested substrate.

A general set-up of a biogas plant consists of storage facilities for the input substrates, one or more digesters, storage facilities for the digested slurry and the infrastructure for utilising the biogas. A reception pit or mixing tank in wet fermentation plants is optional, but should be implemented as it balances fluctuations in the input stream, allows mixing as well as a starting hydrolysis. It is not necessary in dry fermentation plants.

The digester is the heart of the biogas plant. It can be designed as a vertical or as a horizontal tank. To provide an optimal temperature range for the anaerobic bacteria and minimise temperature fluctuations heating and a good insulation of the digester is essential in central and northern Europe. In wet fermentation plants the digester has to be equipped with stirring or mixing devices.

Generally the produced gas is collected and stored in the free space above the digester content. However, gas is not only produced inside the digester, but also in the slurry storage tank. This is due to the fact that for economical reasons the substrate cannot be fully decomposed inside the digester. The rest enters the slurry storage tank where it remains for up to seven months. During this period bacteria continue producing biogas and thus storage tanks tend to be covered. Gas can also be stored in an external gas holder (e.g. if the available volume inside the digester or slurry tank is too small). Prior to using the gas it might need to be refined in specific facilities.

The final user of the gas, be it a conventional cogeneration unit based on internal combustion or a fuel cell, is usually contained inside a separate building that also comprises the technical installations for operating and monitoring the plant and the digestion process. Such a building could also contain the facilities for feeding the refined biogas into the natural gas grid.

The general process flow of a biogas plant is illustrated in figure 2. A more detailed and specific explanation of the process steps is given in the description of the wet and the dry fermentation process. Also, the conditioning of the biogas will be described in a separate chapter.

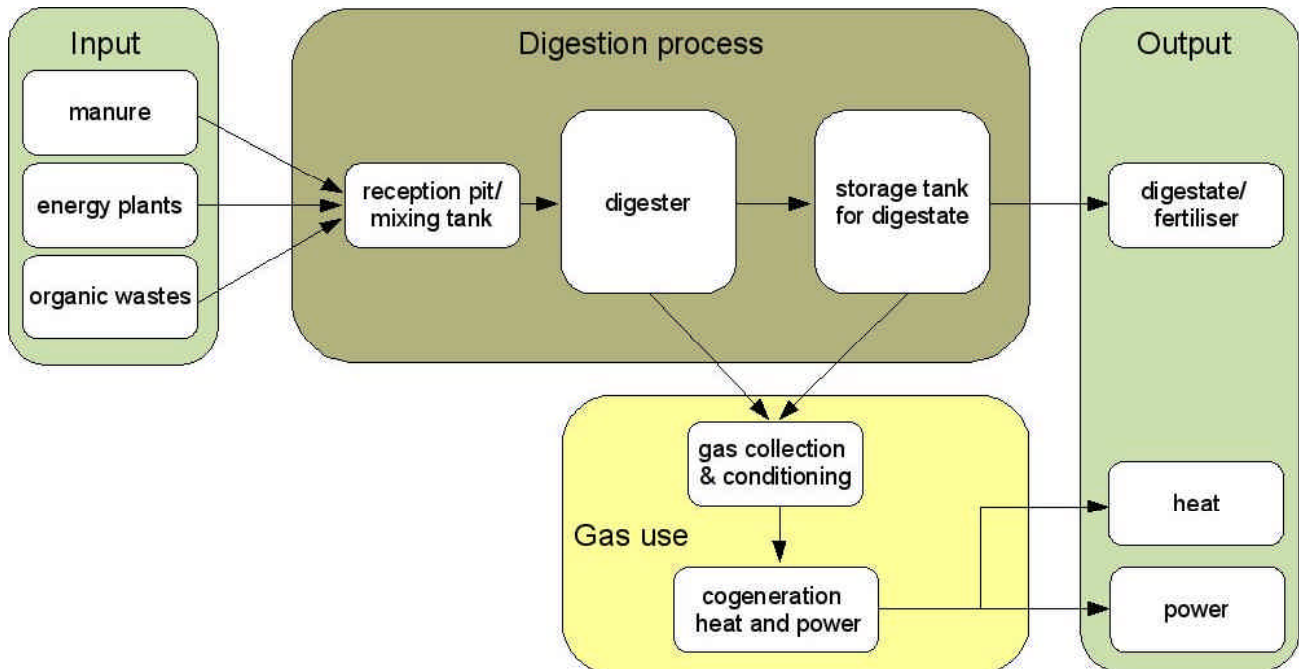


Figure 5: General scheme of the biogas production

Benefits derived from the fermentation process are not only the power and heat produced by any kind of cogeneration unit, but also the digested slurry itself and the avoided greenhouse gas emissions that would otherwise contribute to the greenhouse effect. The value of the digestate is determined by its fertilising value. Compared with raw liquid manure the nitrogen content in the digestate is more readily available for the plants through the mineralisation process. Additionally natural resources and energy are saved when less artificial nitrogen fertiliser is applied to the field.

Wet or liquid fermentation

One refers to wet fermentation, if the input substrate and the digester content are pumpable and mixable. Without applying special technology this is the case when the DM content is below 15 %.

Collection and storage of input substrates

Input substrates for wet fermentation can be all kinds of organic matter that can easily be decomposed by anaerobic bacteria. The input should not consist of substrates rich in celluloses, as the effort for decomposition is too high for the bacteria. The collection and storage of the input substrates depends on the characteristics of the substrates.

Liquid manure is usually pumped from the stable to the biogas plant or delivered in tank wagons, if the local conditions do not allow pumping. The location and size of the storage volume depends on the set-up of the plant. If the farm is close, the manure is most likely stored close to the stables. Storage volume is provided at the biogas plant, if the manure is delivered by tank wagon. *Solid manure* is stored on a heap as close to the feeding system as possible.

Energy crops are usually preserved by ensiling. The silo should be located as close to the feeding system as possible to minimise the costs for transporting. In practice this means that the harvested crops are transported to a central silo located on the premises of the biogas plant which results in higher costs and increased traffic load during harvesting and stocking.

Organic wastes, e.g. from food industries, should not be stored over longer periods at the biogas plant as they can cause substantial odour nuisances and health risks. They are usually delivered in shorter periods and pass through a pasteurisation process before they are fed into the digester.

Conditioning of input substrate and feeding of digester

Whether the input substrates need to be conditioned during the process depends on their characteristics. In general the input substrate has to be cleared of contraries to prevent damages of pumps, pipes and the digester. Liquid substrates are usually mixed in a mixing tank prior to being pumped into the digester. Solid substrates such as corn or grain silage are often fed directly into the digester without entering the mixing tank. Fibrous substrates, e.g. solid manure or grass, need to be chopped up before entering the digester to avoid clogging of pumps and pipes as well as the formation of swimming crusts. Organic wastes such as leftover food, fats and bio waste in general need to be pasteurised to guarantee that the slurry leaving the process can safely be spread on agricultural land. For the pasteurisation the substrate has to be heated up to 70 °C for at least one hour. Solid substrates can enter the digester directly via a feeding system or indirectly by mixing them with the liquid input. All feeding systems have some basic features in common: a storage tank of bigger or smaller volume and a combination of several devices (screw, spiral, pusher, chains) to transport the substrate into the fermenter. They vary in their storage capacity, their specific feed rate, the power demand and the costs.

Mixing of digester content

During the fermentation process the digester content has to be mixed thoroughly. This has three basic effects: nutrients and micro-organisms are distributed evenly within the digester, heat is transported from the heating system to the inner parts of the digester and swimming crusts can be avoided. Also, stirring ensures the release of the gas produced. Stirring or mixing devices can be fixed installations or moveable installations. General features are that either the mixer itself or its paddles can be moved or rotated to change the current stream inside the digester.

Storage of digested substrate and use in agriculture

After the fermentation process the digested slurry is pumped into a storage tank where it remains until it is spread on agricultural land. The volume of the storage tank has to be big enough to bridge the time during which plants are not able to take up the nutrients and, hence, spreading is prohibited (i.e. during winter months). Depending on the local climate and the respective agriculture the accruing slurry from six to seven month needs to be stored. Digested slurry has an increased fertilising value compared with raw manure as a higher proportion of the nitrogen is available in form of ammonia. The decomposition of organic matter also increases the fluidity of the slurry and as a result the infiltration properties of the slurry are improved. To minimise nitrogen losses the slurry should be applied close to the ground, e.g. by using feeding hose or drag pipe systems.

Dry fermentation in batch method

Dry fermentation, in contrast to wet fermentation, solely works with input substrates that are stackable and keep this property during the digestion process. Hence, the output is stackable, too. The dry matter content of the substrate can be as high as 50 % by weight. Higher DM contents inhibit the metabolism of the bacteria. In dry fermentation processes substrates with a high proportion of celluloses can also be applied. They are even needed to provide enough structure for the heap. Dry fermentation plants are often operated in batch method where the digester resembles a garage or a box. The gas production in each box follows a characteristic scheme. At the beginning the gas production rises quickly and declines slowly (figure 3).

To minimise fluctuations in the gas yield and its quality, several digesters are operated parallel and time delayed. The resulting gas is collected from all digesters and mixed inside an external gas holder.

Collection and storage of input substrates

Apart from liquid substrates that cannot be treated in dry fermentation processes the input substrates are collected and stored in the same manner as has been described for the wet fermentation.

Conditioning of input substrate and feeding of digester

Organic wastes have to be pasteurised according to the same conditions as described for wet

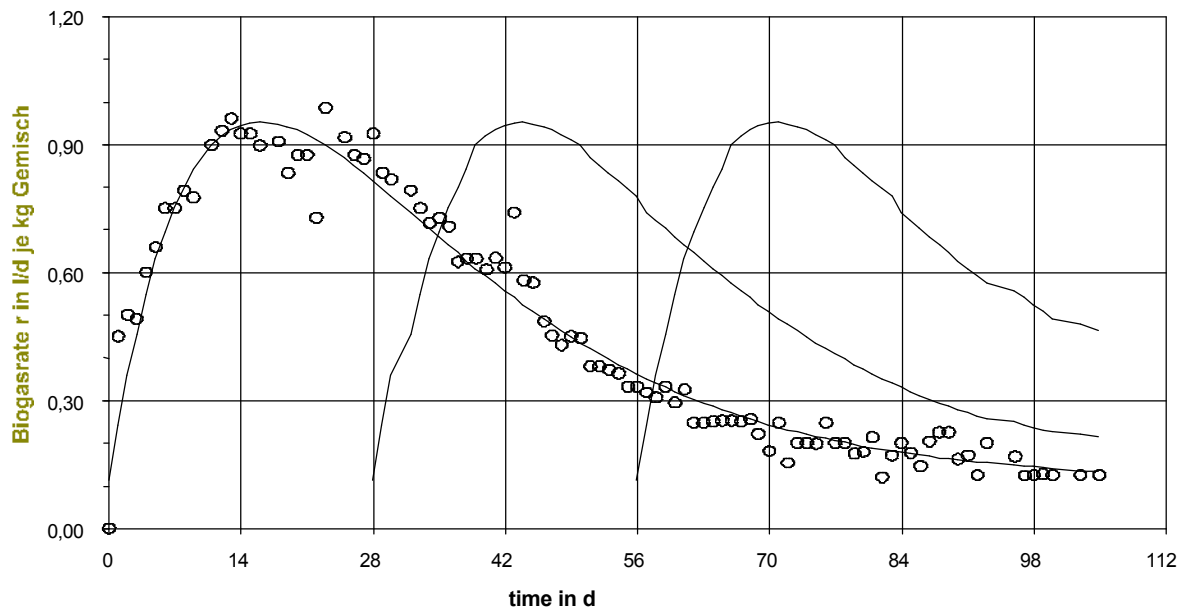


Figure 6: Production of biogas in time delayed operated dry fermentation boxes fermentation during the process. Substrates with a high content of celluloses or long fibres might also need to be chopped up. The remaining stackable substrates require no special treatment. All substrates are either mixed roughly prior to feeding the digester or the digester is filled in several layers. As the substrates are stackable a wheel loader is often used for this purpose. Once the digester is loaded the doors are closed in a gas tight manner and the substrate remains inside the box for 20 to 30 days. During this time no substrate is added nor is any substrate taken out.

Mixing of digester content

Dry fermentation in batch method requires no direct mixing of the substrate once the digester is closed. Nutrients, bacteria and interstage products are distributed through the heap via the percolation of process water. The process water is sprayed on top of the substrate and slowly trickles through the heap and through perforated concrete slabs on the floor of the digester. It is collected in a sink below the floor and pumped up to a storage tank from where it is sprayed onto the substrate. The effort for distributing bacteria and nutrients evenly through the heap is much lower than in wet fermentation.

Emptying of the digester

After the retention time is over, the digester garage is emptied completely using the wheel loader. The material in the front part of the digester is withdrawn and replaced by fresh substrate. The fresh substrate is mixed with older substrate and enters the digester first. Then the remaining old material is

added before the door is closed and the next cycle starts. Thus the fresh substrate passes through the digester within three to four cycles resulting in a total retention time of 80 – 120 days.

Storage of digested substrate and use in agriculture

In this case the digested substrate does not leave the digester in form of a slurry but in a condition that resembles compost with a slightly higher moisture content. This anaerobic compost can be applied to the field immediately. Storing the substrate under aerobic conditions for another few weeks to months is also an option. Apart from the solid matter a liquid fraction also leaves the process. During the increased rate of decomposition the bacteria destroy the cells of the input substrate and the cell water is released. This cell water contributes to the volume of the percolated process water. To keep the amount of process water constant the surplus volume has to be withdrawn regularly. This liquid fraction resembles in its properties digested slurry and thus can be spread on agricultural land.

Appendix 1.2 Conditioning of biogas

Biogas has to be conditioned and refined prior to its use in a fuel cell. The required degree of refinement and conditioning depends on the type of fuel cell in use. Two rough and general distinctions can be made:

- fuel cells that operate in the low temperature range (e.g. PEM) require pure hydrogen as input and thus an external reforming process is necessary
- fuel cells that operate in the high temperature range can perform the reforming process inside the cell and partly depend on the presence of CO₂ for the reforming process itself (e.g. MCFC).

In this project the focus is put on using proton exchange membrane (PEM) fuel cells. They work in the low temperature range, which reduces the requirements concerning the applied material and could therefore lead to lower costs. On the other hand the operating temperature of the PEM-FC is too low for internal reforming and an external reforming process that yields hydrogen as fuel is necessary. Table 2 shows some properties and requirements of PEM fuel cells and compares them with other types of fuel cells. For better illustration the properties of natural gas and also shown.

Table 3: Properties and requirements of different fuel cells compared with two different gas qualities

	<i>PEM</i>	<i>PAFC</i>	<i>MCFC</i>	<i>SOFC</i>	<i>Nat. Gas</i>	<i>Biogas</i>
Temperature °C	60-90	160-220	600-660	800-1000	–	–
Reforming	external	external	ext./internal	ext./internal	–	–
El. Efficiency [%]	30-50	40-45	53-57	30-57	–	–
CH ₄ [%]	> 90	> 50	– ¹	– ¹	84 – 98	50 – 75
CO ₂ [%]	< 3	> 45	– ¹	– ¹	0,1 – 1,5	25 – 50
CO [ppm]	< 20	< 6	– ¹	– ¹	n.a.	< 10.000
N ₂ [%]	< 3,5	< 3,5	– ¹	– ¹	0,8 – 9,9	0 – 10
O ₂ [%]	< 0,2	< 1,3	< 4	< 2	–	0 – 2
H ₂ S [ppm]	< 6	< 4	< 10	< 10	n.a.	< 10.000
NH ₃ [Vol-%]	< 0,5	< 0,5	– ¹	– ¹	n.a.	< 500
Halogens [ppm]	< 1	< 10	< 0,1	< 1	n.a.	< 1
Siloxanes [mg/m ³]	< 1,2	< 1,2	< 1,2	< 1,2	n.a.	0,1 – 5

Originally the PEM fuel cell systems have been designed to work with natural gas. Biogas differs in its properties from natural gas especially regarding its methane content and its lower and variable energy density. Biogas also contains higher proportions of trace gases, especially hydrogen sulphide, that harm the catalysing process, lead to corrosion or could reduce the electrical efficiency [11]. Therefore trace gases have to be eliminated and the methane content of the biogas has to be increased in order to achieve a quality that is equal to natural gas and suitable for reforming.

A variety of well established processes and technologies for conditioning biogas exist (table 1) and basically all processes known from general gas conditioning can also be applied for biogas. German biogas plants already practice the dehumidification and the desulphurisation of the gas to prolong the operating hours of their cogeneration unit. This is generally done by simple measures and thus the gas is still in its crude state compared to the requirements of a fuel cell. The total conditioning and refining follows several steps:

- elimination of solid and liquid components and drying of the gas
- desulphurisation
- accumulation of methane and elimination of carbon dioxide
- elimination of trace gases like halogens, silicates and ammonia.

The actual technical and economic conditions at the plant itself determine the respective steps.

Table 4: Gas purification processes and field of application [2]

	Trace gas	H ₂ O	O ₂	N ₂	CO ₂	H ₂ S	Halogens	NH ₃	Siloxanes
Process									
Cooling to dew point		x						x	x
Deep refrigeration (-25 °C)		x					x	x	x
Activated carbon (adsorption)						x	x	x	
Desulphurisation – other methods									
Biological desulphurisation						x			
Precipitation with iron salts						x			
Adsorption to Iron						x			
Adsorption to ZnO						x			
Scrubbing (water/ NaOH)						x			
Scrubbing with mineral oil					x				x
CO ₂ elimination									
Pressurised washing					x				
Pressure swing adsorption			x	x	x				
Membrane processes		x			x	x			
Catalytic Oxidation			x						

Cooling to dew point and deep refrigeration

Biogas that leaves the digester or slurry tank is usually saturated to 100% with water vapour and has a high content of hydrogen sulphide, which leads to corrosion of pipes, armatures and other aggregates. Aerosols released from the substrate by intensive stirring activities can cause incrustations.

Vapour can be precipitated by cooling the gas down to the dew point of 5 °C. Alternatively the gas can additionally be compressed. This does not only dehumidify the gas, but also partly eliminates siloxanes and reduces the share of ammonia (NH₃) due to its good solubility in water.

If siloxanes and halogens play an important role in the biogenous gas (e.g. in landfill gas or sewage gas) deep refrigeration should be considered instead. By reducing the temperature to -25 °C approx. 99 % of the siloxanes are eliminated as well as the major part of halogens and ammonia.

After refrigeration the temperature of the gas is increased resulting in a much lower relative humidity.

Desulphurisation

Hydrogen sulphides and other sulphides (e.g. carbonyl sulphide COS) are always present in biogas [15], although their concentration varies with the feedstock. It is extremely reactive with most metals and causes corrosion in compressors, gas storage tanks and engines. Hence, it should be removed early in the process. The most common methods for removing hydrogen sulphide are:

- biological desulphurisation
- iron chloride dosing into the digester
- adsorption to iron oxide/ iron hydroxide
- adsorption to zinc oxide
- activated carbon
- scrubbing with water or NaOH

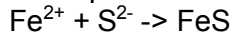
Biological desulphurisation

A simple way to eliminate sulphides is by making use of the naturally occurring bacteria like *Sulphobacter oxydans* that oxidise H₂S to SO₃⁻ when oxygen is present. Biological desulphurisation can either take place inside the digester or slurry tank by simply injecting a small amount of air (3 - 5 % by volume of the total gas yield) into the gas dome or inside extra columns outside the digester [3]. For economic reasons external desulphurisation units are mainly installed in plants with a cogeneration unit of at least 200 kW_{el.} [5].

The advantage of the internal biological desulphurisation is that sulphur precipitates back into the slurry and can be spread on land where it serves as plant nutrient. Internal biological desulphurisation is prone to fluctuations of the process parameters. Sinking temperatures during winter time, for example, lead to reduced bacterial activities and thus higher concentrations of hydrogen sulphides remain in the gas stream. Another problem is that it is often difficult to provide a surface area for the bacteria to grow on which provides enough area for the bacteria to grow on and is stable enough for carrying the weight without collapsing into the digester slurry. Here the external biological desulphurisation offers clear advantages. The temperature can be controlled and filling material inside the column provides a high surface area for the bacteria. Hence, the external desulphurisation displays a more steady and constant performance. However, biological desulphurisation does not reach reduction rates that are high enough to meet the qualities that are required by the reformer. At best the concentration of sulphides can be reduced by external desulphurisation to below 50 ppm.

Precipitation with iron salts

Iron salts (Fe^{2+} ions) like ferric chloride (FeCl_3) or iron sulphate (FeSO_4) can be added in liquid form directly into the digester or into the mixing pit where it reacts with the produced hydrogen sulphide and forms iron sulphide salts (particles):

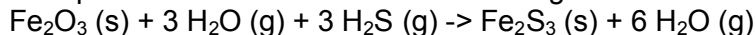


The particles are indissoluble and accumulate in the digestate. Inside the digester the process parameters (pressure and temperature) do not need to be adapted. The reaction runs under the given conditions.

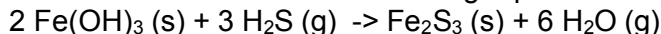
This method is extremely effective in reducing high levels of hydrogen sulphide, but it is not suitable for attaining a low and stable hydrogen sulphide level suitable for the reforming process. Also, this method is not flexible enough to react on load alternations due to varying properties in the feed substrates. Hence, dosing iron ions into the digester or mixing pit can only be regarded as a partial removal process in case of a high H_2S production. For low and stable concentrations in the gas stream this method needs to be complemented with a final removal process. The main advantages of this method are that it is simple to install and that no oxygen is entered into the gas stream. Depending on the sulphur contents in the digester slurry the consumption of iron salts could be high and thus lead to increased operating costs. Typical H_2S concentrations that remain in the gas stream are approx. 100 – 150 ppm [5].

Adsorption to iron oxide/ iron hydroxide

Hydrogen sulphide can also be removed from biogas by using filter beds filled with masses rich in iron oxide (Fe_2O_3) or iron hydroxide ($\text{Fe}(\text{OH})_3$), respectively. Biogas is lead through the filter bed where hydrogen sulphide reacts with the iron containing masses and sulphur finally adsorbs to the filter. Filter beds containing iron oxide consist of either steel-wool, wood chops impregnated with iron oxide or pellets. The adsorption to iron oxide is slightly endothermic and requires a minimum ambient temperature of 12 °C. The optimum temperature range is 25 – 50 °C. The adsorption to iron oxide requires the presence of water and therefore the gas should not be too dry:



Desulphurisation with iron hydroxide works at ambient temperatures and does not require water. The reaction can be described with the following equation:

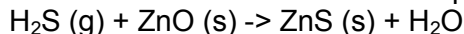


The adsorption of sulphur to the filter mass reduces its available surface and after the adsorptive capacity of the filter mass is exhausted the filter needs to be regenerated by letting air flow through it. To allow a continuous desulphurisation two filter beds should be installed parallel. This allows the regeneration of one filter while the other filter is operating. The regeneration is a highly exothermic process and should be closely monitored to prevent the self-ignition of the filter masses. However, the regenerative process cannot fully restore the adsorptive capacity and filter masses have to be exchanged after several cycles.

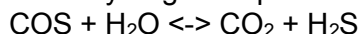
Both methods can reduce H_2S contents from up to 1.000 ppm in the raw gas to below 1 ppm. If the raw gas has higher H_2S contents than 1.000 ppm adsorption to iron containing filter masses becomes uneconomic, because the efficiency of the process decreases. Also, the filter masses have to be replaced more often which increases both the operating and the disposal costs.

Adsorption to zinc oxide

Zinc oxide can also be used to adsorb sulphur according to the following equation:



In addition to hydrogen sulphide COS can also be removed after it has been hydrolysed to H_2S :



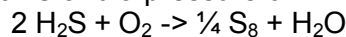
The adsorption to zinc oxide is mainly used to achieve very low levels of sulphides in gases – from less than 1 ppm to several ppb – and is applied before the gas enters sulphide sensitive processes,

e.g. steam reforming. It requires high ambient temperatures of 200 – 400 °C, which – from an energetic point of view – makes its application only reasonable, if it can be directly combined with other hot processes. Another disadvantage is the fact that the zinc oxide cannot be regenerated.

Adsorption to activated carbon

Hydrogen sulphide, siloxanes and halogens can be removed from biogas, if the gas passes a filter bed of activated carbon. In general activated carbon is sensitive to moisture and therefore the gas needs to be dehumidified or its temperature has to be increased to 50 – 70 °C to prevent that water condensates inside the filter.

Best results with respect to H₂S removal are achieved when the activated carbon is doted with potassium iodide (KI). Potassium iodide serves as catalyst to increase the reaction speed, but it also prevents the formation of sulphuric acid. In case of activated carbon doted with potassium iodide oxygen and water have to be present for the reaction [5]. Water builds a thin film on the surface of the filter bed. Hydrogen sulphide and oxygen dissolve in this water film and then react at temperatures of 50 – 70 °C and a pressure of 7 – 8 bar with each other to form water and elementary sulphur:



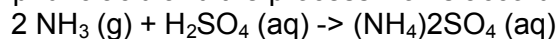
The elementary sulphur adsorbs to the inner surface of the activated carbon and the water desorbs from the catalysts surface. The activated carbon can be loaded with up to 150 % by weight with sulphur. The remaining H₂S concentrations in the biogas can be < 5 mg H₂S/ m³ gas.

Once the loading capacity of the activated carbon is exhausted the filter is usually exchanged by a new one and the old filter is disposed off. Regenerating the activated carbon with hot gas or hot steam (temperatures > 450 °C) is possible, but a partial load still remains. A complete regeneration requires much higher efforts, i.e. a hot steam process at 800 – 850 °C [5].

The advantages of doting activated carbon with potassium iodide are the increased loading capacities, the high level of purity that can be reached and the comparatively low operating temperatures.

However, the process relies on the presence of oxygen and water and can thus not be applied if an oxygen-free gas is required. Doted activated carbons are more expensive than normal activated carbons and therefore this method should only be applied for refined purification [5].

Ammonia can also be eliminated by using activated carbon. In this case the activated carbon is doted with sulphuric acid and the process works according to the following equation:



The quality of the removal process largely depends on the properties of both the activated carbon and the biogas as well as on the reaction temperature [2].

Scrubbing

Hydrogen sulphide is more soluble in water than methane. This fact is used in *water scrubbers* where hydrogen sulphide is removed from the gas in a cross flow process. The whole process is a purely physical absorption process where biogas is lead through a tank filled with water. Hydrogen sulphides, carbon dioxide as well as particles that might be contained in the gas stream absorb to the water. After a while the water needs to be regenerated or exchanged by fresh water.

Another and more sophisticated option is to pressurise the gas and feed it to the bottom of a packed column from where it flows upwards. From the top water flows downwards and absorbs H₂S and CO₂. At the bottom the water leaves the column and needs to be regenerated. Regeneration is possible by de-pressurising the water or by stripping the gases in a second column. A part of the process water might need to be removed and replaced by fresh water. In plants operating at industrial scale an amount of approx. 2 – 4 m³/d needs to be replaced [14]. An advantage of using a water scrubber is the fact that no oxygen enters the gas stream

The absorptive capacity of water can be increased by adding *sodium hydroxide* so that a diluted lye forms. With using sodium hydroxide the absorption is no longer a purely physical but also a chemical process which results in higher deposition rates for H₂S. However, the basic process set-up is similar. Gas and lye pass each other in a cross flow in a packed column and H₂S as well as a part of CO₂ is absorbed. After a while the lye is exhausted and must be regenerated in a second column. In this case oxygen and micro-organisms (*thiobacillus*) have to be present. During the regeneration process salts and acids are formed. For this reason a part of the scrubbing solution has to be removed continuously and must be neutralised to avoid that the scrubber gets acidified. Disposing off the scrubbing solution is unproblematic as no special treatment is required. To provide optimal conditions for the micro-organisms they have to be supplied continuously with a nutrient solution. Care has to be taken regarding the dosage of oxygen as high levels of oxygen favour the undesired formation of sulphates. In the scrubber elementary sulphur is formed by the bacteria. The sulphur precipitates to the scrubbers bottom where it leaves the process in a slurry. After the sulphur has been separated from the slurry by centrifugation, it can either be processed further or marketed.

Hydrogen sulphide loads as high as 30.000 mg/ m³ can be eliminated from the gas stream by scrubbing with sodium hydroxide. Problems rather occur when the H₂S load is too low. Normal concentrations of 2000 ppm H₂S in the gas stream can be reduced down to 50 – 100 ppm. This range is still too high for the purpose of reforming the gas and therefore the scrubbing process is not suitable for refined purification. Its strength is to treat middle to high volume streams of gas that are highly loaded with hydrogen sulphide. A separate process step for further elimination of hydrogen sulphide needs to be added. The technical efforts for this scrubber are high and thus a thorough investigation whether or not the installation is reasonable should be conducted.

Elimination of CO₂/ Enrichment of methane

Before the biogas enters the reformer its properties have to be further modified to resemble natural gas. Otherwise the reformer would degrade too fast resulting in short life expectancies. After the main substances that cause corrosion, i.e. sulphides and ammonia, have been eliminated from the gas it has to be enriched in methane. This is done by eliminating CO₂ from the biogas. Several technologies already exist and are being applied:

- scrubbing under high pressure
- pressure-swing-adsorption (PSA)
- membrane separating process
- catalytic oxidation.

Scrubbing under high pressure

The simplest and cheapest method of removing the CO₂ is by washing the biogas with water under increased pressure. It is also the standard process all over Europe for treating gases of biogenous origins. As described above the principle of scrubbing are the different solubilities of CH₄, CO₂ and H₂S in water or organic solvents that can be added to the water or are used instead of water for increasing the absorptive capacity.

Scrubbing under high pressure consists of the following process steps:

1. removal of aerosols or suspended matter by letting the gas pass a gravel filter
2. compression
3. enrichment of CH₄ and purification of gas
4. drying of gas

Due to the amphoteric character of water acid as well as alkaline components dissolve much better than non-polar and hydrophobic components. In practice this means that CO₂ and H₂S dissolve easily in the water whereas major part of CH₄ remains in the gas stream. Gas and water pass each other

while running over a packed column under pressures of 0,6 – 1 MPa and CO₂ and H₂S are absorbed by the water.

A small proportion of CH₄ is absorbed nevertheless and can be recovered in a separate process step called flashing. In the flashing process the pressure is abruptly reduced from 0,6 – 1 MPa to 0,3 MPa and the absorbed CH₄ is released and fed into the gas stream. The refined gas contains approximately 96 % of methane and 1 – 2 % of CO₂. With CH₄-flashing the losses of methane can be reduced to 2 % and hence the refined gas can contain between 97 – 99 % of methane [14].

When the gas leaves the packed column it is saturated with water vapour so that it needs to be dried afterwards by e.g. combining pressure swing and temperature swing adsorption with molecular sieves. In case of high H₂S loads (up to 10.000 ppm) the dried gas has to pass a filter of activated carbon for further desulphurisation. Oxygen and nitrogen that might have entered the gas stream do not absorb in water. They also need to be eliminated with activated carbon or membrane sieves.

The advantage of scrubbing under high pressure is that it combines the purification of the gas with the enrichment of methane. Depending on the properties of the raw biogas in terms of loads of trace gases, the process is suitable for a refined removal of hydrogen sulphide, siloxanes and ammonia [14]. Figure 4 shows an example of a scrubber that works under high pressure.

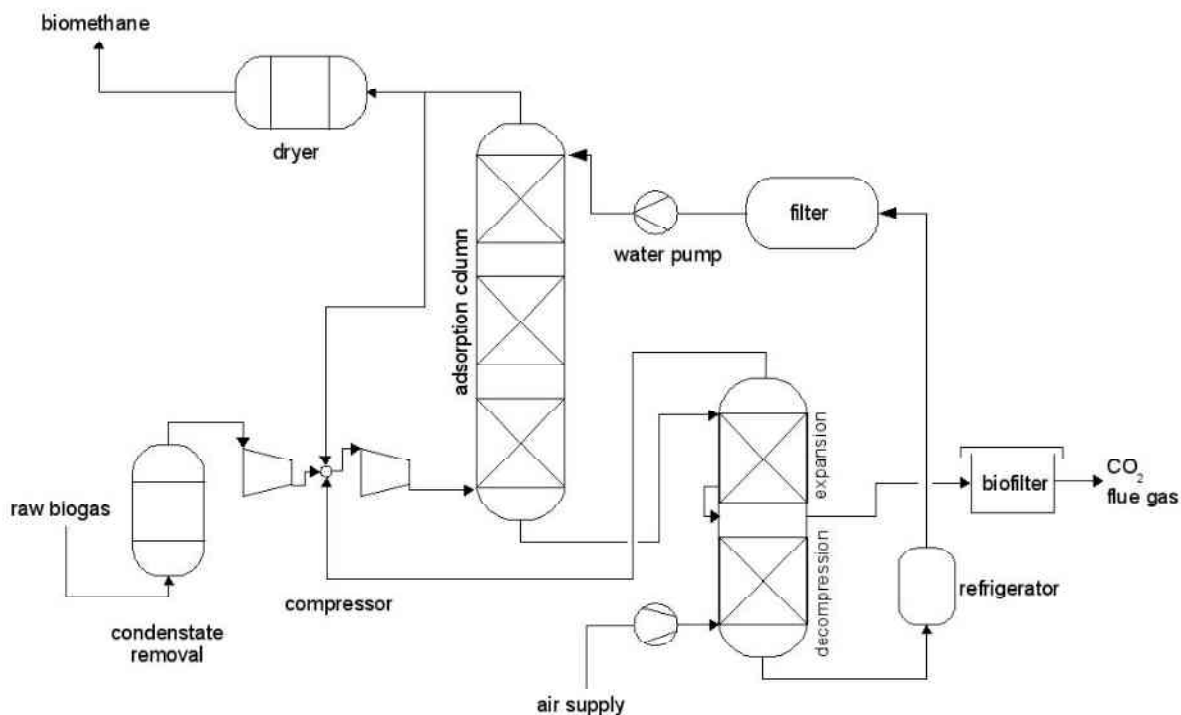


Figure 7: Exemplary layout of a scrubber under high pressure [5]

Selexol scrubbing

If dimethylether of polyethylene glycol (DMPEG) is used as solvent and pressures of 20 – 30 bar are applied, the process is called *Selexol⁴ scrubbing*. In this case the absorption is based on the different solubilities of the acidic gas components in comparison with hydrocarbons. The temperature level is approx. 40 °C or 0 °C for cold processes (the solubility of the acidic components increases with sinking temperature levels). Below 0 °C the viscosity of DMPEG sinks and more energy is needed for

4 Selexol is a trademark of Dow Chemicals

recirculation of the solvent. The process is established in gas purification and is attractive as it allows the refinement to a level that resembles natural gas (i.e. removal of CO₂, H₂S and water) Selexol scrubbing is mainly applied, if the gas stream contains high concentrations of hydrogen sulphide and carbon dioxide or only high concentrations of CO₂. Its advantage compared to water scrubbing is the significantly higher solubility of CO₂ in DMPEG, which requires less solvent and thus less energy for recirculation. Also DMPEG is not toxic nor corrosive, which is a big advantage compared to other organic or physical solvents. If only CO₂ shall be eliminated from a dry gas stream that does not contain hydrogen sulphide, the regeneration of the solvent works like in a water scrubbing process by expansion/ flashing.

Apart from CO₂ other components also absorb very well to DMPEG. Hydrogen sulphide and carbonyl sulphide even show a significantly higher solubility in DMPEG as CO₂ does. Additionally organic sulphur compounds, NH₃, HCN and water are absorbed. From a gas refinement point of view this sounds very promising, but the problem is the regeneration of the solvent, because stripping at low pressure does not yield the necessary level of purification. For a complete regeneration DMPEG has to be decoct which requires a high energy input. Selexol scrubbing can only be applied economically when very high gas volumes must be treated. Then selexol scrubbing of a dry gas free of sulphur compounds could be competitive to water scrubbing from an energetic point of view.

Pressure swing adsorption

The term pressure swing adsorption (PSA) generally describes the application of activated carbons, molecular sieves (zeolite) and carbon based molecular sieves to separate gases or refine gases. PSA is a state-of-the-art process and is usually applied for small to medium flow streams in order to separate hydrogen from process gases, to enrich oxygen for combustion processes or to eliminate nitrogen or carbon dioxide from gases of biogenous origin.

The PSA-process consists of four steps:

- adsorption under high pressure
- desorption by expansion in direct current or counter current
- desorption by flushing with raw or product gas under low pressure
- increase of pressure with raw or product gas.

To produce a highly refined gas from biogas the composition of the biogas needs to be known in detail, because the PSA has to be adapted according to the present proportions of CO₂, O₂ and N₂. If the proportions of oxygen and nitrogen are rather low compared to carbon dioxide the refined gas that leaves the adsorption column will already have the required properties in terms of composition and pressure. If the opposite is the case and the proportion of carbon dioxide is lowest, methane will instead be absorbed and can only be recovered during the regeneration of the adsorption column. In this case a two step process is necessary.

To separate CO₂ from the biogas the gas first has to be compressed to approx. 8 – 10 bar. During compression the temperature of the gas increases to 170 °C. As the adsorption runs best at low temperatures, the gas needs to be cooled down to 40 °C before it is pressed into the adsorption column. During the refrigeration condensate forms which might need to be neutralised before discharging it into the public sewer system. Figure 5 shows an exemplary set-up for a PSA.

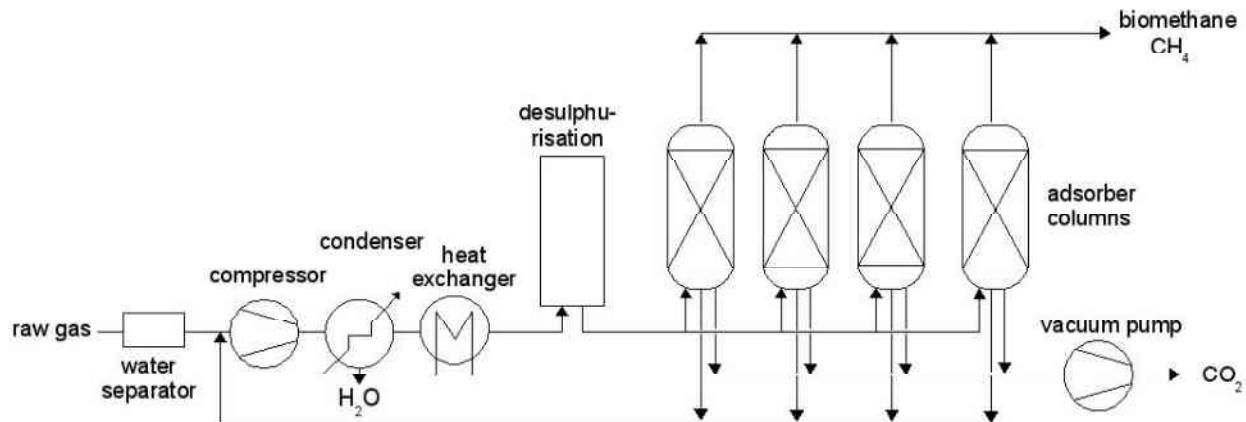


Figure 8: Exemplary set-up of a pressure swing adsorption

Inside the adsorption column activated carbon or molecular sieves that are based on carbon, silica gel or zeolites are applied. Basis for the separation itself are the different sizes and polarities of the particles. The selectivity of the adsorption is achieved with variations in pore sizes and gas pressures. To minimise the energy demand for maintaining the pressure inside the column, several adsorption columns are operated in line. If the pressure inside one column needs to be reduced it is taken up by the subsequent column. At the end of the process the CH₄ content of the refined gas is higher than 96 % by volume. To minimise methane losses a part of the resulting gas from the first desorption step can be fed back into the stream of crude gas before it enters the compressor. Depending on the process management and the absence of leak air the refined gas can achieve a purity grade of 98 % by volume of methane. High purity grades are also facilitated by using molecular sieves on carbon basis, because the losses of methane are minimised and desorption is faster. Additionally they are able to reduce contents of leak air (nitrogen and oxygen). If molecular sieves are applied, H₂S should be eliminated from the gas stream before it enters the PSA process.

Membrane separation process

Applying membranes for refining and conditioning gases is still very young and cannot be regarded as state-of-the-art technology. Especially in the field of refining biogas the membrane separation process is still on the level of pilot plants.

Membrane separation performs on the principles of selective gas permeation. When a gas mixture such as biogas passes a membrane, gas components dissolve into the membrane material and diffuse through it. The solubility and diffusivity of each gas component decides whether or not it can pass the membrane. Water vapour, carbon dioxide and hydrogen sulphide are easy permeable gas components whereas methane or other hydrocarbons permeate slowly.

The driving force of the separation process is the difference in potential. This could either be the difference in pressure or in solubility and diffusion speed. If the process is to be successful, the question of how the potential difference can be reached and maintained must be answered. For separating gas mixtures such as biogas different partial pressures have to be applied at each side of the membrane. The pressure difference can be realised by increasing the pressure on the feed side of the membrane or by generating a vacuum at the permeate side. In practice a pressure difference of 3 MPa is applied. Smaller molecules (CO₂, H₂O, H₂S) permeate the membrane and the CH₄ enriched gas leaves the process on the high pressure side as retentate. To enhance the separation process and increase the methane yield several membranes can be operated in line.

Membrane separating technology is so far not economical for smaller plants. Also, the membrane's life expectancy is only three years. Therefore this method can only be applied economically if biogas

volumes of at least 500 m³ per hour are to be treated. Membrane separation can be combined with scrubbers or adsorption columns for pre-conditioning the gas. As the retentate leaves the process on the high pressure side, membrane separation can be combined with a PSA process.

Catalytic oxidation

Catalytic oxidation is applied, if the further processing requires a gas free of oxygen. This could for example be the case to prevent combustions during a steam reforming process. The oxidation catalytic converter is ideally made from platinum. The gas passes the catalysts surface with a temperature of 400 °C and at atmospheric pressure and the contained oxygen reacts with the catalyst.

Appendix 1.3 Reforming of biogas

Reforming aims at producing hydrogen from the purified biogas. The desired composition of the reformed gas strongly depends on the type of fuel cell in which it shall be used. PEM fuel cells require a fuel gas rich in hydrogen and free of carbon monoxide (< 10 ppm CO), because CO acts as catalyst poison. Other poisons are sulphur compounds, halogens, ammonia and siloxanes, which should be removed from the gas prior to reforming.

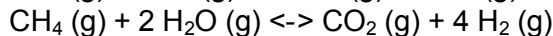
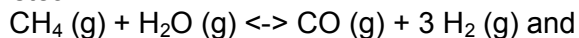
Purified biogas can basically be converted into a hydrogen rich gas by:

- steam reforming (catalytic cracking of methane with water vapour)
- partial oxidation (under-stoichiometric reaction with oxygen)
- autothermal reforming (combination of the previously mentioned processes)

Steam reforming

Steam reforming is a thermo-chemical process to produce hydrogen from hydrocarbons by using high temperature steam (700 – 1100 °C). Steam reforming is the dominant process for producing hydrogen on an industrial scale. Smaller reformer units are being developed to supply mobile or stationary fuel cells with hydrogen.

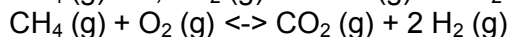
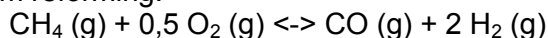
The reforming reaction is endothermic and energy has to be supplied externally – in this case in the form of steam:



A favourable ratio of steam (s) and carbon (c) has proven to be approx. $s/c = 3-3,5$. The reaction takes place inside a reactor that is packed with the catalyst material. A gas burner is usually used for heating up the reactor. For economic reasons the catalyst generally consists of nickel, although catalysts of noble metals would perform better. Depending on the reaction temperature the reformat can reach hydrogen contents as high as 75 – 80 %. The remaining share is composed of CO (10 %), CO₂ (10 %) and traces of methane [2].

Partial oxidation

Partial oxidation refers to the under-stoichiometric reaction with oxygen. In this case only two hydrogen molecules are produced per methane molecule and hence the hydrogen yields is lower than in steam reforming:



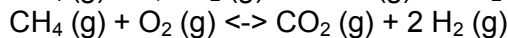
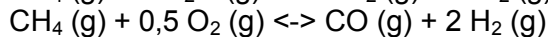
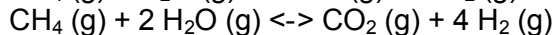
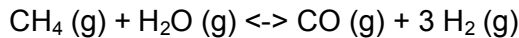
Oxygen is provided by using air as process gas. Air does not only contain oxygen, but also high proportions of nitrogen which dilutes the product gas. Therefore the partial oxidation yield only low concentrations (< 40 %) of hydrogen.

Partial oxidation is a slightly exothermic process and thus does not need to be externally heated. This leads to a very compact construction and an improved cold start behaviour of the reformer. However, the degree of the exothermic process increases with the carbon content of the fuel and might require

additional cooling when gasoline or diesel are reformed. A partial oxidation reformer can additionally be equipped with a catalyst which would further reduce the start-up time at cold starts.

Auto thermal reforming

Auto thermal reforming is a process in which steam reforming and partial oxidation run in parallel in the same catalytic bed. It has been developed to avoid an external heat exchange. The following equations describe the reactions:



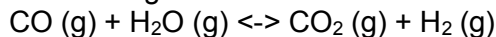
In auto thermal reforming the dosing of water vapour and oxygen or air, respectively, is adjusted in a way that the heat produced at partial oxidation covers the demand of steam reforming. Altogether the auto thermal reforming is a good compromise between the high hydrogen yields of the steam reforming process and the lower complexity and reduced storage volume of the partial oxidation.

Appendix 1.4 Conditioning of reformat

The reforming process does not only yield hydrogen, but also a proportion of 10 – 20 % of carbon monoxide. Carbon monoxide cannot be converted electrochemically inside the PEM-FC and therefore has to be eliminated from the product gas. Depending on the proportion of CO two different processes can be applied for the conversion of CO – the shift reaction and the selective oxidation. If the product gas shall be further enriched in hydrogen, a pressure swing adsorption as described in section 3.3.2 could be installed between the reformer and the fuel cell. The PSA would also eliminate carbon monoxide and thus make further conversion processes superfluous.

Shift reaction

Shift reaction is chosen when up to 10 % of carbon monoxide are contained in the reformat gas. It is usually installed right after the PSA and works according to the following equation:



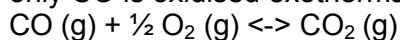
This reaction is exothermal and generally works with a catalyst. Two temperature levels can be distinguished:

- high temperature level > 350°C in combination with Fe₃O₄-catalysts
- low temperature level ~ 200 °C combined with CuO/ ZnO as catalyst.

A positive side effect of the shift reaction is that it also produces hydrogen. The disadvantage is that it cannot completely eliminate CO and, hence, especially the product gas from the low temperature shift reaction still contains 1 – 2 % by volume of CO. The PEM-FC, however, requires CO levels below 50 ppm and therefore another purification process has to be added. Several processes could be applied, but currently the selective oxidation seems to be the most favoured one.

Selective Oxidation

Selective oxidation is used to eliminate CO contents < 1 % by volume in the reformat. For the reaction oxygen is dosed to the gas that passes a catalyst system of Au/Fe₃O₄ or Au/Ti. At the catalyst only CO is oxidised exothermally whereas H₂ simply passes the process:



Appendix 1.5 Use of Biogas in Fuel Cells – current situation in Germany

In Germany several projects have been conducted and are still running that study the use of biogenous gases in fuel cells. As of August 2006 the majority of the projects are being conducted on waste water treatment plants and must still be regarded as pilot projects. The projects mainly test the

performance and efficiency of a MCFC fuelled with sewage gas and are often conducted together with MTU and a power supply company as partners. MCFC systems are chosen because they are developed for utilising gases from biogenous origins and the requirements regarding the gas purification are low compared with the demands of a PEM-FC. In contrast to those, MCFCs need the presence of carbon monoxide or carbon dioxide for the internal reaction, which makes the whole step of eliminating CO₂ and CO, respectively, from the reformed gas superfluous. Another advantage of the MCFC is that it can be fuelled directly with a gas rich in CH₄, because the reforming of the gas takes place inside the fuel cell. The internal reforming is possible, because of the high operating temperatures of the MCFC, and results in higher electrical efficiencies.

One exception regarding the waste water treatment plants is the plant in Köln-Rodenkirchen. In 1998 the City of Cologne decided together with the local energy supplier to install a fuel cell CHP instead of a cogeneration unit based on internal combustion. A phosphoric-acid fuel cell (PAFC) with an electrical capacity of 200 kW has been installed and test runs started in 2000. The experiences with this PAFC showed that the fuel cell itself runs stable and has a high availability. Problems occurred in the periphery of the fuel cell, especially with respect to gas conditioning and purification [2].

Biogas as fuel source

Apart from projects that use sewage gas as feed gas for fuel cells, research institutes as well as manufacturers and operators of biogas plants study the feasibility of combining biogas with a fuel cell CHP. Due to the properties of biogas regarding the high content of carbon dioxide, MCFC's are the main subjects of interest. A very recent project in southern Germany utilises the biogas produced in a dry fermentation process from municipal bio waste in a MCFC⁵. As this plant only started operation in July 2006 no results and experiences are available yet. Nevertheless, the suitability of biogas as basis for operating a PEM-FC has recently been studied at research institutions Germany and Austria. One research project conducted by Schmack Biogas AG, eon and MTU in 2002 – 2003 evaluated the integration of a MCFC into the setting of an agricultural biogas plant. As fuel cells require better gas qualities with respect to the elimination of trace gases than internal combustion units, one focus in this project was put on finding simple, robust and efficient gas purification technologies that can be operated easily in the setting of an agricultural plant. The refined gas was fed into a bench-scale MCFC unit and with this the project showed that it is possible to operate a MCFC on purified biogas. The fuel cell reached an electrical efficiency of 45 %.

A more recent research project conducted at the German Federal Agriculture Research Centre (FAL) aimed at testing the suitability and feasibility of biogas as a fuel basis for PEM-FC. In this context the project attempted to provide evidence that biogas is a suitable fuel for a PEM fuel cell. The second goal was to determine the system parameters that are necessary for an optimal operation of biogas-PEM-FC-systems. Gas was produced in a dry fermentation process and refined using a reformer module that consisted of a steam reforming process with a two stage shift reactor and subsequent selective oxidation. The reformer module also comprised devices for compressing the biogas, desulphurisation as well as for steam generation and internal heat recovery. The reformate gas was fed into a fuel cell module that consisted of two stacks: one test stack (4 cells, 150 W_{el.}) to analyse the effects of trace gases on the cells and one stack (14 cells, 650 W_{el.}) to study the operating performance and identify the relevant energy parameters. The project showed that PEM fuel cells can be operated in combination with biogas, but it also found, that a biogas-PEM-FC-system is not yet fit for marketing. Reforming showed to be one critical component in the system, because the methane conversion rate was comparably low and, hence, hydrogen yields are also low. In the fuel cell stack itself the formation of condensate was a problem when the operating temperature was below 100 °C.

⁵ Anaerobic digestion plant Leonberg, Böblingen District, Germany

For the leading the system to market readiness developing an efficient and reliable reformer for biogas is a crucial precondition.

Another project studying the application of biogas in combination with a PEM-FC was carried out at the University of Graz, Austria. The project also showed that biogas can be upgraded to a quality that can serve as fuel for a PEM-FC. Problems that occurred resembled those at FAL, e.g. the formation of condensate inside the FC stack was found here, too, and efforts had to be made to adapt the gas conditioning and reforming system. One conclusion found by this project is, that Biogas-PEMFC-systems so far show no significant increase in the electrical efficiency compared to conventional cogeneration units.

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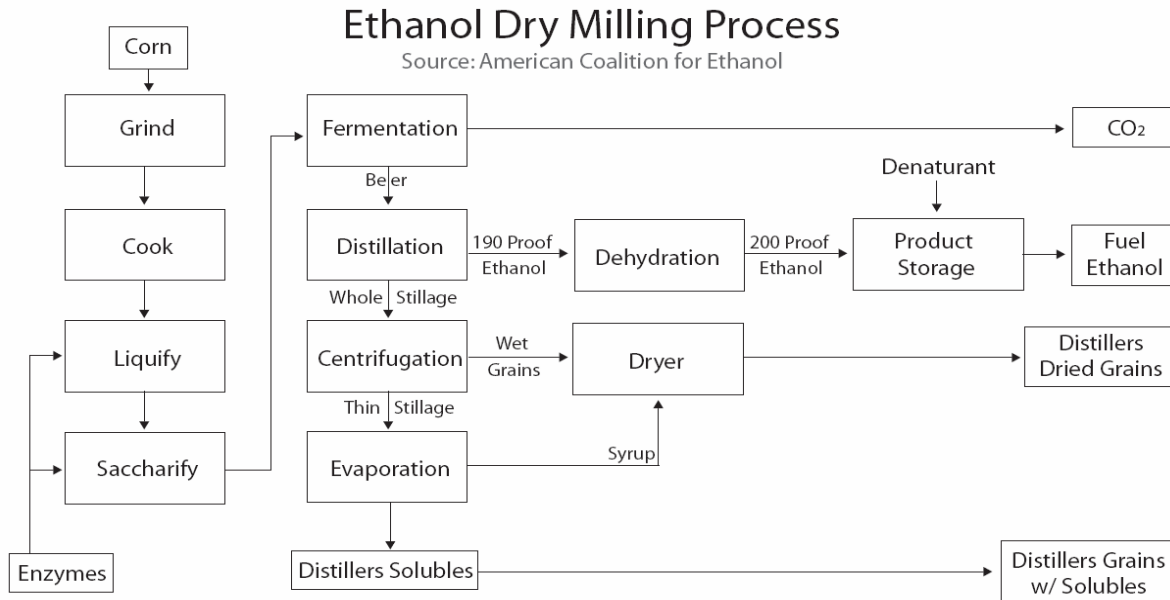
Appendix 2 Technical and Economical description of the combined Methanol and Ethanol Plant

By Martin Moller; DONG energy

Nowadays-Commercial Ethanol Production

The majority of the ethanol produced in the world is made from corn, grain sorghum, wheat, barley, potatoes or sugarcane. All those species contains easily accessible C6 sugars that easily can be fermented by yeast to ethanol.

The major steps in the conventional ethanol production from corn is⁶:



This type of ethanol plant is often referred to as 1st generation plant, and is characterised by only utilising the “easy” part of the biomass for ethanol production.

Milling/grinding

The feedstock passes through a hammer mill, which grinds it into a fine powder called meal.

Liquefaction

The meal is mixed with water and alpha-amylase, then passed through cookers where the starch is liquefied. Heat is applied at this stage to enable liquefaction. Cookers with a high temperature stage (120-150 degrees Celsius) and a lower temperature holding period (95 degrees Celsius) are used. High temperatures reduce bacteria levels in the mash.

Saccharification

⁶ Information is from: <http://www.ethanol.org/howethanol.html>

The mash from the cookers is cooled and the secondary enzyme (gluco-amylase) is added to convert the liquefied starch to fermentable sugars (dextrose).

Fermentation

Yeast is added to the mash to ferment the sugars to ethanol and carbon dioxide. Using a continuous process, the fermenting mash is allowed to flow through several fermenters until it is fully fermented and leaves the final tank. In a batch process, the mash stays in one fermenter for about 48 hours before the distillation process is started.

Distillation

The fermented mash, now called beer, contains about 10% alcohol plus all the non-fermentable solids from the corn and yeast cells. The mash is pumped to the continuous flow, multi-column distillation system where the alcohol is removed from the solids and the water. The alcohol leaves the top of the final column at about 96% strength, and the residue mash, called stillage, is transferred from the base of the column to the co-product processing area.

Dehydration

The alcohol from the top of the column passes through a dehydration system where the remaining water will be removed. Most ethanol plants use a molecular sieve to capture the last bit of water in the ethanol. The alcohol product at this stage is called anhydrous ethanol (pure, without water).

Denaturing

Ethanol that will be used for fuel must be denatured, or made unfit for human consumption, with a small amount of gasoline (2-5%). This is done at the ethanol plant.

Co-Products

There are two main co-products created in the production of ethanol: distillers grain and carbon dioxide. Distillers grain is an important co-product of drymill ethanol production. The drymill ethanol production process uses only the starch portion of the corn, which is about 70% of the kernel. All the remaining nutrients – protein, fat, minerals, and vitamins – are concentrated into distillers grain, a valuable feed for livestock.

Carbon Dioxide is given off in great quantities during fermentation and many ethanol plants collect, compress, and sell it for use in other industries.

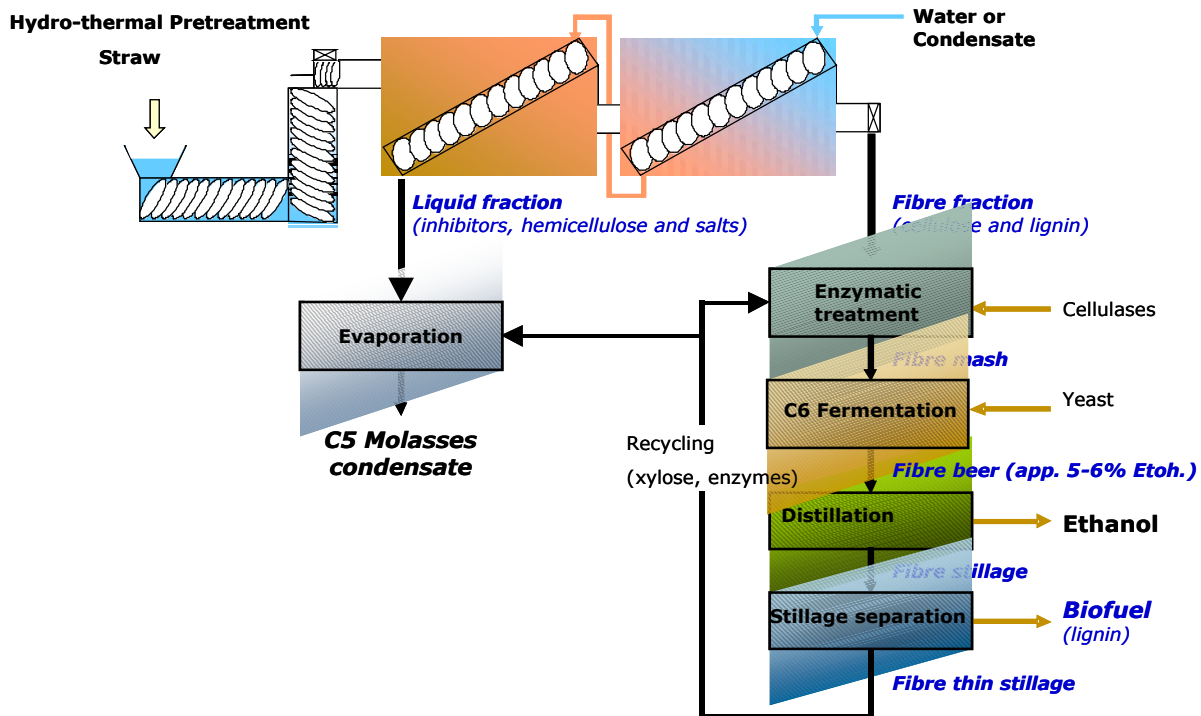
Ethanol Production from lignocellulose, second generation ethanol plants

Lignocelluloses biomass needs to be pre-treated in order to make the cellulose accessible for the enzymes that convert the cellulose to C6 sugars. The major difference between ethanol production from grain and straw is basically the pre-treatment, which liquefies the biomass and convert the liquefied mass to fermentable C6 sugars (dextrose). The fermentation and product upgrading is similar for both processes. This type of plant is referred to as 2nd generation ethanol plant and is characterized by utilizing both the cellulose and starch part of the biomass.

Biomass pre-treatment of lignocellulosic raw materials

The biomass pre-treatment system is developed by ELSAM and is presently under demonstration in a 1 ton per hour pilot plant⁷.

⁷ <http://www.bioethanol.info/>



The biomass is pressurised by newly developed particle pump, and washed with water, at a temperature that wash out the hemicelluloses and salts. Furthermore this thermal treatment makes the cellulose accessible for the cellulase enzymes to convert the cellulose to C6 sugars, that can be fermented by ordinary yeast.

The liquid fraction containing the hemmicellulose and salts is evaporated and converted to a syrup, suitable for animal feed.

The hydrolysed fibre fraction is fermented, and the produced ethanol is removed from the fibres by distillation. The fibre stillage is filtered and the fibres (called the non-fermentables) can be used as a biofuel for generation of electricity, or gasified and converted to synthetic fuels as methanol, FT-Diesel, plastic etc.

Both the fermentation-, distillation-, dehydration- and the denaturing process will be as for ethanol production based on corn, grain, sugar canes etc.

Nowadays-Commercial Methanol Production from fossil fuels

Most of the methanol produced in the world is made from natural gas, and most of the new plants are build in areas with large availability of “Stranded Natural Gas”, where the value of natural gas often is around 0.25 – 1USD/Mmbtu compared to 10-15 USD/Mmbtu in Europe and US (2006 Prices). Typical consumption figures (feed+fuel) range from 29 to 33 GJ per metric ton of methanol produced and varies depending on the individual plant concept.

In China however there exist many smaller Methanol plants based on coal gasification instead of natural gas.

The standard natural gas based methanol plant concept consists of the following process steps⁸:

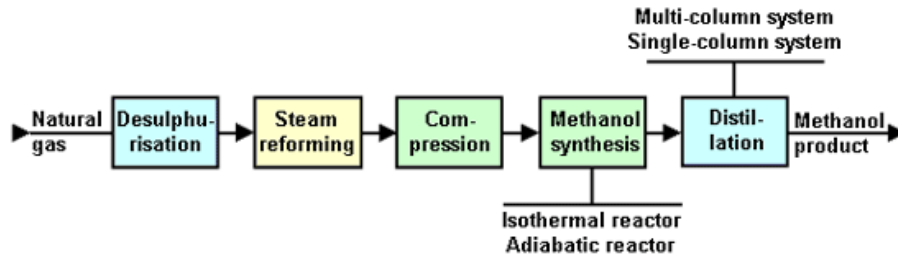


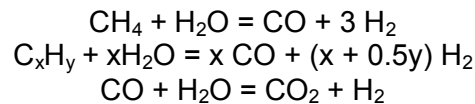
Figure 1

Feed purification

The natural gas is received at around 20-40 bars pressure, and small amount of hydrogen is added in order to convert sulphur components to H₂S, which normally is removed by absorption on ZnO.

Syngas production with steam reforming (SMR) or Autothermal reforming (ATR)

The cleaned natural gas is mixed with steam, and heated to around 800-950 °C. The endothermic reactions takes place across a nickel catalyst packed in tubes in a fired furnace. An excess of steam is used to promote the reforming reaction and avoid carbon deposition on the catalyst. The main reactions are:



Autothermal methane reforming (ATR) is an alternative process to steam reforming of methane (SRM) for synthesis gas and/or hydrogen production. In this process both steam and pure oxygen is added to the cleaned natural gas. By combining an exothermic oxidation reaction with endothermic steam reforming in one reactor, ATR meets the intensive energy demand in conventional SRM and thus allows autothermal reactor operation. The ATR process is the preferred option in today's Mega Methanol plants.

In both the SMR and ATR or any combinations of those, the resulting synthesis gas consists mainly of: H₂, CO, CO₂, H₂O and minor amount of unconverted CH₄.

Syngas cooling and compression

The hot syngas leaving the reforming section is cooled down in a steam boiler generating steam to drive the compressors. The syngas is compressed to around 70 to 150 bar, by the means of large centrifugal compressors before it is feed to the synthesis loop.

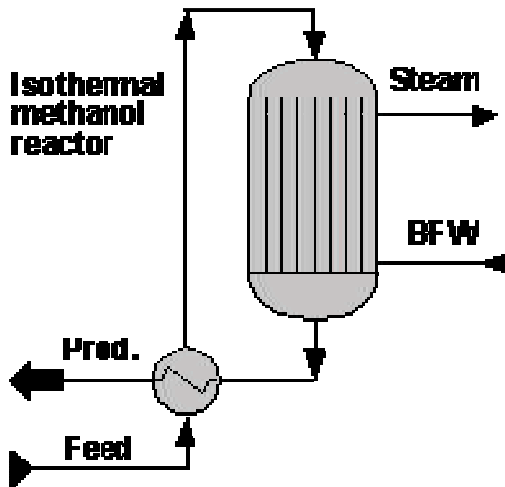
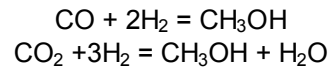
Methanol loop

The synthesis loop consists of a recycle compressor, feed/effluent exchanger, methanol reactor, final cooler and crude methanol separator. Crude methanol, which is condensed downstream of the methanol reactor, is separated from unreacted gas in the separator and routed via an expansion drum to the crude methanol distillation.

⁸ <http://www.uhde.biz/competence/technologies/gas/techprofile.en.epl?profile=3&pagetype=1&pagenum=1>

Methanol Reactor

Methanol is produced from the syngas according to the following reactions:

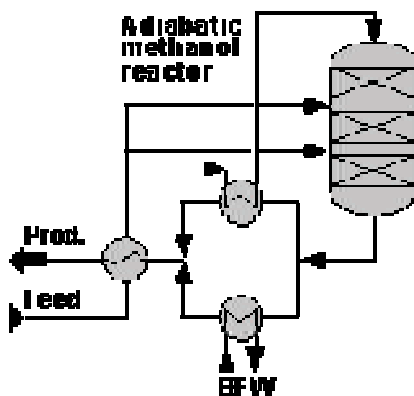


Traditionally Methanol is produced either in isothermal or adiabatic reactors. The isothermal reactor is the most efficient system, as the heat of reaction is directly utilised at reaction temperature level to generate medium-pressure steam.

Normally the isothermal reactor is a tubular reactor with a copper catalyst contained in vertical tubes and boiling water on the shell side. The methanol reaction heat is removed by partial evaporation of the boiler feed water, thus generating 1 metric ton of medium-pressure steam per 1.4 metric tons of methanol.

Figure 2 Isothermal Methanol Reactor

The advantages of this reactor type are: low by-product formation due to almost isothermal reaction conditions, high reaction heat recovery, and easy temperature control by regulating steam pressure.



The multi-bed adiabatic quench is a low cost reactor concept. It is normally used for plants which require no steam generation in synthesis units, due to the fact, that surplus steam is produced during syngas generation (for instance steam reforming).

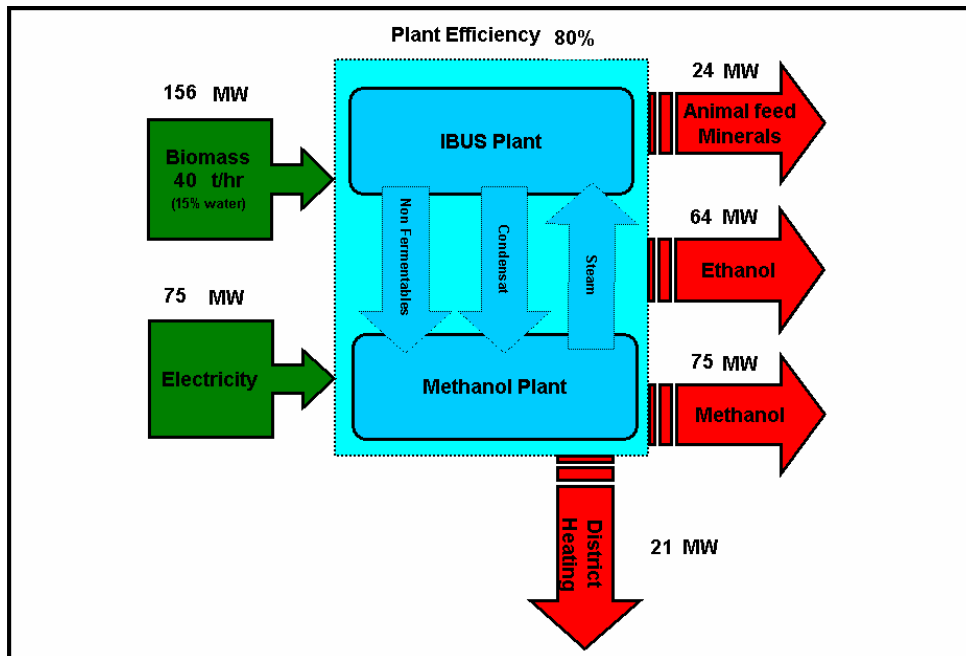
Crude methanol distillation

The conventional distillation unit consists of a topping and a refining section. The light ends present in the raw methanol are removed in the topping column. The stabilised raw methanol, consisting of methanol, water and minor amounts of higher alcohols, is fractionated in the refining section to produce grade AA methanol.

Figure 3 Adiabatic Methanol Reactor

Combined Ethanol and Methanol Process

The second-generation ethanol plant developed by Elsam can utilize the excess heat from a methanol plant, and the methanol plant can utilize the non-fermentable organic matter from an ethanol plant, and hence some important synergies can be obtained. Furthermore the plant includes a 61 MW electrolyser, which will be shut down during electricity peak prices. The methanol plant consists of a gasifier that converts the leftovers delivered from the IBUS plant to synthesis gas. The gasifier uses pure oxygen delivered from the electrolyser.



A more detailed flowsheet can be found at appendix 2.1

A plant based on 40 ton per hour of biomass and 75 MW of electricity, could deliver the following

Yearly Production		
Ethanol	69.360 t/year	1.851.912 GJ
Methanol	97.096 t/year	1.941.917 GJ
Animal Feed, Syrup	82.400 t/year	
District heating	517.330 Gj/year	

It is assumed that the electrolyser is only operated around 6500 hours per year.

Challenges

Presently the IBUS plant is being demonstrated in a pilot plant using 1 ton of straw per hour. The IBUS plant will in the near future most likely be upscaled to around 4 ton straw per hour. The challenges in the IBUS plant will be the mechanical design of the key components; however most of the equipment in an IBUS plant will be somewhat similar to the conventional commercial ethanol plants operating on corn etc.

In the methanol plant focus should be on identifying a suitable gasifier to gasify the leftovers from the ethanol plant. The syngas cleaning, compression, conversion and methanol distillation will be conventional proven technology.

Economy

The total plant investment is calculated to be 190 M Eur. Using 20 years of depreciation and 6% as internal rate of return (IRR), the fuel (Ethanol and Methanol) production cost is calculated to be:

Biomass price	4,70 Eur/GJ
Off peak electricity price, CO ₂ duty paid	32,21 Eur/Mwh
Peak electricity price	46,98 Eur/Mwh
Number of off-peak hours	6500 hr
CO ₂ duty remuneration	20,1 Eur/Ton
Security of supply bonus	0,00 Eur/GJ
Animal feed price	0,08 Eur/kg
District heating sales price	2,68 Eur/GJ
Electrolyser price, Mio Eur / MW	0,40 Mio Eur/MW
Enzyme price, Eur / litre Ethanol	0,15 Eur/ litre Ethanol
Fuel production cost, based on IRR = 6%	16,74 Eur/GJ

Conventional methanol at the world market is sold to around 250 Euro/Ton (12.5 Euro/GJ)

Methanol transport and Storage

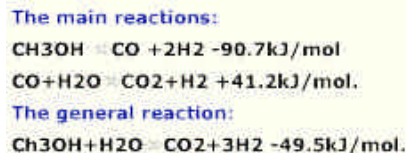
The methanol produced at the above mentioned ethanol and methanol plant need to be transported to a central position located close to the end-user of hydrogen, where it can be reformed to hydrogen, and sent to the local hydrogen grid. The ethanol produced at the plant will be sold to the existing world market for bio ethanol.

The transportation of methanol will be by ordinary methanol transporters. In the case that the combined ethanol and methanol plant is not able to deliver the requested methanol, it can always be procured on the existing methanol market for conventional methanol based on natural gas.

The methanol can be stored commercial available storage tanks. A regional market of say 300 units of 0.75 kWe fuel cell running continuously will consume corresponding to around 2400 kg of methanol per day⁹. A central storage corresponding to the capacity of a truck (20 T) will have enough capacity for 8 days.

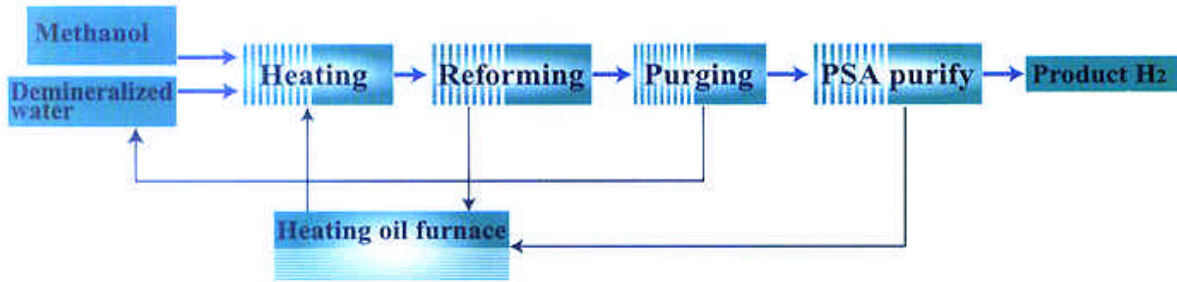
Methanol Cracking/Reforming

Methanol can easily be cracked/Reformed according to the following reactions:



Several commercial methanol reformers suitable to reform in the range of 2400 kg per day are available, please see appendix 3. In general the identified reformers are constructed according to the following diagram from <http://www.airoxniqen.com/hydrogen.htm>

⁹ Calculation can be found in Appendix 2.3



The methanol and water is mixed in specified ratio and pressurized. This mixture is passed through evaporator, metering pump and then to super heater. This hot gas is then fed into a reactor. The reaction of methanol reforming and the shift reaction, takes place in the catalytic reactor of fixed beds simultaneously to form H₂ and CO₂ finally.

A standard commercial methanol reformer plant¹⁰ can deliver from 20-4000 Nm³/hr of 99.99% Hydrogen at 8 – 20 bar. The plant consumes:

Methanol	0.60~0.68 kg/Nm³-H₂
Demineralized water	0.40~0.50 kg/Nm³-H₂
Electricity	0.1 ~ 0.15 kwh/Nm³-H₂

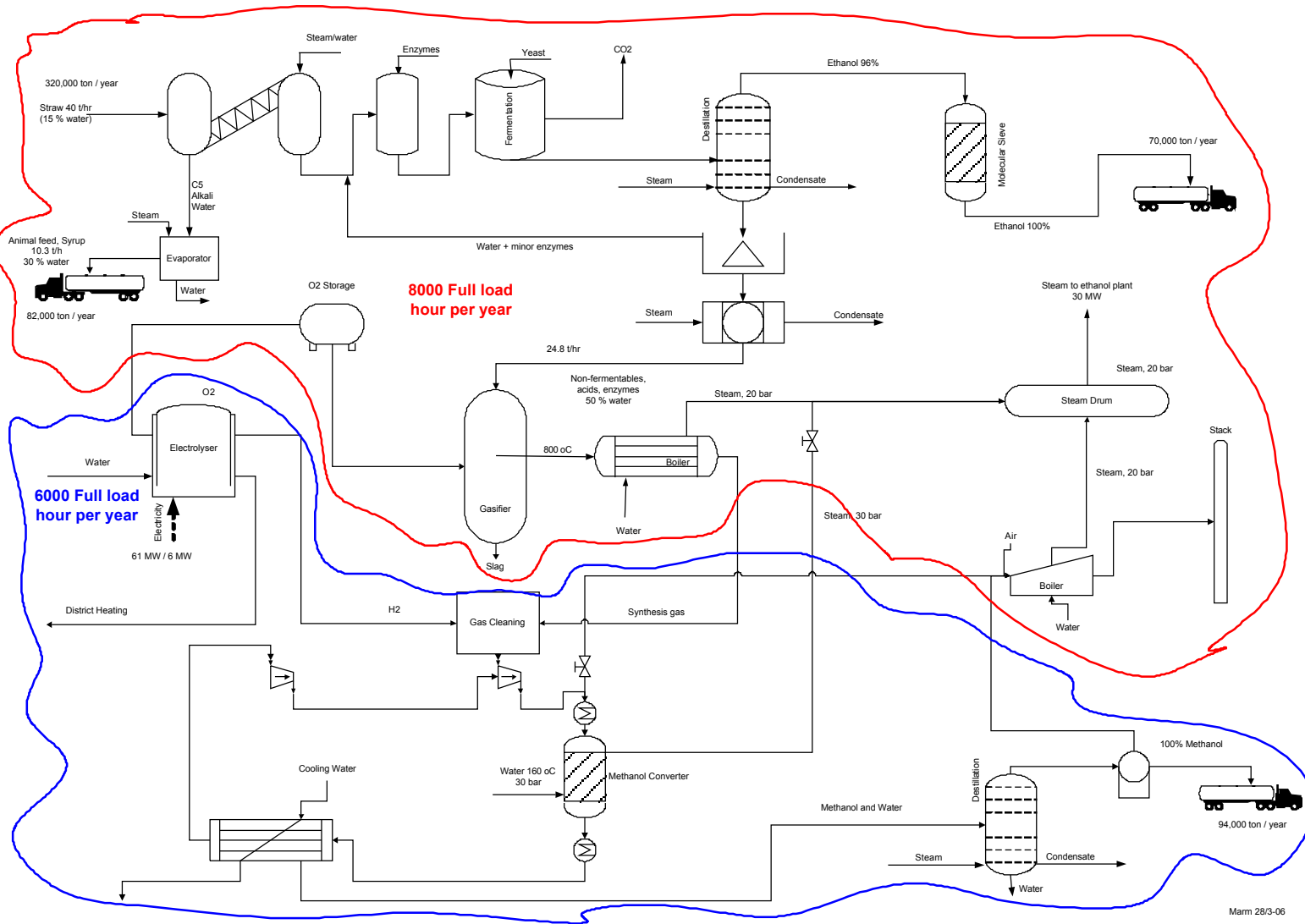
A regional market of 300 units of 0.75 kWe consumes 150 Nm³ hydrogen/hour corresponding to 96 kg methanol per hour¹¹.

Three methanol reformer manufacturers have been contacted, but no price information has been obtained.

¹⁰ <http://www.airoxnigen.com/hydrogen.htm>

¹¹ Calculation is shown on appendix 2.1

Appendix 2.1 Flow-sheet



Mam 28/3-06

Appendix 2.2 Methanol Consumption for a Region

Hydrogen LHV	120.1 MJ/kg
H2 Molar mass	2.0158 kg/kmol
1 Kmol	22.414 Nm ³
Hydrogen LHV	10.80 MJ/Nm ³
Fuel Cell size	0.75 kWe
Number of units per region	300 Pcs
Fuel Consumption	225 kWe
Hydrogen Consumption	150.0 Nm ³ /hr
Relative Methanol Consumption	0.64 kg/Nm ³
Relative water Consumption	0.45 kg/Nm ³
Relative electricity Consumption	0.12 kWh/Nm ³
Methanol Consumption	96.0 kg/hour
Water Consumption	67.5 kg/hour
Electricity Consumption	18.0 kWh

Appendix 2.3 Commercial available methanol reformers/crackers

Mitsubishi Gas Chemical (MGC)¹²

Mitsubishi Gas Chemical (MGC) of Japan has developed a process for producing high purity hydrogen gas from liquid methanol. MGC has built more than 80 methanol-to-hydrogen (MTH) plants ranging in size from 50 Nm³/h (normal cubic meters of hydrogen) to 4,000 Nm³/h. These systems serve small- to medium-sized hydrogen customers in the electronics, glass and ceramics, processing, metal and mining, and fine chemicals industries.

The two-step process consists of a steam reformer using catalyst specially designed for methanol cracking, and a purification system employing pressure swing adsorption. The methanol cracking catalyst is highly active at relatively low temperatures (240-290°C) providing excellent reliability, prolonged service life, and minimal maintenance. The low reaction temperature allows rapid start-up and stop, efficient idling, and flexible operation at loads ranging from 40 to 100%.

Various types of methanol steam reformers have been designed. Earlier designs use catalyst filled tubes that are indirectly heated via combustion of some of the incoming methanol fuel. More recently, there has been an effort to develop “plate type” reformers for methanol reforming. These have a number of potential advantages including compactness, better heat transfer, faster start-up and potentially lower cost. Membrane reactors have also been built for steam reforming methanol. For refuelling station applications, a hydrogen purification stage would be needed, either a pressure swing adsorption unit or a membrane separation stage. The cost of the hydrogen production system might be lower for a methanol steam reformer because it would operate at much lower temperatures than a methane steam reformer. The cost of hydrogen produced from methanol would probably be higher than hydrogen from small-scale steam reforming, because methanol is a more expensive feedstock than natural gas. (Costs for methanol are estimated to be about \$11/GJ versus perhaps \$4-\$5/GJ for methane at the refuelling station.) Assuming an energy conversion efficiency (feedstock to hydrogen) of 75% for each system, feedstock costs alone would be about $(\$11/\text{GJ} - \$5/\text{GJ})/0.75 = \$8/\text{GJ}$ higher for the methanol steam reformer.¹³

¹² www.Methanol.org METHANOL-TO-HYDROGEN FUELING STATIONS

¹³ IEA/H2/TR-02/002 REVIEW OF SMALL STATIONARY REFORMERS FOR HYDROGEN PRODUCTION: *A report for the International Energy Agency Agreement on the Production and Utilization of Hydrogen Task 16, Hydrogen from Carbon-Containing Materials*

Appendix 3 Description of case 3 (only wind to CHP)

By Beatriz Alzueta; CENER

OBJECTIVE

The target of this project is the hydrogen production from renewable electricity sources, in our case from wind energy (by means of water electrolysis), then we storage the hydrogen and use it in a fuel cell to produce both electricity and heat for households.

In this report, we are going to discuss several important aspects of this process: wind power, hydrogen compression, storage and distribution up to the points of use.

WIND POWER

Wind-powered water electrolysis is envisaged as an important source of zero emissions hydrogen in the future. Although it may appear very costly at a first glance, the use of surplus wind power in future scenarios, where wind represents a large share of the electricity market, points to a different outlook.

Wind power has matured greatly over the last twenty years, and the cost of electricity from wind turbines is becoming more competitive with other source, it can compete in profitability with other traditional energy sources like coal-fired power stations (considered traditionally as the cheapest fuel), and even with the nuclear energy, if we consider the costs of repairing the environmental damages.

The conventional way of generating hydrogen from wind turbines is to use electrolyzers.

One of the main problems that can limit the development of the wind power is the chance character of the wind that can give place to severe fluctuations of the wind supply.

A way of reduce this problem is by means of a good weather forecast, in particular of the wind, that it allows to know the wind expected production.

It is important to note that since the power changes with the cube of the wind speed ($P=1/2AV^3$) an error of 5 % in the wind forecast means a much more important error in the power production.

This will be a very important aspect in our project at the time of realizing the estimation of the hydrogen that we need to store, since periods which the wind does not blow and we have no energy to produce hydrogen

Only 30 % of the power installed in the farms is usually going to be use for the production of energy, due to the variability of the wind (among others factors), this will be another factor to take into account to calculate the power which we can have to make our electrolyser work.

From the point of view of the current evacuation from the wind turbines to the electrolyser it will be necessary to create a new line of distribution to move part of the wind power, especially the excesses, from the transformer in the wind farm up to the electrolyser, that is located close to the end-user.^{1,2,3}

HYDROGEN STORAGE

Economics and safety will serve as the main criteria for selecting the appropriate storage technology. The three primary methods for storing hydrogen are compressed gas, liquid, and metal hydride. In relation to our project, since the hydrogen is produced as a gas and in the same state we are going to use it in fuel cells; compressed gas storage has been found to be the most viable option.

Hydrogen has the highest energy content per unit of weight of any known element. It is also the lightest element. As a result, it is characterized by low volume energy density, meaning that a given volume of hydrogen contains a small amount of energy.

One option for compressed gas storage is to increase the operating pressure of the system. This increases the cost of the pressure vessel and compressor, but the reduction in tank size can result in an overall savings. For short storage periods with compressed gas, an optimum occurs where the reduction in tank capital costs is balanced against the increased compressor and capital and O&M costs. At longer storage times, the capital cost reduction becomes the important factor, so the optimum occurs at the maximum operating pressure, which minimizes the tank size and cost.

In the industrial sector a standardization of type has already occurred. As a result, cylindrical tanks with a maximum operating pressure of 50 bar and 2.8m diameter are now available in the following lengths (or heights): 7.3 m (max. capacity at 45 bar: 1305 Nm³), 10.8 m (max. capacity 2250 Nm³) and 19 m (max. capacity 4500 Nm³).

Bottle type storage can also be used as stationary storage as long as the volume is sufficient. Such bottles are available in steel in sizes ranging from 2 to 50 l (corresponding to 0.35 - 8.9 Nm³ and weights of 5.3 - 68 kg) with operating pressures of 200 bar.

The most important problem that we have is the storage size and time estimation due to the fluctuations of the wind, since we will have to think if we want storage hydrogen for a possible absence of wind supply of days or weeks.^{4,5,6,7}

HYDROGEN COMPRESSION

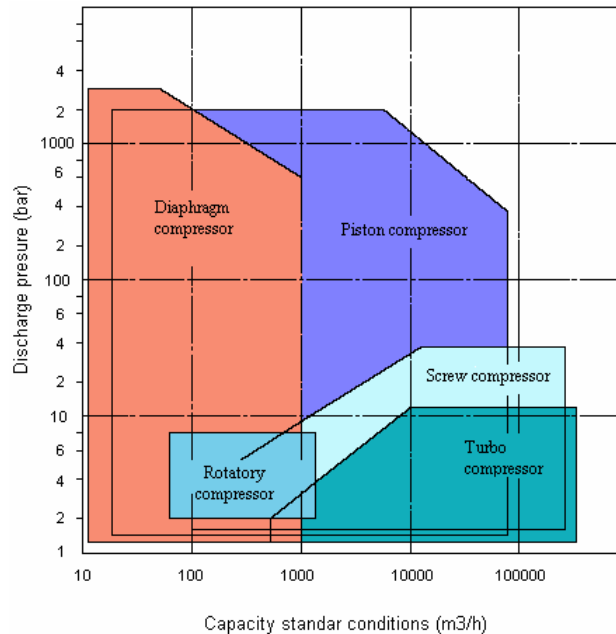
The parameters that we take into account in the election of a compressor are: the nature of gas, the mass flow, the in and out pressure and the temperature of the gas.

Since hydrogen compression is carried out in the same way as compression of natural gas, the procedure is well tested and readily available. New developments are mainly associated with the optimization of the individual units within the total concept.

Almost all common natural gas compressors can be easily modified to be suitable for hydrogen. The range of available compressors for hydrogen therefore ranges from small units with several Nm³/h through put up to those with several hundred Nm³/h. Compressors are primarily used for the filling of stationary high pressure (200-300 bar) and low pressure (10-50 bar) storage tanks.

The compressors that are used are two types, piston and diaphragm. Those of classic piston, they have the disadvantage from which they need lubrication what contaminates the gas that must be purified later. Compressors of piston are developing without lubricating but for the time being, there have other problems of escapes, graze of materials, etc. that reduce considerably the efficiency.

The Figure below represents, by areas, the compressor that it is necessary to use according to the discharge pressure and the capacity



The diaphragm compressors are most adapted probably for our project and due to his characteristics of design, its behaviour comes closer very much the curve of ideal compression for what the efficiencies can be very high.

This logarithmic relationship between the work required and the compression level shows clearly that the initial pressure dominates the level of work required for compression. For example, a compression from 1 to 10 bar requires about the same energy input as a compression from 10 to 100 bar. In any case, it is anticipated that the process of compression supposes an energy expense of approximately 10 % of the energy content of the gas compressed.^{5, 6, 7, 8}

HYDROGEN DISTRIBUTION

The main factors affecting the choice of hydrogen transport are the application, quantity, and distance from the production site to the customer.

The most cost-effective way to move gaseous hydrogen in our project is using pipelines.

The energy loss in an electric power grid can be up to 7.5-8% of the energy it is transferring. This is about double of what is needed to feed gas through a pipeline of the same length.

Hydrogen pipes that are in use today are constructed of regular pipe steel, and operate under pressure at 10-20 bar, with a diameter of 25-30 cm. The oldest existing system is found in the Ruhr area (Germany). It is 210 km long and distributes hydrogen between 18 producers and consumers. This network has been in use for 50 years without any accidents.

It is possible, with certain modifications, to use pure hydrogen in certain existing natural gas lines. This depends on the carbon levels in the pipe metal.

If the use of hydrogen pipelines were to be expanded, possible embrittlement problems would have to be considered. Pipes and fittings can become brittle and crack as hydrogen diffuses into the metal of which they are made. The severity of this problem depends on the type of steel and weld used and the pressure in the pipeline. The technology is available to prevent embrittlement, but depending on the configuration being considered, distribution costs may be affected.

Successful high pressure lines were constructed of austenitic stainless steels which are less prone to hydrogen embrittlement.

The capacity of a given pipeline configuration to carry energy is somewhat lower when it carries hydrogen than when it carries natural gas. In a pipe of a given size and pressure, hydrogen flows about three times faster, but since it also contains about three times less energy per cubic foot, a comparable amount of energy gets through the pipe. Since compressors operate on the volume of a gas, however, not its energy content, the capacity of the compression stations (on an energy basis) is about one third less with hydrogen. In a pipeline system optimized to carry hydrogen, the pipe's dimensions and the size and spacing of the compressors would be changed to accommodate these factors.^{5,6,9,10}

References

- 1._ “Conceptos básicos sobre la inserción d la generación eólica en un sistema eléctrico de potencia” CAMMESA
Downloadable from
<http://energia3.mecon.gov.ar/contenidos/archivos/publicaciones/Insercion%20Eolica.pdf>
- 2._ www.windpower.org
- 3._ www.anglesey-wind.co.uk
- 4._ “An Assessment of Battery and Hydrogen Energy Storage Systems Integrated with Wind Energy Resources in California” Lipman T. E., Ramos R., Kammen D. M.; California Energy Commission, PIER Energy-Related Environmental Research. CEC-500-2005-136.
- 5._ ”Cost of storing and transporting hydrogen” Wade A. Amos
- 6._ “Survey of the economics of hydrogen technologies” GEG Padró and V. Putsche
- 7._ www.hyweb.de
- 8._ www.pdcmachines.com
- 9._ www.ocees.com/mainpages/Distribution.html
- 10._ ” Large Stranded Renewables: The International Renewable Hydrogen Transmission Demonstration Facility” W. C. Leighty, The Leighty Foundation, Juneau, AK

Appendix 3.1 Economical information of case 3 (only wind to CHP)

WIND POWER COSTS

The cost of wind energy is strongly affected by average wind speed and the size of a wind farm. Since the energy that the wind contains is a function of the cube of its speed, small differences in average winds from site to site mean large differences in production and, therefore, in cost.

Wind energy is a highly capital-intensive technology; its cost reflects the capital required for equipment manufacturing and plant construction. This in turn means that wind's economics are highly sensitive to the interest rate charged on that capital.

If environmental costs were included in the calculation of the costs of electricity generation, wind energy's competitiveness would increase further because of its low environmental impacts. Wind energy produces no emissions, so there is no damage to the environment or public health from emissions and wastes such as are associated with the production of electricity from conventional power plants. Wind energy is also free of the environmental costs resulting from mining or drilling, processing, and shipping a fuel.

The main parameters governing wind power economics include the following: Investment costs, including auxiliary costs for foundation, grid-connection, and so on; Operation and Maintenance (O&M) costs; Electricity production/average wind speed; Turbine lifetime; Discount rate.¹ The total cost per installed kW of wind-power capacity differs significantly between countries. The installed cost for a large wind farm was between 850€ and 1,100€ per kilowatt installed.

The total cost per produced kWh (unit cost) is traditionally calculated by discounting and levelizing investment and O&M costs over the lifetime of the wind turbine, divided by the annual electricity production. The unit cost of generation is thus calculated as an average cost over the lifetime. In reality, actual costs will be lower than the calculated average at the beginning of the life, due to low O&M costs, and will increase over the turbine lifetime.

The calculated costs per kWh wind-power as a function of the wind regime at the chosen sites are shown in the figure below.

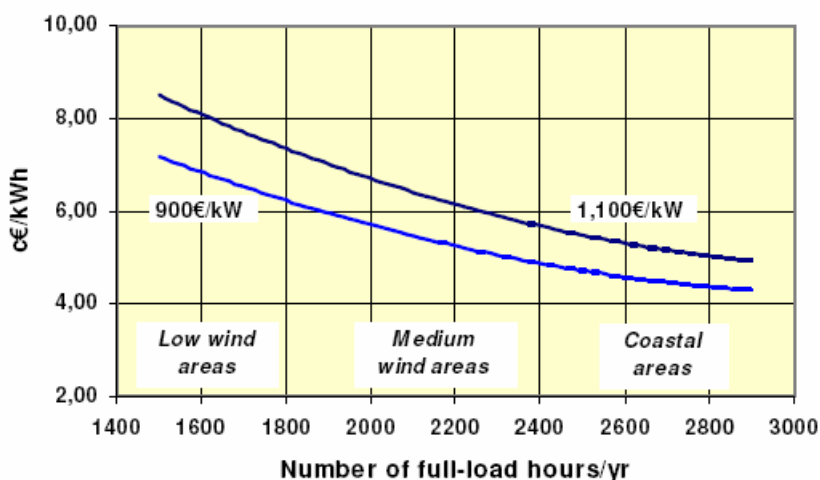
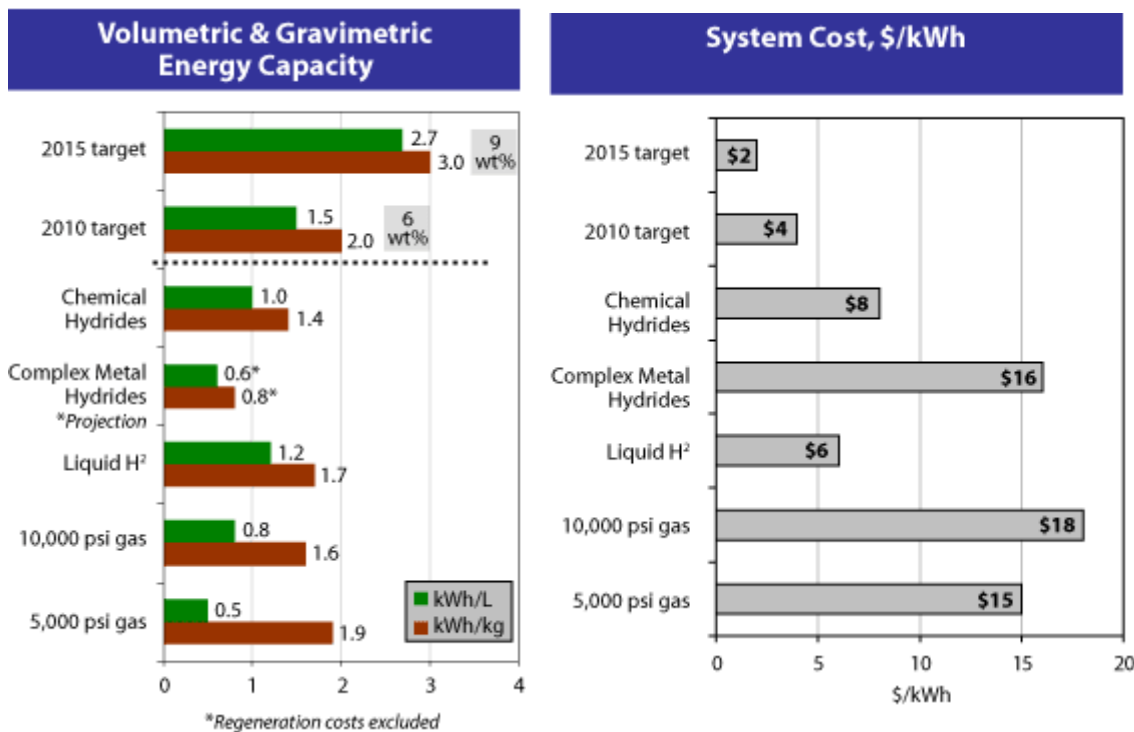


Figura2. Calculated costs per kWh wind-power as a function of the wind regime at the chosen site (number of full load hours)

The cost ranges from approximately 6-8 c€/kWh at sites with low average wind speeds to approximately 4-5 c€/kWh at sites with good average wind speeds.²

STORAGE CAPITAL COSTS

The current status in terms of weight, volume and cost of various hydrogen storage technologies is shown below.³



Capital costs for hydrogen gas storage are 500-2000€/Kg H₂.

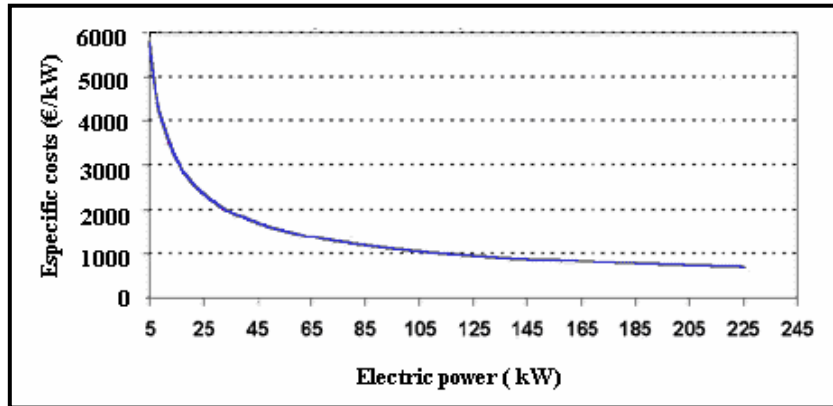
Detailed costs for above-ground compressed gas storage have been estimated by several. Using the standard methodology, the TCI (Total Capital Investment) for daily storage is \$1,700-\$9,000/GJ for stationary vessel storage and \$16,600/GJ for pressurized tube storage.

The cost of hydrogen storage as a compressed gas is highly dependent on the turnover rate. For example, at low turnover rates (e.g., 30 days), the capital cost can be 70%-90% of the storage costs. At high turnover rates (e.g., daily storage), each volume of storage is used more than 300 times per year such that the capital cost, hence the total storage cost for each unit of storage is decreased.^{4,5}

COMPRESSOR CAPITAL COSTS

The exact costs are determined by the choice of a compressor correctly dimensioned in the context of the entire system. As a rough guide, the figure below shows capacity dependent cost data.

Accordingly, prices for small plants (around 10 kWel) can be expected to be up to 5000€/ kWel, with prices falling with increasing plant size to the point where a 250 kWel unit will cost around 500€/kWel.⁶



DISTRIBUTION CAPITAL COSTS

Because a large fraction of the pipeline cost is for installation, natural gas construction prices were used to estimate the pipeline costs.

Hydrogen transport by gas pipelines will cost approx. 1.5 to 2 times the cost of natural gas, per unit energy-distance.⁷

Distribution at local level is carried through pipes of different diameter, at pressures lower than 10 bars and down to a range of 50 to 100 mbar for the individual customers.

Large variations in terms of pipe diameters and pipe material exist in the distribution sector throughout Europe.

Because the distribution networks are by definition constituted by relatively small pipes deployed in populated and often heavily urbanized areas, the cost of their deployment can be considered as independent on pipe diameter, and has a limited dependence on pipe material. Usually, most of the cost is related to the complications of digging, trenching, connecting or more in general carrying the installation of piping in parallel with many other human activities, and without damaging other supply lines and services which are always present under the surface of an ordinary city street.

For this reason, two fixed unit cost values have been assumed in the present report for what concerning investments on distribution lines:

- 1._ A unit cost of 100 €/m for areas at low level of urbanization.
- 2._ A unit cost of 500 €/m for areas at high level of urbanization, based on an estimate of the amount of machinery and manpower necessary for the full replacement of two hundred meters piping in a trafficked road in the centre of a large European city (e.g. identifying old gas, water and electricity mains, cutting into the existing road surface, opening up trenches and divert traffic, etc.).⁸

References

- 1._ “Wind energy-The facts. An analysis of wind energy in the EU-25”
Available from: www.ewea.org
- 2._ “Wind power feasibility 2005”. Available from: <http://www.wfeo.org/>

- 3._ www.eere.energy.gov/hydrogenandfuelcells/storage/tech_status.html
- 4._ "Cost of storing and transporting hydrogen" Wade A. Amos
- 5._ "Survey of the economics of hydrogen technologies" GEG Padró and V. Putsche
- 6._ www.hyweb.de/Knowledge/w-i-energie/w-eng4.html#4.2
- 7._ "Large Stranded Renewables: The International Renewable Hydrogen Transmission Demonstration Facility" W. C. Leighty, The Leighty Foundation, Juneau, AK
- 8._ "Techno-economic assessment of hydrogen transmission & distribution systems in Europe in the medium and long term" P. Castello, E. Tzimas, P. Moretto and S.D. Peteves.

Appendix 4 Identification of electrolyser- technologies

By Lars Yde, BIC

An electrolyser is an on-site hydrogen generating plant based on water electrolysis. Electrolysis takes place when an electric current flows through an electrolyte (in this case, water) from an anode to a cathode. Water molecules are spontaneously split into hydrogen and oxygen gases of high purity, and the resulting gases can then be purified, compressed, stored or distributed according to the requirements.

Three types of electrolysers will be considered for the production of hydrogen by use of wind power for Fuel Cell Household Systems. Solid Oxide Electrolysers (SOE), Proton Exchange Membrane Electrolyser (PEME) and Alkaline Electrolysers (AE).

Solid Oxide Electrolysers (SOE)



SOE is based on a high temperature technology used in Solid Oxide Fuel Cells. The technology offers the possibility of very high efficiencies of more than 90 %.

SOE is in the very beginning of the research phase. Very high current densities have been showed, but it has not so far been possible to achieve useful lifetimes.

Because SOE is not expected to be commercial viable within the next 3 year this technology will not be included in the project.

Proton Exchange Membrane Electrolyser (PEME)



PEME is commercial in sizes up to 44 kW. They deliver hydrogen of high purity and are suitable for pressurizing. Their power density is quite high and therefore useful where space is limited and expensive. As for PEM fuel cells the lifetime is still not sufficient for all applications. More than 40,000 hours is not to be expected.

The most common applications are in labs, submarines and spacecrafts. The efficiency is in the lower end and the price in the high end.

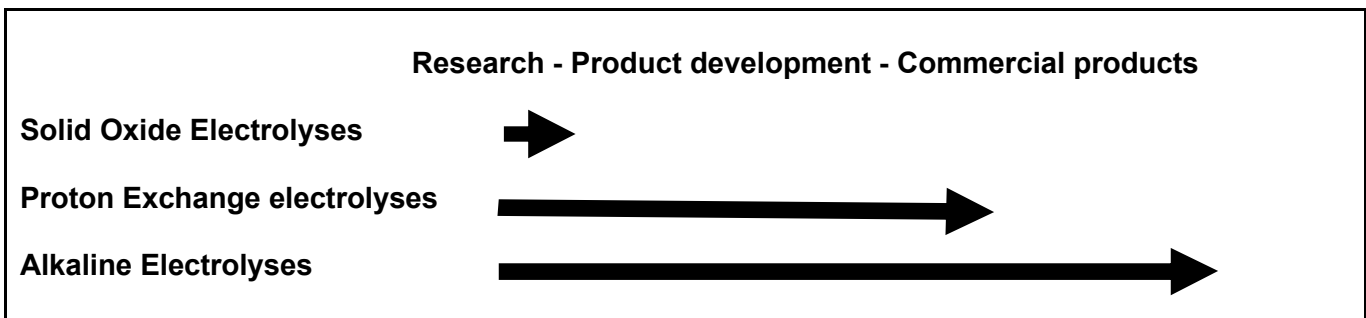
Because of the relative small maximum capacity, the limited lifetime and the high price, the PEME will not be included in the project.

Alkaline Electrolysers (AE)



Production of hydrogen by alkaline electrolysers is an about 100 year old technology used in the chemical and metallurgic industry and for production of fertiliser in the form of ammonia NH₃. The energetic efficiency on converting electricity to hydrogen is reasonably high on modern plants: between 80 and 90%. The lifetime is as high as 20 years, with a major service check every 6 years.

The figure below shows where the three technologies are located on the road from research through development to commercial products.



Intermittent operation

An interesting system aspect of electrolytic processes for the production of hydrogen with electric energy is the possibility of load management in electric grids or locally at the consumer. Like all electrochemical energy converters electrolysers can respond to load changes almost instantaneously. Highly dynamic electrolysers can thus be used for hydrogen production both in the case of fluctuating excess supply e.g. during prolonged, rising renewable electricity production and in the case of demand

deficiencies on the consumer side during low-load periods. In combination with a hydrogen storage tank, an electrolyser can be used for load management in the same way as a variable electricity consumer. This load management can lead to a higher total utilization rate for wind power plants, since generating capacities must be reserved to a minor extent for regulating tasks.

If intermittent operation is used, special attention has to be paid on the lifetime of the electrodes. Such difficulties have been reported by:

Brown, D.E., Mahmood., Man, M. C. M. and Turner, A. K., *Electrochim. Acta*, 1984, 29, 1551-1556.
and

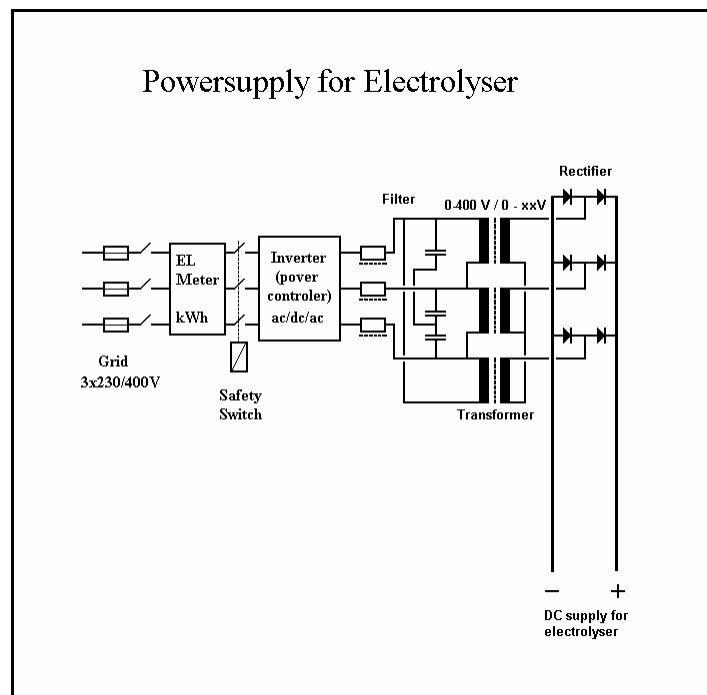
Divisek, J., Schmitz, H. together with Balej, J., *J. Appl. Electrochem.* 1989, 19, 519-530.

AC/DC conversion and power regulating

Electrolysers operates at direct current (DC) at about 1,7 volt per cell. The distribution grid is operated at 400 volt alternating current (AC) at 50 Hertz (Hz). Therefore the current (electricity) from the grid has to be rectified before it can be used to power the electrolyser.

The voltage level also has to be adapted to the level required by the electrolyser by a transformer.

If it is required that the plant can be regulated continuously from zero to full power, a unit for this purpose is also necessary. The drawing below shows the diagram for such a power supply.



Appendix 4.1 Electrolyser market, Western and Eastern

The relative high prices of electrolysers are a barrier for the use of low price wind power for hydrogen production. It is also a significant barrier for the application of hydrogen as an energy carrier in the transport sector and as fuel for micro CHP systems. These applications show a growing interest in EU, Japan and USA. Therefore there is no doubt there will be an increasing market for electrolysers if cheap electrolysers can be brought to the market.

In East Europe, Poland, Ukraine and especially Russia there has been developed knowledge, experience and expertise concerning electrolyser plants, among other to be used in furnaces and ovens in the metal industry and for cooling of power plant generators. Therefore these companies are able to deliver complete plants at a much lower price than the current West European level. However, these companies are not at the moment able to deliver plants to the western market because of the requirements to guarantees, CE-marking, service, etc.

Western market

Seven major western suppliers of alkaline electrolysers have been identified as:

- Hydro in Norway
- Hydrogenics in Canada
- Iht in Switzerland
- ELT in Germany
- AccaGen in Switzerland
- Erre Due in Italy
- DEMAG

The plants can be divided in two groups: Atmospheric and pressurized plants. The atmospheric plant operates at atmospheric pressure of one bar and the pressurized plants operate at pressures from 4 to 30 bar depending of the make.

Western Supplier	Atmospheric plants	Pressure plants
Hydro	200 to 2000 kW	50 to 300 kW
Hydrogenics		60 to 240 kW
Iht / ELT	14 to 1500 kW	500 to 3400 kW
AccaGen		7 to 500 kW
Erre Due		100 to 200 kW
DEMAG	4 to 1000 kW	

ELT and Iht both deal with Lurgi and Bamag electrolysers. ELT has its own production facilities while ELT use sub suppliers.

Erre Due plants are bargained through the Danish company H2Logic.

Below is showed the filled in questionnaire from the five manufacturers. It has not been possible to get all information from all manufacturers.

Norsk Hydro Electrolysers AS

Heddalsveien 11
 P.O. Box 44
 N-3671 Notodden
 Norway
 Phone+47 35 09 39 99
 Fax+47 35 01 44 04
 E-mail electrolysers@hydro.com

Personal contact:
 Marketing and Sales Director
 Mr. Roy Grelland
 Roy.Grelland@hydro.com



Specifications of Electrolysers	Hydro 1 Bar	name /model	name /model	name /model	name /model
(no external equipment, gasseperator, cooling pumps, power supply, etc.)		5010	5020	5030	5040
Max capacity	Nm3/h	50	150	300	377
Max power	kW	205	615	1230	1546
Efficiency	Kwh / Nm3 H2	4.1	4.1	4.1	4.1
Number of cells		31	92	183	230
DC Voltage	V				
DC Current	Amp	4000	4000	4000	4000
Current density	A /cm2				
Outlet Pressure	Bar	1	1	1	1
Operation range	from x % to y%	20 - 100	20 - 100	20 - 100	20 - 100
Operation speed	dA / dt	12 minutes	12 minutes	12 minutes	12 minutes
Purity	% hydrogen	99.9	99.9	99.9	99.9
Weight	Kg				
Diameter	m				
Circulation of electrolyte	l/min				
KOH	%				
Lifetime	Years				
Operation temperature	Celsius	80	80	80	80
Maintenance costs	USD/ year				
Service time	Years				
Anode material					
Cathode material					
Diaphragm material					
Price	Euro				



Specifications of Electrolysers	Hydro 12 Bar	name mode	name mode	name mode	name mode	name mode	name mode	name mode	name mode	name mode	name mode
(no external equipment, gaseparator, cooling pumps, power supply, etc.)											
Max capacity	Nm3/h	10	12	16	20	24	30	40	50	60	65
Max power	kW	48	58	77	96	115	144	192	240	288	312
Efficiency	Kwh / Nm3 H2	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Number of cells											
DC Voltage	V	60	72	104	128	160	192	136	168	200	216
DC Current	Amp	820	820	760	760	760	760	1500	1500	1500	1500
Current density	A /cm2										
Outlet Pressure	Bar	12	12	12	12	12	12	12	12	12	12
Operation range	from x % to y%	50 - 100	50 - 100	50 - 100	50 - 100	50 - 100	50 - 100	50 - 100	50 - 100	50 - 100	50 - 100
Operation speed	dA / dt										
Purity	% hydrogen	99.9	99.9	99.9	99.9	99.9	99.9	99.9	99.9	99.9	99.9
Weight	Kg										
Diameter	m										
Circulation of electrolyte	l/min										
KOH	%										
Lifetime	Years										
Operation temperature	Celsius										
Maintenance costs	USD/ year										
Service time	Years										
Anode material											
Cathode material											
Diaphragm material											
Price	Euro										

Hydrogenics Europe N.V

Nijverheidsstraat 48c,
B-2260 Oevel,
Belgium
+32(0)14.46.21.10
F: +32(0)14.46.21.11
europa@hydrogenics.com

Personal contact:

Christian Machens
cmachens@hydrogenics.com



T:

Specifications of Electrolyzers	Hydrogenics 10 / 25 BAR	name /mode	name /mode	name /mode	name /mode	name /mode	name /mode	name /mode	name /mode	name /mode	name /mode
(no external equipment, gaseparator, cooling pumps, power supply, etc.)		1000/15	1000/30	1000/45	1000/60	1000/90	1000/120	4000/50	4000/100	4000/150	4000/200
Max capacity	Nm3/h	15	30	45	60	90	120	50	100	150	200
Max power	kW	63	126	189	252	378	504	210	420	630	840
Efficiency	Kwh / Nm3 H2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Number of cells											
DC Voltage	V										
DC Current	Amp	1000	1000	1000	1000	1000	1000	4000	4000	4000	4000
Current density	A /cm2										
Outlet Pressure	Bar	10 /25	10 /25	10 /25	10 /25	10 /25	10 /25	10 /25	10 /25	10 /25	10 /25
Operation range	from x % to y%	25 - 100	25 - 100	25 - 100	25 - 100	25 - 100	25 - 100	25 - 100	25 - 100	25 - 100	25 - 100
Operation speed	dA / dt										
Purity	% hydrogen	99.9	99.9	99.9	99.9	99.9	99.9	99.9	99.9	99.9	99.9
Weight	Kg				2600						
Diameter	m										
Circulation of electrolyte	l/min										
KOH	%	30	30	30	30	30	30	30	30	30	30
Lifetime	Years										
Operation temperature	Celsius										
Maintenance costs	USD/ year										
Service time	Years										
Anode material											
Cathode material											
Diaphragm material											
Price	Euro										

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 Clos-Donroux
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 1870 Monthey 1
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www.iht.ch

Personal Contact:
 Ernest Burkhalter
 eb@iht.ch



Specifications of Electrolysers	Iht,	name /model	name /model	name /model
(no external equipment, gasserator, cooling pumps, power supply, etc.)		Lurgi system	Bamag system	
Max capacity	Nm3/h	110 to 760	3 to 330	
Max power	kW	473 to 3268	11.7 to 1287	
Efficiency	Kwh / Nm3 H2	4.3	3.9	
Number of cells			10 to 100	
DC Voltage	V			
DC Current	Amp			
Current density	A /cm2			
Outlet Pressure	Bar	32	1	
Operation range	from x % to y%	25-100	25 to 100	
Operation speed	dA / dt			
Purity	% hydrogen	99.9	99.8	
Weight	Kg			
Diameter	m			
Circulation of electrolyte	l/min			
KOH	%			
Lifetime	Years			
Operation temperature	Celsius			
Maintenance costs	USD/ year			
Service time	Years			
Anode material				
Cathode material				
Diaphragm material				
Price	Euro			

AccaGen SA,
 Via San Mamete,
 CH-6805 Mezzovico
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 F +41 91 940 21 04,
info@accagen.com
www.accagen.com

Personal contact:
 R. Dall'Ara, CEO
r.dallara@accagen.com



Specifications of Electrolysers	AccaGen 6 / 10 / 30 Bar	name /model	name /model	name /model	name /model	name /model	name /model	name /model
(no external equipment, gaseparator, cooling pumps, power supply, etc.)		AGE 1.0	AGE 2.5	AGE 5	AGE 10	AGE 20	AGE 50	AGE 100
Max capacity	Nm3/h	1	2.5	5	10	20	50	100
Max power	kW	4.8	11.8	23.2	45	89	222	440
Efficiency	Kwh / Nm3 H2	4.8	4.7	4.6	4.5	4.5	4.5	4.4
Number of cells								
DC Voltage	V							
DC Current	Amp							
Current density	A /cm2							
Outlet Pressure	Bar	6/10/30	6/10/30	6/10/30	6/10/30	6/10/30	6/10/30	6/10/30
Operation range	from x % to y%							
Operation speed	dA / dt							
Purity	% hydrogen	99.8	99.8	99.8	99.8	99.8	99.8	99.8
Weight	Kg							
Diameter	m							
Circulation of electrolyte	l/min							
KOH	%							
Lifetime	Years							
Operation temperature	Celsius							
Maintenance costs	USD/ year							
Service time	Years							
Anode material								
Cathode material								
Diaphragm material								
Price	Euro							

Erre Due dealer:
 H2 Industrial ApS
 Tjelevej 42
 7400 Herning
 Denmark
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 F +45 9714 0899
www.h2industrial.com

Personal contact:
 Jesper Nissen Boisen
 jb@h2industrial.com



Specifications of Electrolysers	Erre Due	name /model	name /model	name /model
(no external equipment, gasseperator, cooling pumps, power supply, etc.)		32.00	64.00	
Max capacity	Nm3/h	21.33	42.63	
Max power	kW	108	213	
Efficiency	Kwh / Nm3 H2	5.1	5.0	
Number of cells				
DC Voltage	V			
DC Current	Amp			
Current density	A /cm2			
Outlet Pressure	Bar	4	4	
Operation range	from x % to y%			
Operation speed	dA / dt			
Purity	% hydrogen	99.8	99.8	
Weight	Kg	2700		
Diameter	m			
Circulation of electrolyte	l/min			
KOH	%			
Lifetime	Years			
Operation temperature	Celsius			
Maintenance costs	USD/ year			
Service time	Years			
Anode material				
Cathode material				
Diaphragm material				
Price	Euro	130,000	190,000	

DEMAG manufacturer and supplier

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Personal contact:
 Wolfgang Hug
 Project Engineering and Development
wolfgang.hug@ht-hydrotechnik.de



Specifications of Electrolysers	DEMAG	name /model	name /model	name /model	name /model	name /model	name /model	name /model	name /model
(no external equipment, gas separator, cooling pumps, power supply, etc.)		EV1	EV5	EV6	EV12	EV25	EV 50	EV100	EV150
Max capacity	Nm3/h	1.0	4.0	9.0	18.5	37.0	74.0	148.0	250.0
Max power	kW								
Efficiency	Kwh / Nm3 H2								
Number of cells									
DC Voltage	V								
DC Current	Amp								
Current density	A /cm2								
Outlet Pressure	Bar								
Operation range	from x % to y%								
Operation speed	dA / dt								
Purity	% hydrogen								
Weight	Kg								
Diameter	m								
Circulation of electrolyte	l/min								
KOH	%								
Lifetime	Years								
Operation temperature	Celsius								
Maintenance costs	USD/ year								
Service time	Years								
Anode material									
Cathode material									
Diaphragm material									
Price	Euro								
Price	USD								
Price	DKK								

Eastern market

During the search for electrolyser companies contacts to several scientists, businessmen and also with Commercial Consulates Offices in Russia and Ukraine were made. Its purpose was to get as much information as possible. However, due to the nature of the task, Eastern suppliers of electrolysers need more time, than expected, for any activity (answers). For this reason, some information and offers requested from the potential interesting, identified partners could still not be presented in this report.

Luckily the most interesting company Uralhimmash has provided the most detailed information. The answering of the form was followed up by a visit to the factory in Ekaterinbourg, Ural, Russia.

The identified presumed electrolyser suppliers/producers from Russia, Ukraine, Poland, Croatia and China are listed below.

Russia	
1.	"Usolmash" Production Association
2.	"Krasnaya Zvezda", filial
3.	Research Center for Development of Mining Concentration Machinery
4.	Shipbuilding and Repair Works
5.	"Energokhimstroyproyekt
6.	Protvino Branch of Research Institute of Research and Production Association "Luch" Federal State Unitary Ent.
7.	"Liga"
8.	"Zaria" Plant of Chemical Equipment
9.	"Uralkhimmas"
Ukraine	
1.	URALSKI ZAVODY Industrial Company, Ltd
2.	Seredyna-Buda Metallurgic Equipment Plant, PubJSC
Croatia	
1.	TITAN-SISAK doo
China	
1.	Beijing Chemical Machinery Plant
2.	Jilin Mine Exploration Machinery Factory
3.	Harbin Environmental Protection & Hydrogen Equipment Co

Similarly to the Western market of electrolysers, the market in East Europe seems to be dominated by only few reputable companies - located in Russia.

Based on our business trip to Ekaterinbourg, it becomes probable that Uralkhimmash has a monopoly position in the industrial alkaline electrolyser production in Russia and former USSR countries.

Uralhimmash
 JSC “Uralkhimmash”
 Khibinogorsky per. 33
 620010 Ekaterinburg
 Russia

Contact person:
 Andrey Arkadyevich
 Director of the direction of the electrolyzers
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Specifications of Electrolyzers	Uralhim-mash	name /model	name /model	name /model	name /model	name /model	name /model	name /model
(no external equipment, gaseparator, cooling pumps, power supply, etc.)		SEU 4	SEU 10	SEU 20	SEU 40	FV 250M	FV500M	BEU
Max capacity	Nm3/h	4	10	20	40	250	500	125, 250
Max power	kW	20, 6	50	102, 5	205	1 520	3 150	625, 1 250
Efficiency	Kwh / Nm3 H2	5, 15	5	5	5	5, 3	5, 3	5
Number of cells		30	25	50	100	82	166	3x100, 6x100
DC Voltage	V	75	60	115	230	450	850	230
DC Current	Amp	330	1 000	1 000	1 000	8 000	8 000	1 000
Current density	A /cm2							
Outlet Pressure	Bar	1 0	1 0	1 0	1 0	1	1	1
Operation range	from x % to y%							
Operation speed	dA / dt							
Purity	% hydrogen	99	99, 7	99, 7	99, 7	99, 5	99, 5	99, 7
Weight	Kg	1290	3390	4720	7435	59420	101360	7453x3, 7435x6
Diameter	m	0,46	0,89	0,89	0,89	1,6x1,9	1,6x1,9	0,89
Circulation of electrolyte	l/min							
KOH	%	300-400 g/liter						
Lifetime	Years	20	20	20	20	210	210	20
Operation temperature	Celsius	85	85	85	85	85	85	85
Maintenance costs	USD/ year							
Service time	Years	6	6	6	6	6	6	6
Anode material		Fe	Fe	Fe	Fe	Fe	Fe	Fe
Cathode material		Ni	Ni	Ni	Ni	Ni	Ni	Ni
Diaphragm material		асбест	асбест	асбест	асбест	асбест	асбест	асбест
Price	Euro							

Appendix 4.2 Barriers: Prices, Efficiency, CE-Marking, Safety

Prices

Very large plants have been installed for production of fertiliser in countries with cheap hydropower, up to more than 100 MW in capacity. Another common application in Eastern Europe and Russia is the use of hydrogen for cooling of power plant generators.

Although the technology is well known and mature, the price is too high for energy applications. The reason is that the market is limited and there are just a few suppliers to cover the world market. A rough estimate is a magnitude of 10 MW per year.

When in the future electrolyzers will be used in grids with a large amount of wind power, 10 MW will be the magnitude of a single plant necessary to balance just one wind farm.

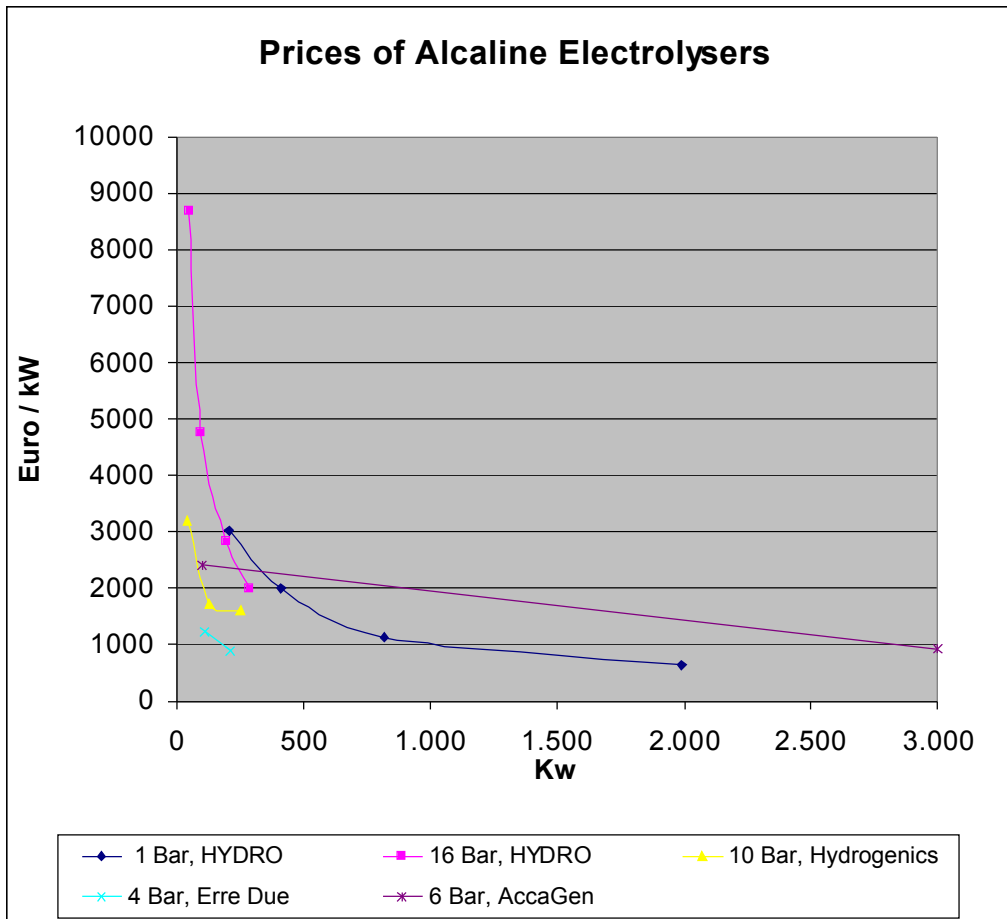
Today the market is characterized by few plants sold annually at high prices for industrial use, contrary to what we will see in the future where a large number of plants for energy use will be sold at a very low price.

If we look at the development of prices of wind turbines we will get a good picture of what will happen when energy plants are produced in large numbers. During the past 20 years the price of wind power is reduced to 20% of what it was 20 years ago.

There is no reason not to believe that we will see the same development for electrolyser plants.

Electrolysers have the reputation of being very expensive. It is true but often when the price per kW of a specific electrolyser is mentioned the size of the plant is not given. The specific price of electrolysers (EURO / kW) is strongly dependent of the size of the plant.

The price analysis below shows it very clearly. It can be seen that the price per kW installed capacity varies with a factor of 10 depending on the size of the plant.

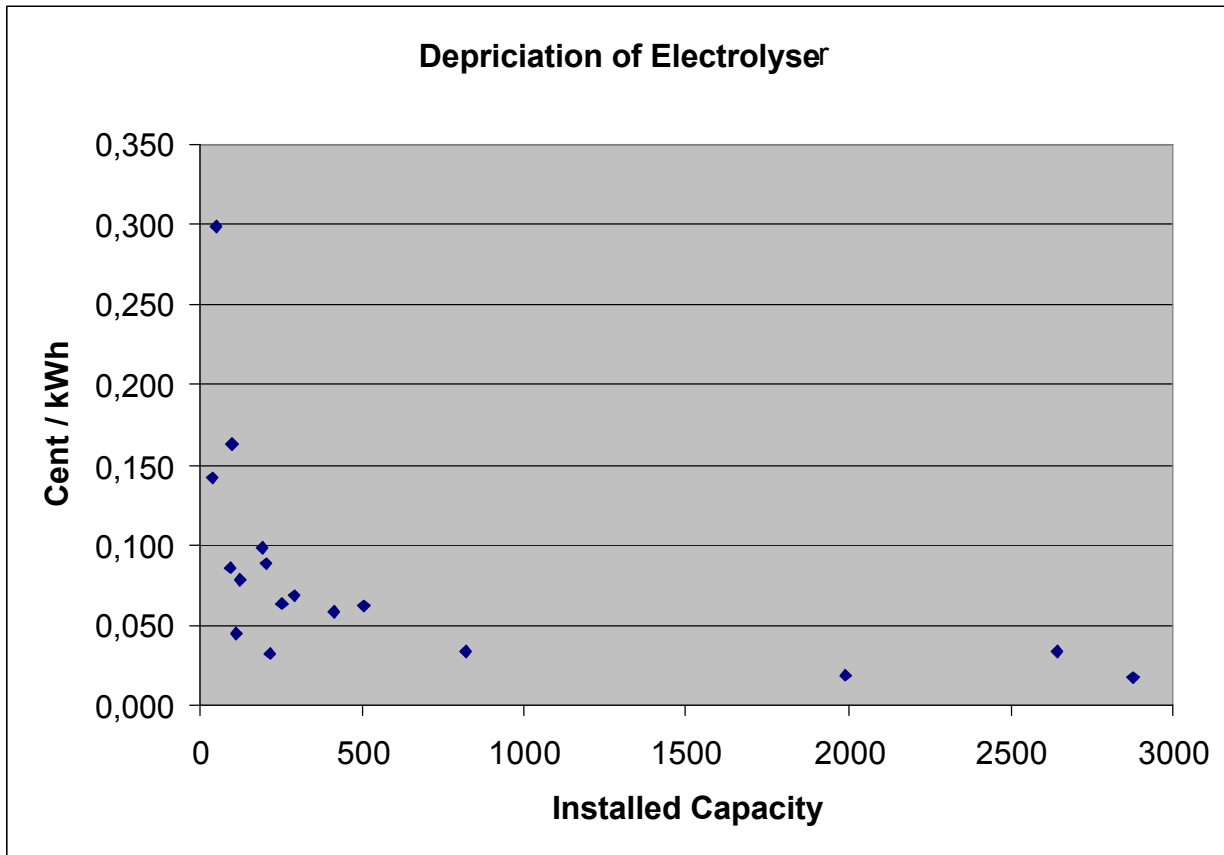


The prices are collected over the last 5 years from year 2000 and therefore not consistent. Electrolyser plants are often tailor-made and direct price comparison between the different manufactures is therefore not possible. Anyhow, the graphic shows clearly that in order to obtain relatively cheap electrolysers, they have to be as large as possible and at least 500 kW.

The company Erre Due seems to disturb the picture, but because they only make small plants and with a low efficiency (69%) it is not so important for this study.

In order to get a picture of the influence of the price of the electrolyser on the hydrogen produced, a calculation has been made using the same data as in the graphic above. Furthermore a depreciation period of ten years and running hours of 4000 per year was used.

For a 2.9 MW plant the depreciation is found to be only 0.018 cent per kWh. To get the price of the hydrogen in Eurocent per kWh the installation costs, price of electricity, running costs and maintenance costs have to be added.



Efficiency

The efficiency of an electrolyser is defined as the ratio of the higher heat value (HHV) of the hydrogen produced and the DC electricity consumption of the electrolyser.

Simple electrodes made of mild steel and coated with nickel have an efficiency of about 68% and the most advanced experimental electrodes manufactured by vacuum plasma spray technique have reached efficiencies as good as 90%.

The commercial electrolysers have an electricity consumption of 4.1 to 4.8 kWh per normal m³ produced. Using the HHV of 3.5 kWh/m³ hydrogen the efficiencies between 85 and 73% are calculated.

The HHV is always used when calculating the efficiency of electrolysers whereas the lower heat value (LHV) of 3.0 kWh/m³ is used when the efficiency of fuel cells is calculated. The reason is that the fuel cell is consuming hydrogen and therefore the calculated efficiency will be higher when the LHV is used.

CE-Marking

All the Western suppliers have the CE- marking that is required for installing electrolyser plants in Europe.

The plants from Russia have only the Russian approvals and need to be CE-marked. In order to obtain the CE-marking, electrolyser plants must meet the requirements in the relevant directives.

Many directives require products/systems with greater risks to be independently certified; this must be done by a "Notified Body". This is an organization that has been nominated by a Member Government and has been notified by the European Commission. Notified bodies serve as independent test labs and perform the steps called out by directives. They have the necessary qualifications to meet the testing requirements set forth in the directives. Notified bodies are private sector organization or a government agency. Manufacturers may choose a notified body in any member state of the European Union.

A Notified Body is able to offer some of the services required:

- product testing
- type examination certificate issue
- Technical File and design dossier evaluation
- surveillance of product and quality system
- identification of standards

In order to have the electrolysers certified by a Notified Body, the following actions have to be made:

1. Select the applicable product standards and test methods for your product and select a Notified Body.
2. Establish an authorized representative in the European Union for your product. Some directives require that a manufacturer designate in the European Union an authorized representative to produce Technical Documentation (or sometimes called Technical File) in a timely fashion when called upon to do so. The CE-Marking itself is not meant to provide details about the product to Surveillance Authorities.
3. Technical Documentation (Technical File): The directives require for many products that a Technical Documentation (Technical File) be prepared by the manufacturer. The Technical Documentation (Technical File) holds information that verifies that the testing was conducted properly and that the product complies with applicable standards.
4. Prepare a Declaration of Conformity. The Declaration of Conformity must contain information adequate for tracing the product back to the manufacturer or the authorized representative in the European Union. It may include a list the directives and standards that your product conforms to, product identification, the manufacturer's name, address and signature.
5. Affix the CE-Marking to your product. There are specific rules to adhere to for the CE-Marking. These rules address the size and location of the Marking; affixing the CE-Marking to products, packaging and material or documents shipped with the product; and specific limitations on when and who is permitted to affix the CE-Marking.

Safety

Safety is an important issue for electrolyser plants and will be handled by the CE-marking. Especially two directives will secure the necessary safety level regarding the hydrogen as a potential explosive pressurized gas. It is:

- 1) DIRECTIVE 94/9/EC concerning equipment and protective systems intended for use in potentially explosive atmospheres.
- 2) DIRECTIVE 97/23/EC concerning pressure equipment

Two other directives will be involved in the approval of the power supply and the control system. That is:

- 1) Council Directive 73/23/EEC relating to electrical equipment designed for use within certain voltage limits.
- 2) Council Directive 89/336/EEC relating to electromagnetic compatibility

Conclusion

Five Western and 15 Eastern companies related to delivery of electrolyser systems have been identified. Prices of the western plants show that systems not smaller than 500 kW have to be used in order to get reasonable specific prices (EURO/kW). One Eastern European company, Uralkhimmash has been visited. Price negotiations are not finished, but promising.

Appendix 5 Status on Balance of Plant components.

by Jesper Thomsen; Dantherm

Today fuel cell systems are surrounded by a lot of confusion as these systems are still in a commercially premature phase. Focus has so far been devoted mainly to developing the core technology and setting up demonstration systems. As the technology today is approaching the targets for commercial use focus is to a large extent turned towards optimizing balance of plant components and system design.

Two focus areas are of outmost importance today:

- System design.
- Development and introduction of new off the shelf components.

System design

Pressure loss

A major challenge in system design today is to identify appropriate air blowers or air compressors enabling low parasitic system losses and long lifetime. A means to overcome this is designing the fuel cell stacks for low pressure drop whereby simple air blowers with long lifetime and low cost may be applicable. Currently low pressure drop is though causing challenges on water management which may lead to compromises on lifetime.

Water management

Water management on fuel cell stacks today is adding complexity and costs to systems. A number of fuel cell manufacturers are trying to design stacks with internal water management. Still this is compromising on lifetime and is therefore mainly in focus for applications requiring a limited number of running hours. For CHP solutions internal water management is currently not attractive.

Components

As system design today is in focus more and more companies are striving towards combining functionality components and thereby enabling more simple and cost effective system architectures. Still this development is not very widespread and today the combined system components are not available off the shelf.

Alternative solutions

An upcoming alternative to the very widespread use of PEM fuel cells is the high temperature PEM fuel cell (HTPEM). This technology requires no water management whereby the system gets simplified. As water management is not an issue on this kind of fuel cells the pressure loss can also be reduced quite significantly whereby the system may be further simplified.

New components:

Due to the promising perspectives of near term market introduction of fuel cell systems a number of component suppliers are devoting an increased effort on developing dedicated components for fuel cell systems. As examples major international component suppliers as Danfoss and Parker are now heavily involved in the fuel cell business. As the business matures most components are expected to available be in greater variety off the shelf.

Important components for dedicated development are:

- Air blower/compressor
- Humidifier
- Fittings for hydrogen
- Sensors

From a technical point of view air blowers are today available for most fuel cell stacks but most of these air blower/compressors are highly costly due to very small production volume or complex design. Lifetime is a big concern on the air blowers and compressors. Only a limited number of blowers are available off the shelf, which makes this a focus area for further development.

Well functioning humidifiers are today available but the associated costs are still causing problems. To some extent these are available off the shelf but the costs makes this a focus area for further development.

Fittings for hydrogen are in general available off the shelf but at very high cost due to the high requirements on tightness make this a focus area for further development.

Sensors for hydrogen safety are available off the shelf but still too expensive for using in commercial CHP units. The price level is expected to reach a reasonable stage as the sales volume increases but simplification and design for mass manufacturing is a focus area.

Fuel cell system cost

Fuel cell systems for residential combined heat and power are today too expensive for commercial use due to the above mentioned cost-related challenges.

Hundreds of systems have been deployed mainly in Europe, US and Japan over the past decade. These systems have served as single demonstration systems or fleet demonstration systems. The price level on natural gas based systems has in most cases been well beyond 100.000 EUR per system but since 2004 the prices were often lowered to 70.000 EUR per system. Still this is only targeting demonstration markets.

At the moment the most aggressive approach is taken in Japan where hundreds of systems are installed in a competition between a number of consortia's. The funding available for each system and the numbers of systems to be installed over the coming years is quite well known so the targets are quite clear for the competitors. Still the official system costs are around \$US 50.000.

In general the price level for 1 kW natural gas based fuel cell systems for residential combined heat and power is today at a level around \$US 50.000 in small quantities.

After deploying a quite significant number of units over the last decade the number of deployed units has been very limited since 2005 in Europe and US whereby price reductions from going into volume production are not really taking place in these regions at the moment.

Still a lot of action is going on by research on higher power density and engineering for cost savings. This goes along with synergies from niche markets where fuel cell systems are about to become competitive whereby the cost in general will be driven down.

Most demonstration projects so far have been based on natural gas where reformers have been a major part of the cost implications that has also been reflected on the fuel cell costs as these have had to be built with resistance to impurities in the reformat gas. When going directly into hydrogen as the energy carrier the reformer and stacks build for reformat gas are no longer necessary. This makes a less complicated system where the development can leverage on fuel cell stack developments for automotive use and for niche applications to a larger extend. This enables system costs well below 10.000 EUR today for a 1 kW system with expectations on further price reductions over the next two years. The implications in this case narrow into the lifetime issue where only 10.000 hours can be

expected when directly using this technology at the moment. Using the fuel cell technology at competitive price level and leveraging on the experiences from the reformat systems regarding lifetime will make the approach of this project quite attractive from a commercial point of view.

Updated system figures (for WP 4.2)

	Size	1,0 kW	0,75 kW	0,5 kW	0,25 kW
LT-PEM	H2	1	0,88	0,80	0,75
	NG	1	0,92	0,86	0,82
	Metanol	1	0,9	0,83	0,80

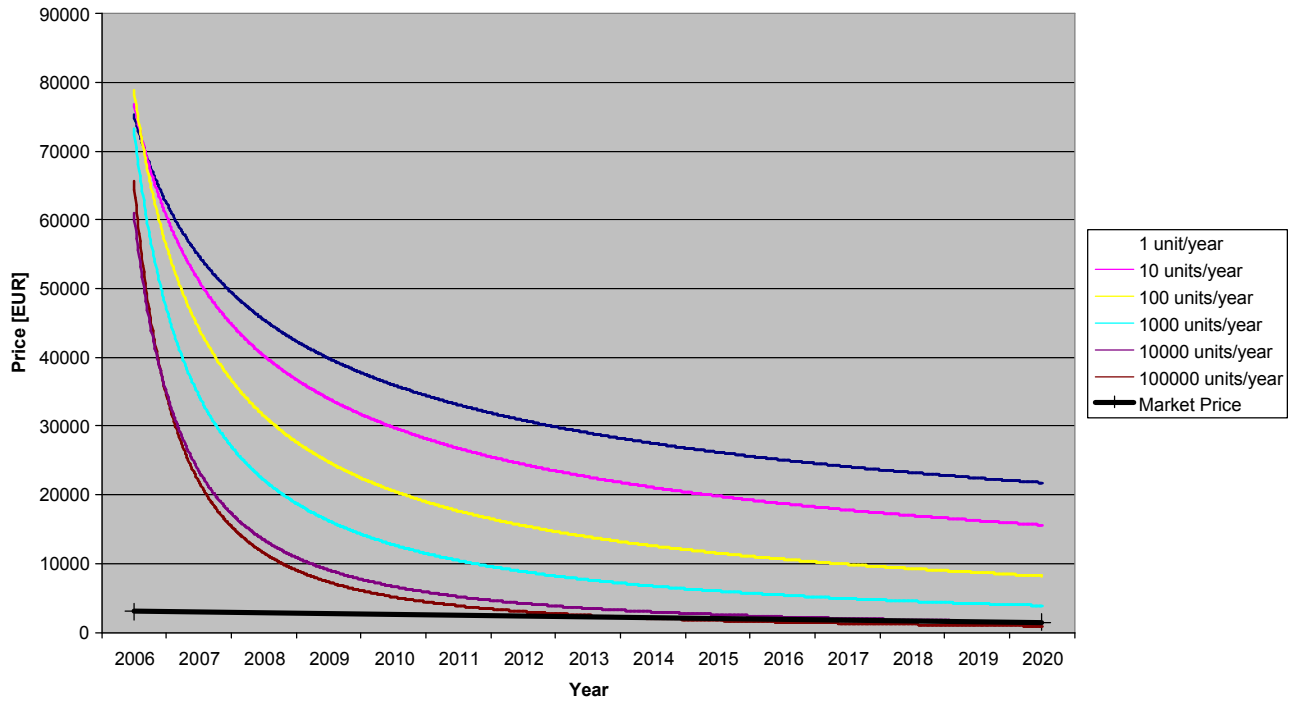
Cost factors for different system sizes for different fuels. Estimated figures based on relations between stack prices, reformer prices and cost of Balance of Plant components.

The cost curves below show the estimated prices for a 1 kWel system .To obtain the price for e.g. a 0,5 kWel system multiply with the factor in the table above. Use the curves for 40.000 hours lifetime – and a depreciation period of 5 years.

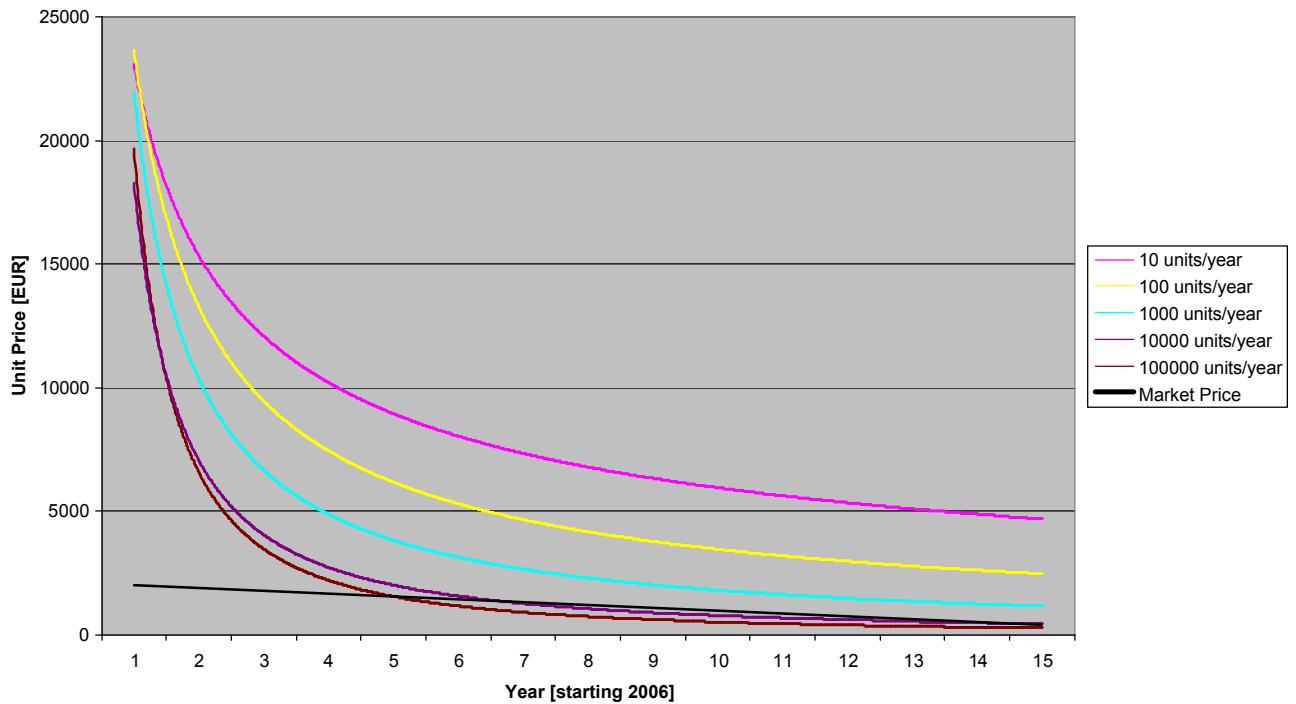
The following curves are estimated cost curves based on existing state of the art PEM fuel cell systems running on the different fuels. It should be mentioned that these curves are quite uncertain, but the curves will show the overall trends for the cost reductions achieved over the coming years based on technological development and by going into higher production volumes. These cost-curves should only be used as an outlook. When basing our calculations on this outlook we have to be aware that things might develop faster than anticipated but also that some things might happen slower than anticipated.

It should be noted that the cost reductions by going into higher production volumes (units/year) will only occur if the system design is basically the same for all delivered systems.

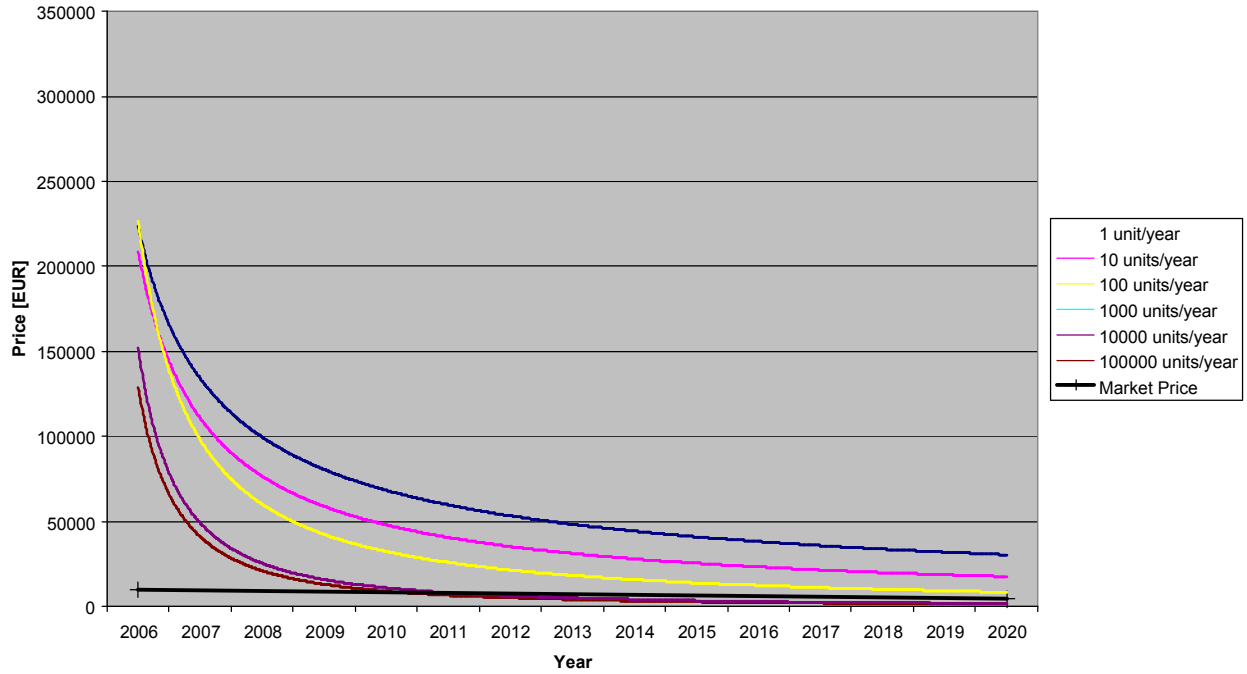
Learning Curve, 1 kW el, Pure Hydrogen, 40.000 Hours Lifetime



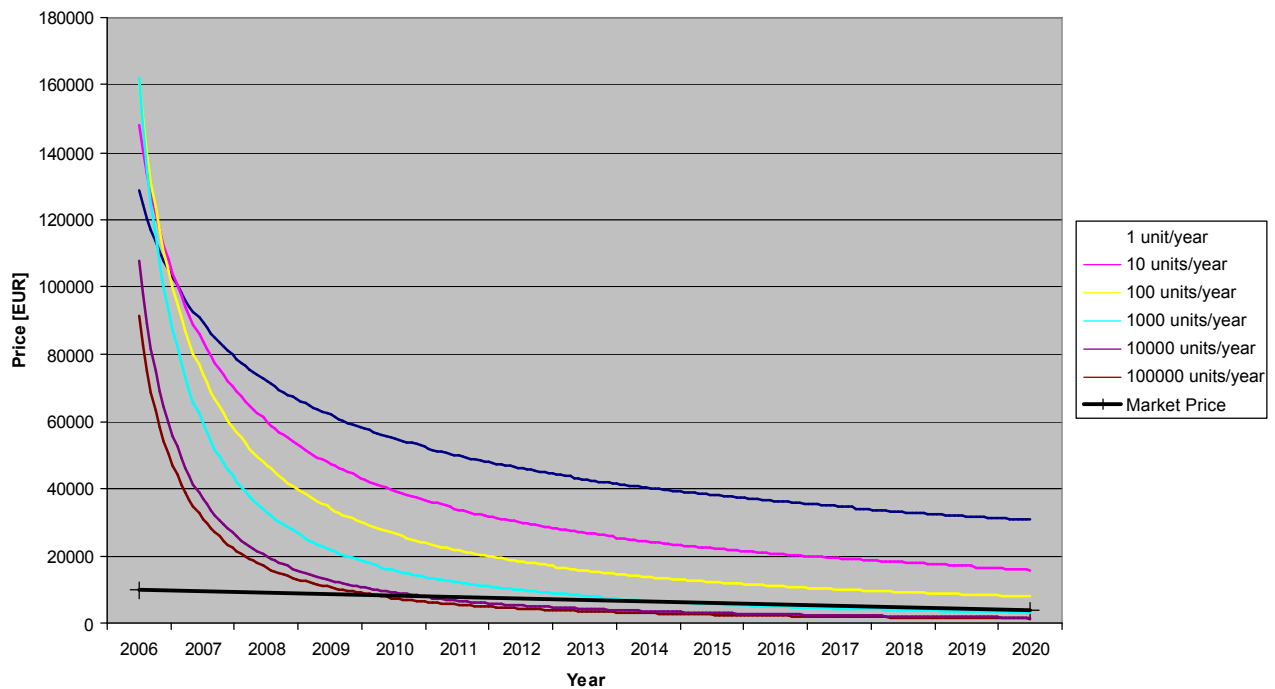
Learning Curve, 1 kW el, Pure Hydrogen, 5.000 Hours Lifetime



Learning Curve, 1 kW el, Natural Gas, 40.000 Hours Lifetime



Learning Curve, 1 kW el, Methanol, 40.000 Hours Lifetime



For calculation of overall energy efficiency a number of system values have been calculated based on best available technology at the moment. These values are based on a 0,5 kWel system designed for long runtimes and running on hydrogen. Efficiency of power management (DC-DC and DC-AC) is assumed to be 90%. The system values are outlined below.

	Electrical efficiency	Total efficiency	Heating value (HHV)	Heating value (HHV)	Electrical Fuel Efficiency	Thermal Fuel Efficiency	Electric Capacity	Heating capacity
	[% HHV]	[% HHV]	MJ/l	kWh/Nm ³	kWh/Nm ³	kWh/Nm ³	kW	kW
H2	41	76	0,013	3,50	1,44	1,22	0,50	0,42
NG	33	76	0,040	11,00	3,63	4,73	0,50	0,65
				kWh/l	kWh/l	kWh/l		
Methanol	35	76	17,2	4,78	1,69	1,94	0,5	0,58

The path to commercialization

As well on system component level as on system design level and fuel cell stack level a challenges still have to be overcome. From a cost perspective the chicken and egg issue is ruling as cost will be difficult to drive down to a commercial stage before the systems are sold in large quantities. On a system design level a lot of advancements have to be achieved in order to get competitive against other technologies. Achievements on system level can be obtained by field testing units and the road towards commercialization can be smoothed by demonstration projects of increasing numbers over time. The timing of field testing and demonstration is crucial in a competitive world and this project serves as a contribution to facilitate large scale demonstration. Leveraging on the commercialization of fuel cell systems for niche applications is a main driver for CHP applications and is in focus in this project.

Appendix 6 Memo on near-commercial fuel cell CHP technology

By Laila Grahl-Madsen, IRD Fuel Cells A/S

Fuel cells (FC) are expected to play a major role in future energy-supply sectors, and in the long-term replacement of a large part of current combustion systems, but the European market for stationary FC systems is still virtually non-existent. The time for market take-off now depends on the availability of reliable and affordable systems (Table 1). Manufacturing costs far exceed competitive prices and will fall significantly only when the supply of components and the manufacturing process have been industrialised. Stationary FC systems incorporating PEM (Proton Exchangeable Membrane) technology are expected to evolve into the leading technology in this market. Unlike North America, Europe will show the highest demand for FC systems in the segment of micro-combined heat and power (CHP). Here, PEM cells are particularly strong and will therefore gain a lead over the more efficient solid-oxide fuel cell (SOFC) technology, which is expected to dominate the US market. However, the efficiency of PEM cells is not sufficient for larger-scale base-load applications, which will probably be the domain of the SOFC and Molten Carbon Fuel Cell (MCFC) technologies. PEM technologies are generally believed to cover the lower end of the output scale e.g. for micro-CHP. A recent analysis has concluded on the following FC micro-CHP specification aimed for an average Danish single family household (de Wit & Iskov 2005):

Fuel	Pure hydrogen or reformat e.g. based on Natural Gas (NG)	
Electrical	Power range (kW _e):	0-3
	Dynamics (kW _e /min):	0.5
	Connection	Grid connected (230/380 V _{AC})
Heat	Power range (kW _{th}):	1-12
	Dynamics (kW _{th} /min):	1
	Connection:	Solely to the single household heating system that includes a heating storage tank
Control	Remote and central	
	Mainly controlled by heat demand, but to a certain extend also used for grid stabilization and local electricity demand.	
Competitive price	k€	10-13

References

de Wit, J. & Iskov, H. (2005):

Mini/mikrokraftvarme, forudsætninger for installation. Dimensionering, afregningsforhold og potentiale. Project report 1 (EFP-2004: Udvikling af 2 kW naturgasreformere for høj og lavtemperatur PEM-brændselsceller), Centre of Danish Gas Technology, 1-74

Table 1 List of commercial and near-commercial micro-CHP products (partly from de Wit & Iskov 2005).

Technology	Brand	Electrical yield	Electrical efficiency	Heat yield	Total efficiency *	Introduction to market	Price	Comments
		kW _e	%	kW _{th}	%	Year	k€	
Combustion engines								
	Honda / Ecowill	1	20	3.25	85	On market		
	Baxi / Senertec	5-5.5	25	12.5	90	On market	13	
	Vaillant / Ecopower	4.7		12		On market		
	Stirling Engines							
	Whisper Tech	0.85-1.2		6-8		On market		
	BG Microgen	1		5-36	93	2007		
	Enatec	1		6-24		2006		
	BBT/Bosch	0.2-0.45	15	1.5-42	105 *			Incl. burner
	Disenco / Sigma	3		9-11				
Fuel cells								
<i>SOFC</i>								
	Sulzer Hexis	1				2005 ??		Field test on-going (>100 units)
	CFCL	1.0	≈40	1.0	≈80	2007		Field test planned (2005)/on-going
<i>LT PEM</i>								
	Vaillant / Plug Power	4.6		1.7-7		2010		Additional burner available
	Baxi / European Fuel cells	1.5				2010		
	EtaGen BBT/RWE/IDATECH	4.6	35	40-160	>85			Incl. reformer

*: Total efficiency calculated on base of LHV