Sky Clean - integration

Interaction with the energy system

REPORT

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0. Preface

In the SkyClean project the main idea is to produce biochar from the residual biomasses in agriculture and store this biochar in the cultivated fields as a "low-cost CCS" method. Furthermore, a major part of the possible benefit is the production of "by-products" as biofuel and/or bio-SNG. The producer gases from the pyrolysis process may be processed in different ways to give different products beneficial for the environment [1].

Different interactions between the SkyClean system and society are described in this report. This is done both with focus on the different parts of the Danish energy system, and secondly focusing on the SkyClean technology and the products. No conclusions are drawn in this document, as the task was purely descriptive.

1. The SkyClean idea

1.1. The main idea of the SkyClean system and technology

The main idea of the SkyClean system is to extract CO_2 from the atmosphere and bury this as carbon in the soil as a “low-cost CCS technology”. Based on the photosynthesis, solar energy is used for production of the green plants of any kind. In this process, CO_2 is extracted from the atmosphere. Figure 1 shows the basic principle of the SkyClean system.

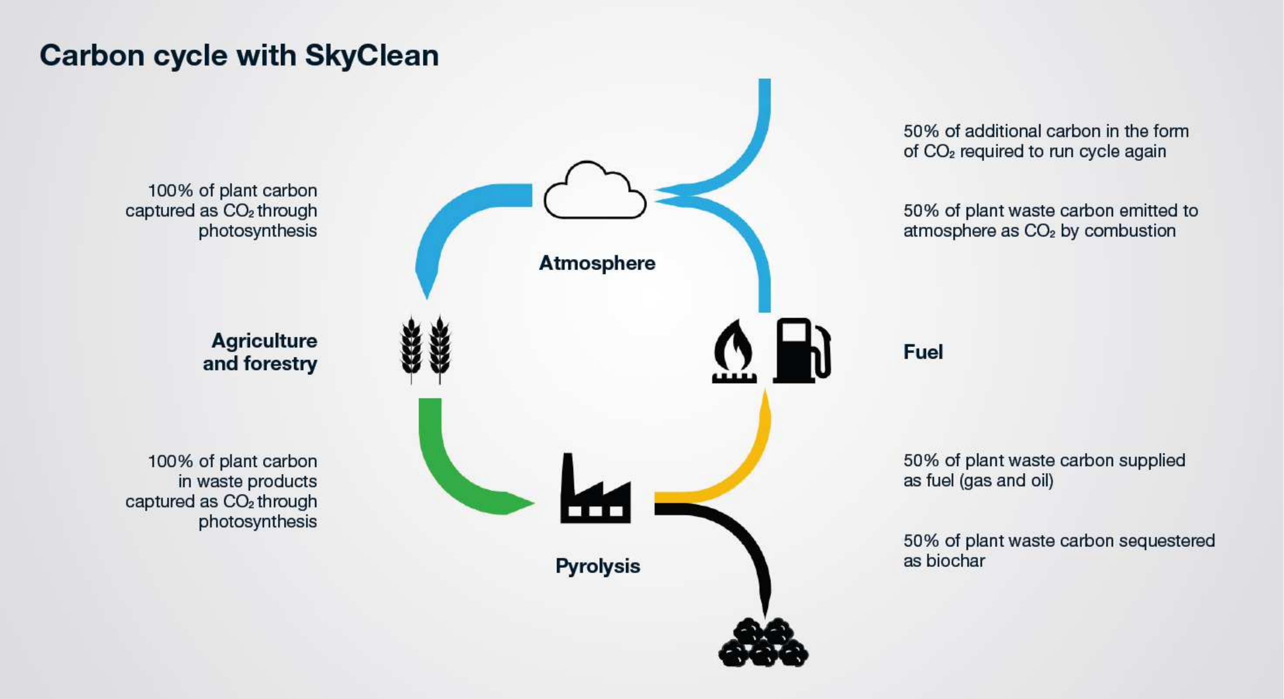

Figure 1 The basic principle of the SkyClean system [2].

Solid biomass of any kind can be used as feedstock for the SkyClean system. The biomass goes through the pyrolysis reactor, and biochar - which consists of carbon, ash and fertilizers - will be returned to the agricultural land for sequestration. However, half of the biomass energy will be in the gases from the process, and they can be converted into thermal energy, bio-oil, or other fuels including energy gases.

Although carbon keeps circulating in this system, a large part of the carbon is extracted from the atmosphere and buried in the farmland or in the forests. Thus, the SkyClean system can achieve a net carbon capture and interact with the climate system in a very positive way.

1.2. How does SkyClean relate to other parts of society?

The SkyClean system interacts with a large part of the society, especially the energy, agriculture and forestry sectors. Figure 2 shows the circular aspects of the system. Biomasses from crop production and/or forests are returned either directly or through animals in the form of waste back to the SkyClean pyrolysis and then converted to useful products.

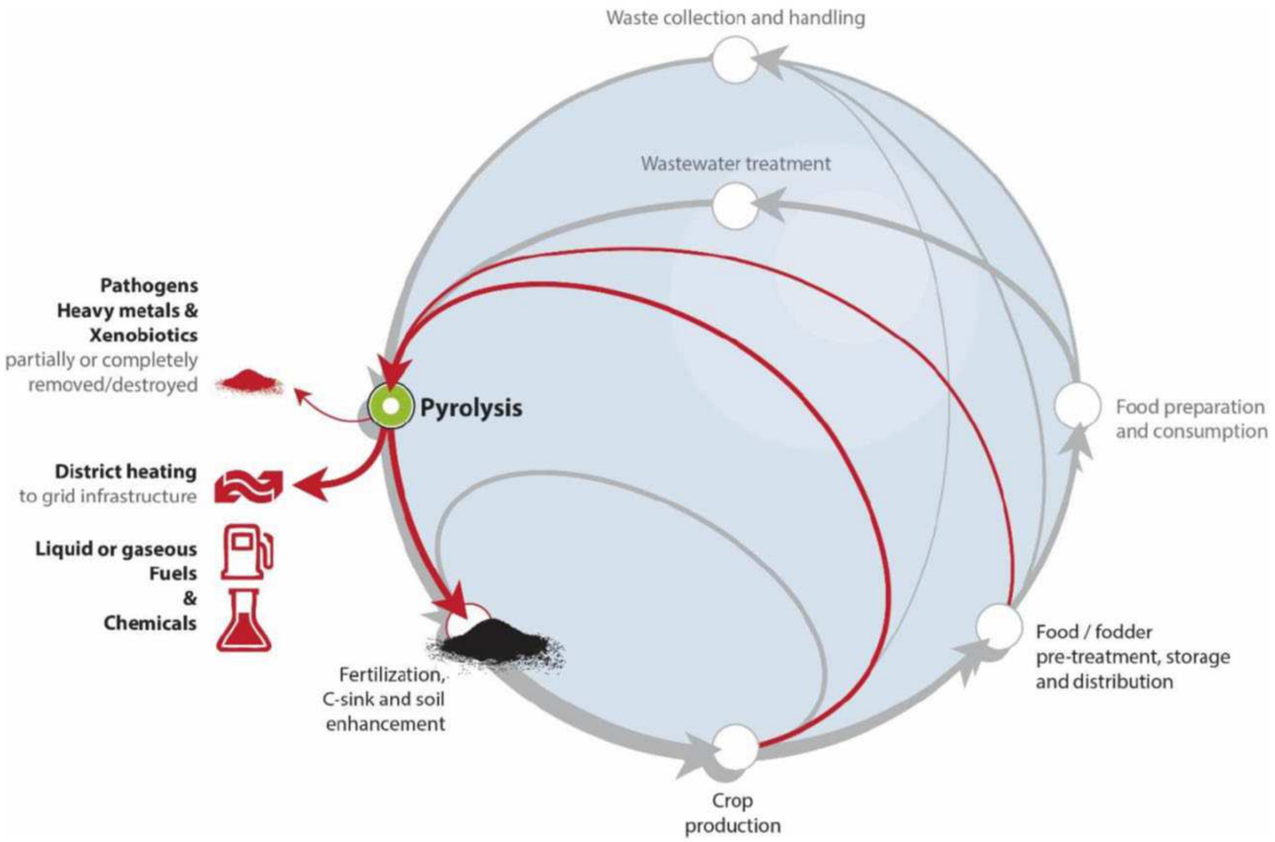

Figure 2 The circular aspects of the SkyClean System [1]

A large part of the SkyClean system includes energy conversion, and its interaction with the general energy system of the society is very important. In the following sections the different interactions are described.

1.3. The gas system and SkyClean

1.3.1. Bio-SNG

One of the main products from the SkyClean system might be the bio-SNG produced from the producer gases of the pyrolysis. The gases intended for bio-SNG must be converted into methane.

If the temperature of the producer gases is kept high, the cleaning of the gases can be limited to a filter taking dust and ash from the gas stream. Then tar must be removed, either by physical removal or cracking to syngas. The syngas can be converted into methane, either by biological or thermochemical methods. Finally, after upgrading (removal of CO_2), the gas consists entirely of methane ready for injection on the natural gas grid. In the note “SkyClean – cost of biomethanation” [3], these processes are explained and in [8] the upgrading technologies.

1.3.2. Quality

The gas system has specific product quality requirements for gases to be accepted for the gas grid. The reason is that the consumers must receive a reliable product ready for the gas appliances, as well as to preserve the grid integrity. Another note made in this project, “SkyClean – Bio-methane quality in the gas grid” [4], describes the necessary condition for the upgraded gas for the gas grid. The main requirement, the Wobbe index, entails a minimum methane content of about 97% by volume in the gas in the Danish gas system.

1.3.3. Price

The price for the bio-SNG added to the gas grid is of major importance for the choice of production from the SkyClean plant. The bio-SNG from the SkyClean pyrolysis system needs to have the same subsidies as received by the biogas plants for the upgraded biogas. The injection of bio-SNG on the gas grid would increase the amount of green gas on the grid and contribute to the necessary CO_2 reduction in the same manner as upgraded biogas. In the note “SkyClean - expected prices on products and feedstock” [5], the possible future prices are listed.

1.4. Electrical system and SkyClean

SkyClean’s connection to the electricity system is mainly related to a possible electrolysis for production of hydrogen. Hydrogen is necessary for deoxygenation of bio-oils from the pyrolysis. Secondly, hydrogen may be produced for addition to the bio-SNG or biofuel production dependent on the price of electricity at that moment.

1.4.1. Variability of electricity prices

The price of electricity might be very variable; therefore, the electrolyser will probably only operate when necessary or secondly when cost effective.

The hydrogen supply for de-oxygenation must be continuous and cannot contribute to the levelling out of varying wind/solar power unless hydrogen storage is included. It is questionable if such storage is profitable. One strategy for electrolysis could be to produce a continuous amount of hydrogen for the deoxygenation of the bio-oil and a variable amount for the secondary fuel production dependent on the electricity cost. In this case, the optimal size of electrolyser will depend on the operating costs of the variable H_2 addition to bio-SNG production.

The overall efficiency for electricity to hydrogen and further on to any fuel containing carbon (C) is in the order of 50%. So, the payments for the bio-SNG or biofuel product based on hydrogen should be 2-3 times as high as the electricity cost (per energy unit). The electrolysis process itself may be optimised to relatively low conversion prices for electricity to hydrogen. However, the total cost for producing hydrogen by electrolysis can never go lower than the cost of electricity for the process plus CAPEX. Therefore, the electricity must be at least 2-3 times cheaper per energy unit than the products utilizing the hydrogen for the production. See reference [5]. Subsidies might change this.

1.4.2. CO_2 emissions from electricity consumption to be included

In the decision of possible addition of an electrolyser, the CO_2 emission from the production of the consumed electricity must be considered. The marginal CO_2-emission from electricity production must be accounted for, hour by hour or minute by minute. If the electricity is fully or partly based on fossil fuels, then the hydrogen based on the electricity is as well, and it can be proven that the CO_2 emission from a coal fired condensing power plant producing electricity for an electrolyser where the hydrogen is converted to methane is 8 times higher than the saved CO_2.

Energinet has information of the minute-to-minute CO_2-emission of the produced electricity.

1.5. District heating and SkyClean

1.5.1. Localities

Using heat from the processes of the pyrolysis for district heating might be a little problematic. District heating must by obvious reasons be rather close to areas where people live, which means populated areas. On the other hand, for reasons of possible smell and transport of feedstock and products, the pyrolysis plants must be of some distance from populated areas. This could be difficult to combine for most plants. Secondly, the feedstock for the pyrolysis unit is found in the countryside, which for obvious reasons is not in highly populated areas. These conditions must be examined for each individual case.

1.5.2. Price of heat

Heat is the easiest product to make from pyrolysis gases by burning the gases in boilers. The producer gas must be kept warm to prevent condensing of tars, but apart from that heat can easily be produced in a boiler and transported in pipes to consumers. The price, of course, will be determined by the competition from other sources of heat in that area and the profitability will depend on this. The competing cost of heat could for some cases be too low to be matched by the pyrolysis plant when cost of transporting heat to populated areas is included. This must be analysed for each case.

1.5.3. Possible internal exploitation

The best option for heat utilisation might be to supply energy to endothermic chemical processes (e.g., pyrolysis and gas reforming) and/or high temperature electrolysis systems. This optimises the overall efficiency of the plant, and if the heat is needed in the process, it might give the highest profit. Only distorting tax conditions would make it profitable to sell heat and simultaneously purchase fuel for heating.

1.6. Industry and SkyClean

1.6.1. Heat for industry

If the pyrolysis plant is in an area with one or more industries, excessive heat might be used for industrial purposes. If an industry that requires heat is located close to a possible location for a SkyClean plant, then it is obvious to exploit the producer gas directly from the SkyClean plant as a source of heat for the industry. But again, the cost of the transport of energy should be low as needed for the profitability. This must be analysed for each case.

1.6.2. Feedstock from industry

The industry might be able to supply low-cost feedstock or residuals for the pyrolysis plant. Biomasses of any kind could be pyrolyzed. The only limitation is to avoid poisonous substances that would pollute the products and surroundings. The amount of industrial feedstock might not be high, but special industries in local areas could provide beneficial feedstocks for certain SkyClean plant locations. The food and fodder industries could be mentioned as an example.

1.6.3. Fuel for industry

On the other hand, the pyrolysis plant could also provide the industry with energy in the form of liquids or gases. Here raw energy gases or liquids might be sufficient for industries close to the pyrolysis plant and upgrading or refining might be unnecessary. Using producer gases directly requires maintaining its high temperature (i.e. 300-500 °C) from pyrolysis all the way to consumption. Such fuels might be competitive compared to other fuels for the industry making it a win-win situation for SkyClean as well as for the industry.

1.7. Agriculture and SkyClean

1.7.1. Biochar for agricultural land

The main product from the pyrolysis plant might be the biochar, which is intended for agricultural areas. In this way it acts both as a fertilizer for the farmland and as a "low-cost CCS". Biochar is reported to stay in the soil for hundreds, may be thousands of years [2], so the carbon is effectively stored. This will contribute to the reduction of CO_2 emissions generally.

1.7.2. Energy wood from agriculture

One of the important feedstocks from agriculture might be energy wood. This means wood from short term wooden areas with harvesting every 1 to 5 years. This is not a very popular feedstock as it prevents production of fodder and food on the same area. However, there might be areas, e.g. fallow land, which would benefit more from producing energy crops than nothing. Also, other wooden feedstock might be available from agriculture in smaller amounts, e.g. from cutting of vegetations at the boundaries between fields.

1.7.3. Straw as a feedstock

Another feedstock for the pyrolysis plant is residual straw from agricultural land. Very large amounts of energy are lost when straw is just ploughed down into the ground. Using residual straw from agriculture for energy purposes and returning the biochar and ash as fertilizer is probably the most straightforward interaction between agriculture and the SkyClean technology.

1.8. Biogas plants and SkyClean

Building pyrolysis plants connected to biogas plants might enable a high number of synergies, as it is described in the following subsections.

1.8.1. Residual fibres as raw material

A different way of getting the fibres originating from straw and other biomasses to the pyrolysis plant is as the residual fibres from biogas plants. The digestion process in a biogas plant is not able to exploit all energy in the biomass slurry. When separating the digestate from the biogas plant into liquid and solids, the solid part still contains 30-50% of the original energy content. This is a cheap feedstock for the pyrolysis plant and the resources are plentiful. As explained for straw earlier, the biochar including fertilizer can be returned to the farmers who delivered the feedstock to the biogas plants.

1.8.2. Heat returned to biogas plants

A biogas plant needs some heat for keeping the biogas reactor warm and for upgrading biogas to natural gas quality (if using amine scrubber for upgrading, see reference [8]). A pyrolysis plant may have excess heat energy from the pyrolysis and methanation processes. This means that if the two plants are located close to each other, heat may be transferred to the biogas plant from the pyrolysis plant when in operation.

1.8.3. Common upgrading to natural gas quality

If the pyrolysis plant produces bio-SNG as one of its products and it is located in connection with a biogas plant, common upgrading to natural gas quality is obvious. This will exploit the upgrading facility with greater efficiency or lower specific OPEX and CAPEX. See [8] for upgrading technologies.

1.8.4. Idea of triple gas production

If a pyrolysis plant and a biogas plant connected to each other is further supplied with an electrolysis plant an even higher synergy may occur. When electricity prices are low it may pay off to produce hydrogen and add it to the methanation process and in this way convert higher amounts of CO_2 into methane. See chapter 2.

1.9. Forestry and SkyClean

Obviously, forestry may deliver large amounts of biomass for pyrolysis plants.

1.9.1. Wood from forestry

In commercial forestry large amounts of biomass are available when thinning the smaller trees, which are intended for nursing and supporting the permanent trees that later will be used in industry. Instead of leaving this biomass in the forest for producing a lot of CO_2 and CH_4 when decaying and producing a surplus of greenhouse gas, it could be used for energy purpose substituting fossil fuels.

1.9.2. Ash returned to the forest

The biochar from pyrolysis could be returned to the forest as fertilizer or it could be an asset for agricultural land. Forest fires is one of the ways nature itself made fertilizers for new plants and trees before man came along and formed the nature for his benefit.

1.9.3. Interaction with agriculture, nutrients, fertilizers

Ash and biochar from a mixture of wood from forestry and biomass fibres from biogas plants may be an even better fertilizer than each of them individually. The biochar may be optimised by mixing the biomasses for the pyrolysis plant from different sources.

2. The SkyClean technology and system

The SkyClean process for pyrolysis may be combined with a biogas plant as well as with an electrolysis plant. This will facilitate utilizing the synergy between pyrolysis and biogas production and it would enable the utilization of low electricity prices for producing low-cost hydrogen for valorisation of the CO_2 in the producer gases. Figure 3 shows the possible synergy for the three processes. Here, the pyrolysis is described in general and not limited to the SkyClean project.

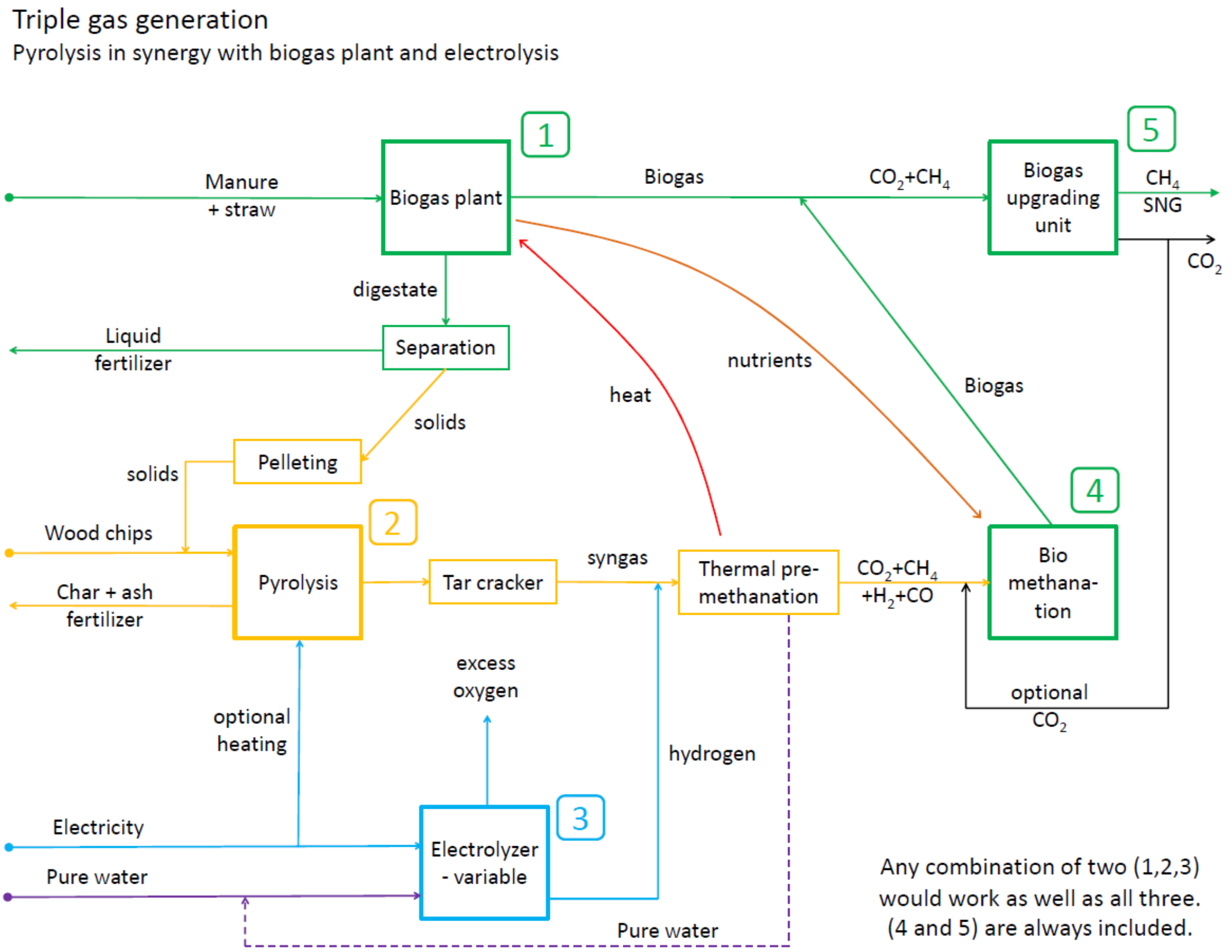

Figure 3 The synergy of the possible combination of pyrolysis with biogas and electrolysis

The idea of this triple combination is the synergy between the processes. Biomass residuals from the biogas plant (as biomass fibres) can be exploited by the pyrolysis plant. Heat from the pyrolysis plant can be utilised for heating in the biogas plant and in the upgrading plant for the biogas. Nutrients and liquids from the biogas plant can be used in the bio-methanation plant. The hydrogen can be used in the methanation plant to convert higher amounts of CO_2 to methane.

Obviously, the biogas plant could run alone including upgrading. Equally, the pyrolysis plant could run alone including methanation and upgrading. Any combination of two technologies could run without the third. But of course, having all three in operation, the full synergy between the processes could be exploited. The biogas plant and the pyrolysis plant should for operational reasons be operated continuously, while the electrolysis should be operated dependent on the electricity cost.

If methanol or bio-oil are preferred as products from the pyrolysis plant, a further (or another) product line should be included.

An earlier note from this project, "SkyClean – different system layouts for the processes" [6], describes 12 different system layouts for the SkyClean technology. These layouts may not all be economically attractive, but possible and relevant.

2.1. The biomasses for feedstock

The most obvious feedstocks for the SkyClean pyrolysis unit are woodchips, wood pellets, straw and fibres from the digestate of biogas plants. On top of that, small amounts of garden waste, cut vegetation, etc. could be added. However, until recently the costs of woodchips, wood pellets and straw were at the same order of magnitude as natural gas measured as DKK/GJ [5]. That means that without subsidies and/or payment for the biochar it would not be possible to base the production of bio-SNG from the pyrolysis process on these biomasses.

Fibres from biogas plants have a much lower price as the cost of production is only the cost of the separation from the liquid. However, the benefit the bio-fibres would bring to the pyrolysis plant would somehow be capitalized by the farmers who deliver. Other cheap biomass residues might be available as well.

2.2. The biochar product

The present price of biochar is rather low. It is only based on private market without subsidies. However, it is expected that new legislation will be made to capitalize the value of the negative CO_2 emissions, which the ploughing down of the biochar entails. This could be made as a subsidy to farmers who plough down biochar based on the amount, or it could be the value of avoided taxes on CO_2 emissions not released. Either way, the value of stored carbon in the ground would be about 3.7 times higher per ton than the CO_2 value, as the molecular weight of CO_2 is 3.7 times the weight of carbon (C).

2.3. The bio-SNG product

The easiest product to make (except from plain heat) from the syngas produced in the pyrolysis process is bio-SNG and it may also be the best way to valorise the producer gases. In the expected size of the plants (~20 MW thermal input), bio-methanation is probably the most profitable way of producing bio-SNG. The bio-methanation process produces biogas, which can be easily upgraded to bio-SNG ready for adding to the gas grid. The fermentation process works at atmospheric pressure and best about 60°C.

If extra hydrogen is added from electrolysis, the bio-methanation process just converts a larger part of the CO_2 to methane and the upgrading process will be easier as less CO_2 should be removed. Ultimately, the upgrading could be done entirely by adding hydrogen and converting all CO_2 to methane. However, this would require a very precise amount of hydrogen continuously and this would probably not be feasible or profitable for “small” plants of 20 MW.

The conversion efficiency from CO and/or H_2 to methane entails an unavoidable thermodynamic loss of about 20% giving an efficiency of 80% [3]. If electrolysis is included for higher CO_2 conversion, the overall efficiency will drop due to losses in the electrolysis process.

Bio-SNG could also be produced by thermochemical processes including catalysts. However, very clean syngas is needed for this process, especially sulphur must be removed completely upstream the methanation catalyst. Furthermore, a very precise relation between H_2 and CO/CO_2 must be kept continuously, which might be too costly.

Further studies should be done to analyse the costs of thermochemical methanation compared to biomethanation including the OPEX cost of manpower necessary to run the methanation plant of 20 MW biomass input [3].

2.4. The bio-methanol product

Bio-methanol is technically a relevant possible product from the pyrolysis process. It is liquid, it has a high price, and it can be produced from the syngas. Methanol plants must operate continuously as the discontinuous operation will be too costly and with too low efficiency [7]. This means that a possible necessary hydrogen supply for conditioning the syngas for methanol production must be continuous as well, unless a costly hydrogen storage is included. Contrary to the bio-methanation process, the methanol synthesis stage operates at about 300°C and 85 bar, which requires a technology at a much higher level than bio-methanation.

According to reference [7], the usual range of methanol plant size is 1.2 million tons of methanol/y. This corresponds to about 800 MW methanol. The biomass input to the SkyClean plant will be in the order of 20 MW. The possible methanol production will be less than half. This means that the possible methanol unit in SkyClean will be about 100 times smaller than present commercial plant size based on natural gas as feedstock. It is questionable if it will be possible to achieve commercially profitable production of methanol from the SkyClean plants, considering high level technology on small scale units and necessity of constant hydrogen supply independent of varying electricity prices for electrolysis.

2.5. The bio-oil product

Also, bio-oil production is a relevant possible product route due to high prices on e.g. bio-based aviation fuels. A possible bio-oil production from the pyrolysis process needs hydrogen for deoxygenation of raw bio-oil. This is necessary for the conditioning of the bio-oil for further refining to fuels for transport or aviation. As the pyrolysis operation will be continuous, the hydrogen supply must be so as well. Possible electrolysis then equally must be continuous independent of electricity prices unless hydrogen storage is included.

Alternatively, the necessary hydrogen for deoxygenation could be produced by WGS (Water Gas Shift) from CO to hydrogen. This would reduce the final amount of fuel from the plant. See [6].

For possible bio-oil production, the same considerations should be done as in the methanol case about high level technology on small scale units.

3. References

[1] The application at EUDP for the SkyClean project, EUDP 2021-I.

[2] SkyClean product brochure, 2022 https://www.stiesdal.com/skyclean/skyclean-is-a-game-changing-technology-for-agriculture/

[3] *SkyClean – Cost of biomethanation*, DGC 2022, Note prepared for the SkyClean project.

[4] *SkyClean – Bio-methane quality in gas grid*, DGC 2022, Note prepared for the SkyClean project.

[5] *SkyClean – prices on products and feedstock, Table 1 - Expected prices on products and feedstock – without taxes*, DGC 2022, Note prepared for the SkyClean project.

[6] *SkyClean – different system layouts for the processes*, DGC 2022, Note prepared for the SkyClean project.

[7] *Technology Data, Renewable fuels*, Danish Energy Agency & Energinet, 2017.

[8] *SkyClean – CO_2 capture processes*, DGC 2022, Note prepared for the SkyClean project

SkyClean – cost of biomethanation

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One of the options in the SkyClean project is to convert all or parts of the producer gases from the pyrolysis into a gas equal to conventional biogas, which is then upgraded to a quality ready for the natural gas system. Knowledge of the cost of the main equipment for the methanation process is important to be able to evaluate the feasibility and profitability of the technology. In this note only biomethanation is considered and not thermochemical methanation. The reason is that for plants in the size of about 20 MW, the thermochemical conversion would be too costly. Secondly, the technology for thermochemical conversion would be at a high technological level, not feasible for farmer-based pyrolysis plants, especially considering the OPEX cost. Such plants must be operated at the same level as biogas plants to be widespread in the agricultural sector.

There are four main items of equipment for the methanation process:

- A dust filter to clean the raw producer gas before the tar cracker/reformer
- The tar cracker/reformer to convert the raw gas and tars into syngas ready for methanation
- The biomethanation unit
- The CO_2 removal unit to condition the gas for the gas grid

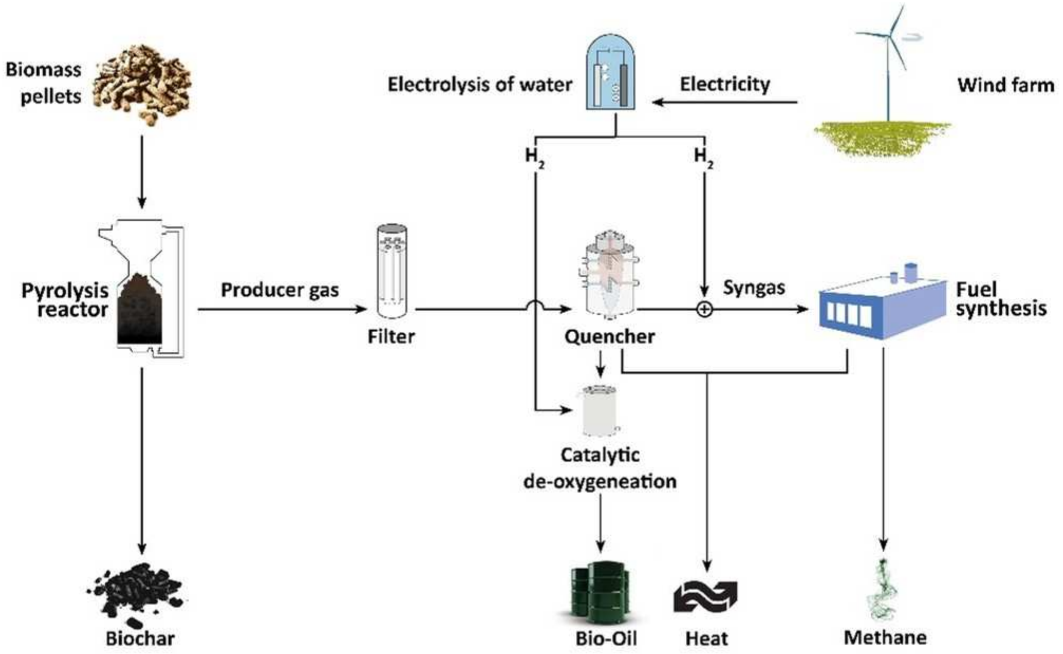

Figure 1 The processes of the SkyClean plant.

Figure 1 shows the processes of the SkyClean plant as illustrated in the application for EUDP [1]. In case of biomethanation of all gases, there will be no Quencher but a tar cracker that converts all gases into syngas, including the bio-oil. The output from the biomethanation will be a biogas consisting of CH_4 and CO_2 (about 50/50) ready for upgrading. This is based on calculations of conversion of ash free biomass from straw.

Dust filter

The raw product gas must be cleaned by a dust filter before entering the tar cracker system, which may consist of thermal catalysts. Such catalysts would be fouled by possible dust, which would reduce efficiency. An ordinary fabric filter would probably not be suitable, as this filter usually has a max temperature of about 300 °C. The raw producer gas has a temperature of about 600°C or higher. A possible solution is to use a ceramic filter, which could resist temperatures of >1000°C. Alternatively, a sintered metal filter would also be resistible for high temperatures.

Tar cracker (reformer)

Tar is not very “welcome” in the biomethanation reactor as it will poison the microbes if too high in concentration. A thermal process supported by catalyst(s) seems to be a very suitable method for removal of tar (see reference [2]). A precondition for this is a relatively high amount of steam in the product gas and a high temperature of about 800-900°C. Essentially, the steam (H_2O) will react with the carbon in the tar to produce H_2 and CO.

Biomethanation

The biomethanation process is a biological process running at temperatures between 37 and 65°C. The most advantageous temperature is about 60°C. The microbes convert the syngas consisting of CO, H_2, CO_2 and CH_4 into CO_2 and CH_4, only. It is an exothermal process from which the microbes extract energy for their reproduction. Water (H_2O) may be used or produced dependent on the relation between H_2 and CO/CO_2. The environment for the microbes must be wetted by water as they can only extract gases from liquid water. Any tar would poison the system and the microbes are only able to cope with small amounts. Four molecules of a mixture of CO and H_2 will be converted into one molecule of CH_4 as long as sufficient carbon is present. This process will inevitably by thermodynamic necessity cause an energy loss of about 20% (as heat). A part of this energy may be regained by conversion of dead microbes to methane.

CO2 removal

The relation between H_2 and CO/CO_2 may be too small to convert all carbon (C) into CH_4. Electrolytical conversion of water into H_2 to add more H_2 may be too expensive at that time. As a result, the final product (biogas) from the biomethanation unit has to be cleaned for CO_2 to condition the biogas for the gas grid. In the biogas community this is called “upgrading” of biogas. As a reference, only the amine scrubbing is included here as the upgrading method.

Cost prediction method (CAPEX)

The cost of the above mentioned four pieces of equipment depends on the input of producer gases to the system. The cost for each item of equipment is estimated by the following well established equation for scaling of equipment [3].

$C = C_o*(S/S_o)\text{^}f$

where

C = cost of that equipment
C_o = reference cost of that equipment at a certain reference gas flow S_o
S_o = the reference gas flow for that equipment
S = the actual gas flow of that equipment
f = the scaling factor when increasing or reducing the gas flow relative to reference

Table 1 below shows the chosen parameters for the different parts of equipment. A gas flow of 1.0 m^3/s of biogas from the biomethanation unit, which relates to about 20-22 MW of energy flow, is included as an example. The investment cost is estimated to be about 218 MDKK for these four pieces of equipment. If this is related to 10 years of simple depreciation the **CAPEX cost would be about 1.50 DKK/m^3 of methane.**

Comments on the choice of parameters for the different items of equipment

Dust filter

The price of the dust filter is not very accurate. However, the cost is less than 0.1% of the total cost of the four items of equipment, so it is not important. The data are based on a paper by Menin et.al. [3]

Tar cracker (reformer)

Different kinds of tar cracker or reformer might be chosen. In this note the cost is based on Menin et.al. [3] presenting costs of producing bio-SNG from gasification and biomethanation plants.

Biomethanation

Biomethanation of syngas is a relatively new technology and commercial full-scale plants are not available. However, the technology is developed at pilot scale, and biomethanation plants for CO_2/H_2 mixtures are now offered commercially [4]. The difference between biomethanation of syngas and of CO_2/H_2 mixtures is small. The information of the cost of biomethanation units is based on presentations and personal communication with the company BiogasClean who is offering full-scale biomethanation plants as an addition to their well-established sulphur removal units for biogas cleaning.

CO_2 removal

The cost of the CO_2 removal to condition the product gas for the gas grid is based on costs of amine scrubbing plants. This technology is considered as the most convenient and cost-effective technology for CO_2 removal from biogas in the size around 20 MW methane flow. In this note the information of the cost of the amine scrubber technology has been taken from personal communication with the company Ammongas offering biogas upgrading plants with this technology [5]. The estimated costs for this equipment from this reference only differ less than 10% from the same estimate based on Menin et.al. [3].

Balance of Plant (BoP)

The different pieces of equipment have to be connected by pipes, heat exchangers, wiring, control system etc. The cost of this extra equipment has not been taken into account in this document.

Figure 2 shows the relation between the CAPEX costs of the four different pieces of equipment for methanation of producer gas from pyrolysis.

OPEX costs

The total cost of the biomethanation process includes the operational costs of the different units. In Table 1, the estimations of the OPEX have been included. For the four pieces of equipment, the total **OPEX cost is estimated to be in the order of 0.90 DKK/m^3 of methane.**

The OPEX cost of the dust filter and the tar cracker is suggested to be 5%/y of the CAPEX costs. This is effectively zero for the dust filter compared to other equipment and very low for the tar cracker.

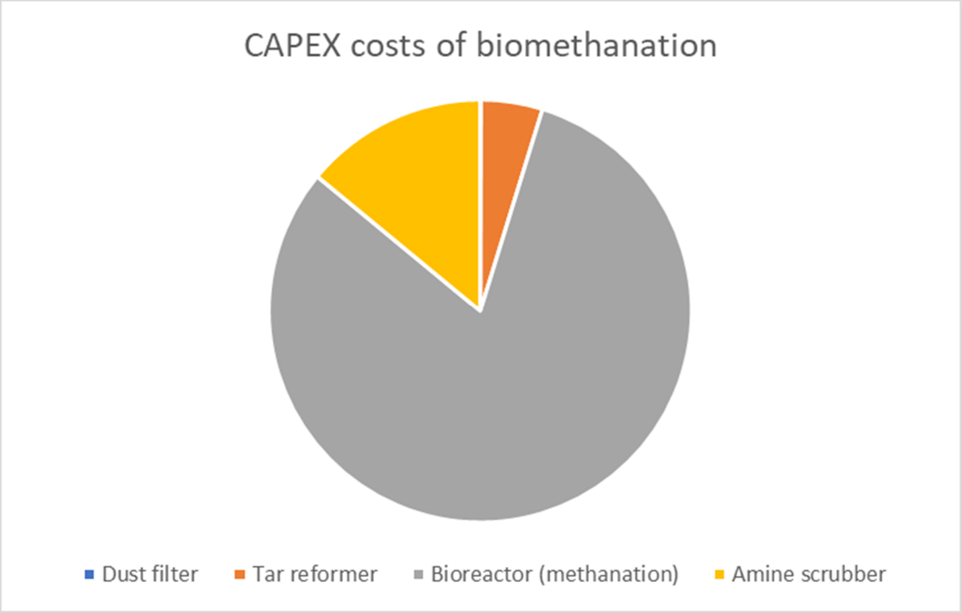

Figure 2 CAPEX Costs of equipment for methanation

As the operation of the biomethanation reactor and upgrading units needs energy, the OPEX of these units depend strongly on the energy prices. This entails a high uncertainty on these figures. Data from reference [6] have been used for energy prices.

The biomethanation unit has an OPEX cost related to electricity demand of 100 kW and about 50 DKK/h for nutrients in the reference unit [4]. This ends up in about 0.37 DKK/m^3 CH_4.

The amine scrubbing unit for upgrading to natural gas quality has a power demand of about 0.1 kWh electricity/m^3 biogas and 0.6 kWh heat/m^3 biogas [5]. This ends up in OPEX related to energy consumption of about 0.51 DKK/m^3 CH_4.

Figure 3 shows the relation between the OPEX costs of the four different pieces of equipment for methanation of producer gas from pyrolysis.

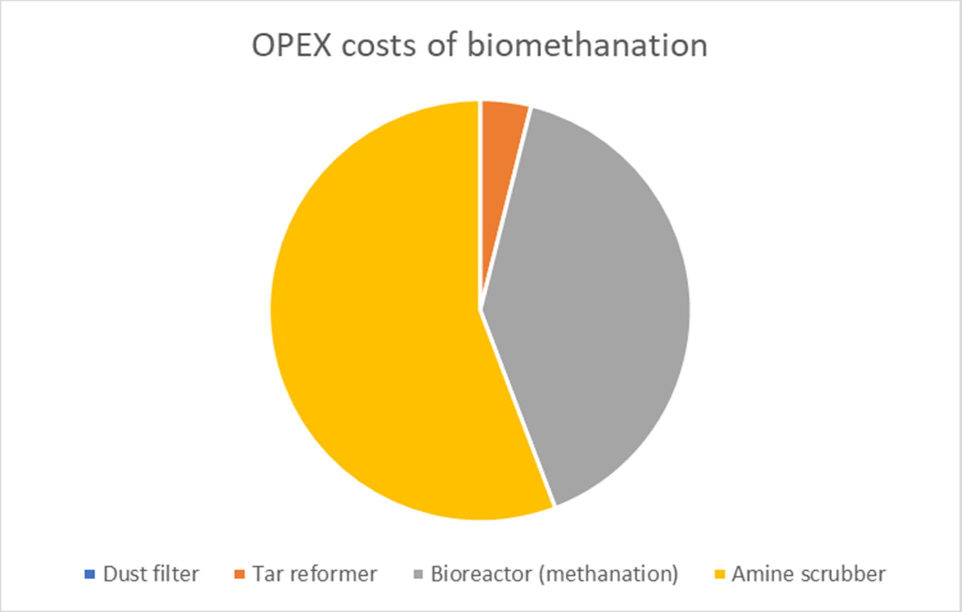

Figure 3 OPEX Costs of equipment for methanation

References:

[1] The application at EUDP for the SkyClean project, EUDP 2021-I.

[2] Niels Bjarne K. Rasmussen, Ioannis V. Skiadas, Hariklia N. Gavala, Georgios M. Kontogeorgis. *Converting wood to biogas via syngas – the SYNFERON project*. 7th International Conference on Renewable Energy Gas Technology, REGATEC 2020, Weimar, Germany 2021

[3] *Competitiveness of syngas biomethanation integrated with carbon capture and storage, power-to-gas and biomethane liquefaction services: Techno-economic modeling of process scenarios and evaluation of subsidization requirements*, Menin et.al., Biomass and Bioenergy, Volume 161, June 2022.
https://www.sciencedirect.com/science/article/abs/pii/S0961953422001362?via%3Dihub

[4] Presentations from and personal communication with the CEO of the company "BiogasClean"

[5] Personal communication with the CEO of the company "Ammongas A/S"

[6] *SkyClean – prices on products and feedstock, Table 1 - Expected prices on products and feedstock – without taxes*, DGC 2022, Note prepared for the SkyClean project.

The Table 1 is included after this page.

Table 1 COSTS of biometanation

CAPEX

$C=C_o*(S/S_o)$^f Well established equation for scaling

1€=7.44DKK

	C_o (k€)	S_o	unit S_o	f	S	Cost (k€)	Cost (DKK)	%
Dust filter	61.9	15.6	m^3/s raw gas through	0.77	2	1.27E+01	9.47E+04	0.0
Tar reformer	8.43E+04	192.9	m^3/s syngas out	0.9	2	1.38E+03	1.03E+07	4.7
Bioreactor (methanation)	6720.43	0.265	m^3/s biogas out	0.95	1	2.38E+04	1.77E+08	81.2
Amine scrubber	4032.26	0.972	m^3/s biogas in	0.6	1	4.10E+03	3.05E+07	14.0
					Total cost	**2.93E+04**	**2.18E+08**	100.0

References:						
Lorenzo Menin (paper)	Fabric filter (k€)	61.9	15.6	m^3/s	? 0.77	m^3/s at normal temperature
Lorenzo Menin (paper)	Tar reformer (k€)	8.43E+04	31000	kmol/h at exit	0.9	1 kmol relates to 22.4 m^3 normal
BiogasClean (company)	Bioreactor (MDKK)	50	381	m^3 CO$_2$/h	0.95 at >381 m^3/h	S_o: originally CO$_2$ converted, but total gas is better := CO$_2$/0.40
Ammongas (company)	Amine scrubber (MDKK)	30	3500	m^3 biogas/h	0.6	S_o: originally 2000 m^3 CH$_4$/h, but total gas is better := 3500 m^3/h

C = cost of that equipment
C_o = reference cost of that equipment at a certain reference gas flow S_o
S_o = the reference gas flow for that equipment
S = the actual gas flow of that equipment
f = the scaling factor when increasing or reducing the gas flow relative to reference

Simple depreciation time (years)	10
CH$_4$ % in biogas from methanation	50
Annual operational time (hours)	8000
CAPEX of equipment (DKK/m^3 CH$_4$)	**1.51**

OPEX

Electricity price	350	(DKK/GJ)	Price of heat 60

					S	€/m^{3}CH$_4$	**DKK/m^{3}CH$_4$**	%
Dust filter	effectively zero				2	0.000	0.00	0.0
Tar reformer	5.00 % of CAPEX/y				2	0.005	0.04	3.9
Bioreactor (methanation)	kW el	100	Nutrients: DKK/h	50	1	0.050	0.37	40.3
Amine scrubber	kWh-el/m^3 biogas	0.10	kWh varme/m^3 biogas	0.6	1	0.069	0.51	55.8
					Total cost	**0.123**	**0.92**	100.0

SkyClean – Bio-methane quality in gas grid

Dansk Gasteknisk Center
Niels Bjarne Rasmussen

One of the options in the SkyClean project is to convert all or parts of the product gases into bio-methane, which is then upgraded to a quality ready for the natural gas system. At this point it is necessary to define which quality is needed for the natural gas grid.

Energinet, which is the transmission grid operator in Denmark, has some Quality and Delivery Specifications for the natural gas received and transported in the Danish Gas System, [1] (App 1). Following these requirements for the quality of the gas would be sufficient for specifying the content of the possible bio-SNG for the gas grid.

However, the total picture is a bit more complicated. The actual specifications to follow are described in the “Bekendtgørelse om gaskvalitet”, 21 March 2018 (in Danish), [2] (App 2). This document describes the requirements for all kinds of energy gases delivered and used in the Danish energy system.

Possible bio-SNG gases from the SkyClean system could be added to the Danish gas system if it complies with the requirements in App 2. This means that it should be defined as “Bionaturgas”. Looking at the definitions in App 2 we find that “Bionaturgas” is “Biogas, which has been upgraded to natural gas quality”.

This again leads to the definition of Biogas, which in App 2 is described as “Combustible gas, which is produced by anaerobic fermentation of organic materials from, e.g., manure, sludge from sewage treatment plants, energy crops or organic waste, and where methane and carbon dioxide are the most important components”.

This definition of biogas is the traditional definition, which is very limited. With this definition, bio-SNG from thermochemical methanation of syngas would not be biogas, and hence it would not be “Bionaturgas” and hence would not be covered by the permitted gases for the natural gas system. This is a paradox as, e.g., straw fermented in a biogas plant and converted into bio-SNG would be permitted, while straw treated in a pyrolyzer and converted into bio-SNG would not. The result is that if the pyrolysis gas from the SkyClean system is methanized in a bio-methanation plant it would be permitted as this is a fermentation process, while the thermochemically methanized pyrolysis gas from SkyClean would not be permitted in the gas grid.

The question is if this obstacle is legal as it could be considered as a “technical barrier to trade”.

However, there might be other possibilities. In the RED-II from the European Union (Renewable Energy Directive) [3], which must be ratified by all countries in EU, a new comprehensive definition of biogas is “’Biogas’ means gaseous fuels produced from biomass” (see point (28) of App 3, Definitions). If this definition is included in Danish legislation, then bio-SNG from thermochemical methanation of syngas would be covered as being “Bionaturgas”.

References:
[1] Terms and Conditions for Gas Transport, Quality and Delivery Specifications, APPENDIX 1, Energinet October 2021.
https://en.energinet.dk/Gas/Rules

[2] Bekendtgørelse om gaskvalitet, 21 March 2018 (in Danish).
https://www.retsinformation.dk/eli/lta/2018/230

[3] DIRECTIVE (EU) 2018/2001 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 11 December 2018 on the promotion of the use of energy from renewable sources.
https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001

Appendix 1 to 3 are included after this page.

Appendix 1 - Quality_and_delivery_specifications
Appendix 2 - Bekendtgørelse om gaskvalitet
Appendix 3 - RED II - CELEX_32018L2001_EN_TXT

Appendix 1 - Quality_and_delivery_specifications

APPENDIX 1

Quality and Delivery Specifications

1 October 2021

Natural Gas received, transported and redelivered in the Danish Gas System under a Capacity Agreement or storage agreement shall at all times comply with the Danish gas regulation (Gas-sikkerhedsloven) and the following Quality Specifications.

1. Quality Specifications

a) Wobbe Index: During normal operation the Wobbe Index for the Natural Gas shall not be lower than 50.76 MJ/m^3 or higher than 55.8 MJ/m^3. During abnormal state of operation the Wobbe Index for the Natural Gas shall not be lower than 50.04 MJ/m^3 or higher than 55.8 MJ/m^3 – require a preparedness plan approved by The Danish Safety Technology Authority (Sikkerhedsstyrelsen). A preparedness plan for the Entry Point at Ellund has been approved.

b) Relative Density: The Relative Density of the Natural Gas shall not be lower than 0.555 or higher than 0.7.

c) CO_2: The CO_2 content of the Natural Gas shall not exceed 2.5 mol-%.

d) O_2: The O_2 content of the Natural Gas shall not exceed 0.1 mol-% on a 24-hour basis for the Entry Points, the Transit Points and the Storage Points. The O_2 content of the Natural Gas/Biomethane shall not exceed 0.5 mol-% for the Transition Points and the Metering Points for Biomethane.

e) H_2S and COS: The content of H_2S + COS in the Natural Gas measured as sulphur shall not exceed 5 mg/m^3. However, under extraordinary operating conditions in relation to the Entry Points, the Transit Points and the Storage Points, the H_2S + COS content may for a period of maximum 2 hours constitute up to 10 mg/m^3, although not more than 5 mg/m^3 on a 24-hour basis.

f) Mercaptans: The mercaptans content of the Natural Gas measured as sulphur shall not exceed 6 mg/m^3.

g) Total sulphur content: The total sulphur content shall not exceed 30 mg/m^3.

h) Water dew point: The water dew point of the Natural Gas shall not exceed minus 8 ^{o}C at any pressure up to 70 bar absolute pressure.

i) Hydrate formation: The Natural Gas must not form hydrates at temperatures of minus 8 ^{o}C or higher at any pressure up to 70 bar absolute pressure.

j) Hydrocarbon dew point: The Natural Gas must not form liquid hydrocarbons at temperatures of minus 2 ^{o}C or higher at any pressure up to 70 bar absolute pressure.

k) Dust and liquids: The Natural Gas shall be technically free of gaseous, solid or liquid substances to the extent that this may involve a risk of blocking and malfunction or corrosion of ordinary gas installations and standard gas equipment. This provision does not apply to such liquid formation that occasionally occurs in Natural Gas in the form of very small droplets and that cannot be removed from it.

l) Odorisation: The Natural Gas shall be delivered unodorised at the Entry Point. Odorisation of the Natural Gas shall take place at the Transition Point.

m) Other components and contaminants: The Natural Gas shall not contain other components and/or contaminants to an extent which may imply that it cannot be transported, stored and/or marketed without further adjustment of the quality or treatment of the Natural Gas.

2. Delivery specifications

Temperature: The temperature of the Natural Gas during normal operation shall be no lower than 0 °C and no higher than 50 °C; however, under extraordinary operating conditions or due to bona fide technical circumstances, the temperature of the Natural Gas may be as low as minus 10 °C for periods of up to two hours.

3. Revision of Appendix 1

This Appendix 1 is subject to regular revision by Energinet, Gas Storage Denmark and the Distribution Companies in step with changes in the General Terms and Conditions for Gas Transport and/or changes in the quality and delivery specifications typically applying in Europe.

Appendix 2 - Bekendtgørelse om gaskvalitet

Udskriftsdato: 1. februar 2022

BEK nr 230 af 21/03/2018 (Gældende)

Bekendtgørelse om gaskvalitet

Ministerium: Erhvervsministeriet	Journalnummer: Erhvervsmin., Sikkerhedsstyrelsen, j.nr. 215-14-00001

Bekendtgørelse om gaskvalitet

I medfør af § 5, stk. 1, nr. 5, og stk. 2, § 26, stk. 1 og 2, § 27, § 28 og § 31, stk. 2, i lov nr. 61 af 30. januar 2018 om sikkerhed for gasanlæg, gasinstallationer og gasmateriel (gassikkerhedsloven) fastsættes efter bemyndigelse:

Kapitel 1

Anvendelsesområde og definitioner

Anvendelsesområde

§ 1. Bekendtgørelsen fastsætter krav til kvaliteten af brændbare gasser, der indgår ved brug af gasanlæg, gasinstallationer og gasmateriel i henhold til anvendelsesområdet i gassikkerhedsloven.

Stk. 2. Den, der leverer brændbare gasser, jf. stk. 1, er ansvarlig for at leve op til kravene i denne bekendtgørelse.

Stk. 3. Krav til gastyper eller blandinger af gastyper, som ikke er nævnt i denne bekendtgørelse, men som er omfattet af anvendelsesområdet i gassikkerhedsloven, fastsættes individuelt af Sikkerhedsstyrelsen.

Definitioner

§ 2. I denne bekendtgørelse forstås ved:

1) Gaskvalitet: Udtryk for gassens egenskaber, herunder brændværdi og densitet.
2) Gasfamilier: Grupper af gaskvaliteter med beslægtede forbrændingsegenskaber, der opdeles i 1., 2. og 3. gasfamilie på basis af gassernes øvre Wobbeindeks, jf. EN 437 + A1:2009.
3) 1. gasfamilie: Bygaskvaliteten i Danmark betragtes som værende en blanding af metan og atmosfærisk luft og inddeles i gruppe a med specificerede variationer i gassens Wobbeindeks.
4) 2. gasfamilie: Naturgaskvaliteter med højt metanindhold. Naturgaskvaliteter opdeles i grupperne H, E og L med specificerede variationer i gassens Wobbeindeks.
5) 3. gasfamilie: Flaskegaskvaliteter, propan, butan og blandinger heraf.
6) Biogas: Brændbar gas, som fremstilles ved anaerob forgæring af organiske materialer fra eksempelvis gylle, slam fra renseanlæg, energiafgrøder eller organisk affald, og hvor metan og kuldioxid udgør de væsentligste komponenter.
7) Bionaturgas: Biogas, som er opgraderet til naturgaskvalitet.
8) Brint: Brændbar gas, som eksempelvis fremstilles katalytisk eller ved elektrolyse.
9) Erstatningsgas: Gaskvalitet, der ved samme tilslutningstryk og uforandret apparatindstilling udviser tilsvarende forbrændingsforhold som den gaskvalitet, der erstattes. Erstatningsgas for bygas kan være flaskegas/luft eller blandinger af naturgas og biogas/luft.
10) Spidsbelastningsgas: Gaskvalitet, der under spidsbelastningsforhold kan tilsættes en gaskvalitet op til et af Sikkerhedsstyrelsen på forhånd fastsat maksimalt indhold, hvorved forbrændingsforholdene anses for uforandrede.
11) Gasmængde: Angives som masse (kg) eller gasvolumen.
12) Gasvolumen: Defineres enten som normalkubikmeter (Nm^3), der er tør gas ved 273,15 K og 1013,25 mbar absolut tryk, eller som standardkubikmeter (Sm^3), der er tør gas ved 288,15 K og 1013,25 mbar absolut tryk.
13) Densitet: Massen pr. volumenhed (ρ) angivet i kg/Nm^3.
14) Relativ densitet: Forholdet mellem massen af lige store rumfang gas og tør luft ved samme tryk og temperatur. Angives som (d).
15) Nedre brændværdi: Den varmemængde, der udvikles ved forbrænding under konstant tryk af en enhed gas (Nm^3 eller kg), når gas og luft til forbrændingen har temperaturen 25 °C, forbrændings-

produkterne bringes til 25 °C, og det ved forbrændingen dannede vand er til stede i luftformig tilstand. Den nedre brændværdi (H_n) angives i MJ/Mn^3 eller MJ/kg.

16) Øvre brændværdi: Den varmemængde, der udvikles ved forbrænding under konstant tryk af en enhed gas (Nm^3 eller kg), når gas og luft til forbrændingen har temperaturen 25 °C, forbrændingsprodukterne bringes til 25 °C, og det ved forbrændingen dannede vand er til stede i flydende tilstand. Den øvre brændværdi ($H_ø$) angives i MJ/Nm^3 eller MJ/kg.
17) Wobbeindeks: Udtryk for brænderbelastningen på eksempelvis atmosfæriske brændere, hvorefter to gaskvaliteter med samme Wobbeindeks vil give samme brænderbelastning.
18) Nedre Wobbeindeks: Den nedre brændværdi divideret med kvadratroden af den relative densitet. Nedre Wobbeindeks (W_n) angives i MJ/Nm^3.
19) Øvre Wobbeindeks: Den øvre brændværdi divideret med kvadratroden af den relative densitet. Øvre Wobbeindeks ($W_ø$) angives i MJ/Nm^3.
20) Metantal: Gassens tendens til at modvirke bankning ved anvendelse som motorbrændstof. Metantallet beregnes for en given sammensætning af gassen. Udgangspunktet er, at ren metan pr. definition har metantal 100, og at ren brint har metantal 0.
21) Gastryk: Angives som overtryk (p) i bar eller mbar.
22) Tilslutningstryk: Gastrykket umiddelbart foran de gasforbrugende gasapparater eller deres regulatorer.
23) Transmissionsnet: Ledningsnet, der forsyner distributionsnettet og professionelle slutbrugere.
24) Distributionsnet: Ledningsnet, hvor enhver form for gas distribueres frem til stikledningen, der forsyner gasforbrugerne.
25) Lokalt biogasnet: Ledningsnet, der fører biogas fra et eller flere biogasanlæg til en eller flere slutbrugere i nærområdet.

Kapitel 2

Generelle sikkerhedskrav

§ 3. Gasser skal være fri for luftformige, faste eller flydende stoffer i koncentrationer, der kan indebære en risiko for blokering og fejlfunktioner eller korrosion af installationer og udstyr.

§ 4. Enhver erstatnings- og spidsbelastningsgas skal godkendes af Sikkerhedsstyrelsen.

§ 5. Støv skal filteres fra gasser, hvis det kan forårsage fejlfunktion ved efterfølgende målere, regulatorer og andre komponenter.

§ 6. Bakterier og mikroorganismer i gasser må ikke udgøre en helbredsmæssig risiko.

§ 7. Indholdet af umættede og aromatiske kulbrinter i gasser skal begrænses.

§ 8. Vanddugpunktet skal være lavt af hensyn til risikoen for hydratdannelse og korrosion.

Stk. 2. Vanddugpunktet i naturgas må ikke overstige minus 8 °C ved ethvert tryk op til 70 bar absolut tryk.

§ 9. Totalindholdet af svovl (S) og svovlbrinte (H_2S) skal begrænses af hensyn til korrosionsrisikoen.

§ 10. Gasinstallationer og gasforbrugende udstyr til særlige formål i erhverv, kraft- eller varmeproducerende anlæg og industri kan nødvendiggøre, at der stilles yderligere krav til egenskaber ved gassen, herunder gassens renhed og filtrering, tryk og temperatur, metantal eller flammetemperatur, der ikke er reguleret i disse bestemmelser. For installationer, hvor sådanne krav er relevante, skal gasdistributionsselskabet i samarbejde med ejerne eller brugerne af installationerne aftale supplerende sikkerhedsmæssige foranstaltninger til at forebygge følgerne af forudsigelige variationer af gaskvaliteten.

§ 11. Tilslutningstrykket for gasforbrugende apparater til anvendelse i husholdning og mindre industri er baseret på et standard tilslutningstryk og tilladte variationer, jf. EN 437 + A1:2009, og er fastsat til følgende:

1) For 1. gasfamilie er tilslutningstrykket 8 mbar. Det tilladte minimumstryk er 6 mbar, og det tilladte maksimumstryk er 15 mbar.
2) For 2. gasfamilie er tilslutningstrykket 20 mbar. Det tilladte minimumstryk er 17 mbar, og det tilladte maksimumstryk er 25 mbar.
3) For 3. gasfamilie er tilslutningstrykket 30 mbar. Det tilladte minimumstryk er 25 mbar, og det tilladte maksimumstryk 35 mbar.

Kapitel 3

Bygas

§ 12. Bygas karakteriseres som 1. gasfamilie, gruppe a, i EN 437 + A1:2009.

Stk. 2. Bygas skal have et øvre Wobbeindeks i intervallet 23,6 – 26,2 MJ/Nm^3.

§ 13. Ved erstatningsgas for bygas, hvor distributionsnettet er opbygget til at transportere fugtig gas, fastsættes fugtindholdet af gasdistributionsselskabet ud fra kendskabet til distributionsnettets opbygning.

Kapitel 4

Naturgas

§ 14. Naturgas karakterises som 2. gasfamilie, gruppe H, i EN 437 + A1:2009.

Stk. 2. Naturgas skal ved normale forsyningsforhold have et øvre Wobbeindeks i intervallet 50,76 – 55,8 MJ/Nm^3.

Stk. 3. Den relative densitet (d) af naturgaskvaliteter må ikke være lavere end 0,555 og ikke højere end 0,7.

§ 15. Forsyning af naturgas ved unormale forsyningsforhold, hvor Wobbeindeks er mellem 50,04 og 50,76 MJ/Nm^3, kan tillades under forsætning af, at Sikkerhedsstyrelsen har godkendt en særlig beredskabsplan.

§ 16. Den særlige beredskabsplan, jf. § 15, skal indeholde

1) et aktionsprogram, hvor udvalgte installationstyper overvåges i perioden, hvor forsyning sker i det unormale område, og
2) et varslingssystem, der sikrer, at udvalgte forbrugere med større, følsomme naturgasinstallationer bliver informeret om den større variation i naturgaskvaliteten.

§ 17. Kulbrintedugpunktet i naturgas må ved ethvert tryk op til 70 bar absolut tryk ikke overstige minus 2 °C.

§ 18. Det samlede indhold af svovlbrinte (H_2S) og carbonylsulfid (COS) målt som svovl i naturgas må ikke overstige 5 mg/Nm^3.

Stk. 2. Under unormale driftsforhold må det samlede indhold af H_2S og COS i perioder på maksimalt 2 timer højst udgøre 10 mg/Nm^3. Gennemsnittet på døgnbasis må uanset 1. pkt. ikke overstige 5 mg/Nm^3. De unormale driftsforhold må ikke overstige 132 timer pr. år.

Stk. 3. Indholdet af merkaptaner i naturgas målt som svovl må ikke overstige 6 mg/Nm^3.

Stk. 4. Det totale svovlindhold i naturgas må ikke overstige 30 mg/Nm^3.

Stk. 5. Værdierne i stk. 1-4 er eksklusiv eventuelle svovlforbindelser fra odorant.

Kapitel 5

Flaskegas

§ 19. Flaskegas karakteriseres som 3. gasfamilie, gruppe B, P eller B/P, i EN 437 + A1:2009.

Stk. 2. Flaskegas skal have et øvre Wobbeindeks i intervallet 76,9 - 92,1 MJ/Nm^3.

§ 20. Der må ved de aktuelle driftstryk og temperaturer ikke ske udfældning af kulbrinter og vand.

§ 21. Flaskegas til husholdningsbrug skal opfylde ISO 9162:2013 for propan (Class F). Opfyldelsen medfører, at der højst må være 7,5 procent (molær) butan og 0,2 procent (molær) højere kulbrinter (C_5) i flaskegas.

Stk. 2. Flaskegas til industrielle anvendelser kan leveres med andre blandingsforhold end anført i stk. 1, når anvendelsen er godkendt af gasdistributionsselskabet, og installationen er indrettet hertil.

§ 22. Flaskegas til campingbrug kan indeholde butan, som skal opfylde ISO 9162:2013 for butan (Class F), hvis flasken er særligt mærket med dette indhold. Opfyldelsen medfører, at der højst må være 2,5 procent (molær) højere kulbrinter (C_5) i butanen.

Kapitel 6

Biogas

§ 23. Bionaturgas, som tilsættes naturgasdistributionsnettet, skal foruden de generelle sikkerhedskrav opfylde kravene i § 8, stk. 2, § 14, stk. 2 og 3, § 17 og § 18 og følgende:

1) Højst 3 mg/Nm^3 ammoniak (NH_3).
2) Højst 0,5 molprocent ilt (O_2).
3) Højst 3,0 molprocent kuldioxid (CO_2).
4) Højst 1,0 mg/Nm^3 siloxaner.
5) Samme koncentration af odorant, som for naturgas, jf. § 31.

§ 24. Bionaturgas, som tilsættes transmissionsnettet, skal opfylde kravene i § 23, nr. 1 og 4, og Energinets gældende kvalitetsspecifikationer i Regler for gastransport.

§ 25. For biogas, der tilsættes til bygasdistributionsnettet, fastsættes andelen af biogas individuelt af Sikkerhedsstyrelsen. Fastsættelsen sker bl.a. på baggrund af gasdistributionsselskabets kendskab til apparatbestanden og dennes kompleksitet og dokumentation for test af apparaternes sikre funktion.

Stk. 2. Enhver blanding af biogas og bygas skal opfylde § 12, stk. 2, og følgende:

1) Indholdet af ammoniak (NH_3) fraregnet lufttilsætning og de ikke brændbare bestanddele i biogassen må ikke overstige 3 mg/Nm^3.
2) Indholdet af siloxaner fraregnet lufttilsætning og de ikke brændbare dele i biogassen må ikke overstige 1,0 mg/Nm^3.
3) Koncentrationen af odorant fraregnet lufttilsætning og de ikke brændbare dele i biogassen skal være som angivet i § 31 for naturgas.
4) Indholdet af svovlbrinte (H_2S) fraregnet lufttilsætning og de ikke brændbare dele i biogassen må ikke overstige 30 mg/Nm^3.

§ 26. Biogas, som distribueres i lokale biogasnet, skal opfylde følgende:

1) Udsving i Wobbeindeks skal aftales med forbrugerne, da det påvirker det gasforbrugende udstyr.
2) Indholdet af ammoniak fraregnet de ikke brændbare bestanddele i biogassen må ikke overstige 3 mg/Nm^3.
3) Indholdet af siloxaner, fraregnet de ikke brændbare dele i biogassen, må ikke overstige 1,0 mg/Nm^3.
4) Odorant tilsættes som angivet i § 33, hvis det er påkrævet på grund af rensemetode.

5) Indholdet af svovlbrinte (H_2S) fraregnet de ikke brændbare dele i biogassen må ikke overstige 30 mg/Nm^3.
6) Der må ikke ved aktuelle driftstryk og temperaturer ske udfældning af vand.

Stk. 2 Pålidelig drift af lokale biogasnet og gasinstallationer skal sikres med indbygning af vandudskillere, uanset stk. 1, nr. 6, hvis der ved aktuelle driftstryk og temperaturer kan ske udfældning af vand, og hvis der udelukkende sker distribution til professionelle slutbrugere.

Stk. 3. Den udsendte gaskvalitet skal godkendes af Sikkerhedsstyrelsen inden opstart.

Kapitel 7

Brint

§ 27. Brint, som tilsættes naturgasdistributionsnettet, skal opfylde følgende:
1) Mindst 98 volumenprocent brint (H_2).
2) Højst 0,1 volumenprocent ilt (O_2).
3) Højst 0,2 volumenprocent kuldioxid (CO_2).
4) Højst 0,5 volumenprocent kulbrinter (C_nH_m) målt som metan.
5) Vanddugpunkt under -50 °C målt ved atmosfæretryk.

Stk. 2. Volumenindholdet af brint i naturgasdistributionsnettet skal godkendes af Sikkerhedsstyrelsen.

§ 28. Brint, der forsynes direkte til stationære brændselsceller, eller som distribueres i lokale brintnet, hvor der er tilsluttet stationære brændselsceller, skal opfylde følgende:
1) Mindst 98 volumenprocent brint (H_2).
2) Højst 0,1 volumenprocent ilt (O_2).
3) Højst 0,1 volumenprocent kuldioxid (CO_2).
4) Højst 0,005 volumenprocent kulbrinter (C_nH_m) målt som metan.
5) Vanddugpunkt under -60 °C målt ved atmosfæretryk.

§ 29. Tilsætning af brint til naturgasdistributionsnettet med andre renhedsgrader end anført i §§ 27 og 28 kan kun ske efter Sikkerhedsstyrelsens godkendelse.

Kapitel 8

Odorisering

§ 30. Enhver gas, der distribueres, skal indeholde et lugt- eller odoriseringsstof i en sådan koncentration, at en person med normal lugtesans er i stand til med sikkerhed at spore en gas- eller luftblanding svarende til højst 20 procent af gassens nedre eksplosionsgrænse.

Stk. 2. Naturgas, der føres i transmissionsnettet, er undtaget fra kravet i stk. 1.

§ 31. Det er tilladt at anvende odoriseringsstofferne THT og merkaptaner i følgende blandingsforhold:
1) På alle forbrugssteder for naturgas skal odorantkoncentrationen med THT være mindst 10 mg/Nm^3 og for flaskegas (dampfase) være mindst 23,5 mg/Nm^3.
2) På alle forbrugssteder for naturgas skal odorantkoncentrationen med merkaptaner være mindst 4 mg/Nm^3 og for flaskegas (dampfase) være mindst 8,8 mg/Nm^3.

Stk. 2. Anvendelse af andre odoriseringsstoffer end THT og merkaptaner skal godkendes af Sikkerhedsstyrelsen.

§ 32. Den aktuelle odorisering må ikke udsætte personer eller materialer for skadelige påvirkninger.

§ 33. Biogas, som distribueres i lokale biogasnet, skal ikke tilsættes odorant, hvis § 30, stk. 1, er opfyldt.

Stk. 2. Hvis der anvendes rensemetoder til fjernelse af vand, svovlbrinte eller andre bestanddele, som fjerner biogassens lugtstoffer, skal biogassen tilsættes odorant.

Stk. 3. Koncentrationen af odorant, jf. stk. 2, skal være som angivet i § 31 for naturgas fraregnet de ikke brændbare bestanddele i biogassen.

§ 34. Brint, som distribueres i flasker, tankanlæg eller lokale brintnet, skal ikke tilsættes odorant, hvis gasinstallationen etableres med automatisk overvågning og lukkefunktion.

Kapitel 9

Krav til overvågning af gaskvaliteter

§ 35. Ved måling og bestemmelse af gaskvaliteten skal der tages hensyn til måleusikkerheden, således at gassen altid ligger inden for kravene til gaskvaliteten, der er fastsat i denne bekendtgørelse.

Bygas

§ 36. Der skal for gas i distributionsnettet ske periodevis bestemmelse af odorantkoncentrationen i henhold til den til enhver tid gældende aftale mellem Sikkerhedsstyrelsen og gasdistributionsselskaberne vedrørende odoranttilsætning og kontrol af odorantindhold.

Naturgas

§ 37. Der skal ske kontinuerlig måling og bestemmelse i transmissionsnettet af følgende parametre:

1) Wobbeindeks.
2) Svovlbrinte.
3) Vand- og kulbrintedugpunkt.
4) Relativ densitet.

§ 38. Der skal ske periodevis måling og bestemmelse i transmissionsnettet af totalsvovl.

§ 39. Der skal for gas i distributionsnettet ske periodevis bestemmelse af odorantkoncentrationen i henhold til den til enhver tid gældende aftale mellem Sikkerhedsstyrelsen og gasdistributionsselskaberne vedrørende odoranttilsætning og kontrol af odorantindhold.

Bionaturgas til distributionsnettet

§ 40. Der skal ske kontinuerlig måling og bestemmelse af følgende parametre:

1) Øvre Wobbeindeks.
2) Vanddugpunkt.
3) Svovlbrinte (H_2S).

§ 41. Der skal ske periodevis måling og bestemmelse, hvor perioden fastsættes ud fra erfaringer fra hver enkelt anlægstype, af følgende parametre:

1) Relativ densitet.
2) Iltindhold (O_2).
3) Kuldioxid (CO_2).
4) Ammoniak (NH_3).
5) Siloxaner.
6) Odorantkoncentration i henhold til den til enhver tid gældende aftale mellem Sikkerhedsstyrelsen og gasdistributionsselskaberne vedrørende odoranttilsætning og kontrol af odorantindhold.

§ 42. Kontinuerlig måling og bestemmelse af parametre skal i nødvendigt omfang erstatte periodevis bestemmelse af enkelte eller flere parametre, jf. § 41, afhængigt af opgraderingssystemets stabilitet.

Bionaturgas til transmissionsnettet

§ 43. Kontinuerlig og periodevis bestemmelse af parametrene i transmissionsnettet skal overholde kravene fastsat i §§ 40-42 og bestemmelserne i Energinets kvalitetsspecifikationer i Regler for gastransport, hvis disse bestemmelser indeholder parametre ud over de i §§ 40-42 fastsatte.

Stk. 2. Bionaturgas, der tilsættes transmissionsnettet, er fritaget for krav om odoranttilsætning, jf. § 30, stk. 2.

Biogas til bygasdistributionsnet

§ 44. For blandingen af biogas og naturgas/luft skal der være kontinuerlig måling og bestemmelse af følgende parametre:

1) Wobbeindeks.
2) Svovlbrinte (H_2S).

§ 45. Der skal ske periodevis måling og bestemmelse af følgende parametre:

1) Øvre brændværdi.
2) Relativ densitet.
3) Kuldioxid (CO_2).
4) Ammoniak (NH_3).
5) Siloxaner.
6) Odorantkoncentration i henhold til den gældende aftale mellem Sikkerhedsstyrelsen og gasdistributionsselskaberne vedrørende odoranttilsætning og kontrol af odorantindhold.

Biogas til lokale biogasnet

Lokale biogasnet, der udelukkende forsyner professionelle slutbrugere

§ 46. Ved distribution af biogas i lokale net, der udelukkende forsyner professionelle slutbrugere, skal der ske kontinuerlig måling og bestemmelse af følgende parametre:

1) Wobbeindeks.
2) Svovlbrinte (H_2S).

§ 47. Ved distribution af biogas i lokale net, der udelukkende forsyner professionelle slutbrugere, skal der ske periodevis måling og bestemmelse af følgende parametre:

1) Øvre brændværdi.
2) Vandindhold.
3) Kuldioxid (CO_2).
4) Ammoniak (NH_3).
5) Siloxaner.
6) Odorantkoncentration, hvis det er påkrævet på grund af rensemetode, jf. § 33, stk. 2.

Stk. 2. Fastlæggelse af perioden mellem målinger skal ske ud fra erfaringer med hver enkelt anlægstype.

§ 48. Kontinuerlig måling og bestemmelse af parametre skal i nødvendigt omfang erstatte periodevis bestemmelse af enkelte eller flere parametre, jf. § 47 afhængigt af opgraderingssystemets stabilitet.

Lokale biogasnet med tilslutning til beboelsesenheder og mindre erhverv

§ 49. Ved distribution af biogas, som distribueres i lokale net, hvor der er tilsluttet beboelsesenheder og mindre erhverv, skal der ske kontinuerlig måling og bestemmelse af følgende parametre:

1) Wobbeindeks.
2) Vanddugpunkt.
3) Svovlbrinte (H_2S).

§ 50. Ved distribution af biogas, som distribueres i lokale net, hvor der er tilsluttet beboelsesenheder og mindre erhverv skal der ske periodevis måling og bestemmelse af følgende parametre:
1) Øvre brændværdi.
2) Kuldioxid (CO_2).
3) Ammoniak (NH_3).
4) Siloxaner.
5) Odorantkoncentration, hvis det er påkrævet på grund af rensemetode.

Stk. 2. Fastlæggelse af perioden mellem målinger skal ske ud fra erfaringer med hver enkelt anlægstype.

§ 51. Kontinuerlig måling og bestemmelse af parametre skal i nødvendigt omfang erstatte periodevis bestemmelse af enkelte eller flere parametre, jf. § 50, afhængigt af opgraderingssystemets stabilitet.

Flaskegas

§ 52. Der skal ske periodevis måling og bestemmelse af følgende parametre:
1) Vægtfylde.
2) Kaustisk soda.
3) Korrosive stoffer.
4) Vandindhold.
5) Odorantkoncentration.

Brint

Brint som tilsættes til naturgasdistributionsnettet

§ 53. Der skal ske kontinuerlig måling og bestemmelse af følgende parametre:
1) Brintindholdet (H_2).
2) Vanddugpunktet.
3) Iltindhold (O_2).

§ 54. Der skal ske periodevis måling og bestemmelse af CO_2-indhold.

Brint som distribueres i lokalt brintnet, hvor der er tilsluttet stationære brændselsceller

§ 55. Der skal ske periodevis måling og bestemmelse af følgende parametre:
1) Brintindhold (H_2).
2) Vanddugpunkt.
3) Iltindhold (O_2).
4) Kuldioxidindhold (CO_2).
5) Kulbrinter (C_nH_m) målt som metan.

Brint som distribueres i flaske eller fra tank Forsyningen sker til stationære brændselsceller

§ 56. Der skal ske periodevis måling og bestemmelse af følgende parametre:
1) Brintindhold (H_2).
2) Vanddugpunkt.
3) Iltindhold (O_2).
4) kuldioxidindhold (CO_2).

Forsyningen sker til apparatbestand uden stationære brændselsceller

§ 57. Renhedsgrader, som er godkendt af Sikkerhedsstyrelsen i henhold til § 29, eftervises ved periodevis måling og bestemmelse af følgende parametre:

1) Brintindhold (H_2).
2) Vanddugpunkt.
3) Iltindhold (O_2).
4) Kuldioxidindhold (CO_2).
5) Kulbrinter (C_nH_m) målt som metan.

Kapitel 10

Administrative bestemmelser

§ 58. Skriftlig kommunikation til Sikkerhedsstyrelsen skal foregå digitalt.

Stk. 2. Ved ansøgninger om godkendelse eller dispensation skal blanket på Virk (www.virk.dk) anvendes.

Stk. 3. Sikkerhedsstyrelsen kan undlade at sagsbehandle ansøgninger efter stk. 2, der ikke indsendes via Virk.

Stk. 4. Skriftlig kommunikation mellem Sikkerhedsstyrelsen og gasdistributionsselskaberne skal foregå digitalt.

§ 59. De standarder, som denne bekendtgørelse henviser til, indføres ikke i Lovtidende, men kan købes ved Dansk Standard eller gennemses ved Sikkerhedsstyrelsen.

Stk. 2. Standarder, jfr. stk. 1, er gældende, selvom de ikke foreligger på dansk.

Kapitel 11

Straffebestemmelser

§ 60. Med mindre strengere straf er forskyldt efter anden lovgivning, straffes med bøde den, der

1) leverer gas, som ikke opfylder de generelle sikkerhedskrav, jf. §§ 3-11,
2) leverer bygas eller erstatningsgas for bygas, som ikke opfylder kravene i § 12, stk. 2, og § 13,
3) leverer naturgas, som ikke opfylder kravene i § 14, stk. 2 og 3, § 15 og §§ 17 og 18,
4) leverer flaskegas, som ikke opfylder kravene i § 19, stk. 2, og §§ 20-22,
5) leverer bionaturgas, som ikke opfylder kravene i §§ 23 og 24,
6) leverer biogas, som ikke opfylder kravene i §§ 25-26,
7) leverer brint, som ikke opfylder kravene i §§ 27-29,
8) leverer gas, som ikke opfylder kravene til odorisering, jf. § 30, stk. 1, og §§ 31-34, eller
9) ikke foretager periodevis eller kontinuerlig måling og bestemmelse af gaskvaliteter, jf. §§ 36-57.

§ 61. Der kan pålægges selskaber m.v. (juridiske personer) strafansvar efter reglerne i straffelovens 5. kapitel.

Kapitel 12

Ikrafttræden

§ 62. Bekendtgørelsen træder i kraft den 21. april 2018.

Stk. 2. Bekendtgørelse nr. 1264 af 14. december 2012 om gasreglementets afsnit C-12, bestemmelser om gaskvalitet ophæves.

Sikkerhedsstyrelsen, den 21. marts 2018

LONE SAABY

/ Anders Holt

Appendix 3 - RED II - CELEX_32018L2001_EN_TXT

accordance with the principles laid down in the Interinstitutional Agreement of 13 April 2016 on Better Law-Making (1). In particular, to ensure equal participation in the preparation of delegated acts, the European Parliament and the Council receive all documents at the same time as Member States' experts, and their experts systematically have access to meetings of Commission expert groups dealing with the preparation of delegated acts.

(127) The measures necessary for the implementation of this Directive should be adopted in accordance with Regulation (EU) No 182/2011 of the European Parliament and of the Council (2).

(128) Since the objective of this Directive, namely to achieve a share of at least 32 % of energy from renewable sources in the Union's gross final consumption of energy by 2030, cannot be sufficiently achieved by the Member States but can rather, by reason of the scale of the action, be better achieved at Union level, the Union may adopt measures, in accordance with the principle of subsidiarity as set out in Article 5 of the Treaty on European Union. In accordance with the principle of proportionality, as set out in that Article, this Directive does not go beyond what is necessary in order to achieve that objective.

(129) In accordance with the Joint Political Declaration of 28 September 2011 of Member States and the Commission on explanatory documents (3), Member States have undertaken to accompany, in justified cases, the notification of their transposition measures with one or more documents explaining the relationship between the components of a directive and the corresponding parts of national transposition instruments. With regard to this Directive, the legislator considers the transmission of such documents to be justified.

(130) The obligation to transpose this Directive into national law should be confined to those provisions which represent a substantive amendment as compared to Directive 2009/28/EC. The obligation to transpose provisions which are unchanged arises under that Directive.

(131) This Directive should be without prejudice to the obligations of the Member States relating to the time-limit for the transposition into national law of Council Directive 2013/18/EU (4) and Directive (EU) 2015/1513,

HAVE ADOPTED THIS DIRECTIVE:

Article 1

Subject matter

This Directive establishes a common framework for the promotion of energy from renewable sources. It sets a binding Union target for the overall share of energy from renewable sources in the Union's gross final consumption of energy in 2030. It also lays down rules on financial support for electricity from renewable sources, on self-consumption of such electricity, on the use of energy from renewable sources in the heating and cooling sector and in the transport sector, on regional cooperation between Member States, and between Member States and third countries, on guarantees of origin, on administrative procedures and on information and training. It also establishes sustainability and greenhouse gas emissions saving criteria for biofuels, bioliquids and biomass fuels.

Article 2

Definitions

For the purposes of this Directive, the relevant definitions in Directive 2009/72/EC of the European Parliament and of the Council (5) apply.

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(1) OJ L 123, 12.5.2016, p. 1.

(2) Regulation (EU) No 182/2011 of the European Parliament and of the Council of 16 February 2011 laying down the rules and general principles concerning mechanisms for control by Member States of the Commission's exercise of implementing powers (OJ L 55, 28.2.2011, p. 13).

(3) OJ C 369, 17.12.2011, p. 14.

(4) Council Directive 2013/18/EU of 13 May 2013 adapting Directive 2009/28/EC of the European Parliament and of the Council on the promotion of the use of energy from renewable sources, by reason of the accession of the Republic of Croatia (OJ L 158, 10.6.2013, p. 230).

(5) Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (OJ L 211, 14.8.2009, p. 55).

The following definitions also apply:

(1) 'energy from renewable sources' or 'renewable energy' means energy from renewable non-fossil sources, namely wind, solar (solar thermal and solar photovoltaic) and geothermal energy, ambient energy, tide, wave and other ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas, and biogas;

(2) 'ambient energy' means naturally occurring thermal energy and energy accumulated in the environment with constrained boundaries, which can be stored in the ambient air, excluding in exhaust air, or in surface or sewage water;

(3) 'geothermal energy' means energy stored in the form of heat beneath the surface of solid earth;

(4) 'gross final consumption of energy' means the energy commodities delivered for energy purposes to industry, transport, households, services including public services, agriculture, forestry and fisheries, the consumption of electricity and heat by the energy branch for electricity, heat and transport fuel production, and losses of electricity and heat in distribution and transmission;

(5) 'support scheme' means any instrument, scheme or mechanism applied by a Member State, or a group of Member States, that promotes the use of energy from renewable sources by reducing the cost of that energy, increasing the price at which it can be sold, or increasing, by means of a renewable energy obligation or otherwise, the volume of such energy purchased, including but not restricted to, investment aid, tax exemptions or reductions, tax refunds, renewable energy obligation support schemes including those using green certificates, and direct price support schemes including feed-in tariffs and sliding or fixed premium payments;

(6) 'renewable energy obligation' means a support scheme requiring energy producers to include a given share of energy from renewable sources in their production, requiring energy suppliers to include a given share of energy from renewable sources in their supply, or requiring energy consumers to include a given share of energy from renewable sources in their consumption, including schemes under which such requirements may be fulfilled by using green certificates;

(7) 'financial instrument' means a financial instrument as defined in point (29) of Article 2 of Regulation (EU, Euratom) 2018/1046 of the European Parliament and of the Council (1);

(8) 'SME' means a micro, small or medium-sized enterprise as defined in Article 2 of the Annex to Commission Recommendation 2003/361/EC (2);

(9) 'waste heat and cold' means unavoidable heat or cold generated as by-product in industrial or power generation installations, or in the tertiary sector, which would be dissipated unused in air or water without access to a district heating or cooling system, where a cogeneration process has been used or will be used or where cogeneration is not feasible;

(10) 'repowering' means renewing power plants that produce renewable energy, including the full or partial replacement of installations or operation systems and equipment for the purposes of replacing capacity or increasing the efficiency or capacity of the installation;

(11) 'distribution system operator' means an operator as defined in point (6) of Article 2 of Directive 2009/72/EC and in point (6) of Article 2 of Directive 2009/73/EC of the European Parliament and of the Council (3);

(12) 'guarantee of origin' means an electronic document which has the sole function of providing evidence to a final customer that a given share or quantity of energy was produced from renewable sources;

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(1) Regulation (EU, Euratom) 2018/1046 of the European Parliament and of the Council of 18 July 2018 on the financial rules applicable to the general budget of the Union, amending Regulations (EU) No 1296/2013, (EU) No 1301/2013, (EU) No 1303/2013, (EU) No 1304/2013, (EU) No 1309/2013, (EU) No 1316/2013, (EU) No 223/2014, (EU) No 283/2014, and Decision No 541/2014/EU and repealing Regulation (EU, Euratom) No 966/2012 (OJ L 193, 30.7.2018, p. 1).

(2) Commission Recommendation 2003/361/EC of 6 May 2003 concerning the definition of micro, small and medium-sized enterprises (OJ L 124, 20.5.2003, p. 36).

(3) Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (OJ L 211, 14.8.2009, p. 94).

(13) ‘residual energy mix’ means the total annual energy mix for a Member State, excluding the share covered by cancelled guarantees of origin;

(14) ‘renewables self-consumer’ means a final customer operating within its premises located within confined boundaries or, where permitted by a Member State, within other premises, who generates renewable electricity for its own consumption, and who may store or sell self-generated renewable electricity, provided that, for a non-household renewables self-consumer, those activities do not constitute its primary commercial or professional activity;

(15) ‘jointly acting renewables self-consumers’ means a group of at least two jointly acting renewables self-consumers in accordance with point (14) who are located in the same building or multi-apartment block;

(16) ‘renewable energy community’ means a legal entity:

(a) which, in accordance with the applicable national law, is based on open and voluntary participation, is autonomous, and is effectively controlled by shareholders or members that are located in the proximity of the renewable energy projects that are owned and developed by that legal entity;

(b) the shareholders or members of which are natural persons, SMEs or local authorities, including municipalities;

(c) the primary purpose of which is to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits;

(17) ‘renewables power purchase agreement’ means a contract under which a natural or legal person agrees to purchase renewable electricity directly from an electricity producer;

(18) ‘peer-to-peer trading’ of renewable energy means the sale of renewable energy between market participants by means of a contract with pre-determined conditions governing the automated execution and settlement of the transaction, either directly between market participants or indirectly through a certified third-party market participant, such as an aggregator. The right to conduct peer-to-peer trading shall be without prejudice to the rights and obligations of the parties involved as final customers, producers, suppliers or aggregators;

(19) ‘district heating’ or ‘district cooling’ means the distribution of thermal energy in the form of steam, hot water or chilled liquids, from central or decentralised sources of production through a network to multiple buildings or sites, for the use of space or process heating or cooling;

(20) ‘efficient district heating and cooling’ means efficient district heating and cooling as defined in point (41) of Article 2 of Directive 2012/27/EU;

(21) ‘high-efficiency cogeneration’ means high-efficiency cogeneration as defined in point (34) of Article 2 of Directive 2012/27/EU;

(22) ‘energy performance certificate’ means energy performance certificate as defined in point (12) of Article 2 of Directive 2010/31/EU;

(23) ‘waste’ means waste as defined in point (1) of Article 3 of Directive 2008/98/EC, excluding substances that have been intentionally modified or contaminated in order to meet this definition;

(24) ‘biomass’ means the biodegradable fraction of products, waste and residues from biological origin from agriculture, including vegetal and animal substances, from forestry and related industries, including fisheries and aquaculture, as well as the biodegradable fraction of waste, including industrial and municipal waste of biological origin;

(25) ‘agricultural biomass’ means biomass produced from agriculture;

(26) ‘forest biomass’ means biomass produced from forestry;

(27) ‘biomass fuels’ means gaseous and solid fuels produced from biomass;

(28) ‘biogas’ means gaseous fuels produced from biomass;

SkyClean – prices on products and feedstock

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Niels Bjarne Rasmussen

In the SkyClean project the main idea is to produce biochar from the residual biomasses in agriculture and store this biochar in the cultivated fields as a “low-cost CCS” method. However, a major part of the possible benefit is the production of “by-products” like biofuel and/or bio-SNG. The prices on the different possible feedstock for the SkyClean plants and on the different possible products will make the framework conditions, within which the profitability of the SkyClean system can and will develop.

An overview of present and possible future prices on both feedstock and on possible products, therefore, is essential to make estimates of and suggestions for the possible profitable routes of the biomasses from feedstock through the SkyClean system into valuable products. In work package 9 of the SkyClean project, one of the tasks is to make both technical and economic analysis of the SkyClean system. For this purpose, the list of prices is essential.

Table 1 below lists the present and possible future prices on feedstock and products. Different references have been studied and the predictions from the different references are presented. The list of applied references is included in the table.

Table 1	**Expected prices on products and feedstock – without taxes**									
				Danish Energy Agency		Danish Energy Agency		Other references		
DKK/GJ	Commodity		Present	Expected		Including transport				
	Product	Feedstock	start 2022	2022	2030	2022	2030	2022	2030	References
Biochar	+		0							
Bio-oil	+									
Methanol	+		201							4
Methane (NG)	+		250	130.4	46.8			30.0	46.2	3, 1, 9
Diesel	?		320	105.4	97.3	112.6	104.5			5, 1
District heat	+?		44					40-50	40-50	6
Process heat	+	+?								
Electricity		+	363	350	108	406	149			2, 1
Straw		+				44.2	46			1
Woodchips		+		51.2	53.4	52.3	54.3	45	67	1, 8
Wood pellets		+		83.3	73.4	85.6	75.7			1
Bio-fibres		+	0							
DKK/ton										
CO2 - predicted	+		589	617	738					1, 10
CO2 – low	+		589	589	591					1, 10
CO2 – high	+		589	669	1520					1, 10
CO2 – tax-predict	+		0	?	1125					7

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5) OK.dk, April 2022
6) Varmeplan TVIS, bilag E1, marts 2022
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8) MarE-fuel: Energy efficiencies in synthesising green fuels and their expected cost, p. 55, DTU 2021
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SkyClean – different system layouts for the processes

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In the SkyClean project the main idea is to produce biochar from the residual biomasses in agriculture and store this biochar in the cultivated fields as a “low-cost CCS” method. However, a major part of the possible benefit is the production of “by-products” as bio-fuel and/or bio-SNG. The product gases from the pyrolysis process may be processed in different ways to give different products.

In the table below, different system layouts are presented for the pyrolysis system with biochar production, oil production and possible SNG production. The different layouts focus on different products and processes. Below the listed layouts are explained.

1) This is the base case with bio-oil production, bio-SNG production and electrolysis added for producing the hydrogen necessary for the catalytic hydrodeoxygenation process. In addition, hydrogen is used for thermochemical methanation of the syngas from the process and there is no CO_2 output from the processes. This system layout will require a constant production of hydrogen independent of the electricity price for electrolysis.
2) This layout is as 1), but the electrolysis is variable dependent of the electricity prices, and hydrogen storage is included.
3) This layout is as 2), but with thermochemical Water-Gas-Shift (WGS) for additional hydrogen production instead of H_2 storage. The relation between hydrogen from electrolysis or from WGS is determined by the electricity price.
4) This layout is as 3), but without WGS and including conventional biogas upgrading removing the excess CO_2. The electrolysis has a minimum covering the hydrogen production for the hydrodeoxygenation and for converting all CO to methane in the thermochemical methanation.
5) This layout is as 4), but the thermochemical methanation has been exchanged with bio-methanation. The variable electrolysis should only cover the hydrogen for deoxygenation of bio-oil. The WGS is not necessary as the bio-methanation has an automatic bio-WGS.
6) This layout is as 5), but the necessary hydrogen for deoxygenation is produced by WGS instead of electrolysis.
7) In this layout, the production of bio-oil has been excluded and except for biochar only bio-SNG is produced. This is the simplest layout. All product gasses are converted to 100% syngas in a tar cracker with steam reforming and hydrocracking. The syngas is converted

100% in a bio-methanation unit, which has automatic bio-WGS. Conventional biogas upgrading removes the excess CO_2.

8) This layout is as 7), but a variable electrolysis has been included to account for possible cheap electricity increasing the amount of product bio-SNG.
9) In this layout, only bio-oil is produced excluding the bio-SNG production. The necessary hydrogen for deoxygenation is produced by constant electrolysis. The excess product gas is just burned for heating purposes giving CO_2 emissions.
10) This layout is as 9), but the constant electrolysis has been exchanged with constant WGS.
11) This layout is as 10), but a variable electrolysis has been included to account for possible cheap electricity replacing a part of the WGS.
12) This layout is as 11), but the WGS has been replaced by hydrogen storage.

Some of these layouts may be unrealistic for economic or other reasons. A few of them should be chosen for analysis, technically and/or economically.

Layout number 4) and 5) may be the most realistic ones when producing simultaneously biochar, bio-oil and bio-SNG. Both layouts have a minimum electrolysis with 5) having the lowest as only hydrogen for hydrodeoxygenation of bio-oil is needed.

Layout 7) (and 8)) are the most realistic ones when producing biochar and bio-SNG only. Here tar/oil cracking is necessary to convert all product gases to syngas for bio-SNG production. Layout 8) uses variable electrolysis, which can be reduced to zero giving 7) and avoiding CAPEX and OPEX for electrolysis.

Layout 9) might be the most realistic one when producing biochar and bio-oil only. A constant electrolysis is needed for the hydrodeoxygenation of bio-oil and the excess product gas is used for possible heating.

SkyClean – different system layouts – bio-oil production and/or bio-SNG production - plus biochar production

Dansk Gasteknisk Center – 20 May 2022

	Cases	Tar/oil cracking	Bio oil production	Bio-SNG production	Electrolysis	Thermochemical Water-Gas-Shift	H2-storage	Thermochemical methanation	Bio-methanation	Conventional biogas upgrading
1	Base case with oil and gas		+	+	+ Constant			+ No CO2 output		
2	Variable electrolysis with storage		+	+	+ Variable		+	+ No CO2 output		
3	Variable electrolysis with WGS		+	+	+ Variable	+		+ No CO2 output		
4	Variable electrolysis convent. upgrading		+	+	+ Variable			+		+ CO2 output
5	Variable electrolysis convent. upgrading		+	+	+ Variable				+ With auto bio-WGS	+ CO2 output
6	No electrolysis convent. upgrading		+	+		+			+ With auto bio-WGS	+ CO2 output
7	Gas only No electrolysis	+		+					+ With auto bio-WGS	+ CO2 output
8	Gas only Variable electrolysis	+		+	+ Variable				+ With auto bio-WGS	+ CO2 output
9	Base case with oil only		+		+ Constant					Gas burned for heat (CO2 output)
10	Oil only with WGS only		+			+				Gas burned for heat (CO2 output)
11	Variable electrolysis with WGS		+		+ Variable	+				Gas burned for heat (CO2 output)
12	Variable electrolysis with storage		+		+ Variable		+			Gas burned for heat (CO2 output)

SkyClean – CO_2 capture processes

Dansk Gasteknisk Center
Niels Bjarne Rasmussen

One of the options in the SkyClean project is to convert all or parts of the product gases into biomethane, which is then upgraded to a quality ready for the natural gas system. In this process, one of the main challenges is to remove the CO_2 from the final product gas.

This can be done in different ways. Either the CO_2 can be combined with hydrogen (H_2) from electrolysis in a perfect match and then by methanation be eliminated giving electromethane, which may be “green” if the electricity producing the H_2 was green.

However, a different approach is to remove the CO_2 from the final product gas leaving the pure methane ready for the natural gas system. The extracted CO_2 could be vented or stored underground or used for other purposes.

Different technologies are available for capturing CO_2 from the product gas. In the biogas industry this process is called “upgrading” the biogas, as the biogas consisting of mainly about 60% methane (CH_4) and 40% CO_2 is upgraded to natural gas quality, which means >97% CH_4 in the Danish natural gas system.

The report “BIOGAS UPGRADING – TECHNICAL REVIEW” [1] (Appendix 1) describes six different upgrading technologies, all used in the biogas industry. Some are more prevalent than others, but they are all relevant for possible use in upgrading biogas to natural gas quality. Excerpts of the report have been added as appendix to this short note on CO_2 capture processes.

The following upgrading technologies of biogas including advantages and disadvantages are described in the App 1.

- Pressure swing adsorption (PSA)
- Water Scrubbing
- Amine scrubbing
- Organic physical scrubbing
- Membrane separation
- Cryogenic upgrading

These upgrading technologies, mainly used for biogas upgrading, can be used for conditioning the process gases from the pyrolysis after methanation as well. After methanation (without adding H_2) the product gas consists mainly of about 50% methane and 50% CO_2 with minor impurities. If the chosen methanation process is bio-methanation, the product gas is very similar to biogas.

The specific investment costs are in the same range for all technologies. Figure 22 of the App 1 shows that the specific cost for biogas upgrading plants with capacities higher than 1500 Nm^3/h of raw biogas is in the range of 1000 to 1500 €/(Nm^3/h) (2016 prices). For capacities lower than 500 Nm^3/h the specific cost is much higher.

The energy requirement for the upgrading process is also in the same range for the different upgrading technologies. The amine scrubbing uses less electricity but more heat for the processes. For all processes, the energy requirement for upgrading one Nm^3 of biogas is in the range of 0.2-0.3 kWh electricity equivalent.

As the amine scrubbing is very selective giving very clean CO_2 and CH_4 streams, this technology should be preferred in case pure streams of both are required. The typical methane slip of the different technologies is also shown in Table 17 of App 1.

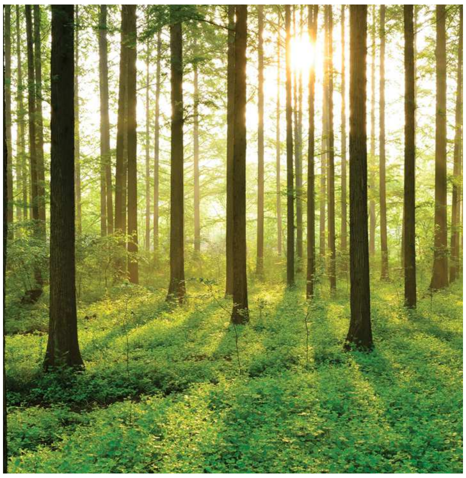
References:

[1] BIOGAS UPGRADING – TECHNICAL REVIEW, Energiforsk Report 2016:275. https://energiforskmedia.blob.core.windows.net/media/22326/biogas-upgrading-technical-review-energiforskrapport-2016-275.pdf

Appendix 1 is included after this page.

BIOGAS UPGRADING – TECHNICAL REVIEW

REPORT 2016:275



TRANSPORTATION AND FUELS

Energiforsk

Biogas Upgrading - Technical Review

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2 Description of the available upgrading technologies

The basic concept of biogas upgrading is to concentrate the CH_4 in the raw biogas stream (~65%) by separating CO_2 (~35 %) and other minor gases (H_2S, H_2O, H_2, N_2, O_2 and VOC) from the inlet gas. This process can be carried out by applying different kind of separation technologies which utilize the different chemical and physical behavior of these gases. Accordingly, these technologies can also be grouped depending on which type of chemo-physical mechanisms they mainly utilize for the separation. These mechanisms are:

1. Adsorption
2. Absorption (physical and chemical)
3. Gas permeation
4. Cryogenic distillation

In the first group (1) the selective affinity of CO_2 onto a surface of a media (adsorption) at different pressures is used for controlling the separation. The technology is thus also called pressure swing adsorption (PSA) (see chapter 2.1).

The second group (2) is using the difference in selective affinity of solving gas into a liquid media (absorption). In this group, several different technologies have been developed based on different liquid absorption medias in which the CO_2 is dissolved and the CH_4 is not, depending on pressure and temperature. The temperatures and pressures utilized for controlling the absorption and desorption (stripping) process are subject to which media is used. Examples of medias are water, different kind of amines, as well as organic solvent and thus the main biogas upgrading techniques using absorption for separation are water scrubbing (see chapter 2.2), amine scrubbing (see chapter 2.3) and organic physical scrubbing (see chapter 2.4).

The third group (3), gas permeation, is using the fact that CO_2 and CH_4 gas molecules travel with different ease (permeates) through membranes. The permeability is higher for CO_2 than for CH_4, and membranes can thus separate this mixture. Biogas upgrading with membrane technology is further described in chapter 2.5.

The last group (4) is using the fact that CO_2 and CH_4 have different boiling points (- 164 ˚C for CH_4 and -78 ˚C for CO_2 at 1 atm(a)). When biogas is cooled to these low temperatures, cryogenic distillation is possible and thus allows for separation of CH_4 and CO_2. Cryogenic distillation is further described in chapter 2.6.

In the following section the technologies available on the market, with brief notes on their benefits and limitations, are briefly described. Details on the theoretical background and processes are described in the previous report [2]. The below chapters have been written in collaboration with the suppliers of biogas upgrading systems which were part of the reference group on this project: Air Liquide, Ammongas, Biofrigas, BMF Haase Energietechnik, Carbotech, DMT, EnvTec, Greenlane, Malmberg Water, NeoZeo, Pentair, Purac and Sysadvance. These have all contributed, but none of them is alone responsible of any particular content of this report.

2.1 PRESSURE SWING ADSORPTION

Pressure swing adsorption (PSA) is a dry method used to separate gases via their physical properties. The basic principle is that raw biogas is compressed to an elevated pressure and then fed into an adsorption column, which retains the carbon dioxide but not the methane. When the column material is saturated with carbon dioxide the pressure is released and the carbon dioxide can be desorbed and led into an off-gas stream. For a continuous production, several columns are needed as they will be closed and opened consecutively. The typical set-up contains 4 adsorption columns (see process diagram in Figure 3) which are operated in parallel in 4 step cycles (the Skarstrom cycle) and thereby allows for a continuous operation. Adding even more columns and also optimising more advanced flow between the columns is way to increase separation efficiency and potentially also energy efficiency, but has to be balanced against acceptable complexity and investment costs. More details on the PSA process and operation is thoroughly described in the previous report [2].

The choice of adsorbent, the bed material, which selectively adsorbs CO_2 from the raw gas stream, is crucial for the function of the PSA unit. Common adsorbents materials are activated carbon, natural and synthetic zeolites, silica gels and carbon molecular sieves (CMS), but investigations into new adsorbents such as metal-organic frameworks are under development. Research and development of PSA technology is currently focusing on minimizing PSA units, optimizing the technology for small-scale applications and reducing energy use. Work is done also in combining different adsorbents to combine adsorbent characteristics and integrating separation of H_2S and CO_2 in a single column, which otherwise has to be separated in pre-treatment unit prior to the PSA columns. The same issues are as with free water in the raw gas which also has to be removed upstream of the PSA.

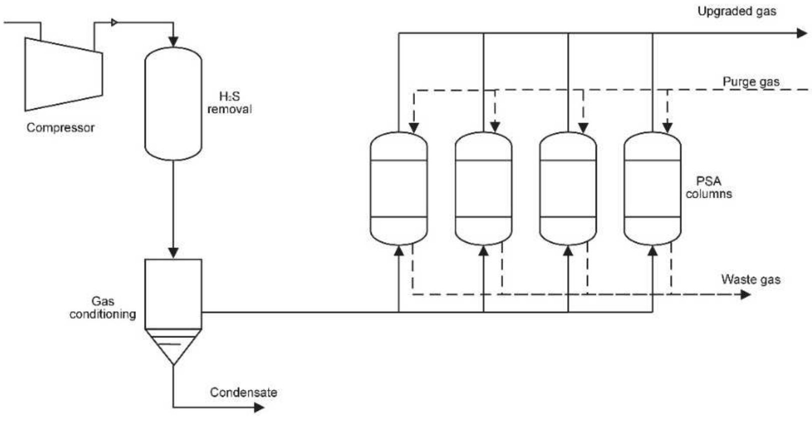

Figure 3. Process diagram for biogas upgrading with pressure swing adsorption (PSA)

H_2S will irreversibly bind to the adsorption media in a PSA process and therefore needs to be removed in the pretreatment. This is commonly done using a carbon filter, which is economically feasibility for low and moderate concentrations of H_2S. Also NH_3 as well as VOC present in the raw biogas needs to be removed, which is done within the upgrading process in an adsorption column after the compression stage.

The biomethane leaving a PSA upgrading process has a dew point below -50 °C and is dry enough to be used without additional drying. O_2 and N_2 are removed efficiently from the biogas.

2.2 WATER SCRUBBING

In biogas upgrading using water scrubbing technology, water is used to separate the carbon dioxide from biogas. The process is based on the difference in solubility of carbon dioxide and methane in water and process parameters such as pressure and temperature in the water scrubber are chosen to maximize this difference in solubility. Today, most water scrubbers are operated at a pressure around 6-8 bar(a).

Often, the process water is recirculated in the biogas upgrading plant, which requires a desorption of the carbon dioxide from the process water. Carbon dioxide is desorbed from water in an air stripper at ambient pressure and temperature. To recover as much as possible of the methane dissolved in the process water in the absorption column, the water is lead through a flash column with lower pressure before desorption. The flashed gas is recirculated in the water scrubber and lead back to a point before compression and absorption. Waste gas treatment may be needed mostly to reduce the concentration of methane or H_2S. The process diagram of a water scrubber is presented in Figure 4.

The waste gas, e.g. the stripper air, from a water scrubber contains traces of methane. The water scrubber is a robust technology for biogas upgrading, which is able to handle various impurities in the raw biogas. Compounds such as H_2S, ammonia and certain VOC are dissolved in the process water and released with the stripper air. In many cases, post treatment of the stripper air is needed to fulfil environmental legislation. Alternatively, to remove e.g. H_2S in the stripper air it may be interesting to consider removing it in the raw gas before the upgrading process.

The upgraded gas is saturated with water and needs to be dried to the required dew point. Compounds such as H_2S, ammonia and VOC present in the raw biogas are usually removed by the water scrubber to a necessary extent and no further post treatment is needed.

For stable operation, the pH needs to be kept stable and a base is needed to increase the pH and to compensate the pH drop in the process water, which is a result of oxidation of mostly H_2S in the raw biogas. An antifoam agent may also be needed to improve mass transfer in the absorption column and increase the separation between carbon dioxide and methane. Growth of microorganisms in the columns in a water scrubber may be a problem. This is reduced in recent water scrubbers operating at a lower temperature and may be further minimized by the addition of biocides or treatment of the fresh water to the upgrading plant to minimize the amount of nutrients in the process water.

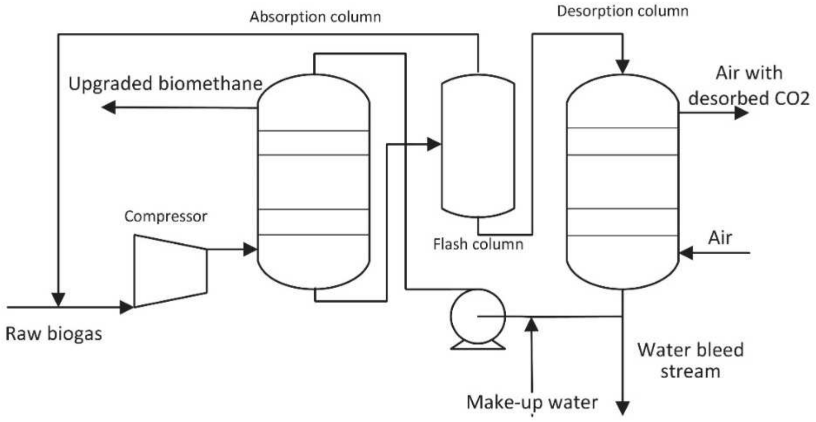

Figure 4. Process diagram for biogas upgrading with a water scrubber

This report focuses on the main biogas upgrading techniques, but these are also able to mix with each other to achieve positive synergies. One example of this is the recent study by [7] who investigated the theoretical potential to improve the performance of a water scrubber by adding a membrane unit. In this study, a membrane unit is placed in the gas from the flash column, which usually is recycled in the water scrubber. By bulk removal with membranes, the volumetric gas flow can be reduced and in this way, capacity in the compressor is freed. This hybrid solution leads to significant increase in capacity as well as a significant reduction in energy demand compared to a pure water scrubber.

2.3 AMINE SCRUBBING

The features of amine scrubbing are to use a reagent that chemically binds to the CO_2 molecule, removing it from the gas. This is most commonly performed using a water solution of amines (molecules with carbon and nitrogen), with the reaction product being either in the molecular or ion form. The most common amines used historically are methyldiethanolamine (MDEA), diethnolamine (DEA), monoethanolamine (MEA) [8] and primarily activated MDEEA (aMDEA) which is a mixture of MDEA and piperazine.

The inlet raw biogas enters the absorber from the bottom and is set in contact with the amine solution. The CO_2 content of the biogas reacts with the amine and is transferred to the solution. The spent amine solution is then led to the stripper where the CO_2 desorbs by regeneration with heat, Figure 5.

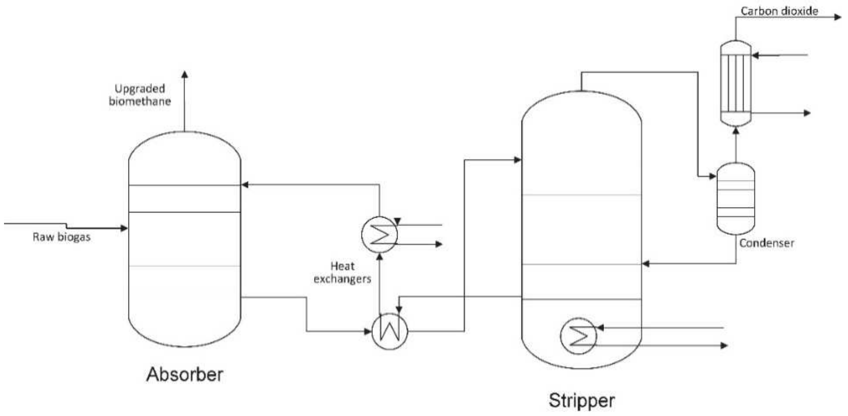

Figure 5. Process diagram for biogas upgrading with an amine scrubber

The amine scrubber process is able to handle gas without pretreatment as long as there are no liquid or solid impurities present. Most of the H_2S and NH_3 present in the raw gas is passed on to the CO_2 rich stream and may need removal there due to environmental legislation. It is, however, often an advantage to be able to remove these compounds in the CO_2 rich stream instead of the raw gas because there are no restrictions in the amount of air that may be introduced in this gas stream. When the heat needed for an amine scrubber biogas upgrading process is produced in a steam boiler, the CO_2 stream can be lead through this boiler and H_2S will be removed. In an amine scrubber, very pure CO_2 may be produced, which makes this process suitable to combine with the utilization of CO_2, chapter 5.

O_2 and N_2 are passed through the absorption column together with the upgraded biomethane. Whether removal is needed there depends in gas quality requirements. For more details, see chapter 4. When H_2S is present in the raw gas in high concentration, a polish filter for H_2S may be needed in the product gas since not all H_2S is removed in the absorption column. Whether this is needed, depends on the requirements on product gas quality as well, but also on the amine used in the process, since the solubility of H_2S in the amine solution differs between different amines used. Furthermore, the biomethane leaving the absorption column is saturated with water and the produced biomethane needs to be dried to lower the dew point.

The amine scrubber differs from the other techniques described in this report in electrical energy required for the biogas upgrading. The demand for electricity in this process is lower than that required in the other techniques. However, in an amine scrubber, energy in the form of heat is required for the regeneration. An amine scrubber works at low pressure (100-200 mbar) compared to the other techniques described in this report. This gives a flexibility depending on the need of pressure in the product gas. When low pressure in the biomethane stream is sufficient, this biogas upgrading technique has lower energy consumption for compression compared to the other techniques. When higher pressure is needed, the produced biomethane is compressed to the desired pressure, with the result of an increased energy consumption. In this way, compression is only needed for the CH_4 stream and no energy is needed to compress CO_2.

Figure 6. Amine scrubber from Ammongas in Freva, Norway

There are four major areas of operating issues that are commonly identified in operating amine systems. These are failure to meet specifications, foaming, amine loss and corrosion [9]. The first operating issue is as worrying as it is multifaceted. It should be dealt with by assuring the right design specifications, e.g. inlet CO_2-concentration, inlet temperature of CO_2, gas and liquid flow rates and inlet temperature of the amine solution to the absorber. Another issue may be the change in amine concentration due to reasons such as leakage, degraded solvent and foaming among others. Difficulties to meet specifications is of course not a problem related specifically to amine scrubbers, but is valid for all biogas upgrading techniques. The difference lies rather in the ways to solve the problem.

Foaming may occur at any point of operation. This is, however, most common during start-up and not usually needed continuously as in a water scrubber. Several reasons are possible but the most recurring reason is hydrocarbons (from oil-rests from manufacturing pipes and vessels). This can usually be prevented by good hygiene, insuring no contaminants in the feed and to foam test the make-up water.

Amine loss can arise from obvious leakage in joints, gauges etc. but may also be due to entrainment of liquid to the gas streams. A more sudden amine loss is most likely to be derived from failure of demister components. Only minor amounts of amine are lost in an amine scrubber during normal operation.

Corrosion is a broad topic and may cause serious issues in operation and result in downtime. It is therefore important to use appropriate materials and design the plant properly. More information on troubleshooting this type of problem may be found elsewhere [10].

2.4 ORGANIC PHYSICAL SCRUBBING

Among organic physical scrubbers, Genosorb® is the most used solvent for biogas upgrading processes. The solvent consists of a mixture of dimethyl ethers and polyethylene glycol. The absorption occurring in these organic physical scrubbers can be explained similar to the absorption in a water scrubber, by Henry's law. The solubility of CO_2 in the organic solvent compared to water is however much higher. This results in the recirculating volume of the solvent being much lower when using the organic solvent and thus the required column diameter is much smaller.

The process flow and operating much resembles the one for a water or amine scrubber. The biogas is compressed to a pressure of 7-8 bar(a) and cooled and then fed to the bottom of an absorption column. Here CO_2 is absorbed to the liquid phase. The spent solvent is then primarily led to a flash drum where some of the CO_2 and CH_4 is desorbed and then further on to the desorption column where the rest of the solvent is regenerated by adding heat.

The heat needed is supplied from waste heat within the process. This makes the energy consumption for an organic physical absorber resemble the consumption for a water scrubber, only requiring electricity for mainly the compressor, the cooler and the feed pump. The process diagram for an organic physical scrubber is presented in Figure 7.

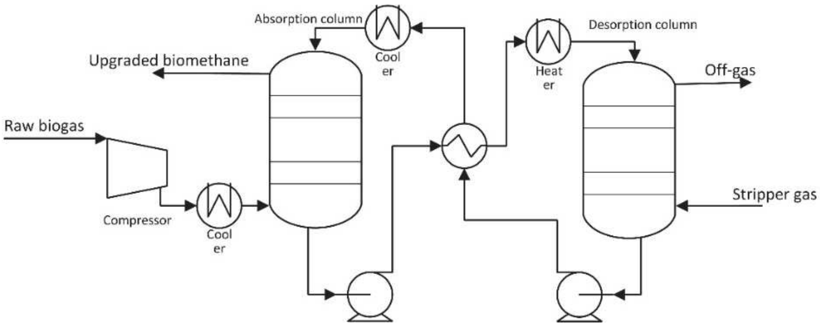

Figure 7. Process diagram for biogas upgrading with an organic physical scrubber

The corroding effect seen in the amine scrubber is not present in the Genosorb® scrubber as the solvent is anti-corroding. This results in piping not being necessarily made in stainless steel. The foaming issue seen in amine scrubbers can also be neglected, however the addition of organic solvent make-up may be necessary to compensate for minor evaporation losses.

Figure 8. Organic physical scrubber from BMF Haase in Wolfshagen, Germany

The organic physical scrubber is a robust technology being able to handle various impurities in similarity to the water scrubber. Most other impurities such as H_2S, NH_3 and VOCs are dissolved in the organic solvent and in this way passed on to the stripper air. Therefore, post treatment of the stripper air for mostly H_2S may be needed in many cases due to environmental legislation. In these cases, it may be a good idea to remove the H_2S already in the raw gas instead of the stripper air. However, the process itself is not harmed or compromised by high concentrations of H_2S or NH_3 in the raw gas. Only the combination of these two will be a problem when present at high concentrations resulting in precipitation of ammonium sulphate. In this case, one of them needs to be removed in the raw gas.

The water soluble fraction of the VOCs present in the raw gas are mostly removed with the condensate during compression of the gas prior to the actual organic scrubber. The solvent soluble VOCs such as limonene will dissolve in the organic solvent used in the scrubbing process and will thus be concentrated. However, this problem may be solved relatively simple through the addition of a cleaning step of the solvent, e.g. by solvent distillation, to remove these VOCs. This constitutes a more economical alternative to the often used active carbon filter otherwise used to remove VOCs from the raw gas, especially for biogas with high concentrations of VOCs, where the cost for activated carbon would be relatively high.

O_2 and N_2 present in the raw gas pass through the absorption in a physical organic scrubber and will be present in the product biomethane. The product gas also contains small amounts of water. For dew point standards lower than -20 ˚C at 1 bar(a), further drying of the product gas is needed.

2.5 MEMBRANE SEPARATION

Biogas upgrading using membrane technology uses the fact that gases have different permeability through a membrane fiber. During separation of carbon dioxide and methane in biogas upgrading, polymeric hollow fiber membranes are used. The membrane separation commonly occurs at pressures in the range of 10 to 20 bar(a). This results in higher pressure in the produced biomethane than that for other upgrading techniques. When using the biomethane in high pressure applications, this is an advantage, but it is important to consider that the pressure in the biomethane needs to be reduced for certain applications. The membrane fibers on the market are continuously improved to gain better selectivity and higher permeability to achieve better separation and lower methane slip. Also, to increase the methane concentration in the product gas, several membrane stages are usually used in sequence (see Figure 9(ii)). To acquire lower methane slip, a third membrane stage may be added in the permeate, e.g. the waste gas, from the first membrane step (see Figure 9(iii)). More details on the 2 and 3 stage membrane process for biogas upgrading are given in the previous report [2]. Process configurations within membrane separation for biogas upgrading are constantly developed further with the latest development of a four stage process, which further reduces the recycle rate. The process design with several membrane stages in biogas upgrading results in a flexible process, where parameters such as methane slip, energy consumption, etc. can be optimized. In this way, a good trade-off can be found in order to optimize the economics of each project depending on its constraints (energy cost, biomethane price, environmental requirements, etc).

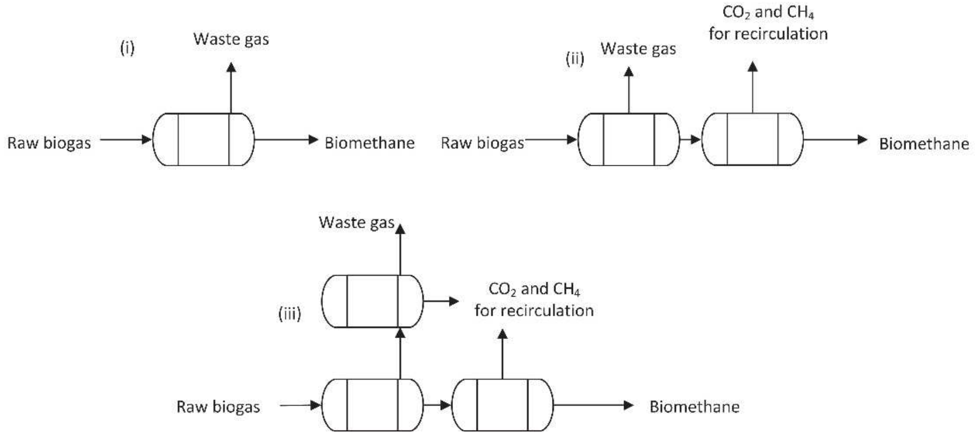

Figure 9. Different process configurations in biogas upgrading with membranes: (i) one stage, (ii) two stages, (iii) three stages

Most membranes are sensitive to liquid water, oil and particles and these need to be removed in condensate filters, coalescence filters or even activated carbon filters for extra security. Also condensation on the membrane surface should be avoided especially if compounds such as H_2S or NH_3 are present in the gas, which would result in the formation of acid on the membrane surface. Therefore, it is important that the gas remains above the dew point through the separation process.

Part of the H_2S in the biogas is also removed with the CO_2 stream, but separation is not sufficient to handle high concentrations of H_2S in the raw biogas and separation of H_2S prior to the membrane upgrading is common. It is, however, important to remember that moderate concentrations of H_2S do not damage the membrane surface as long as no condensation of water occurs there. Also NH_3 is harmful to the membranes if it is dissolved in condensed water on the membrane surface. NH_3 present in the raw gas is, however, removed efficiently in the biogas drying steps which are common practice in biogas upgrading with membranes, and it is unusual to find NH_3 in the gas in the membrane separation step. Certain VOCs may be harmful to the membrane fiber and damage these irreversibly and VOCs are therefore commonly removed prior to the membrane separation step.

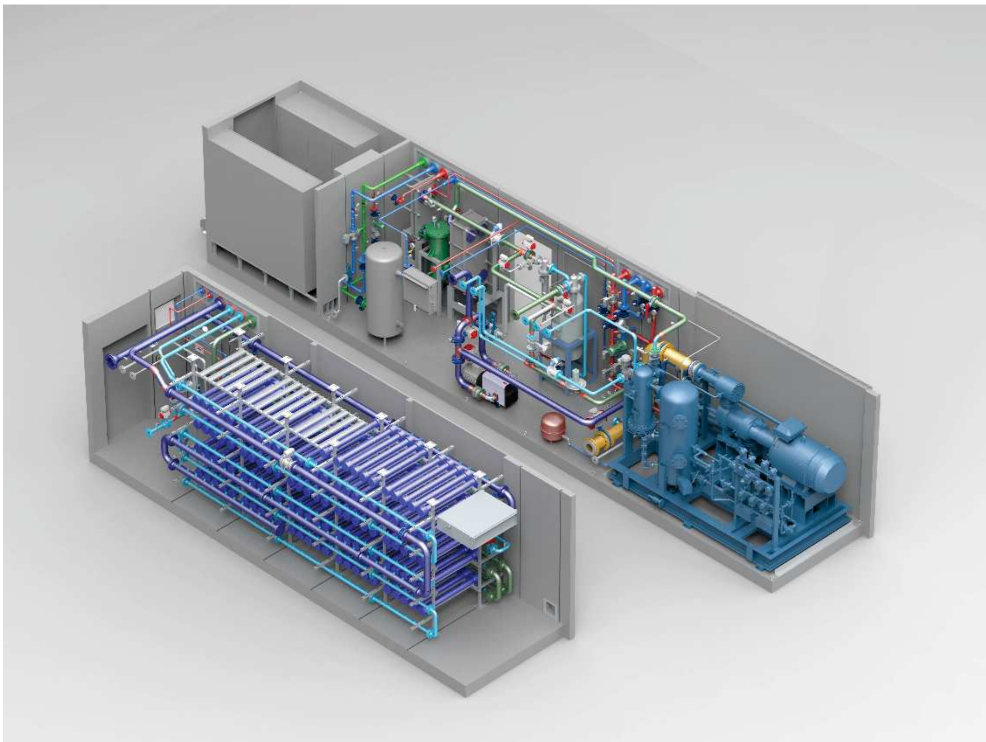

Figure 10. Typical layout of a membrane upgrading plant from EnviTec.

In membranes used for biogas upgrading, water vapor is removed from the biogas together with the carbon dioxide and drying of the product gas is usually not necessary. O_2 is partly removed with a membrane process. Whether additional separation is necessary depends on the concentrations in the raw biogas and requirements in the upgraded biomethane (see chapter 4).

Few consumables are used in a membrane upgrading plant. The lifetime of membranes for biogas upgrading is dependent on the biogas quality, the quality of pretreatment as well as the quality of operation. There are, however, membrane upgrading plants on the market which have been running successfully with their initial membranes for more than 10 years.

2.6 CRYOGENIC UPGRADING

When biogas is cooled under pressure, the CO_2 turns to its liquid state, while methane remains in a gaseous state. In this way, these two gases can be separated from each other. This simple transition however only happens under elevated pressure. At atmospheric pressure the CO_2 will sublimate, going directly from the gaseous to the solid state. For details on this, please refer to the phase diagram in [2]. Cryogenic distillation is, however, to our knowledge not used commercially for biogas upgrading in any larger scale. In [2] the technology of the Dutch company Gas Treatment Services was described in depth. The commercial ventures described failed, and to our knowledge there is only one smaller demonstration plant, situated close to the headquarters of the company. Biofrigas in Sweden sells small scale (ca. 35 Nm^3/h raw gas) biogas upgrading and liquefaction with cryogenic distillation. The French clean tech company Cryo Pur has built a pilot plant with a capacity of 120 Nm^3/h raw gas at the site of Valenton waste water treatment plant in Paris (see Figure 11) and are planning their first larger scale project during this and next year.

Figure 11 Cryogenic biogas upgrading and liquefaction, pilot plant from Cryo Pur, Valeton, France

The raw biogas needs to be pretreated to remove H_2S before the cryogenic upgrading, as the H_2S otherwise may damage the heat exchangers. VOC and siloxanes are efficiently removed during the cooling and condensation process which is a natural part of the cryogenic upgrading process.

Biogas upgrading with cryogenic distillation can be used to remove trace contaminants from landfill gas. In this way, O_2 and N_2 can be removed from the methane, which is otherwise only possible with biogas upgrading using pressure swing adsorption. This is described in more detail in the previous report [2].

Cryogenic distillation is used for several other purposes, such as methane removal from CO_2 streams (see chapter 3.7.4) and liquefaction of CO_2 to produce bio-LNG or LBG (see chapter 4.5).

6 Comparison between the different upgrading technologies

6.1 INVESTMENT COSTS

In order to compare the specific investment cost for biogas upgrading using the different techniques described in chapter 2, data was collected from the suppliers of biogas upgrading equipment which were part of the reference group in this study. The data is valid for biogas upgrading with the specifications presented in Table 16 and is presented in Figure 22.

	Raw gas specifications	Product gas requirements
Pressure:	20 mbar(g)	> 4 bar(g)
Methane concentration	60 vol%	> 97 vol%
Sulphur concentration	200 ppm H_2S	< 20 mg/Nm^3 (excl. odorisation)
Water concentration	Saturated with water at 40 ˚C	Dew point -10 ˚C at 200 bar(g)
Other requirements	Max. 0.1 vol% O_2 and 0.4 vol% N_2, no siloxanes, max. 100 ppm NH_3	

Table 16. Requirements for biogas upgrading for the collection of data for the specific investment cost. Furthermore, the requirement was a methane slip under 1%, no heat recovery, costs for an annual average as well as a container based scope or similar.

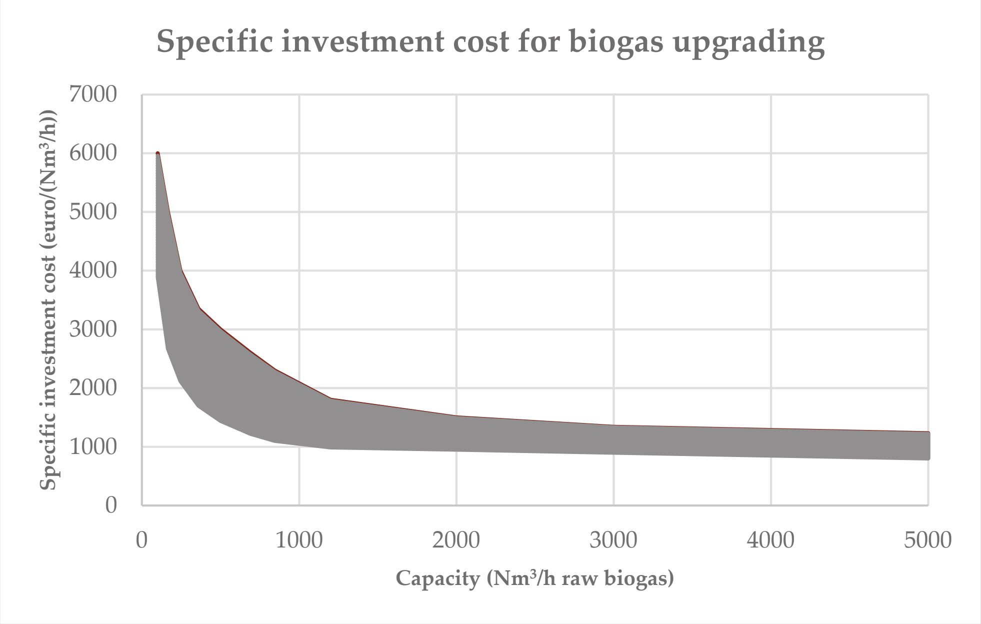

Figure 22. Specific investment cost for biogas upgrading, data collected from different suppliers of biogas upgrading equipment.

The specific investment cost for biogas upgrading decreases with increased capacity. Furthermore, the variation of investment cost figures from different suppliers is greater in smaller upgrading plants. There is a certain spread between specific investment costs, but from the data given by the biogas upgrading suppliers which were part of this study, no general trend could be seen regarding the difference in investment cost between techniques. The spread between investment costs of different suppliers for the same biogas upgrading technique was as wide as between different techniques. The data, however, shows that the economy of scale, e.g. lower specific investment cost for larger capacities, is more pronounced for membrane upgrading in the lower capacity range and for the other techniques in the upper capacity range.

It is important to remember that the investment costs presented in Figure 21 are valid for a certain base case. For specific projects there may of course be a more or less economic choice regarding upgrading technique depending on the circumstances in the project. Our conclusion from the data reported by the biogas upgrading suppliers is first of all that biogas upgrading techniques need to be compared in particular projects in which also other aspects such as operational cost, need of pretreatment, etc. are considered (see chapter 6.2 to 6.5).

6.2 ENERGY CONSUMPTION

The energy required to upgrade one Nm^3 biogas is usually around 0.2-0.3 kWh electricity [2]. Biogas upgrading with amine scrubber requires less electricity but has a heat demand which none of the other technologies have. Plant data was collected for this report from operators of biogas upgrading plants using various upgrading techniques. 6 plants were visited; 2 membrane plants, 1 amine scrubber, 1 organic physical scrubber, 1 water scrubber and 1 PSA plant. The collected data confirms the picture given in Bauer et. al. [2]. The amount of data is, however, not sufficient to draw any more detailed conclusions than those given in Bauer et al, and the difference between two plants using the same upgrading technique is not generally smaller than the difference between different techniques. Interestingly enough, at least from an academic standpoint, the amount of useful energy (exergy) required for performing the upgrading is exactly the same independent of technology. If translated into electricity equivalents using the method suggested in [72] all of the upgrading technologies are in the 0.2-0.3 $kWh_{\text{electricity equivalents}}/Nm^3$ of biogas range.

6.3 ADDITIONAL FACTORS AFFECTING SPECIFIC PRODUCTION COST

There are many factors that affect the specific production cost for a biogas upgrading unit. As already mentioned in the chapters above, the different techniques differ in need of consumables as energy and chemicals such as absorption agent, anti-foam, pH regulation, etc. (chapter 2). Also other consumables such as replacement oil for compressors and other equipment need to be taken into account. Biogas upgrading units may be equipped with more or less heat recovery which influences the investment cost. Logically, a biogas upgrading plant with more heat recovery will have a lower operational cost than one without heat recovery, but this is usually a trade-off with slightly higher investment cost.

One more important factor resulting in a price difference between different upgrading plants is the variety of service agreements available on the market. These are closely related to guarantees given on availability, which often require a certain service level or redundancy package regarding equipment. It is therefore important to look at a certain project and compare prices. This report can only give a rough overview of price levels and the exact price for a biogas upgrading plant will depend on local circumstances as well as customer needs and will best be asked for directly from the suppliers of biogas upgrading plants.

6.4 METHANE SLIP

The methane slip of a biogas upgrading plant is a measure of the methane lost in the process and thus not present in the upgraded product gas. It is, however, important to keep in mind that there are different definitions used to present the methane slip. In this report, we refer to methane slip as a measure of product loss. The methane slip is thus reported as the amount of methane in the product gas in relation to the amount of methane in the raw gas:

$$methane\ slip\ (\%) = 100 - \frac{methane\ content\ in\ product\ gas\ (\frac{Nm^3}{h})}{methane\ content\ in\ raw\ gas\ (\frac{Nm^3}{h})} \cdot 100$$

The methane slip can be influenced through both process optimization and process design. Therefore, it may vary between plants using the same upgrading technique and in some cases, the methane slip can be decreased by altering the process design with more membrane steps or changed operational parameters such as pressure levels. There is therefore in some case a tradeoff between methane slip and investment or operational cost. The methane slip for the biogas upgrading techniques discussed in this report are summarized in Table 17. The numbers presented in this table reflect on what is achievable with the different techniques. However, in some cases, extra investment packages are needed to reach the lowest reported methane slip.

	Methane slip
Pressure swing adsorption (PSA)	1-1.5%
Water scrubber	1%
Amine scrubber	<0.1%
Membrane separation	0.5%
Organic physical scrubber	0.5-2%
Cryogenic upgrading	No data[5]

Table 17. Methane slip for different biogas upgrading techniques

As already mentioned above, it is important not to confuse the methane slip reported in Table 17 with the methane concentration in a stream released to the atmosphere such as the stripper air in a water or organic physical scrubber. This concentration is dependent on the stripper air flow and the methane concentration can be decreased as described in chapter 0. The numbers presented in Table 17 do neither reflect any concentrations of methane in side streams in other upgrading techniques such as membrane separation or cryogenic upgrading.

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[5] For pilot plant data, reference [21]

6.5 REQUIREMENTS GAS QUALITY – INLET AND OUTLET

The composition of biogas produced in anaerobic digestion depends on the substrate used in the digester [18]. When choosing a suitable technique for biogas upgrading, it is therefore important to also consider how different compounds present in the biogas affect the process, the product gas as well as possible need for treatment of other streams such as waste gas or process water.

Scrubber techniques using water, amine or organic solvents to dissolve CO_2 and in this way separate it from CH_4 are robust technologies able to handle moderate concentrations of various impurities such as H_2S and NH_3. These are mostly dissolved in the solvent together with CO_2 and in this way removed with the CO_2 rich stream or, in the case of NH_3 in the water scrubber, with the process water. In an amine scrubber, the separation of H_2S from the gas is not as efficient as for the other techniques and significant amounts can be passed to the product gas, resulting in the need of a polishing filter to reduce H_2S to gas quality requirements. These technologies are also able to handle some VOC, which is removed with the condensate water or the CO_2 rich stream. Biogas upgrading using membrane separation requires more pretreatment as impurities such as VOC may damage the membranes.

Inert gases such as O_2, N_2 and H_2 take different paths in the different biogas upgrading processes, where they are passed to the product gas stream in water, amine and organic solvent scrubbers while they are only partly passed to the product gas in membrane separation. In biogas upgrading with PSA, these inert gases are passed to the CO_2 stream and thus removed from the biogas.

Gaseous water is removed in biogas upgrading with membrane separation and PSA together with the CO_2. In a water scrubber, the product gas is saturated with water and needs to be dried. Also the produced biomethane from an amine and organic physical scrubber contains some water which in most cases needs to be dried before grid injection. In pure cryogenic upgrading, where the biogas is directly refrigerated, low-concentration impurities such as water, hydrogen sulfide and siloxanes will be removed in the first stage, when the gas is chilled down to approximately -25 °C.

The produced biomethane leaves the upgrading process with various pressures. The amine scrubber process occurs at almost ambient pressure and the biomethane is usually compressed after the scrubber. This gives the flexibility to produce gas with any desired pressure. The water, amine and organic physical scrubber produce biomethane with moderate pressures in the range of 5-8 bar(a), whereas biomethane produced by membrane separation usually hold a higher pressure around 10-20 bar(a). When used in a low pressure application, some of the pressure is thus lost from the compression in membrane upgrading. On the other hand, when compressing the biomethane to even higher pressures after the biogas upgrading process, the compression needed after upgrading is smaller in biomethane produced with membrane separation than the other techniques available.

The aspects regarding requirements of biogas quality are summarized in Table 18. We have chosen not to include water in this table due to the fact that biomethane drying is a standard operation in biogas upgrading with techniques which do not produce dry biomethane and this is therefore in our opinion not considered a post treatment but rather a part of biogas upgrading. It is, however, important to remember that biomethane drying is required after upgrading with water scrubbers, amine scrubbers and in some cases organic physical scrubbers, while the biomethane produced with membrane separation and PSA is dry enough to be used directly.

	H_2S	O_2, N_2, H_2	VOC	NH_3
PSA	Low concentrations	Passed to CO_2 stream, H_2 passed to product gas	Removal in raw gas needed.	Removal in raw gas needed.
Water scrubber	Moderate concentrations; main part passed to the stripper air	Passed to the product gas	Moderate concentrations; main part removed with the condensate and stripper air	Moderate concentrations; main part removed with process water
Amine scrubber	Moderate concentrations; main part passed to CO_2 stream; polish filter may be needed in product gas	Passed to the product gas	Moderate concentrations; main part removed with the condensate and CO_2 stream	Moderate concentrations; main part passed to the CO_2 stream
Organic physical scrubber	Moderate concentrations; main part passed to the stripper air	Passed to the product gas	Moderate concentrations; main part passed to the stripper air	Moderate concentrations; main part passed to the stripper air
Membrane upgrading	Low concentrations; in part passed to product gas	Passed to the product gas and CO_2 stream	Removal in raw gas needed.	Usually removed with condensate during raw gas drying
Pure cryogenic upgrading[6]	Moderate concentrations; removed during first stage refrigeration	Passed to the product gas	Moderate to high concentrations; removed during first stage refrigeration	Moderate to high concentrations; removed during first stage refrigeration

Table 18. Summary of the effect of different contaminants in the raw gas on the various biogas upgrading techniques and their pass through the process.

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[6] Only based on pilot scale data, reference [21]

7 Concluding remarks

Biogas upgrading, e.g. the removal of carbon dioxide to produce biomethane for the use in natural gas grids and as vehicle fuel, is continuing to gain interest around the world. Compared to 2013 when our last report was published [2], there are today roughly twice as many biogas upgrading plants. In Germany we see increased interest in building new biogas upgrading plants and Sweden is continuing to have a large market share, although not growing as fast during the recent years. During the last years, also England, France, Denmark, Finland and Korea have experienced a significant increase of the number of biogas upgrading plants.

Three years ago, we saw that water scrubbers and PSA were the main biogas upgrading techniques on the market and that amine scrubbers had started to take significant market shares. Membrane technology, organic scrubbers and cryogenic biogas upgrading were then described as upcoming technologies [2]. In the present report, we can see that there now are more membrane than PSA biogas upgrading plants and also organic scrubbers are present with a significant amount of upgrading plants. The development of cryogenic biogas upgrading appears to be somewhat slower and this is still a marginal biogas upgrading technique.

In the present report, we show that there is no general significant difference in neither investment cost nor energy demand between the different biogas upgrading techniques other than the amine scrubber requiring less electricity but more heat than the other techniques. It is therefore more important to consider other aspects such as necessity to pre- or posttreat depending on the raw material quality and product gas standards. During recent years, product gas standards have been more and more well defined. Also, the use of a larger variety of substrates for biogas production results in a larger heterogenity of biogas compositions.