Danish roadmap for a sustainable gas grid transition - status and potential role of thermal gasification

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HIGHFLEX

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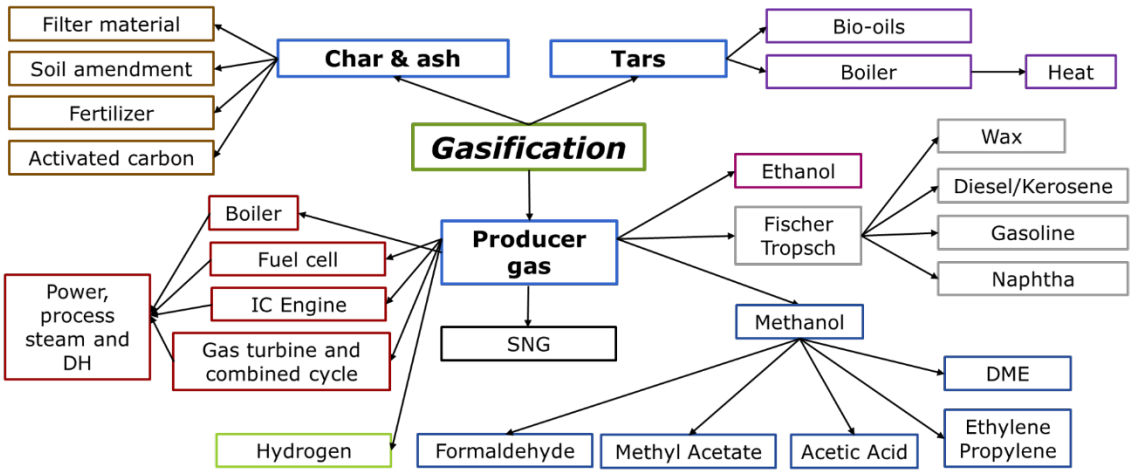
1. Context and objectives of this report

Gasification is a partial thermal oxidation of carbon-rich materials yielding a non-condensable gas product (CO_2, CO, H_2, H_2O and other gaseous hydrocarbons), smaller quantities of by-products such as char, ash, and condensable fractions including water and tars. Biomass gasification platforms are most commonly designed for conversion of wood in the form of wood pellets, wood chips or other types of waste wood. However, it is possible to extend the potential range of organic material fractions converted in thermal gasification to cover various other organic resources. This includes agricultural, municipal and industrial by-products and residues such as cereal straw, fiber residues, sewage sludge and many further municipal and industrial organic waste fractions.

The gasifying agents for biomass gasification at moderate temperatures are usually either air, steam, pure oxygen or their combination. Air is widely used as an oxidant for the biomass gasification, with equivalence ratios of 0.2–0.3 (O_2 supplied/O_2 required for stoichiometric combustion), because of its low-cost availability. However, the producer gas from air-blown biomass gasification contains around 30–50 vol% N_2, has a lower heating value (4–7 MJ/Nm^3) and is therefore mostly used for heat and power applications. Instead, a combination of steam and oxygen can increase the heating value of the producer gas (10–18 MJ/Nm^3) and the H_2/CO ratio. A high H_2/CO ratio is required for producing liquid fuels through synthesis. Figure 1 shows the potential of biomass gasification to produce a very broad variety of bio-products. In addition, a gasification plant can be designed to produce more than one product - such as electricity and chemicals -at a time and/or to fully or partly shift between such products (polygeneration).

Figure 1 Potential bio-products that can be obtained from biomass gasification, adapted from [1]



The project "HighFlex" ("Highly Flexible Energy Production by Oxy-Fired Biomass Gasification" - EUDP 64018-0028) studied the use of oxygen transport membranes (OTMs) to produce oxygen for biomass gasification. These membranes operate at high temperature (usually >700˚C) and the driving force is the difference in oxygen partial pressure across the membrane. The use of OTMs in oxygen blown biomass gasification could reduce the actual high costs for both oxygen supply equipment and operation that are limiting the commercial implementation of this technology.

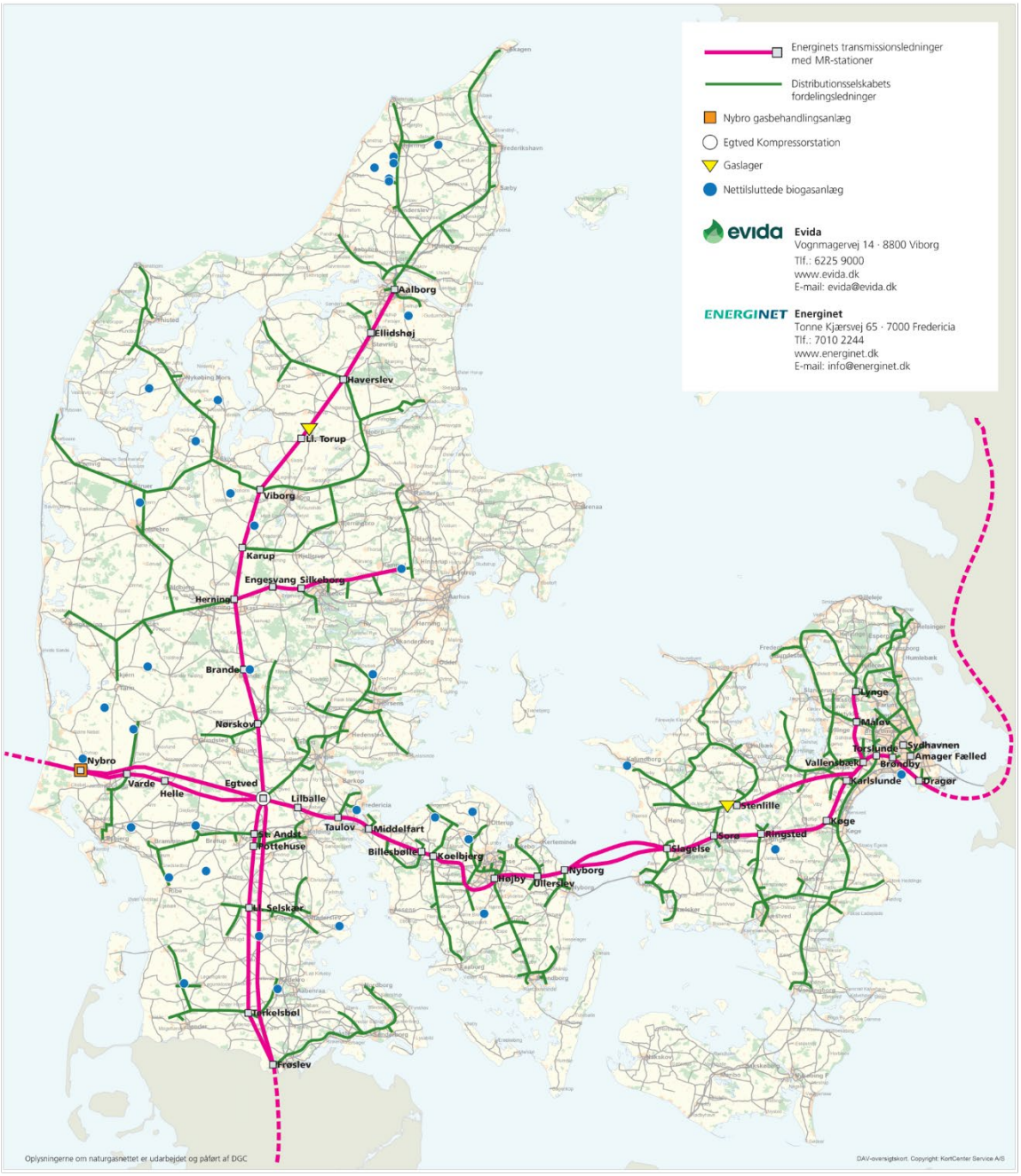
This report is written in the framework of the HighFlex project and aims at assessing the current situation and future potential for oxygen blown biomass gasification, with a focus on of SNG production. It considers visions of the future gas grid outlined in publications and more actual input from different relevant stakeholders.

2. State of the art

2.1 Danish gas grid

2.1.1 Structure of the Danish gas grid

Figure 2 Illustration of the Danish gas grid with transmission and distribution grid along with installed biogas plants pr. 11. May 2020 [3]



As a consequence of the oil crises in 1973 and 1979, the Danish parliament decided in 1979 to establish the gas supply system as we know it today. It consists of a transmission and multiple distribution grids with varying pressure levels. Energinet owns and operates the transmission

grid (TSO) and Evida owns and operates the distribution grid (DSO). Figure 2 illustrates the Danish gas grid structure.

The transmission grid is typically operated at pressure levels between 55 and 80 bar. It connects the gas supply from the North Sea with the entry/exit points to Germany, Sweden and soon Poland (Baltic Pipe). Energinet also owns Gas Storage Denmark who owns and operates the Stenlille (Central Zealand) and Ll. Torup (Northern Jutland) underground gas storage facilities. These are used for leveling out seasonal, periodic and daily fluctuations as well as serving as a backup in emergency cases. They are operated on market conditions and have the possibility of storing energy that corresponds to approximately 1/3 (about 10.820 TWh) of the Danish yearly electricity consumption [2]. It should be mentioned that the conversion efficiency from gas to electricity can vary depending on the used process, and that a comparison of TWh heating value of the gas to TWh electricity is therefore not straight forward.

The distribution grid is widely branched throughout Denmark and consists of distribution grids of various pressure levels. This part of the grid is the infrastructure that is nearest to the majority of consumers. It is connected to the transmission grid at measure and regulations (M/R) stations that are operated and owned by Energinet. At these M/R stations, the pressure is reduced to between 19 and 55 bar and injected into a distribution line. Large consumers, biogas plants and smaller M/R stations are connected to these distribution lines. At the smaller M/R stations, the pressure is reduced again to between 0.011 and 4 bars (g) before injection into a smaller distribution grid that connects the final consumers and some biogas plants. Around 374,000 households are currently heated by gas.

2.1.2 Regulation of the Danish gas grid

The establishment of the Danish gas supply system was followed by a Natural Gas Supply Act (LBK nr 126 af 06/02/2020). Its purpose is to secure that Denmark's gas supply is organized and planned in accordance with security of supply, socioeconomics, environment, consumer protection and EU-regulatory obligations.

The Natural Gas Supply Act regulates access to the gas system. It states that all have the right to use the transmission grid, distribution grid and LNG facilities against a payment. The access should be granted on an objective, transparent and non-discriminatory criteria. When supplying gas to the gas system, the Executive Order on Gas Quality should be followed. This order sets requirements in relation to the quality of combustible gasses that are used by gas plants, gas installations and gas equipment.

2.1.3 Operation of the Danish gas grid

The Danish gas system has traditionally been operated as a one directional flow from the North Sea or Germany towards Egtved and then distributed throughout Denmark to the final consumers. However, as seen in Figure 2, the grid has experienced a large increase in decentralized biomethane production plants since 2014. This poses an operational challenge in times of low demand as the biomethane production and injection is quite constant throughout the year. Therefore, Energinet and Evida have installed compressors at some M/R stations to increase the gas pressure in order to transport it towards parts of the grid with a higher demand. This ensures higher grid flexibility because the gas can be supplied from different locations.

Specific requirements for gas quality must be followed. The gas quality is regulated by the Executive Order on Gas Quality. Wobbe index and relative density are two parameters that are used for ensuring the gas quality. Gas in the gas grid is regulated to have a Wobbe index of between 14.1 and 15.5 kWh/Nm^3 while the relative density should be within 0.555 and 0.7 (BEK nr 230 af 21/03/2018). However, under special circumstances, by approval from the Safety Technology Authority it is allowed to supply gas that has a Wobbe index of between

13.9 and 14.1 kWh/Nm^3. Typically, North Sea gas has a Wobbe index of 15.31 kWh/Nm^3 and relative density of 0.662. The Wobbe index and relative density of biomethane is around 14.52 kWh/Nm^3 and 0.556, respectively.

2.2 Differences between biogas and SNG

Biogas is a mixture of methane, CO_2 and small quantities of other gases produced by anaerobic digestion of organic matter in an oxygen free environment. The biogas composition depends on the type of feedstock and the production pathway; these include the following main technologies [4]: biodigesters, similar reactors at wastewater treatment plants and landfill gas recovery systems. The methane content of biogas typically ranges from 45% to 75% by volume, with most of the remainder being CO_2. This variation means that the energy content of biogas can vary and the lower heating value (LHV) is between 16 MJ/m^3 and 28 MJ/m^3 [4]. Biogas can be used directly to produce electricity and heat or as an energy source for cooking.

Synthetic natural gas - SNG (also known as "biomethane" or "renewable natural gas") is a near-pure source of methane produced either by "upgrading" biogas (a process that removes any CO_2 and other contaminants present in the biogas) or through thermal gasification of solid biomass followed by methanation:

- Upgrading biogas: This accounts for around 90% of total SNG produced worldwide today [4]. Upgrading technologies make use of the different properties of the various gases contained within biogas to separate them, with water scrubbing and membrane separation accounting for almost 60% of biomethane production globally today [5].
- Thermal gasification of biomass followed by methanation: through gasification process, biomass is converted into a mixture of gases, mainly carbon monoxide, carbon dioxide, hydrogen and methane. To produce a more pure stream of methane, this syngas is cleaned to remove any acidic and corrosive components. The methanation process then uses a catalyst to promote a reaction between the hydrogen and CO or CO_2 to produce methane. Essentially any remaining CO_2 or water is or can be removed at the end of this process.

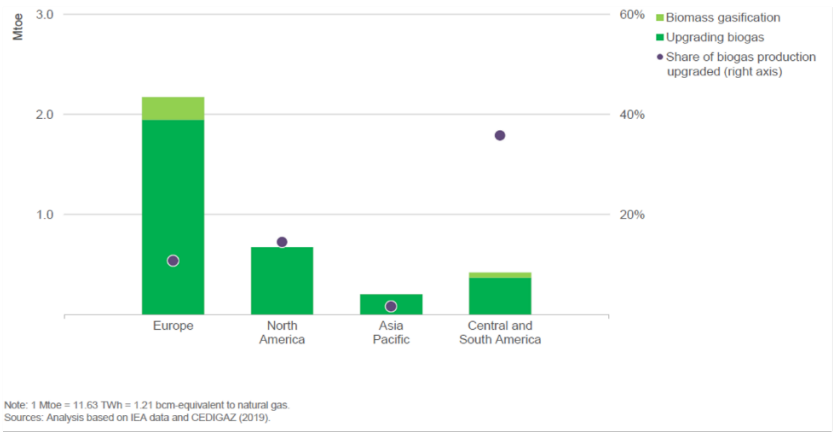
SNG has a LHV of around 36 MJ/m^3 [4]. It is indistinguishable from natural gas and so can be used without the need for any changes in transmission and distribution infrastructure or end-user equipment, and is fully compatible for use in natural gas vehicles

2.3 Current production of SNG

The SNG industry is currently very small, it represents 0.1% of natural gas demand today and only 3.5 Mtoe of SNG are produced worldwide [4]. Most of the production lies in European and North American markets with some countries such as Denmark and Sweden boasting more than 10% shares of biogas/SNG in total gas sales [4]. However, there is an increasing interest in several countries for its potential to deliver clean energy to a wide array of end users, especially when this can be done using existing infrastructure. An increasing number of government policies are supporting its injection into natural gas grids and for decarbonising transport. For example, Germany, Italy, the Netherlands and the United Kingdom have all introduced support for SNG in transport.

Most of the SNG produced comes from upgrading biogas (Figure 3). The percentage of biogas produced that is upgraded varies widely between regions [4]: in North America it is around 15% while in South America it is over 35%; in Europe, the region that produces the most biogas and SNG, around 10% of biogas production is upgraded (although in countries

Figure 3 Biomethane production and share of total biogas production that is upgraded in selected regions, 2018 [4]



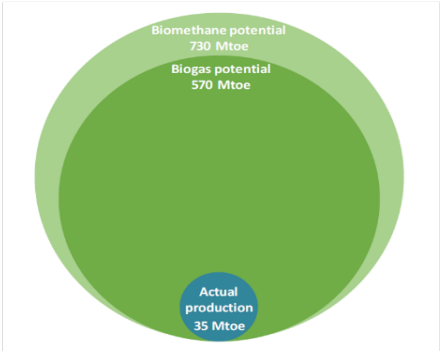
such as Denmark and Sweden the percentages are much higher); in Asia, the figure is 2%. The main co-product of biogas upgrading is CO_2, which is produced in a relatively concentrated form and therefore could be used for industrial or agricultural purposes or combined with hydrogen to yield an additional stream of methane. Another option would be to store it underground, in which case the SNG would be a CO_2-negative source of energy.

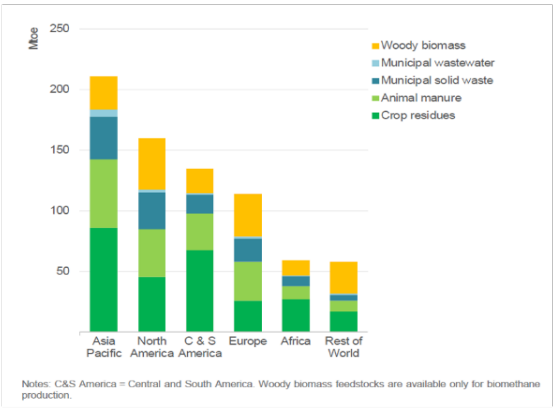
The rising interest in SNG means that the number of operating plants worldwide (both biogas upgrading and biomass gasification facilities) is expected to exceed 1,000 in the course of 2020 [4]. Around 60% of plants currently online and in development inject SNG into the gas distribution network, with a further 20% providing vehicle fuel [4]. The remainder provides methane for a variety of local end uses.

2.4 Potential for biogas and SNG production

The IEA [4] conducted a detailed, bottom-up study of the worldwide availability of sustainable feedstocks for biogas and SNG. The study shows that the technical potential to produce these gases is huge and largely untapped. These feedstocks include crop residues, animal manure, municipal solid waste, wastewater and – for direct production of SNG via thermal gasification – also forestry residues. In the study, only feedstocks that do not compete with food for agricultural land were considered. Biogas and SNG production in 2018 was around 35 Mtoe,

Figure 4 Left: Biogas and biomethane production in 2018 against the sustainable potential today [4], Right: Production potential for biogas or biomethane by feedstock source, 2018 [4]





only a fraction of the estimated overall potential (Figure 4). Full utilisation of the sustainable potential could cover some 20% of today's worldwide gas demand [4].

The different regions of the world have significant scope to produce biogas and/or SNG (Figure 4), and the availability of sustainable feedstocks for these purposes is set to grow by 40% over the period to 2040 [4].

2.5 SNG supply chains

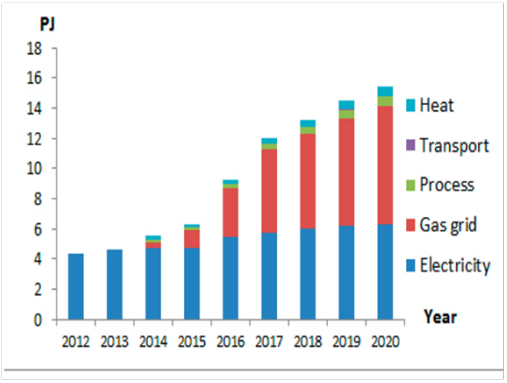
2.5.1 SNG from anaerobic digestion

Biogas is generated by micro-organisms in the absence of air by a so called anaerobic metabolism. Biogas is produced at: sewage treatment plants (sludge fermentation stage), landfills, sites with industrial processing industry and at digestion plants for agricultural organic waste, both mesophilic (35 °C) and thermophilic (55 °C) [6]. The nature of the raw materials and the operational conditions used during anaerobic digestion, determine the chemical composition of the biogas. Raw biogas consists mainly of methane (CH_4, 40–75%) and carbon dioxide (CO_2, 15–60%). Besides moisture (H_2O, 5–10%), trace amounts of other components such hydrogen sulfide (H_2S, 0.005–2%), siloxanes (0–0.02%), halogenated hydrocarbons (VOC, < 0.6%), ammonia (NH_3, <1%), oxygen (O_2, 0–1%), carbon monoxide (CO, <0.6%) and nitrogen (N_2, 0–2%) can be present and might be inconvenient when not removed [6].

The methods for upgrading biogas to SNG can be divided into two categories:

- Biogas upgrading by removal of the CO_2 fraction and other components of the biogas by physical or chemical processes. A complete review of these processes can be found in [6,7]
- Biogas upgrading by including methanation of biogas by reacting the CO_2 fraction of the biogas with hydrogen from another source. A complete review of this process can be found in [8]

Figure 5 Historical and expected biogas production and its use in Denmark (2012-2020) [11]



In Denmark, there are currently 163 biogas plants, of which 50% use agricultural products, 31% sewage residues, 3% industrial products and 16% are using landfill gas [9]. The first full-scale biogas upgrading process at a wastewater treatment plant was established in Fredericia in 2011 [10]. The production of biogas in Denmark is rapidly increasing. The total production is expected to more than triple from 2012 to 2020 (Figure 5). To date the majority of the produced biogas is used directly for producing electricity and heat. However, in Denmark, most of biogas is upgraded to SNG. In the future it is expected that, worldwide, a greater share of the produced biogas will be upgraded and delivered to the natural gas grid [11]. Today, the gas network takes delivery of upgraded biogas from more than 50 biogas plants, making Denmark the country with the highest share of biogas in the gas consumption in Europe at 16.9% in 2020.

2.5.2 SNG from thermal biomass gasification

Whereas "biogas" is produced by anaerobic digestion of organic materials, SNG production via thermal gasification typically contains the following steps: Initial gasification of the biomass followed by gas conditioning ("syngas production"), SNG synthesis and gas upgrading. After thermal gasification processes, gas cleaning is necessary before the methanation unit, which in most cases needs a clean and conditioned gas not to poison the catalysts and to damage other components. The most common cleaning steps required are [12,13]:

- Dust cleaning to avoid blocking of catalyst and other mechanical components
- Tar conversion/separation to avoid blocking downstream equipment and catalyst as well as to increase the overall efficiency
- Sulphur and chlorine removal to avoid destruction of catalysts and to avoid corrosion of mechanical parts in the plant. Normally, HCl could be removed by $Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$ at around 400˚C and H_2S removal could occur in a ZnO-fixed bed [14]
- Reforming including reversed water shift are chemical processes to condition the syngas, i.e. to adjust the concentration of chemical components before entering the methanation process. In some thermal gasification technologies, however, these processes are included in the gasification and no further reforming or shift is needed.

Once syngas is clean and properly composed, it enters the methanation unit where hydrogen, carbon monoxide and carbon dioxide in the syngas are converted to methane and water according to following reactions (Sabatier reaction):

$$CO + 3H_2 \rightarrow CH_4 + H_2O \qquad \Delta H = -206 \text{ kJ/mol}$$

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \qquad \Delta H = -165 \text{ kJ/mol}$$

Methanation normally takes place over a nickel based catalyst at a temperature of approx. 250 – 450 ˚C. The methanation reaction is a reversible exothermic reaction, and it is important to design catalysts to reach the maximum conversions at around 350 ˚C. The H_2/CO ratio and temperature have the greatest influence on syngas methanation. Basically all metals located in groups 8–10 of the periodic table are suited for catalyzing the methanation reaction. Due to a good combination of price, activity, and selectivity, however, nickel catalysts are predominantly applied in commercial methanation plants. Current investigations focus on an improvement of the thermal stability and sulfur resistance of methanation catalysts. More on catalysts can be found elsewhere [15].

The methanation processes is strongly exothermic and the methanation reactor is usually cooled by recycling product gas through built in heat exchangers. The strong and hard to manage heat release is an important reason to choose a gasification technique and process conditions that favor methane formation already in the gasification step.

A multitude of methanation concepts were brought to pilot and commercial scale in the past but only a few of them are currently available on the market. All of those commercially available concepts are fixed-bed reactor concepts that are predominantly equipped with gas recycling and intermediate cooling (TREMP, HICOM, Lurgi methanation). However, to reduce investment and operational efforts, there is the trend to avoid recycle-gas compressors in future applications (e.g. Vesta, TREMP modified).

Finally, after the methanation, the gas has to be adapted to the required specifications, for example natural gas grid quality. The main step in gas upgrading is the removal of carbon dioxide, which represents a substantial fraction of the gas after methanation. The pressure level at which the produced SNG is to be delivered is also an important parameter. Since high pressure is advantageous or even necessary for optimal operation of some of the process step options, pressure levels within the different sub-processes have to be chosen with care. Compression work and process equipment size are important parameters, influencing investment and running costs.

Relevant biomass gasification technologies for SNG production were reviewed by the Danish Gas Technology Centre (DGC) [12]. This review included the following technologies: Lurgi

process, Güssing gasifier, Chalmers gasifier, MILENA and OLGA processes, SilvaGas plant, GreatPoint Energy, Absorption Enhanced Reforming at ZSW, Blue Tower concept, CORTUS-WoodRoll three-stage gasification and AGNION Heat Pipe technology. All of them are indirect or allothermal gasification technologies. For SNG production, it is required to avoid using air as gasifying agent. Oxygen and nitrogen (which are present in product gases when gasifying with air) are unwanted in the final product, which should consist almost exclusively of methane (CH_4), to cope with gas quality requirement. For this reason, only allothermal gasification technologies or direct steam/oxygen-steam gasification technologies are of interest. DGC report [12] also reviews other direct gasification technologies that could be used for SNG production if steam/oxygen-steam gasification could be implemented. Three of all the reviewed gasification technologies (Güssing, AGNION, Viking-Firgas) were selected for further analysis [16]. In addition to these three ones, recently, the LT-CFB gasifier has been successfully tested using O2/CO2 as gasifying agent, making it another option worth considering. Another report from DGC [17] screens the projects and technologies for Power-to-Gas and SNG from gasification. There are also thermodynamic evaluation studies for the production of synthetic natural gas from biomasses in order to determine parameters such as purity and productivity obtained with different configurations process [18–20].

There are few biomass gasification plants for SNG currently in operation and they are mostly at demonstration scale producing relatively small volumes. The European Technology and Innovation Platform – Bioenergy offers a list of SNG projects from biomass gasification in Europe [21]. Since this is a less mature technology than anaerobic digestion, thermal gasification arguably offers greater potential for technological innovation and cost reductions. In this context, the advantage of LT-CFB gasifier to gasify "difficult" biomass, which can neither be efficiently utilized in anaerobic digesters nor in the gasifiers mentioned above, should be considered, as well as the possibilty to recirculate environmentally healthy ash containing nutrients and biochar. Details regarding this process can be found in section 4.2.

2.5.3 Power-to-gas

Power-to-gas (P2G) is based on the principle of electrolysis: using electricity to separate water into hydrogen and oxygen. The aim is to use cheap electrical energy from renewable sources to produce hydrogen (with oxygen as by-product). The electrolysis process is applied to water (after some initial purification process) and is broadly the reverse of the process to produce electricity in a hydrogen fuel cell [22]. Different technologies are available: Alkaline Electrolysis (AEL), Polymer Electrolyte Membrane (PEM) and Solid Oxide Electrolysis (SOEC) [22].

The hydrogen produced from electrolysis can be used directly in a variety of applications (Figure 6). Alternatively, in an additional processing step, the hydrogen can be reacted with a carbon source (either CO or CO_2) to produce methane (Power-to-methane, P2M). Some versions of such methanation are mature technology which is already widely applied in industrial processes such as ammonia synthesis. Two types of methanation are being tested in P2M demonstration plants based on biogas [22]:

- Catalytic methanation. This is a thermo-chemical process, taking place in the range 200 to 750°C, typically using a nickel catalyst. While this has been the main method used in industrial processes to date, it is less well suited to intermittent operation and for handling impurities which may be present in the CO_2 stream, for example when derived from anaerobic digestion.
- Biological methanation. This converts H_2 and CO_2 to methane using methanogenic microorganisms. These microorganisms operate under anaerobic conditions in an aqueous solution at a temperature in the range 20-70°C. A demonstration plant exists in Allendorf, Germany [23] and another one, BioCatProject, near Copenhagen, Denmark [24]

Figure 6 Power-to-gas schematic overview [22]

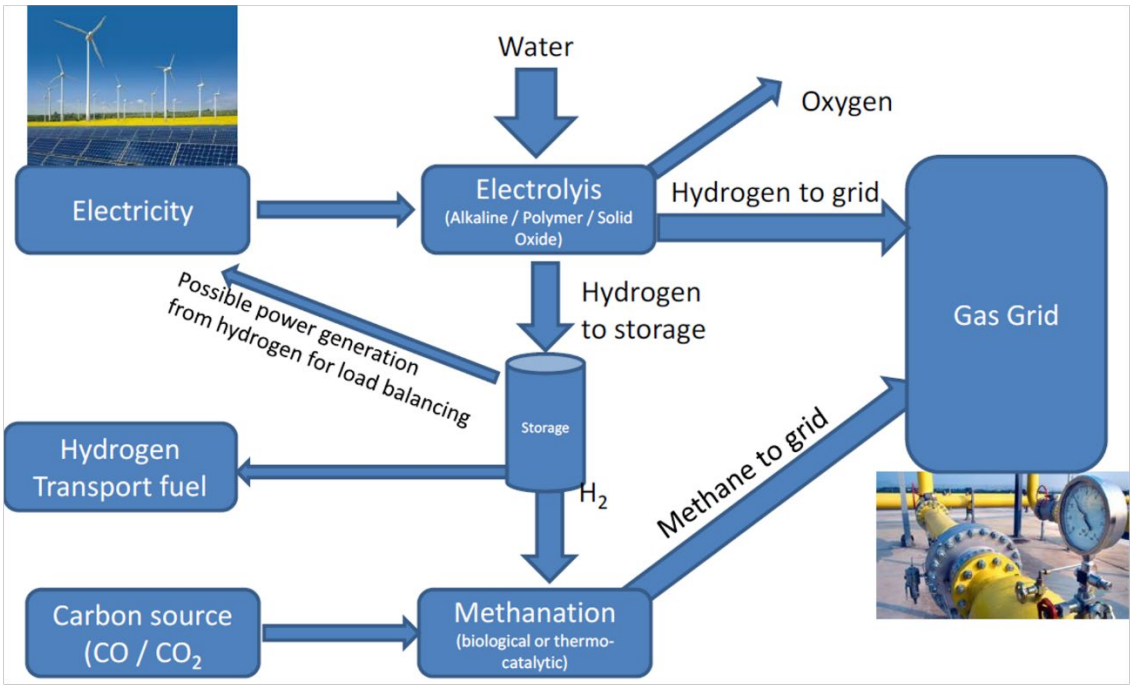
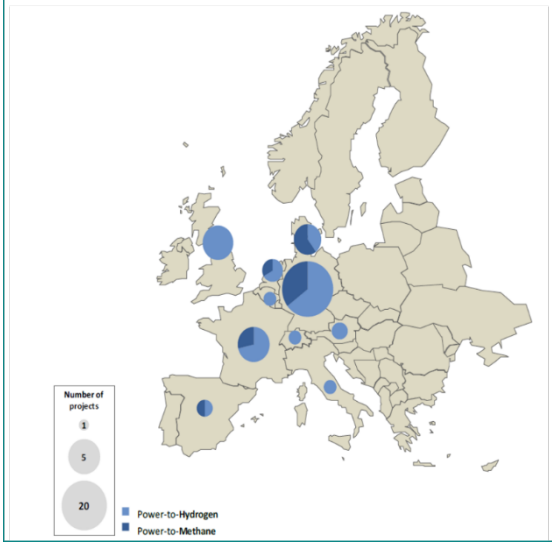


Figure 7 Demonstration and pilot projects of P2G in Europe [25]



It should be noted that the commercialisation of P2G technology (hydrogen/methane) is at a very early stage of development, with around 50 pilot and demonstration plants in operation or under development, mainly in Europe [22] (Figure 7). The largest electrolyser capacity developed is less than 10MW [22]. To produce 1Bm^3 of SNG yearly would require an electrolyser capacity of around 2.5 GW, operating continuously. However, P2G can add considerable new flexibility to the energy system by coupling the gas and electricity systems, and large demonstration projects with several 100 MW are expected in the near future.

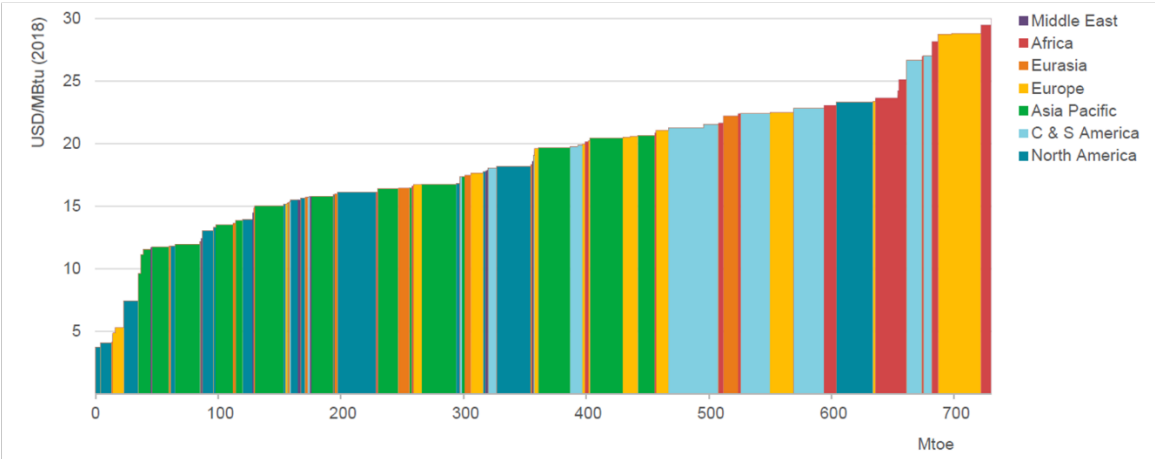
2.6 Estimated pricing for SNG production

According to the IEA study [4], more than 700 Mtoe of SNG could be produced sustainably today, equivalent to more than 20% of global natural gas demand. Figure 8 shows the cost curve of potential global SNG supply by region for 2018. According to IEA, by 2040, this potential grows to more than 1,000 Mtoe with a global average production cost of less than 15 USD/MBtu (Figure 9).

The vast majority of global biomethane potential today is linked to the upgrading of biogas. IEA report [4] estimates that the global average cost of producing biomethane through biogas upgrading today is around USD 19/MBtu. Most of this cost is attributable to the production of the biogas, with the upgrading process costing around USD 2/MBtu to USD 4/MBtu for a facility that upgrades around 3.5 million m^3 of biogas per year [4]. The cost of the upgrading process can vary significantly for different facility sizes and across different regions. According to the IEA report, grid connection represents a potential additional cost typically of USD 3/MBtu [4].

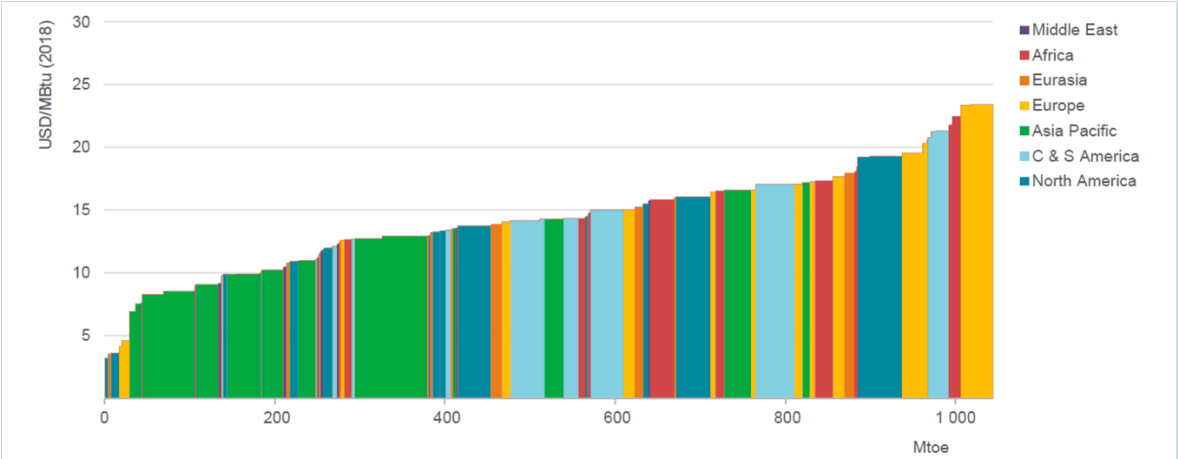
Gasification is currently the more expensive method of production in all regions with average costs around USD 25/MBtu globally [4].

Figure 8 Cost curve of potential global SNG supply by region, 2018 [4]



Notes: C & S America = Central and South America. The curve integrates technology and feedstock costs; injection costs are not included. The chart incorporates all the biogas potential that can be upgraded to biomethane.1 MBtu = 0.29 MWh.

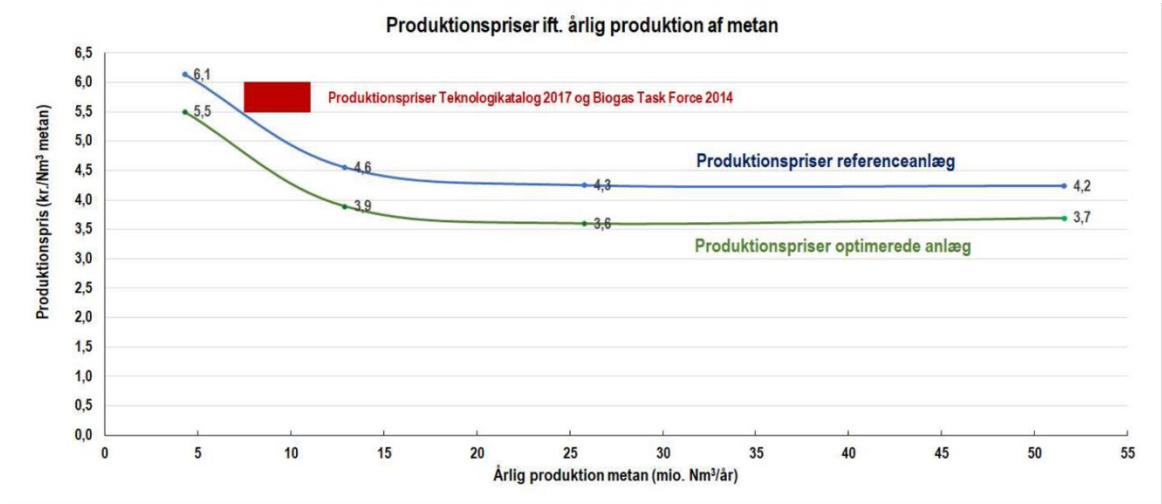
Figure 9 Cost curve of potential global SNG supply by region, 2040 [4]



Notes: C & S America = Central and South America. The curve integrates technology and feedstock costs; injection costs are not included. The chart incorporates all the biogas potential that can be upgraded to biomethane. 1 MBtu = 0.29 MWh.

Regarding P2G technology, according to Lambert [22], costs of production, assuming some future economies of scale, are likely to be in the range 50-100 €/MWh for hydrogen and 100-150 €/MWh for methane. These ranges are broad because of the early stage of development and uncertainty regarding the extent to which economies of scale may be achievable. A further uncertainty is the extent to which low cost renewable power will be available as input to the P2G process. The price of power-to-methane is higher than the price of SNG derived from anaerobic digestion. A study on cost of producing upgraded biogas conducted by Danish Gas Technology Centre [30] examines the cost of producing upgraded biogas in a reference and optimised scenario. The reference is based on the portfolio of already installed biogas plants whereas the optimised is based on what cost optimisations could be done with the current knowledge. The results are as seen in Figure 10. It is shown that the cost of production could be lower than 4 DKK/Nm^3.

Figure 10 Biomethane production price for reference and optimised plants with its yearly production of biomethane [30]



3. Vision for the future Danish energy system and gas grid in 2040/2050

3.1 Future role of gas infrastructure

In the Analysis Projection for Energinet 2020 (AF20) [26], it is expected that the use of gas for heating will decrease in the future due to the availability of other technologies for the same purpose. This decrease will be experienced in three sectors: electricity and heat, industry and households. These sectors will only use gas for products and services that cannot be replaced by alternative and cost-effective technologies. This includes peak hour production of electricity and heat, high temperature process heat and direct flame applications. It is also expected an increase in gas consumption for transportation. The consumption profile for transportation will be highly dictated by its use purpose and if it is used directly or indirectly through Gas-to-Liquid plants.

As mentioned, the Natural Gas Supply Act states that organization and implementation of the gas grid should be conducted under consideration of security of supply and socioeconomics. The security of supply is highly affected by the changes in consumption. The available consumption capacity in the grid will in most parts of the gas grid increase as a result of decreased consumption. However, the consumption patterns will fluctuate based on externalities such as electricity price, peak heat demand, economic fluctuations etc. An increasing injection of biomethane with a steady production profile will result in an imbalance between consumption and production of renewable gas. Today the gas grid mainly has a one-directional flow which is expected to change towards reaching a 100% renewable gas grid. It is essential to ensure high security of supply and cost-effective grid operation. The gas grid is therefore expected to be highly flexible in the future as a result of having a meshed grid where bidirectional flow will occur. This secures that gas can be transported from decentralized production plants towards more centralized consumption in times of need. The design is though dictated by the future local supply and demand. This means that the future role of the grid will be an adaptation based on changes to supply, demand, regulation and legislation

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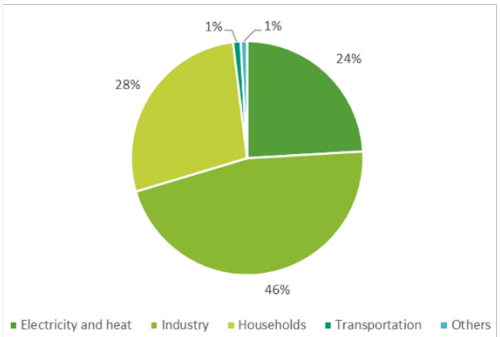
3.2 Future gas supply and demand

Figure 11 Share of gas used by each gas consuming sector based [26]



This section uses the Analysis Projection for Energinet 2020 (AF20) along with current political agreements to describe the future gas supply and demand. The current gas demand is distributed as seen in Figure 11.

Figure 12 shows AF20's projection for gas consumption towards 2040. AF20 estimates a decrease of 40% towards 2030 and 54% towards 2040 in the total gas consumption. AF20 estimates a green gas share in Danish gas consumption of around 63% in 2030 and 100% in 2040 (Figure 13).

Figure 12 AF20's projection of gas consumption towards 2040 [26]

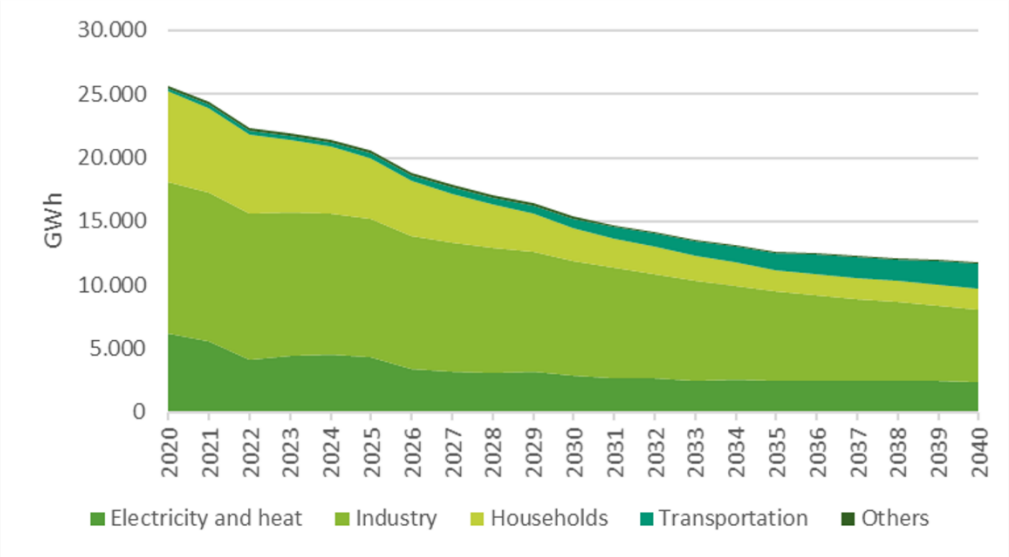
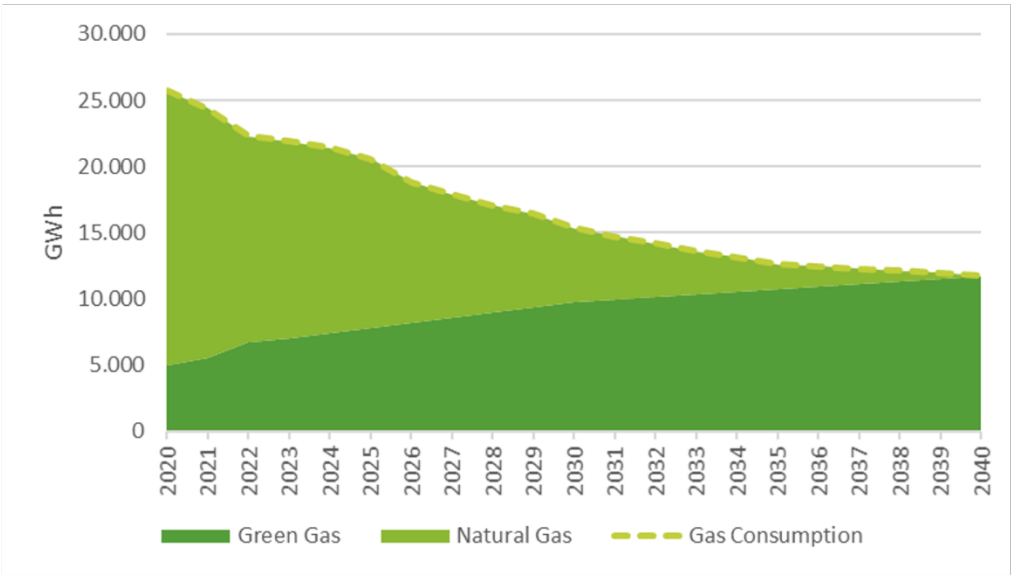


Figure 13 AF20's projection of green gas injection towards 2040 [26]



The Danish Energy Agency recently published a note about expecting 32 PJ of biomethane injection in the grid by 2030 [28]. This is a result of a large increase in projects that have applied for a subsidy. Evida estimates, based on the expected injection stated in the biogas plant connection agreements projected, a biomethane injection of 28 PJ in 2023 [29].

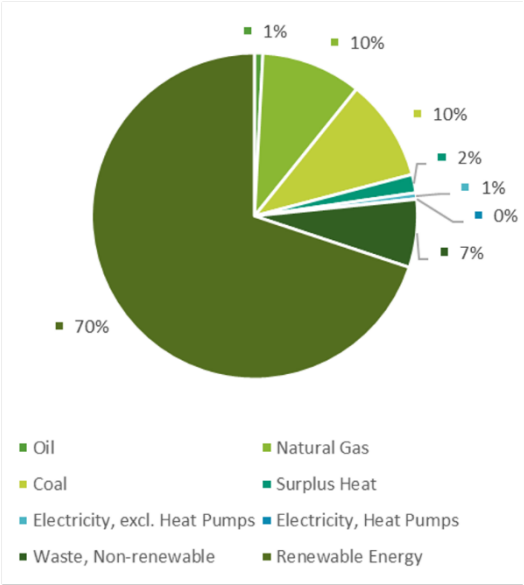
These projections are aligned with a study on cost of producing upgraded biogas conducted by Danish Gas Technology Centre [30].

3.3 Demand and sectors that will be in focus

3.3.1 Domestic heating

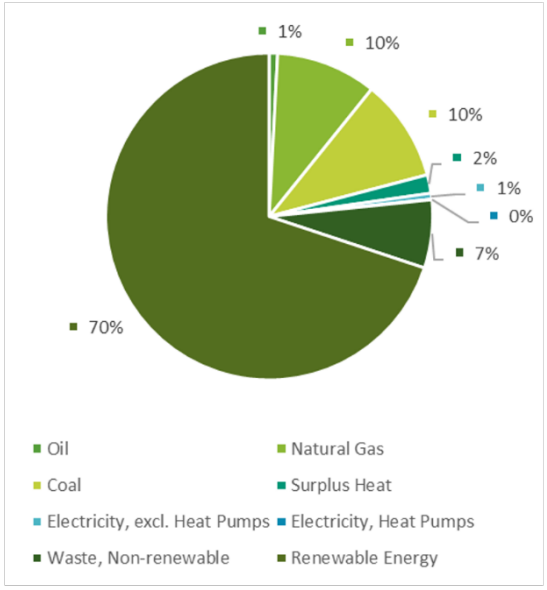
In Denmark, the biggest supplier of heat with about 1.8 million households is district heating. The second largest supplier of heat is the gas grid with about 374,000 households. The remaining houses are heated by oil, electricity, heat pumps and others (Figure 14).

Figure 14 Share of sources for domestic heating in Denmark 2019 [31]



As a result of the Danish Climate Agreement for Energy and Industry 2020 it is expected that around 120.000 - 170.000 gas boilers will be replaced by district heating and heat pumps by 2030 [32]. This ultimately results in a decrease of approximately 60% of the gas heated households. The AF20 also shows a decrease in the amount of gas being consumed by domestic heating. It projects that the gas consumption for household heating will decrease by approximately 65% in 2030 and 76% in 2040 [26].

Figure 15 Electricity and heat energy demand in Denmark 2019 [31]



3.3.2 Industry

Gas for industry accounts for approximately 46% of today's gas demand and it accounts for approximately 17% of the total industry energy demand [31]. This is expected to decrease in the future as a result of higher electrification in the industry sector. In AF20 it is expected that the gas consumption would decrease with approximately 24% in 2030 and 53% in 2040 [26].

3.3.3 Combined heat and power generation

Electricity and heat generation in Denmark accounts for 24% of the gas consumption, but only 10% of electricity and heat is produced based on natural gas as seen in Figure 15.

The cost of electricity from solar and wind has decreased over the last years and it is expected to decrease even more in the coming years. With the political will to electrify the heating sector, an increase in electricity consumption is expected together with an increase of electricity generation from solar and wind. AF20 estimates a reduction of the gas consumption for electricity and heat generation of 54% in 2030 and 61% in 2040 [26]. The remaining gas consumption is expected to be used for balancing the electricity grid and peak heat demand of district heating.

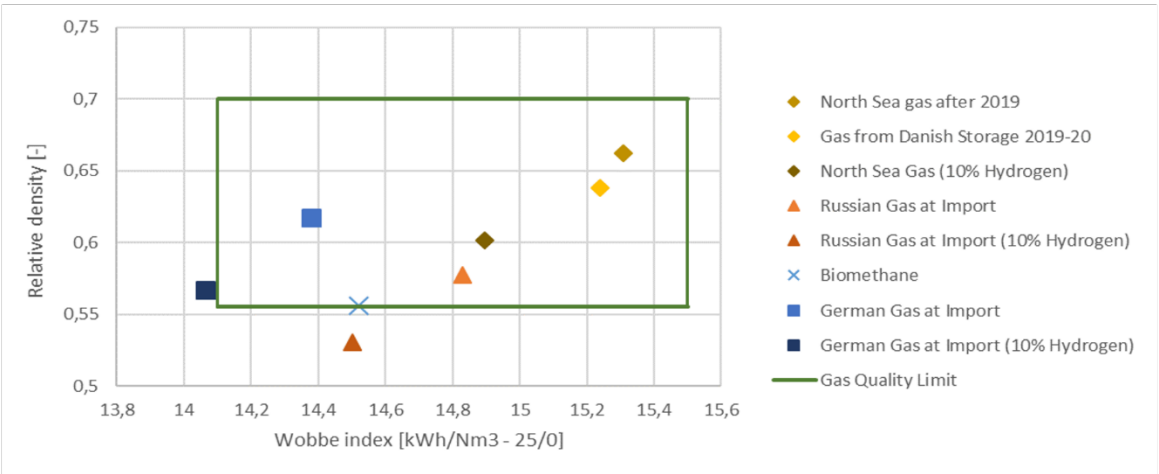
3.3.4 Transportation

Gas for transportation accounts for approximately 1% of the total gas demand today. It is expected, based on AF20, that it will increase to approximately 5% in 2030 and 17% in 2040 [26]. This increase results from assuming an increase of the gas demand for transportation from 272 GWh in 2020 to 783 GWh in 2030 (approximately 188%) and about 614% from 2020 to 2050 (1938 GWh). However, there is a lot of uncertainty on this estimations because the transportation sector is ongoing a deep transformation. Today, the gas injected into the grid is used mainly for road and maritime transportation. However, by implementing Gas-to-Liquid processes, gas can be converted into jet fuel and other hydrocarbons. Currently, there is no ideal alternative for jet fuel due to its high energy density. Utilizing gas from renewable sources for production of jet fuel would reduce the CO_2 emissions from aviation. The demand for gas for transportation could therefore potentially increase even more than projected in the AF20.

3.4 Quality requirements for SNG

Before injection to a gas grid, SNG must comply with the requirements of the grid concerning gas composition and quality. One of the requirements concerns the Wobbe Index, which is a measure of the combustion energy of a gas.

Figure 16 Gas quality of natural gas with and without 10% hydrogen mix and biomethane. The green boundary represents the Danish gas quality regulation [33]



The typical Wobbe Index for natural gas from the North Sea is around 54.9 MJ/Nm^3. Other requirements for injection to the gas distribution grid concern e.g. the moisture content (dew point) and the sulfur content of the SNG. Figure 16 shows the upper and lower boundary requirements for Wobbe index and relative density for gas along with where different types of gasses are located within those requirements.

FutureGas project [34] conducted an investigation on the impact of gas quality worldwide with a specific view to Europe and Denmark. The investigations carried out showed that the parameter that is relevant for most applications is the Wobbe Index. Variations of ±5% seem to be acceptable by the majority of applications. Technical developments offer possibilities to extend the range in the future.

4. Recommendations for biomass gasification in a future green gas grid

4.1 Geographical placement: important factors

When looking for a placement for a renewable SNG production plant in an energy system, it is important to consider sector integration. Sector integration can help optimizing the financial viability of the plant and supply cost effective services for several sectors. For the gasification plant several sector integrations could transpire such producing biomethane for grid injection, producing electricity in times of high electricity prices and utilizing excess heat for district heating. When such a sector integration is considered, the plant should be located near to a district heating system that is close to both a gas M/R station and a fairly large electricity connection. This, however, depends on the size of the plant. When locating a district heating system, it is important to consider its size as it should accommodate a base load heat supply from the gasification plant. When looking at the gas grid, it would be favored to locate the plant in a grid of high capacity meaning a geographically widespread distribution grid. This creates the opportunity to distribute the gas over a larger area resulting in a larger consumption and collection of renewable gas from multiple places before compressing or distributing towards a demand.

4.2 Highly flexible CHP plants for the future Danish energy system

In this section, two concepts (centralized and decentralized) for highly flexible plants capable of operating in CHP and SNG mode are presented. Both plants are based on the *Low Temperature Circulating Fluidised Bed (LT-CFB)* gasification process. The *LT-CFB* process was selected as it is a very fuel flexible platform that has been proven to operate on many different fuels including cereal straw, biogas- and manure fibers and organic residues from industry while also producing an environmentally healthy ash containing nutrients and biochar. More details, including schematics on the LT-CFB process design and operational results, can be found here [35-38].

4.2.1 Common characteristics of the LT-CFB gasifier plants

Both of the plants described in the following paragraphs and outlined in the process diagrams in Figures 17 and 18 are based on the highly fuel flexible *LT-CFB gasifier* and share the following characteristics and advantages:

- Utilization of cheap and local organic residues such as straw, biogas residue fibers, sewage sludge and other municipal or industrial waste streams
- Ability to shift between electricity and SNG production (CHP mode or Syngas mode) depending on market prices and demands
- Production of residual heat in both operating modes
- Compatible with CO_2 capture for CCS/CCU in both operating modes, allowing to convert CO_2 to additional SNG (CCU) (details described below)

- Combined use of H_2 and O_2 from an electrolysis operated in SNG/fuel production mode
- Capable of using O_2 from oxygen transport membranes, especially when O_2 from electrolysis is not available (plant being operated in CHP-mode)
- Valuable by-products: Ash can be used as fertilizer (valuable nutrients like P, K, …), biochar can be used as long-term CO2 storage (Bio-CCS)
- Due to the available O_2 from the oxygen transport membranes, the use of air for gasification as well as combustion is avoided, meaning that i) a syngas essentially without N_2 can be achieved, and that ii) nearly pure streams of CO_2 can be obtained
- In both operating modes (electricity or SNG/fuel production), a part of the CO_2 is recirculated for the LT-CFB gasifier

It should be emphasized, that the two concepts are in principle CCU/CCS ready. Independent from the operation mode, "capture ready CO_2" can be obtained from simply condensing out the H_2O in the flue gas (CHP mode) or the syngas (syngas mode). Since significant more CO_2 is produced in the CHP mode, this operation mode is especially interesting for CCU/CCS. The net CO_2 can simply be stored/compressed, or can be used directly converted on-site to SNG. The last option would require the availability of green H_2 from water electrolysis.

In case of insufficient subsidies for said CCS/CCU process, the use of pure O_2 and recirculated CO_2 for the combustion stage in CHP mode can simply be replaced by the more traditional use of air, without any hardware modifications.

4.2.2 Central bio-CHP and -SNG plant

Figure 17 Central bio-CHP and SNG plant

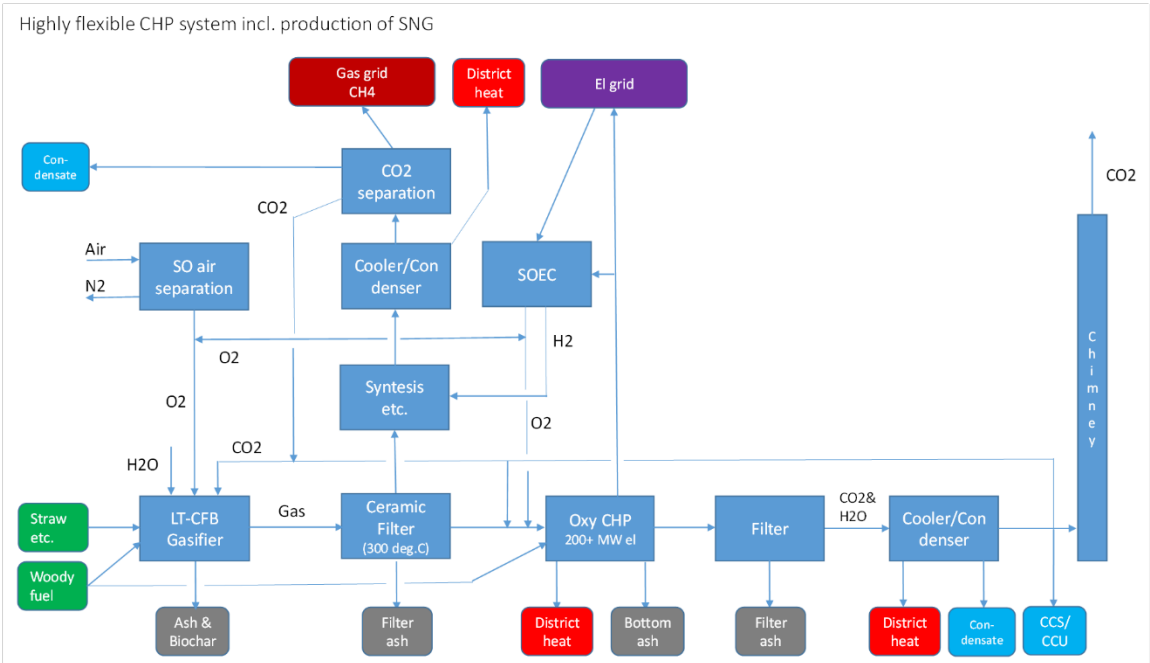


Figure 17 illustrates the idea of a large >200 MW_e "central" CHP plant, also being able to produce SNG. In the case of new-building a moderately sized CHP part (200 - 250 MWe), the steam cycle can now be made efficient to the high level normal for the somewhat larger central CHP-plants being built in Denmark from around 30 years ago. Hence, such still existing

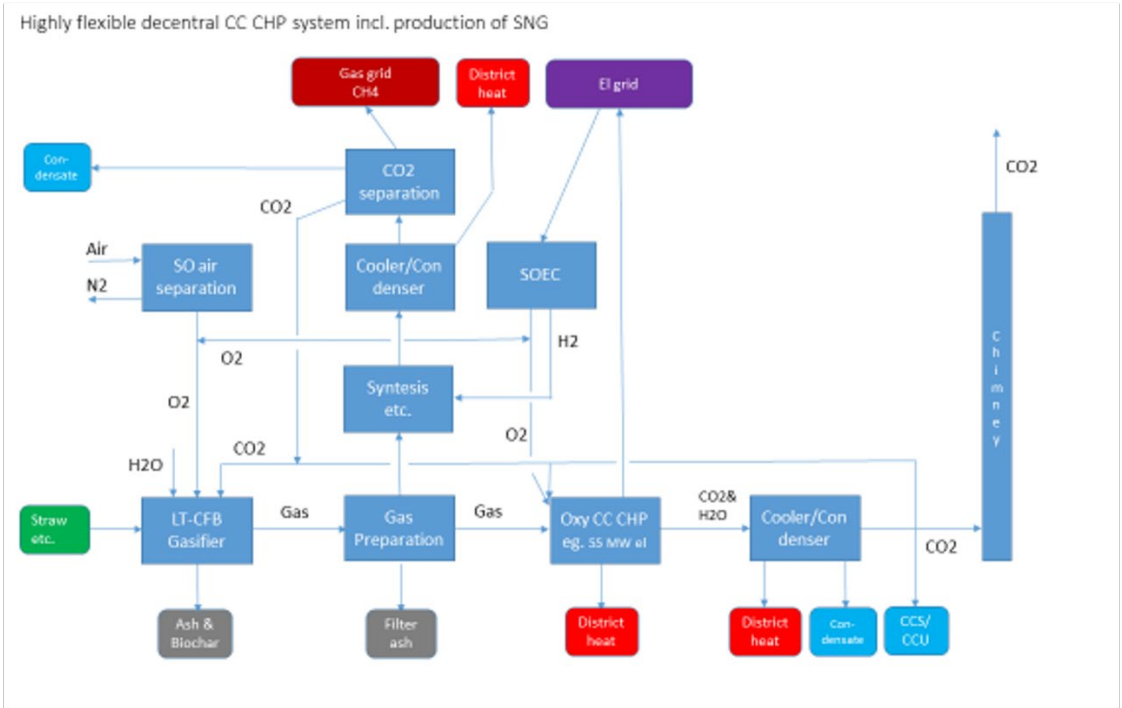
central CHP plants with sufficient residual/extendable lifetime could similarly effective be utilized, provided sufficient supply of sustainable biomass and sufficient need for residual heat.

Most typically the fuel added directly to the relatively large CHP boiler will be woody fuels, but the inclusion of the *LT-CFB* gasifier allows the further use of difficult bio-fuels by separating ash containing corrosive components (e.g. K, Cl, ,) prior to the CHP boiler. Thus, high temperature super heater corrosion and other problems can be minimized. The separated ash with a variable content of biochar can be recirculated to the fields as a fertilizer, soil improvement and carbon sequestration.

In Fig. 17 the process step labeled "Synthesis etc." represents several sub processes besides the catalytic CH_4 synthesis. This includes tar reforming and/or separation, converting and removing components containing sulphur and chlorine, compression and various heat exchange. If tars are condensed out, further processing of the raw products, e.g. to catalytically upgraded bio-oil, is possible (not indicated in Fig. 17).

4.2.3 Decentral Bio CC CHP and SNG plant

Figure 18 De-central bio-CC-CHP and SNG plant



A further, somewhat related possibility are decentralized Bio combined cycle (CC) CHP and SNG plants (Fig. 18). Again this concept is not limited to new plants, but can also be realized by converting existing natural gas fired CHP plants, like the approx. 25 years old but highly effective combined cycle plant located in northern Viborg (mid Jutland). The operation of this plant has long been limited by the often depressed price for electricity and relatively high cost for gas from the grid.

The alternative use of cheap local organic residues instead of gas from the grid in combination with being able to shift between producing electricity or SNG could make it economical to again operate, especially in periods with need for the residual heat (~8-9 month a year). It is estimated, that such a plant

would run 20-40 % of the time in CHP mode and the remaining time in SNG mode. Additionally, the option of selling thermally cleaned bioash/biochar containing nutrients as fertilizer and the valorization of CO_2 in CCS/CCU processes should be considered. Especially the (on-site) combination with electrolysis could be an attractive CCU scheme to produce SNG or other fuels/chemicals, as outlined before.

If the capability to operate the CHP-part of the system (partly) on gas from the grid is retained, this plant can produce electricity "on-demand" even in periods with insufficient biomass supply, which is excellent for grid balancing and grid stability. In both operation modes, i.e. either electricity generation using the gas turbine or SNG production, the produced gas must be effectively cleaned and compressed (above 12 bars(g) for the gas turbine). For SNG production, the starting point would be effective reforming and/or separating tar components from the product gas of the LT-CFB gasifier. These cleaning steps, including filtering and compression, common to the SNG- and the CHP-process line (labeled "Ceramic Filter" in Figure 17) are broadly summarized as "Gas Preparation" in Figure 18.

Due to the required elevated pressure of the cleaned product gas going into the gas turbine combustion chamber, the two arrows indicating the addition of O_2 and CO_2 to the inlet of the (main) gas turbine compressor - are now depicted independently from the fuel gas arrow.

One technical detail in this concept, which should be carefully checked, is the interplay of the (rather large) recycling stream of CO_2 and the gas turbine. Hence, involving gas turbine suppliers in evaluating the technical feasibility would be necessary, to find out if e.g. changes to the gas turbine would be required.

Providing enough gas for e.g. the combined cycle plant in Viborg, would call for two (parallel) LT-CFB gasifiers of approximately the size (63 MW fuel input) planned and already designed in high details for further demonstrating the LT-CFB technology based on the experiences gained with the 6 MW "Pyroneer" plant in Kalundborg. Later the full amount of gas could probably be provided cheaper by only one further up-scaled gasifier.

5. Conclusions

The Danish Energy Agency estimates a decrease of 40% towards 2030 and 54% towards 2040 in the total gas consumption. It also estimates a green gas share in Danish gas consumption of around 63% in 2030 and 100% in 2040. The gas consumption for household heating is expected to decrease by approximately 65% in 2030 and 76% in 2040. Gas consumption in the industry sector is also expected to decrease by approximately 24% in 2030 and 53% in 2040. Another sector that will also see a decrease on the gas consumption is the heat and power generation which is expected to decrease by 54% in 2030 and 61% in 2040. However, gas consumption is expected to increase in the transportation sector that it is currently going through significant changes.

Methanation of syngas deriving from thermal biomass gasification is a viable alternative to the use of fossil fuels and it has the great advantage of producing SNG which could be directly injected into the distribution grid and sold. However, this process involves additional costs that, nowadays, make it more expensive than the cost of methane from biogas plants. The use of oxygen transport membranes in biomass gasification would reduce the costs of oxygen supply for oxygen-blown biomass gasification and as a result for SNG production. Nowadays, most of the SNG production comes from upgrading of biogas from anaerobic digestion and only few demonstration scale biomass gasification plants for SNG are in operation. However, since this is a less mature technology than anaerobic digestion, thermal gasification offers greater potential for technological innovation and cost reductions. Two conceptual plant options for highly flexible integration of SNG production in highly fuel flexible but still highly effective central and decentral CHP plants have been suggested for further evaluations.

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