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Skov, Iva Ridjan; David, Andrei; Mathiesen, Brian Vad; Sorknæs, Peter

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AND
MARKET POTENTIAL FOR BIOGAS METHANATION

BIOGAS UTILISATION IN ENERGY SYSTEM AND MARKET POTENTIAL FOR BIOGAS METHANATION

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Iva Ridjan Skov

Andrei David

Brian Vad Mathiesen

Aalborg University
Department of Planning

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Department of Planning
Aalborg University
Rendsburggade 14
9000 Aalborg
Denmark

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Abstract

This report provides an overview of the cost for the utilization of biogas in the different parts of the energy system. Analysis included eight scenarios that simulated utilization of biogas, biomethane or e-methane for power production, industrial purposes or transportation. Results show both fuel costs, system costs and biomass consumption. Furthermore the analysis included the growth curves and needed investment levels to reach the projected capacities of electrolysis and e-methane in the energy system for both Denmark and EU.

We regard biogas methanation as one of the key technologies in future renewable energy systems.

This report is prepared as a part of Task 6.5 in the EUDP Biocat Roslev project

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UTILISATION OF BIOGAS IN EU-28 AND DENMARK

Biogas is a secondary energy carrier that can be used for different purposes in the energy system such as production of electricity, heat and transport fuel. Once purified to biomethane it can be injected to the gas grid and used for the transport sector. Biogas has been used for energy purposes from the end of 19th century in England. The biogas development has had many stagnation periods from its first developments, but with the implementation of EU renewable energy and climate policies the biogas production for energy purposes has been growing.

In 2017, there were 17,783 biogas plants in Europe, of which 62% were located in Germany and only 0.8% in Denmark. The biggest growth happened between 2009 and 2010, were the number of plants increased by 69%, while in the last few years the growth has stagnated.

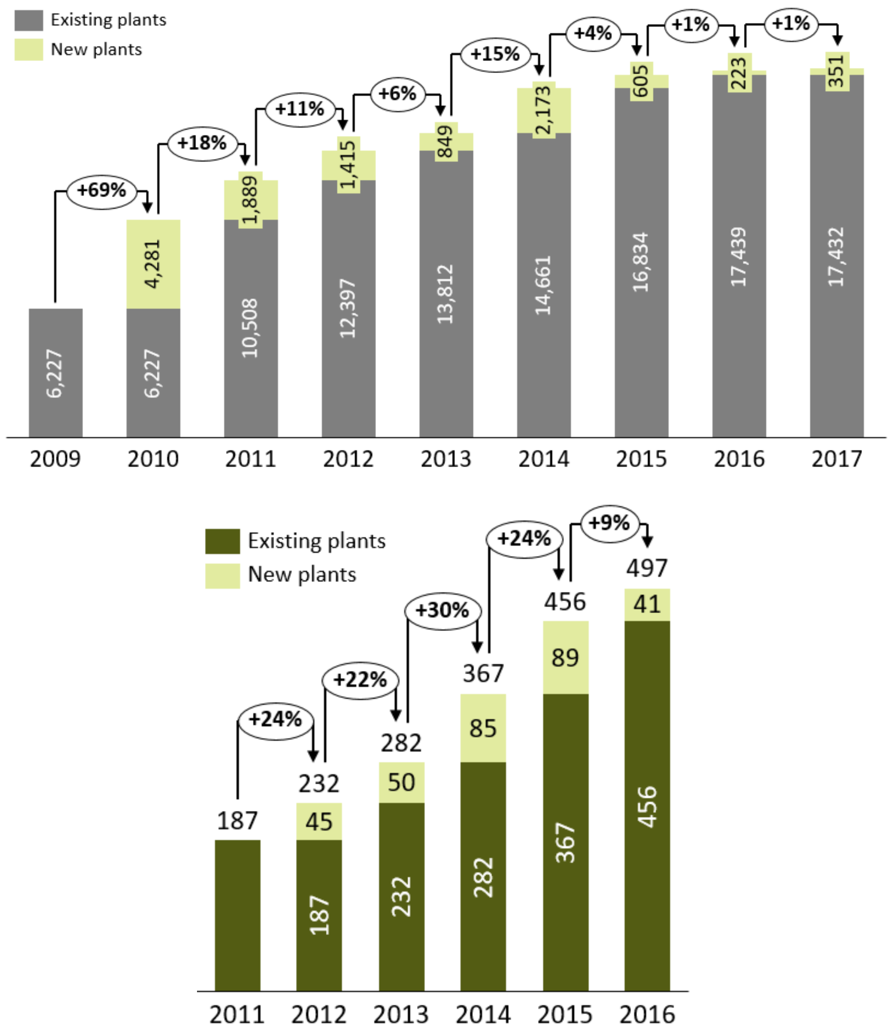

Figure 1. Growth of biogas (above) and biomethane plants (below) from 2009 to 2017 in EU. Adapted from [1,2]

Germany is producing half of the European biogas and the most active developments in the last few years have been in France and UK [1]. Biomethane plants by biogas purification and grid injection have also been increasing in number, from 187 plants in 2011 to 497 in 2016 as illustrated in Figure 1. Biogas production in the EU has more than doubled from 2008 to 2017 where it reached 704,463 TJ (see Figure 2).

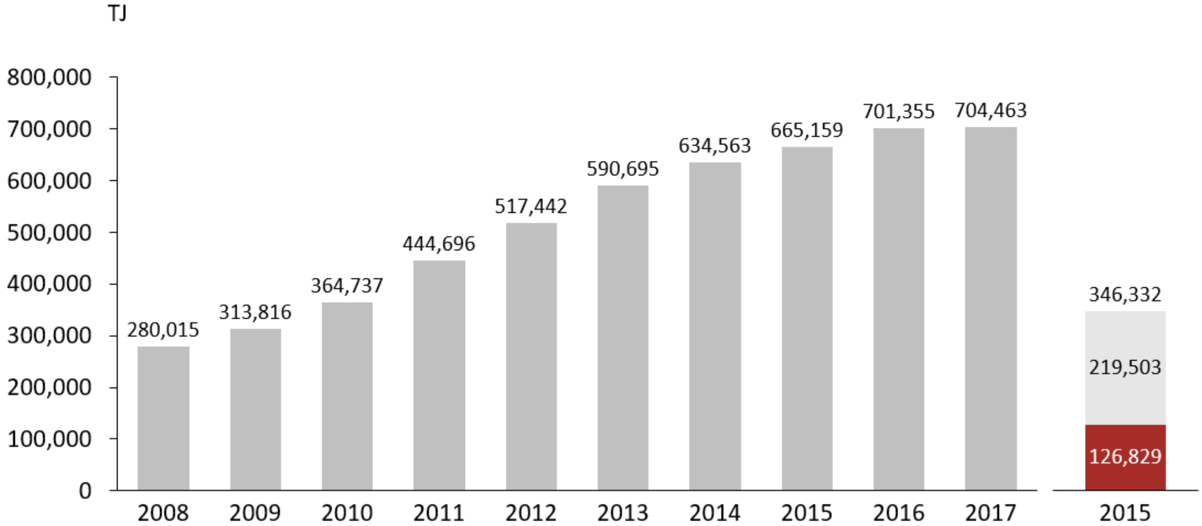

Figure 2. Development of biogas production in EU-28 and production of heat and electricity from biogas in 2015

Most of the biogas produced in the Europe has been used for electricity generation followed by heat production. The share of using biomethane in transportation is still rather low. The increase of the biogas plants and production in EU, stems primarily by the growth of agricultural biogas plants followed by landfill and sewage plants. Currently EU-28 is producing 1.37 GJ/capita of biogas.

According to AEBIOM [3], around 58% of the total biomethane potential of ~2800 PJ can be used until 2020. Only agricultural crops for energy generation can reach maximum potential in 2020 while the rest of the resources utilisation varies from only 5% for straw to 66% for sewage sludge. This results in a total potential of 5.44 GJ/capita[1] of which 3.14 GJ/capita can be utilised in 2020.

[1] The population of EU-28 per January 2019 (513.5 million).11

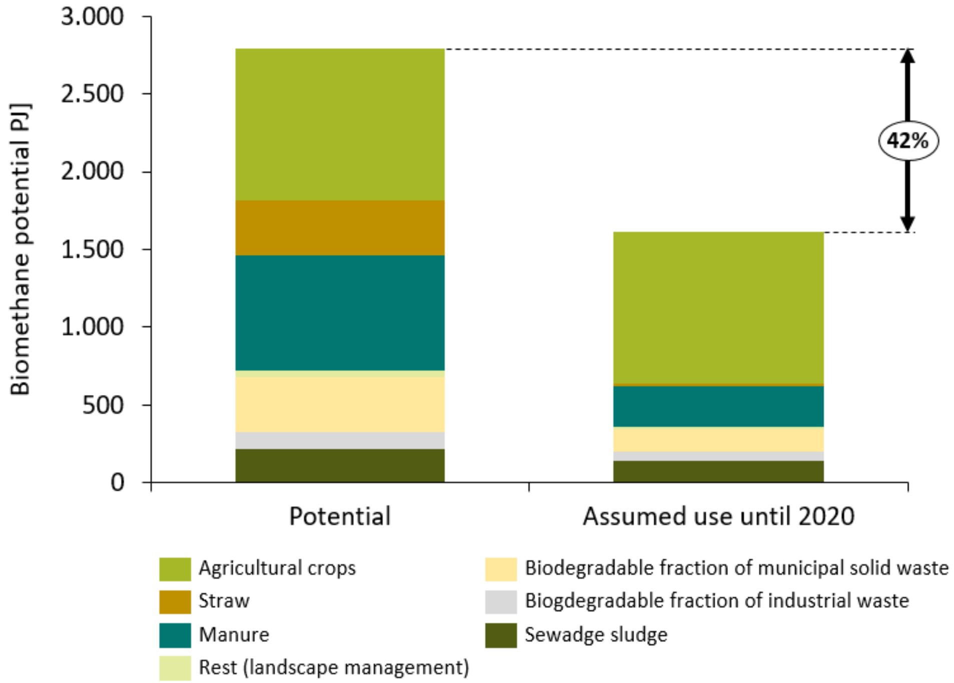

Figure 3. Detailed overview of biogas potential from agriculture and waste in EU-27. Adapter from [3].

Biogas potential from manure in EU-28, as illustrated in Figure 3, is between 736-817 PJ, while it is to expect that only ~70% of this potential is realistic to be utilised in the future [4]. The realistic potential is lower than the theoretical one as it accounts only the collectible manure and the efficiency of anaerobic conversion of the feedstock. Potential for biogas from manure for EU-28 is therefore 1.12 GJ/capita.

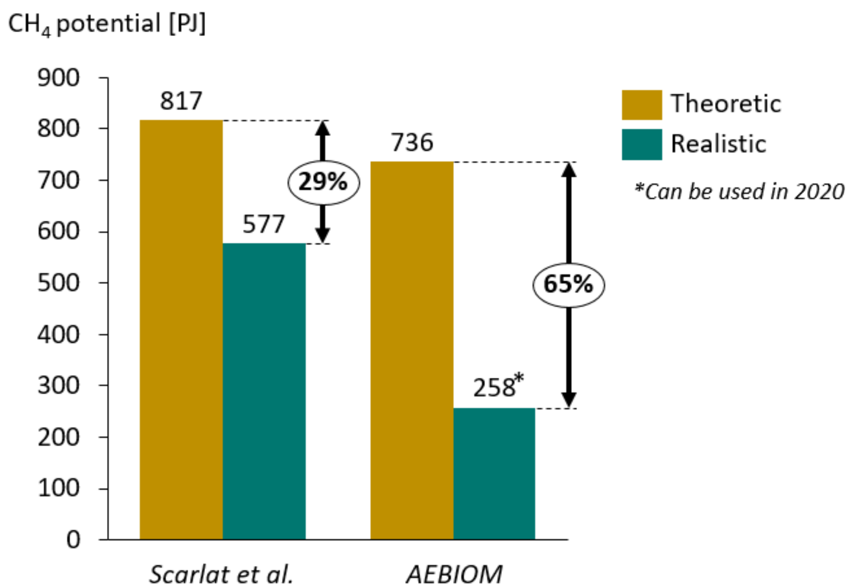

Figure 4. Potential for biogas from manure in EU-28 [4,5]

According to AEBIOM assumptions for available land for energy production, without causing harm for the food production and environment, only 35% of the biomethane potential from manure can be produced and utilised in 2020 [3]. If 258 PJ is to be utilised in 2020 then there is 55% of the total potential left for the future use if compared to Scarlat *et al.* [4] estimations.

Denmark is ranking 14 on the number of biogas plants in EU [1], but is number nine in terms of number of plants per 1 mio capita (26 plants/1 mio capita). The first biogas plant in Denmark was inaugurated in 1920s [6].The biogas production has been growing rapidly in Denmark over the last years, achieving 11.2 PJ in 2017 [7], where most of the biogas was used for electricity production followed by injection to the gas grid (see Figure 5). As in Europe, half of the biogas production plants in Denmark are agricultural based plants. Today Denmark is using 1.95 GJ/capita of biogas in the energy system, which is higher than the EU-28 production and is in the top five countries in Europe. Denmark has the highest share of biogas in the gas consumption. The share peaked in July 2018, by being 18.6% which was 50% higher than the year before [8].

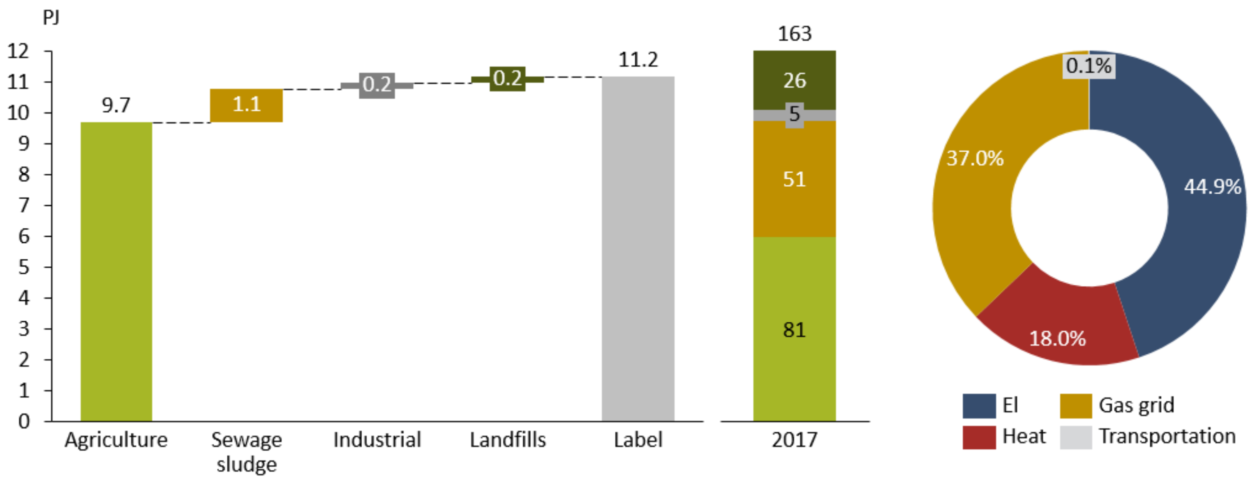

Figure 5. Biogas production, number of the biogas plants and utilisation in 2017

The historical growth of biogas plants in Denmark is primarily driven by the political agenda. It is expected that the growth of biogas is going to continue in the next few years due to the new support scheme for the green gases [9]. While most of the utilisation of biogas in the system is supported by the government, methanation of biogas with the addition of hydrogen is currently exempted from the support schemes.

The resource potential for biogas production has been mapped in [10,11]. The future potential for biogas from manure in Denmark is 460 million Nm^3 CH_4 or 16,518 TJ [4] making up to 2.87 GJ/capita. The Danish production of biogas from different resources is expected to increase in the future from 11.2 PJ in 2017, to levels between 59 and 107 PJ, depending on the technology advancements (see Figure 6).

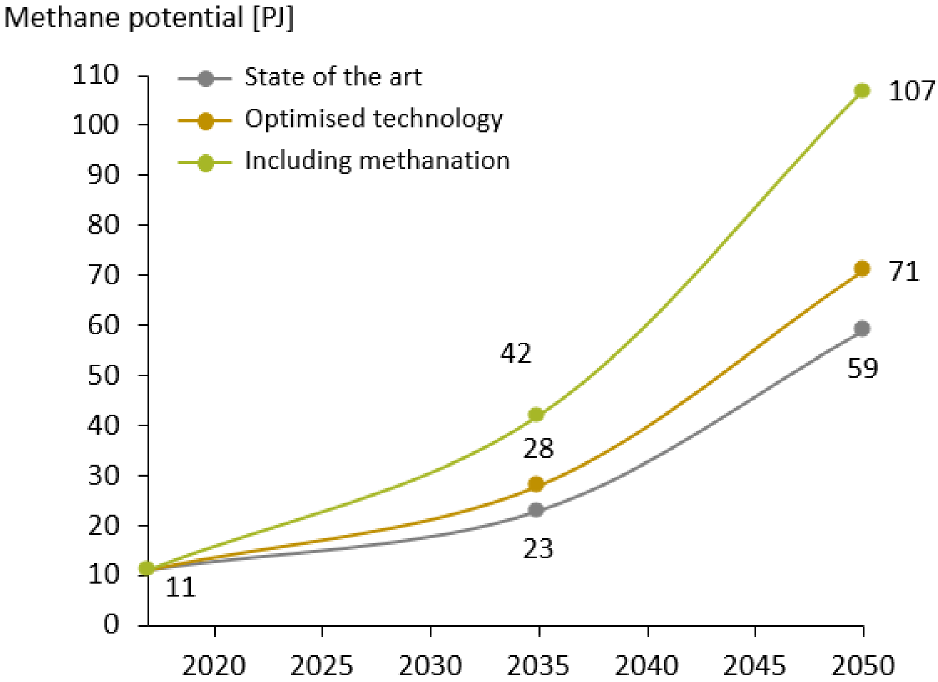

Figure 6. Methane potential based on the different technology advancements [12,13]

Since the production of biogas in Denmark is increasing steadily, the literature reports different potentials and biogas appears as one of the main fuels in the transition to renewable energy systems, it is important to do energy system analysis and determine which levels of the biogas potentials result in the best system performance together with other renewable energy technologies. Further in this report only the projections that have been modelled by energy system analysis will be used [14,15]. These two projections also have different methane potentials, IDA Energy Vision has a methane potential from biogas of 5.3 GJ/capita in 2050 and DEA scenarios have almost double of 11.3 GJ/capita.

POSSIBLE UTILISATION OF BIOGAS IN THE ENERGY SYSTEM

Biomass, in all its forms, is mostly subject to land availability, competition with food production and in some cases is influenced by dietary choices. The latter applies to the main feedstock used for biogas plants: animal manure, organic waste from food processing, straw and to some extent to energy crops.

Biogas has some limitation in terms of where it can be used, depending on the level of purity. Raw biogas, without any type of CO_2 and impurities removal can be burned in gas engines to produce electricity and/or heat. It can be used in large scale boilers or individual boilers, but the latter option is not used on large scale.

Biogas can also be used in industrial processes, where in some industries the level of purity is not an issue. However, it cannot be a direct replacement for natural gas, except if it is cleaned of CO_2 and other impurities. This is hereby named biomethane, and can be used as a direct replacement for natural gas in all its end use applications and energy sectors. Similar to biomethane, e-methane can also be used in all end use applications where biomethane is used, the only difference being the pathway it is obtained. This pathway involves the addition of hydrogen produced through electrolysis that is combined with the CO_2 molecule to produce methane (CH_4).

Unlike biogas, both bio-methane and e-methane have higher levels of purity that allows these gases to be used in the transport sector. For this purpose the methane needs to be compressed or liquefied. The compressed gas is known as *compressed natural gas'* (CNG), a fuel that refers to the fossil counterpart. To make a distinction from it, in this report the term used is '*compressed biogas'* (CBG). CBG has to be compressed at 200 bars so the storage in both vehicles tanks and stationary tanks has to be done at high pressures.

In its liquefied form, gas is known as '*liquefied natural gas'*, term that applies when using natural gas. The renewable version of the name, as in the case of CBG, is LBG *'liquefied biogas'*. To reach the liquid form, the methane needs to be cooled to -162°C and stored in insulated cryogenic tanks. Compared to CBG, LBG has a higher energy density, but also a higher price, making it suitable for certain types of vehicles such as heavy-duty.

ENERGY SYSTEM ANALYSIS ON THE FUTURE ROLE OF BIOGAS - THE CASE OF DENMARK IN 2050

It can be difficult to estimate the role of biogas in the future energy system in Denmark given the multiple applications this fuel can have. The previous chapter has explained the potential technical applications, but not all these technical solutions can be recommended for the implementation in the energy system.

For instance the case of utilising the biogas (in the form of biomethane or e-methane) in the heating sector as fuel for gas boilers has been analysed before, both for Denmark and the EU. Results showed that solutions in the form of district heating and individual heat pumps bring improved cost reductions and lower consumption of biomass compared to individual gas boilers. Therefore, such an application for biogas utilisation has not been included in the present analysis. However, it is possible to use waste heat produced by power-to-gas technology but the value streams have not been monetized in the modelling.

The energy system analysis in this study focuses on the remaining three energy sectors: electricity, industry and transport to determine which pathways present the lowest costs and lowest primary energy supply. It is important to conduct a technical energy system analysis in order to determine the efficiency gains the different forms of biogas can bring to the system. The analyses conducted use costs that reflect technology investment costs stripped out of taxes and subsidies (the same applies to O&M). The analysis looks into the year 2050 to provide a long term perspective into the utilisation of different forms of biogas.

The analysis of 100% renewable energy systems requires tools and models which can provide parallel analyses of electricity, thermal and gas grids. The design of a 100% renewable energy system also requires high temporal and data granularity that can encompass all the energy system sectors. EnergyPLAN was the tool of choice to perform this analysis because it includes the balancing of the energy system in its fuel cost calculations. The tool operates on an hourly resolution based on the principle of cross-sector integration, enabling the results to be more comprehensive than simulating the energy sectors isolated from each other. Consequently, it provides a holistic overview of the operation of the entire energy system, a requirement in the design of national energy planning strategies.

The reference system and the scenarios are analysed with technical simulation, meaning that the tool operates to minimise the fuel consumption, an important metric when measuring the use of resources as biomass and biogas. All scenarios are modelled as a closed system, independent of fuel imports. Excess electricity production is limited to 10% of the domestic electricity demand and the gas balance is 0, meaning that the total gas demand matches the supply over the year.

In order to determine the utilisation costs and the energy system effects of different forms of biogas and derived methane products, 8 scenarios were created and compared to a reference scenario. The reference scenario is 2050 Danish 100% renewable energy system based on [14] and the eight scenarios are created based on the reference one. The reference scenario has no form of biogas in the energy system, and biogas was displaced with other green or e-gases from biomass gasification. Throughout the chapter, three terms were used, as explained in the previous chapter: *biogas* as of raw biogas, *biomethane* from biogas purification and *e-methane* from biogas methanation with the addition of electrolytic hydrogen.

The utilisation overview is illustrated in Figure 7. The application of biogas was simulated for supplying power production and utilisation in the industry. Biomethane was used for power production, industrial purposes and in the gas vehicles as a transport fuel. Same as biomethane, e-methane was used for all three applications.

	Biogas	Biomethane	E-methane
Power plants	x	x	x
Industry	x	x	x
Transport		x	x

Figure 7. Utilisation overview

THE DANISH REFERENCE SYSTEM FOR 2050

The reference system model used in this analysis presents one potential version of a 100% renewable energy system model for Denmark in the year 2050. The reference system is based on the original model built in [14], but for the purpose of this analysis, it was adapted to accommodate an energy system without any biogas production. In this model, all methane demands, in the power and industry sectors, originate from biomass gasification and purification and biomass hydrogenation.

In the 2050 reference system developed for this analysis, the electricity production is dominated by variable renewable energy sources as wind and solar that produce 85% of the electricity in the energy system. The rest comes in equal shares from power plants and CHP fuelled by gas from biomass gasification.

In the heating sector, two-thirds of the heat demands are supplied with district heating and the rest of the individual heating demands mainly by heat pumps. The industry demands are supplied by 70% methane produced via biomass hydrogenation and the remaining share by biomass directly.

In the transport sector, priority is given to electrification and compared to the 2050 scenario developed in [14], there is a higher degree of electrification in personal transport. This allowed reducing the demand for e-liquids as DME and methanol by 12%. Table 1 provides an overview of the supply, conversion and demands of the chosen energy system.

Table 1 – Main parameters of the reference system in EnergyPLAN

	Unit	Reference scenario
Primary energy supply		
Onshore wind	TWh/year	16.20
Offshore wind	TWh/year	53.06
PV	TWh/year	6.35
Wave	TWh/year	1.35
Biomass	TWh/year	59.73
Conversion capacities		
Onshore wind	MWe	5,000
Offshore wind	MWe	16,650
PV	MWe	5,000
Wave	MWe	300
Large CHP	MWe	3,500
Small CHP	MWe	1,500
Power plants	MWe	4,500
Electrolysis	MWe	8,784
Energy demands		
Domestic electricity	TWh/year	36.36
Electricity for electrolysers	TWh/year	37.22
Electricity for transport	TWh/year	9.43
Electrofuel transport	TWh/year	29.78
Industry	TWh/year	11.82
DH demand	TWh/year	28.19
Individual heating	TWh/year	14.51

THE BIOGAS UTILISATION SCENARIOS

The different biogas scenarios are built starting from the reference system by displacing green gas and e-liquids as follows:

- In the ***biogas scenarios***, raw biogas is substituting gasified biomass in power production and substituting e-gas from gasified biomass in industry. Having a scenario where biogas replaces gas in the industry is not fully representative, as it is likely that not all demands in the industry can be supplied by biogas only, but it was included to demonstrate the utilisation costs.

- In the ***biomethane scenario***, biomethane is substituting gasified biomass in power production, e-gas from gasified biomass in industry and liquid e-fuels in the transport sector.
- In the ***e-methane*** scenario, e-methane is substituting gasified biomass in power production, e-gas from gasified biomass in industry and liquid bio-electrofuels in the transport sector.

In order to find the right biogas, biomethane and e-methane demand for the analysis, several criteria was used. A selection of e-methane demands were analysed in a reference system with different electrolysis configuration. The results show that the marginal cost difference increases with higher e-methane production in the system but also grows when additional electrolysis capacity and storage is increased. However, if the system produces 8.41 TWh (~30 PJ) of e-methane, the costs are nearly the same for electrolysis without buffer capacity and the 100% buffer capacity and a week of hydrogen storage. If we then compare the biomass demand and wind production for this specific case, it is visible that the system with additional electrolysis capacity provides a reduction in biomass consumption and an increase in wind production.

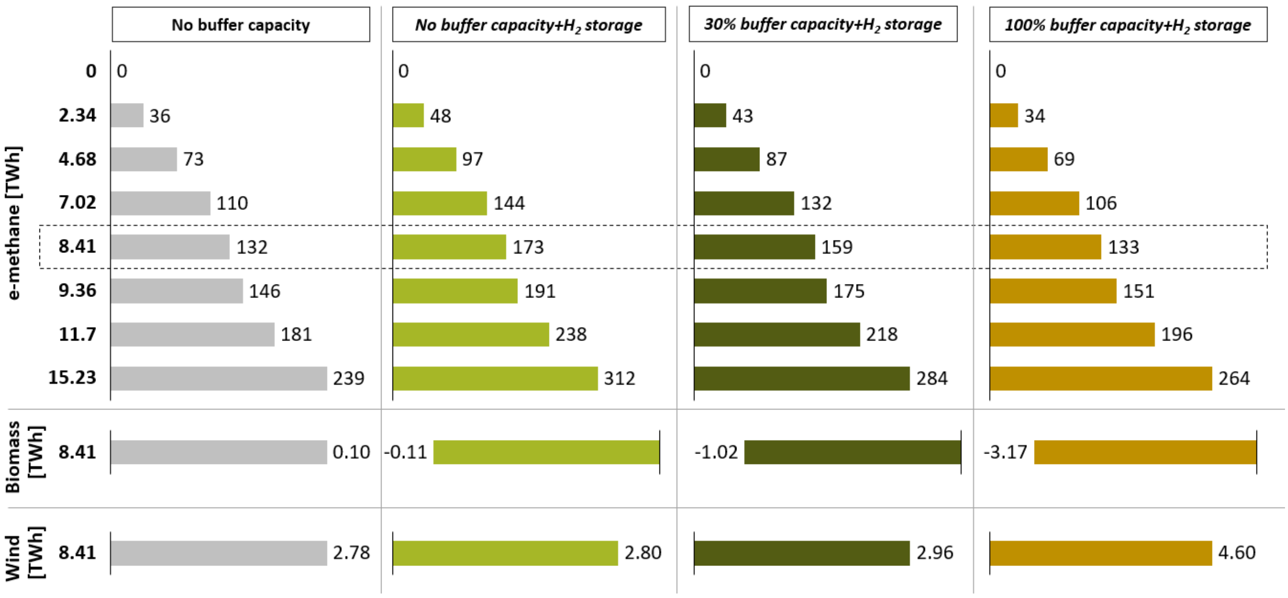

Figure 8. Marginal cost difference in M€ for different levels of e-methane (upper), biomass consumption in TWh (middle) and wind production in TWh (bottom) for different electrolysis configurations

Lastly, this allows for a cross-sector simulation of the same gas demand across all energy sectors and is equal to the methane demand in the industry sector of the reference scenario. Therefore, all the scenarios have the same gas demand for power, industry and transport of 8.41 TWh that is supplied either with biogas, biomethane or e-methane.

When biomethane and e-methane are used in the transport sector, in their respective scenarios, these are substituting more than 80% bio-based e-fuels. The rest of the substituted liquid fuels are e-fuels produced through the CO_2 hydrogenation pathway (CCU with hydrogen addition). This approach was used as there was not enough bio-based e-fuels in the reference scenario to be replaced without affecting the electrified transport demands.

In the scenarios for the transport sector, the biomethane and e-methane are compressed when prepared for vehicle use, so a 8% compression loss is included, hence requiring an increased amount of feedstock in the biogas plants to achieve the fixed demand of 8.41 TWh used throughout the scenarios. The scenarios where biomethane and e-methane are used for the transport sector also include different costs for vehicles in comparison to the reference scenario, as CBG (compressed biogas) vehicles are considered more expensive than vehicles running on methanol or DME according to [16]. This equals to an increase in the annualised costs of 108 M€ including O&M and refuelling stations.

Table 2 – Main costs used in the analysis

	Unit	Investment (M€/unit)	Lifetime (years)	O&M (% of investment)	References
Electricity production					
Onshore wind	MW_e	0.93	30	3.4	[17]
Offshore wind	MW_e	1.71	30	1.88	[18]
PV	MW_e	0.56	40	132	[18]
Wave	MW_e	1.6	30	4.9	[18]
Large CHP	MW_e	0.8	25	3.25	[18]
Small CHP	MW_e	0.85	25	1	[18]
Power plants	MW_e	0.8	25	3.25	[18]
Fuel conversion					
Biogas plant	TWh/year	159.03	20	14	[19]
Biogas purification plant	MW_{fuel}	0.25	15	2.5	[19]
Biogas methanation plant	MW_{fuel}	0.2	25	4	[20]
Gasification plant	MW_{fuel}	1.33	20	2.4	[19]
Gasification upgrade plant	MW_{fuel}	0.68	20	1.7	[19]
Chemical synthesis	MW_{fuel}	0.3	25	4	[20]
Jet fuel synthesis	MW_{fuel}	0.37	25	4	[21]
Electrolysers	MW_e	0.4	20	3	[19]
Hydrogen storage	GWh	7.6	25	2.5	[19]

Some of the technology costs (the most important in relation to the analysis) used in the scenarios are presented in Table 2. In addition to these costs, detailed analysis of future transport demand and substitution of different fuel and vehicle types with gaseous vehicles was used in determining the vehicle and infrastructure costs, both for the reference system, but also in the scenarios where biomethane and e-methane are used in the transport sector. For this purpose, a scenario modelling tool called TransportPLAN [22] using transport statistics for Denmark was used. The tool enables the user to define scenarios that can then be used as inputs for EnergyPLAN. The scenarios account for the change in vehicle and infrastructure costs when a part of the demand is supplied by gaseous fuels. The vehicle and infrastructure costs are taken from [16].

RESULTS

The best way to interpret the results is by understanding the consequences of replacing each of the fuels in the reference scenario by the biogas – biomethane - e-methane line-up, more than the sector it is replaced in (see Figure 9). In the power plant and industry scenarios the new fuel line-up is essentially replacing the same fuel, methane, but produced through different pathways and with different feedstock, that being biomass for biomass gasification.

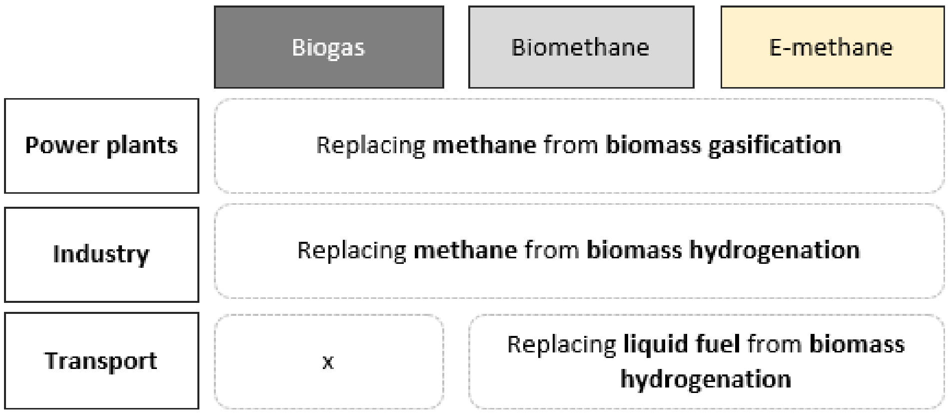

Figure 9. The energy sectors and the fuels replaced

Figure 10 illustrates the gas demands and supply through the scenarios. The total gas demands vary between the scenarios, as the scenarios with the utilisation of the gas in transport have additional gas demand for this purpose, while in the other scenarios the transport demand is met by liquid e-fuels. All the methane produced is sent to the gas grid, from which the consumers (electricity, industry and transport sectors) take the needed quantities. That means that the supply equals the demand in all cases, as shown in Figure 10, but the composition of the gas supply varies from scenario to scenario. However, in each instance the gas produced through biogas, biogas purification or biogas methanation replaces the same share of gas as in the demand mix.

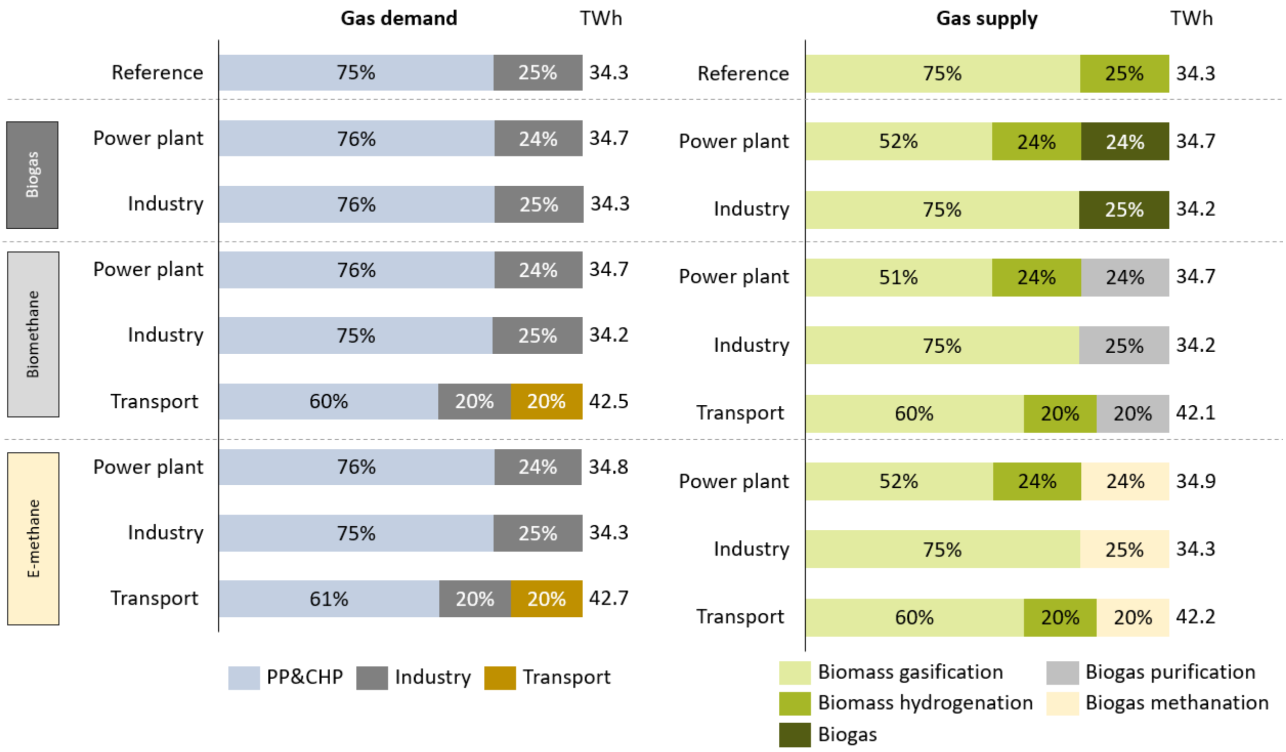

Figure 10. Gas demands and gas supply in different scenarios

WIND AND ELECTROLYSIS CAPACITIES

As the gas supply changes throughout the scenario, so does the installed offshore wind and electrolysis capacities (Figure 11). The wind and electrolysis capacities are lower in the industry and transport scenarios than in the reference scenario. In the case of industry, this is as the production of biomethane does not require additional hydrogen, and therefore its implementation in the system reduces the hydrogen demand needed for hydrogenating gasified biomass. The lower electrolysis capacity in e-methane transport scenario is as the production of e-methane is less hydrogen intensive than production of liquid e-fuels (methanol and DME). The increase in the capacities for wind and electrolysis in the power plant scenarios for e-methane is as these scenarios have additional hydrogen demand for producing e-methane for supplying power plants, in addition to the already high hydrogen demand for e-fuels for the transport sector and e-gas for the industry.

There is a clear correlation in the increase and decrease of the wind and electrolysis as the more electrolysis is in the system, the more wind is the system able to integrate, as shown in Figure 11. On the other hand, the scenarios with high wind and electrolysis capacity are able to be more flexible and create less excess electricity than in the cases with low wind and electricity capacity.

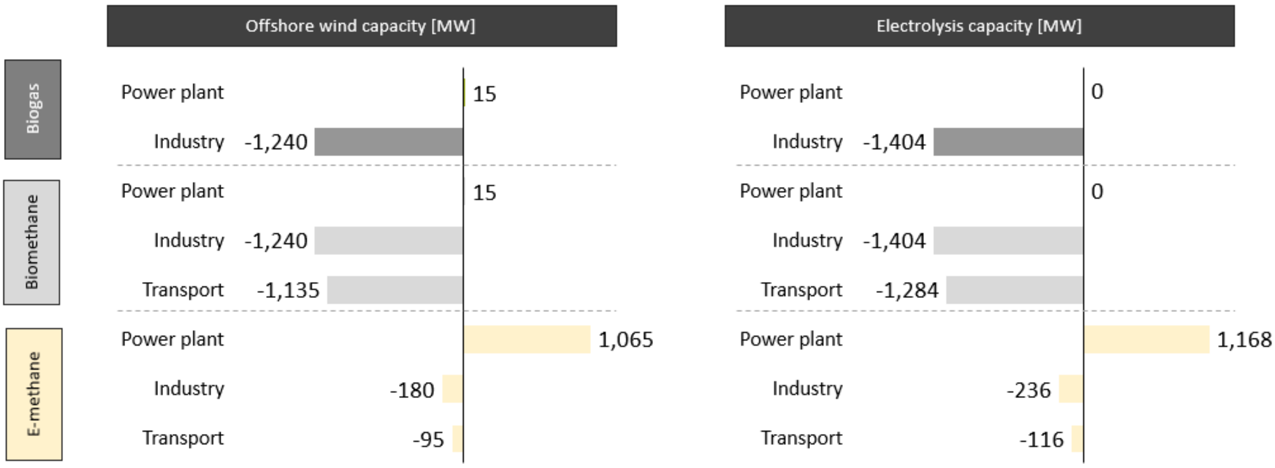

Figure 11. Installed wind and electrolysis capacity in comparison with the reference system

PRIMARY ENERGY SUPPLY AND BIOMASS

As illustrated in Figure 12, the scenarios where any form of biogas or methane is used for power production are the most efficient from the biomass consumption perspective, while the industry and transport scenarios as well as the reference are the least efficient. However, all the scenarios offer savings in dry biomass in comparison to the reference scenario. These savings are directly connected with the fuels that are being displaced by biogas or methane.

As in the case of power plants all scenarios are displacing dry biomass for biomass gasification providing savings of ~16% in comparison to the reference scenario. In case of industry where scenarios are displacing gasified biomass that is further hydrogenated with electrolytic hydrogen savings are lower ~8%, however still significant. Using any form of gas in the transport sector offers similar savings, as in the case of industry, to the dry biomass in comparison to the reference scenario where liquid bio-electrofuels are used for meeting transport demand.

Overall results indicate that the e-methane scenarios have the highest primary energy supply due to the higher share of wind in the system. Even though the e-methane scenarios use lower amounts of biogas feedstock due to the hydrogen addition, in the overall energy system picture these do not use significantly less dry biomass than the biogas and biomethane scenarios.

This is explained through the energy system effects, where even though biogas feedstock is used more efficiently in the methanation unit, dry biomass is used in other parts of the energy system to fulfil other demands. In fact, even though the total biomass consumption is higher in the biogas and biomethane scenarios, the overall primary energy supply is reduced compared to the e-methane scenarios due to the lower wind supply in the system.

As the biomass is going to be a very scarce resource in the future, the reduction of use of dry biomass in the system is one of the main factors when determining which technology choices are better than other from the system perspective.

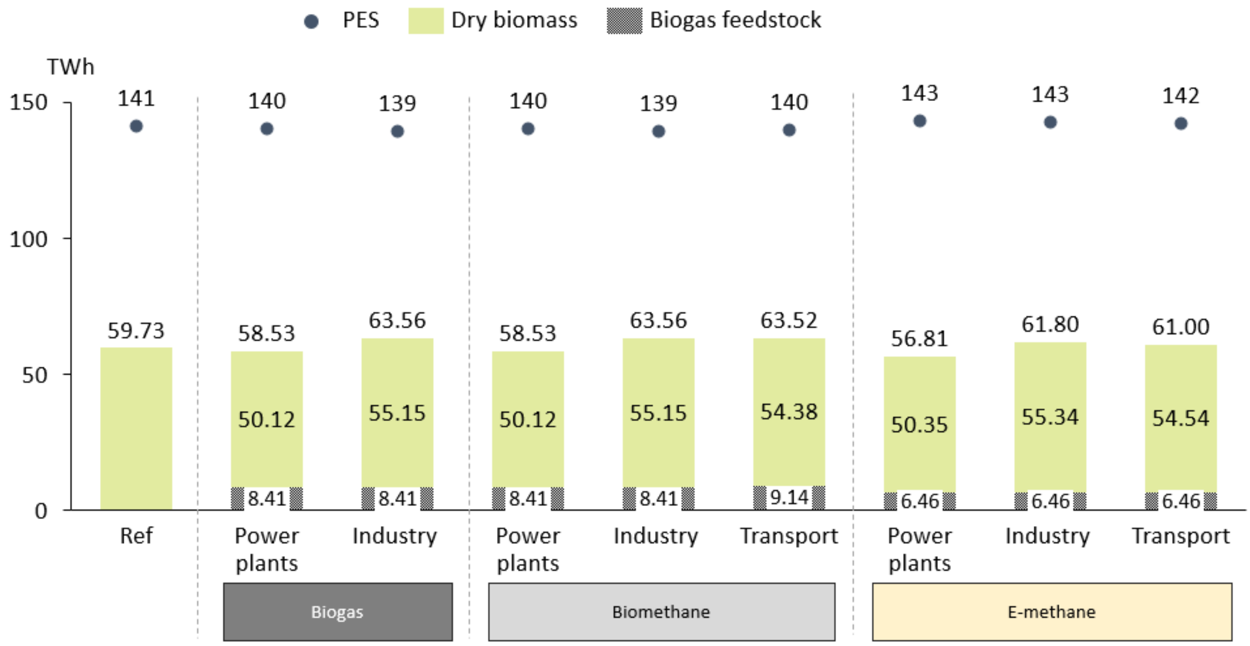

Figure 12. Primary energy supply for different scenarios including dry biomass and biogas supply

SYSTEM COST COMPARISON

The energy system costs were calculated for all 8 scenarios with four different biogas feedstock costs including transportation. The results are presented as a marginal cost difference from the reference scenario that has no biogas utilised in the system. It is to be noted that in reality only part of the gas demand in the industry could be substituted with biogas, therefore this specific scenario is not necessarily fully representative, but it was hereby used to illustrate the utilisation costs.

Figure 13 illustrates the marginal cost difference of different scenarios to the reference scenario with a fixed biomass price of 6 €/GJ. The results are visually separated by a colour gradient from low cost (dark green) to high (red) costs, where low indicated larger savings in relation to the reference scenario and red cost increase. As all the scenarios with different feedstock prices are related to the reference scenario, the colour gradient is applied across all results.

The energy system costs show that using biogas for power generation offers more savings than using biomethane or e-methane. This happens as biogas has considerably lower production costs than methane produced through biomass gasification and purification. This indicates that the utilisation of biogas should be prioritised in power plants especially if the manure prices are low. Similar, in the case of industry, utilisation of biogas offers more savings than using biomethane or e-methane, but one must make a clear distinction that not all methane demands in industry can be replaced with biogas. If looked across the fuels, prioritizing both biogas and biomethane in the industry offers the highest savings for the overall system.

Marginal system cost difference [M€]		Biogas		Biomethane			E-methane		
		Power plants	Industry	Power plants	Industry	Transport	Power plants	Industry	Transport
Biogas feedstock prices [€/GJ]	0	-132	-173	-106	-146	-164	51	8	-29
	4.5	3	-37	29	-11	-17	155	112	75
	5.2	25	-15	51	11	-7	172	129	92
	5.9	47	6	73	32	30	189	144	108
Displacing		Gasified biomass	Gasified biomass + H_2	Gasified biomass	Gasified biomass + H_2	Liquid bio-electrofuels	Gasified biomass	Gasified biomass + H_2	Liquid bio-electrofuels

Low

High

Figure 13. The marginal cost difference to the reference scenario for utilisation of biogas in different parts of the energy system with different levels of manure costs with fixed biomass price of 6 €/GJ

Once purified, biomethane and e-methane show reduced energy system costs when utilised in the transport sector. In the case of free manure, where manure is paid for by the agriculture sector instead of the energy sector, the highest savings can be achieved by using biomethane for transportation in comparison to the e-methane in transport. It also shows that it is slightly cheaper to use the biomethane for the industry than using biogas for power plants.

However, if the biomass price is increased to 8 €/GJ, the results show a somewhat different trend (see Figure 14). By zooming into the use of biogas for power generation or industrial purposes, the price difference becomes minor, though still with slightly higher savings in case of industrial application. The same trend is visible in case of biomethane for all three purposes. It is still clear that displacing the more expensive liquid fuels for the transport sector, results in the highest savings if using biomethane in this sector in comparison to the other two energy sectors. The higher the manure price the lower saving is of using biogas for power generation instead of using e-methane. It is also visible that in case of free manure, it is not anymore cheaper to use biomethane in the industry than biogas for power generation, however, it does show that utilisation of biomethane in the transport sector is still 1% cheaper than using biogas for the power generation.

Marginal system cost difference [M€]	Biogas		Biomethane			E-methane		
Manure prices [€/GJ]	Power plants	Industry	Power plants	Industry	Transport	Power plants	Industry	Transport
0	-201	-205	-175	-179	-202	-16	-23	-66
4.5	-66	-70	-40	-43	-55	88	81	38
5.2	-44	-48	-18	-22	-31	105	98	55
5.9	-22	-26	4	0	-8	122	115	71

Low — High

Figure 14. The marginal cost difference to the reference scenario for utilisation of biogas in different parts of the energy system with different levels of manure costs with fixed biomass price of 8 €/GJ

The increase in biomass price makes the choice of prioritisation of different forms of biogas more complicated, though still with the similar overall trend that biogas should be used for power generation, which is also aligned with the biomass consumption of these scenarios in comparison to others as illustrated before in Figure 12. Once the biogas is purified to biomethane, transport sector shows the highest savings, however, these are minimised with the increase of the biomass costs.

As the difference between the costs in some of the cases are almost negligible, it is difficult to conclude on if some of the applications should be preferred than others.

FUEL COST COMPARISON

The fuel costs are based exclusively on the investment costs in production chain of fuels including wind and electrolysis investments for e-fuels. The fuel costs for biogas, biomethane and e-methane are illustrated for four different levels of biogas resource price from 0 to 5.9 €/GJ (Figure 15).

It is clear from the fuel price comparison that the cost increases gradually from the biogas to e-methane with the same pattern with different manure prices. Cost of biogas for power or industry is the cheapest in comparison with both biomethane and e-methane. The cost of biogas with manure price of 5.9 €/GJ results in 65% of the increase in the price in comparison to the costs when the feedstock is free. Using biomethane in the transport sector is 8% more expensive than using it for power or industrial purposes, however this difference is reduced to 6% with the manure price increase.

The costs for biomethane for the transport sector is slightly higher due to the additional compression costs needed for obtaining the fuel for transport sector. E-methane costs are highest as expected and there is no differentiation between different sectors. With the highest manure costs of 5.9 €/GJ the costs increases by 40% in comparison to the free manure. The price difference between the use of biogas or biomethane to e-methane is slightly reduced with increased manure costs. In case of free manure e-methane has almost 50% higher costs in relation to biogas and 26-36% higher in comparison to biomethane. However, when the manure price increases, cost of e-methane are only 26% higher in comparison to biogas and 13-20% higher in comparison to biomethane.

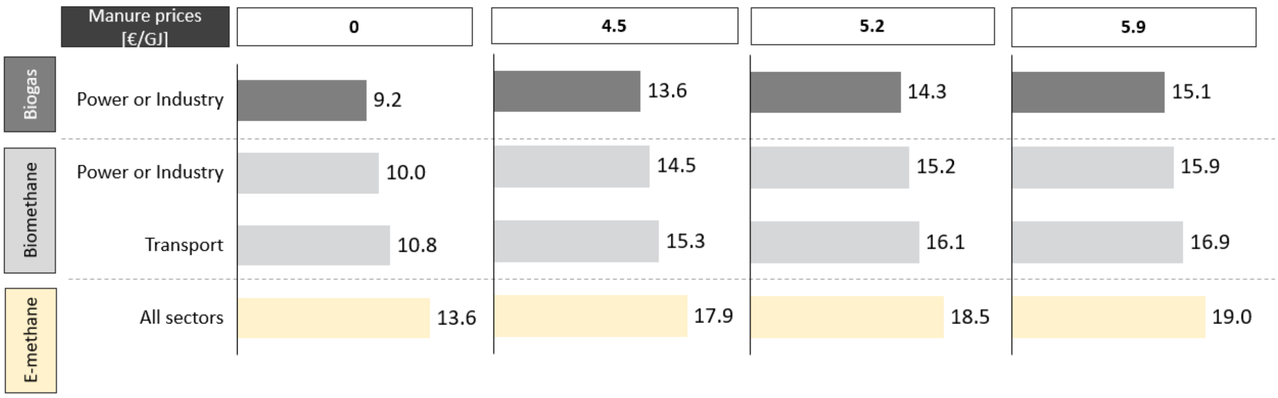

Figure 15. Fuel prices in €/GJ with different manure cost levels and utilisation in different sectors for biogas, biomethane and e-methane

When compared to the prices of the fuels in the reference scenarios, which are being substituted with the biogas derived fuels in other scenarios, it is visible that the biogas, biomethane and e-methane via biogas route can be cheaper than the fuels produced via biomass gasification route depending on both manure and biomass price levels (Figure 16). If the manure is free, costs of producing biogas and biomethane are lower than producing methane, e-methane or CCU e-methanol. However, it is still slightly cheaper to produce liquid e-fuels via gasified biomass than e-methane. If compared with CCU e-fuels, only in the case of free manure is e-methane less expensive.

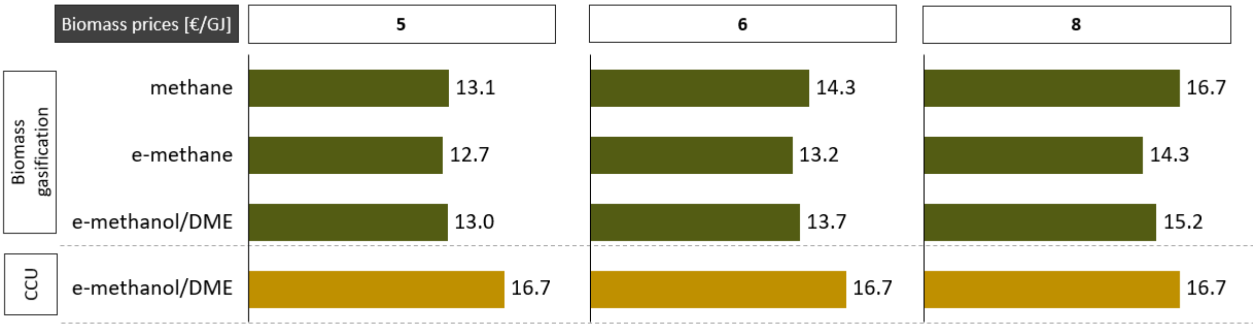

Figure 16. Fuel prices for methane, e-methane and e-methanol/DME produced via biomass gasification route and e-methanol/DME via CCU route in the reference scenario

The cost distribution for biogas, biomethane and e-methane is illustrated in Figure 17. The cost of biogas is consisting only of the biogas plant costs, while in the case of biomethane between 8-9% of the costs is the biogas purification part. E-methane has more complex cost structure, including biogas plant costs (47%), methanation costs (4%), costs for electrolysis (20%) and offshore wind capacity (29%) corresponding to the electricity demand for hydrogen production. The costs illustrated here are without biogas feedstock (manure) costs. As illustrated, the fuel costs are strictly linked to the investments, O&M and feedstock prices. The price of electricity is not accounted as such, but rather investments in the wind power needed for the hydrogen production.

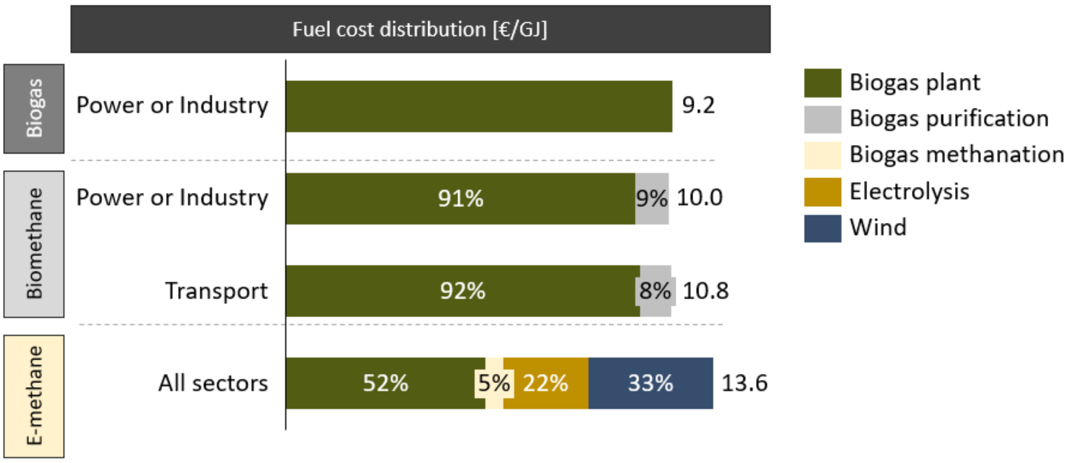

Figure 17. Fuel cost and distribution shares for biogas, biomethane and e-methane without biogas feedstock/transportation expenses

Additional sensitivity analysis was conducted to identify the fuel cost changes for the e-methane when several variables are altered (Figure 18). The different costs are listed in Table 3.

Table 3. Technology cost for the sensitivity analysis. Based on [19].

	Unit	2020	2030	2050
SOEC	M€/MW	2.2	0.6	0.4
Biogas methanation	M€/MW	0.6	0.3	0.2
Biogas plant	M€/TWh	195.64	176.19	159.03
Wind offshore	M€/MW	2.3	1.99	1.71
Wind onshore	M€/MW	0.99	0.91	0.93

The reference cost structure represents 2050 costs for all the indicated technologies and is using offshore wind for hydrogen production. If the offshore wind is exchanged with an onshore wind price reduction of 15% can be achieved. If the technology costs remain unchanged from 2020, the costs are increased by 82%. As implementation of onshore wind costs still did not break even with the costs of producing biomethane by biogas purification, an additional price reduction of electrolysis was sought to reach the breakeven costs. In order to reach the same costs as biomethane (10.8 €/GJ) electrolysis cost in 2050 needs to drop to 0.19 M€/MW. This price reduction is highly unrealistic to be achieved as even the optimistic technology price projections for SOEC were 0.28 €/MW$_e$ [23].

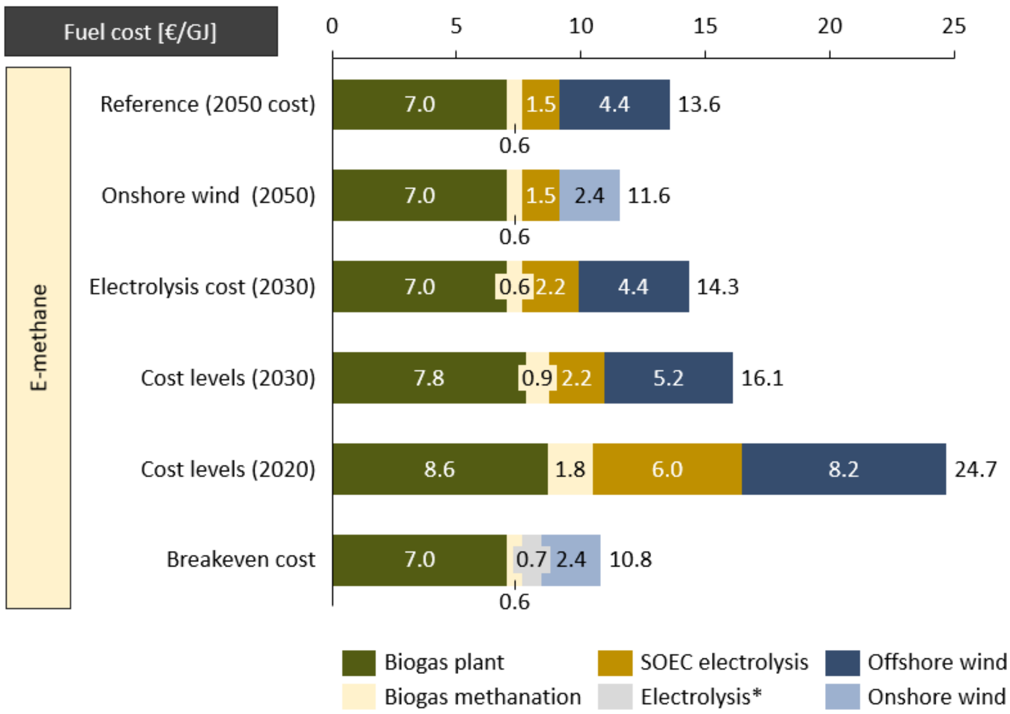

Figure 18. Fuel cost sensitivity analysis with different cost parameter variations (Electrolysis indicates the needed cost reduction to breakeven with biomethane)*

DISCUSSION AND CONCLUSION

This section aims to summarise the results by explaining the pros and cons of using the three new fuels across all sectors, continued by an explanation of recommended solutions per energy sector.

If biogas is the preferred end fuel, then this has the benefit of low production costs, due to the lower number of technologies needed to produce it. However, being an impure gas, it has limited end-use applications. Electricity and heat production seem to be a good match for it from a cost and biomass consumption perspective, making it a suitable fuel to be used in times when variable renewable energy cannot supply the heat and electricity demands. Utilisation of biogas in industry brings similar benefits, especially if biogas is to replace the same fuel as in case of power plants and CHP. However, the application to industry will likely be limited as in the future the quality of the gaseous fuels for industrial purposes will outreach the low quality of biogas. Furthermore, it is important that the produced biogas can be transported to the needed destination for industrial purposes. In case of power and heat production it is assumed that they are closely connected.

If biomethane is the preferred end fuel, this had two main advantages compared to the other two analysed fuels - it can be used in more applications than biogas and has a lower production cost than e-methane. Current results indicate that biomethane application brings similar cost reductions across all energy sectors especially in the scenarios with increased biomass prices. However, transport seems to be the energy sector that brings the most cost savings in case of biomethane. This happens as it is replacing a more expensive chemical synthesis for the production of liquid electrofuels that also requires higher share of hydrogen for fuel generation. The results are also influenced by the fact that, due to the reference scenario limitations, biomethane as CBG is also replacing ~15% of the CO_2 based liquid electrofuels (CCU electrofuels), that are significantly more expensive than biomass based electrofuels.

If e-methane were to represent the fuel choice, then it would be clear that in all cost variations the end use should only take place in the transport sector, where e-methane would be replacing similarly priced liquid electrofuels as methanol or DME. E-methane shows unfeasibly high costs if used in power and heat production and industry sectors simply because it is replacing a cheaper fuel that does not require electrolysis in the production process. Further business case analysis could show better results for e-methane if the revenues from the supplying waste heat and income from providing ancillary services is accounted.

In the power and heat sector the results indicate clearly that biogas is the preferred fuel, as it reduces the dry biomass consumption and costs. Biomethane can be a second preferred fuel if the electricity and heat production plants already have a gas grid connection or if biogas cannot prove as a feasible solution in the first place. Biomethane can be used in existing gas engines or gas turbines without conversion of the existing equipment, but in the new heat and electricity developments biogas should be the preferred fuel. One argument against suggesting this approach would refer to the possibility of using biomass directly in plants, without any conversion losses. Previous work has demonstrated though that using gaseous fuels in power and heat production presents more benefits than burning biomass directly, both from the cost and biomass savings perspective as well as for the system flexibility improvements [24].

In the industry sector, the recommendations are interchangeable with the ones from the power and heat sector if the same type of fuel is replaced. The argument of using biogas in industry grows higher if the cost of biomass is on the upper level whilst at the same time it proves more resilient to increased biogas feedstock prices. As mentioned previously, biomethane should be preferred after biogas, if that is required by the industrial processes.

In the transport sector the only two gaseous fuel choices are biomethane and e-methane. Results show high potential of cost savings if more expensive liquid fuels are replaced, even by accounting for higher vehicle costs and CBG refuelling stations. In the current analysis, the vehicle efficiencies for gas engines do not differ considerably from their liquid fuel counterparts, according to the sources used in this study [16]. The increased reductions are also given by the replacement of a part of the CO_2 based electrofuels which otherwise would not make such a good case for CBG vehicles. In any case, one must be vigilant in recommending CBG as the preferred solution for the transport sector, as it may be more impractical than using liquid fuels. Von Rosenstiel *et al* [25] in their article investigated the problems with gas vehicle implementation in Germany, where the strong correlation between the development of the infrastructure and willingness to invest in new technology has been hindering the implementation. Authors indicate six reasons for market failure, externalities including fuel price regulation, coordination of vehicle manufacturers and infrastructure development and lack of competition, imperfect information, bounded rationality and principle-agent problems. Moreover, it is likely than electrification may take an even larger share of the transport demands, in which case BEV should prioritised in front of any type of electrofuels.

Overall, it is important to consider the arguments and incentives on why to use biogas for energy purposes. In their new report Dubgaard and Ståhl [26] point out that production of biogas is socially most expensive alternative for mitigation of CO_2 in the agriculture sector among the analysed measures. However, these result do not show overall cost-effectiveness as they are limited to the agriculture sector only.

The price of biogas resources is naturally a big influencer of the fuel prices for any biogas based fuel types as shown previously. Therefore it is also debatable who ought to pay for the resources needed for the biogas production, in the Danish case mainly manure. Should this be agriculture sector that needs to discard it or the energy sector that is using it for different energy and fuel production? Lastly, the conversion to the organic farming reduces significantly manure production, therefore collaboration between biogas producers and local farmers needs to maximise the synergies for both parties.

MARKET POTENTIAL FOR BIOGAS METHANATION IN FUTURE DANISH AND EU ENERGY SYSTEM

Danish energy system has been changing towards higher shares of renewable energy for many years. With the long-term goal of being 100% renewable in 2050, many different long-term energy system designs that meet these targets have been created [14,27–29]. All these scenarios have recognised electrofuels as a necessary part of the future energy system and use electrolysis for establishing sector coupling and integration of variable electricity. All the scenarios include production of e-gas from biogas and also production of other e-fuels.

For the case of Denmark, a comparison between the scenarios done by Danish Energy Agency and IDA Energy Vision [14,27] is presented, as these sources have system projections until 2050. The comparison will focus on biogas methanation and electrolysis capacities in these scenarios as a background for the needed investment projections. The IDA Energy Vision 2050 scenario has been adjusted with new inputs for the transport sector and e-fuel production, where the share of the electric vehicles have been increased from 75 to 90% which resulted in lowering electrolysis capacity by 20%.

In Figure 19 we can see the electrolysis capacity in different scenarios. The main difference between DEA scenarios and IDA scenario is the different type of electrolysis used.

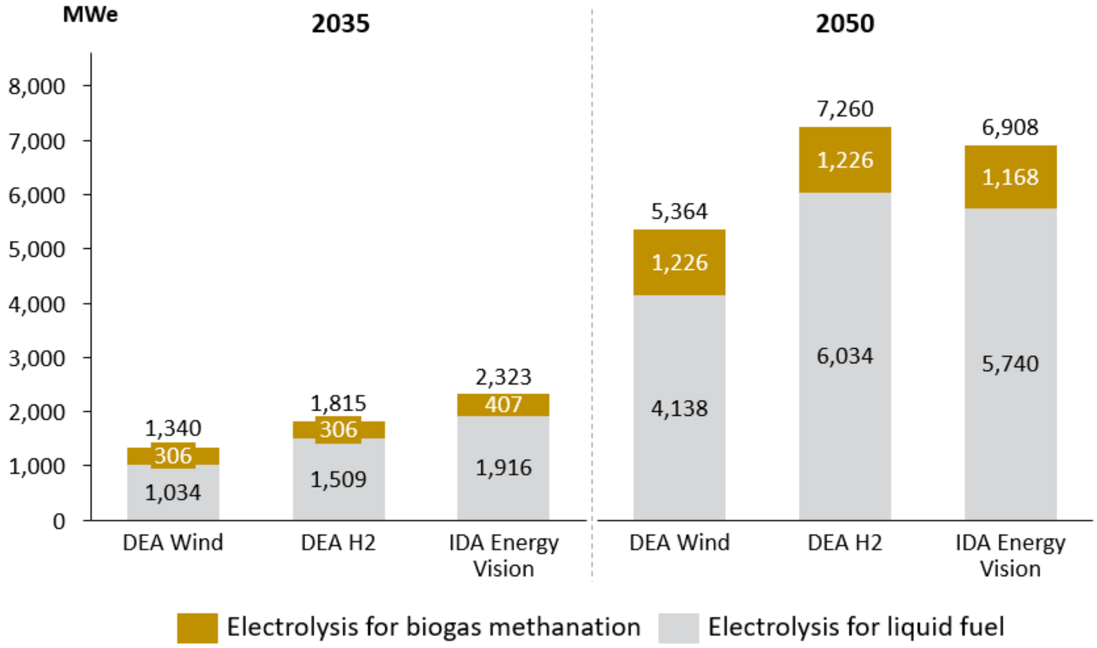

Figure 19. Electrolysis capacities for biogas methanation and e-fuels in DEA Wind, DEA H2 and IDA Energy Vision

Both IDA scenarios for 2035 and 2050 have additional capacity for electrolysis installed. In 2035, 30% additional buffer capacity is installed and 100% capacity buffer is installed in 2050. As explained in previously in the report, these electrolysis configurations bring the best results for the overall system, by enabling more variable electricity integration and reducing biomass use. It is visible that the electrolysis for biogas methanation is slightly higher in IDA 2035 in comparison to DEA Wind and H_2, however in 2050 it is opposite, where IDA has slightly lower installed capacity.

When it comes to the production capacity, all scenarios in 2035 have 16 PJ of e-methane from biogas methanation. In 2050, DEA scenarios have all the biogas in the system methanated with hydrogen to e-methane with, while in IDA 2050 there is 30 PJ of e-methane 19 PJ of biomethane obtained by biogas purification. The e-methane production in DEA scenarios is increased by four times from 2035 to 2050, in comparison to increase by factor of two in IDA scenario.

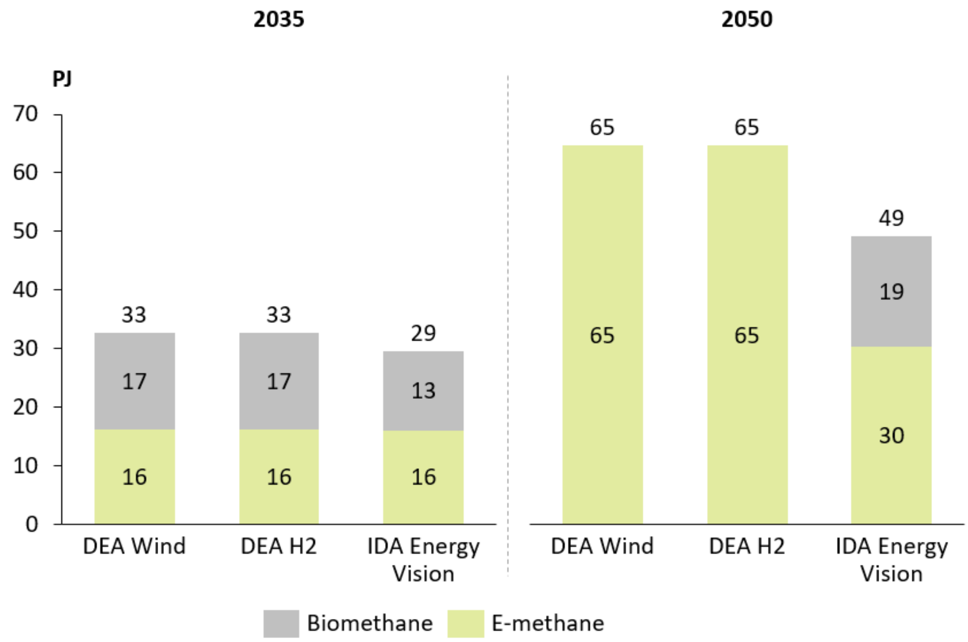

Figure 20. Biomethane and e-methane production

Due to the different electrofuel demands and electrolysis capacity, electricity consumption and hydrogen production vary across the scenarios. The alkaline electrolysis is applied in DEA scenario, with efficiency of 58%$_{LVH}$ and in IDA SOEC electrolysis with 74% $_{LVH}$. It can be seen from Figure 21, that IDA scenarios is more efficient due to the higher electrolysis efficiency getting higher output of hydrogen per electricity stored.

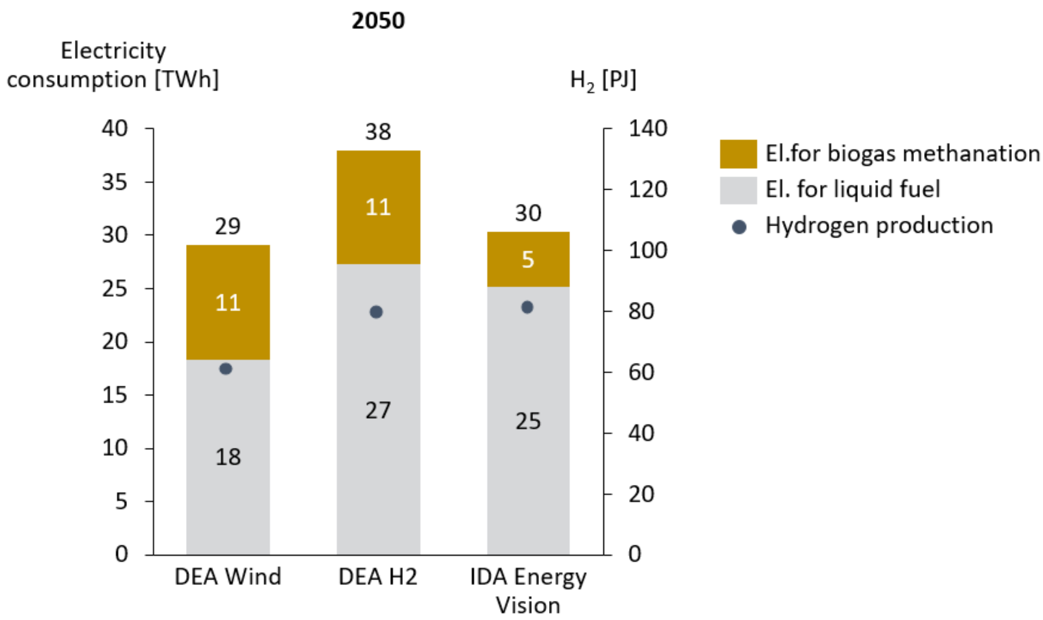

Figure 21. Electricity consumption and corresponding hydrogen production

Determining the e-methane potential from biogas methanation in the EU took a point of the departure in Smart Energy Europe scenario [30]. Smart Energy Europe is a scenario for a 100% renewable energy in Europe by the year 2050. As the original scenario did not have any biogas capacity in the system, the first step was to integrate the biogas and e-methane in the scenario.

The potential for biogas was adapted from Scarlat *et al* [5], and 0.16 TWh of biogas was implemented in the system. This scenario illustrates the case that the whole biogas potential from manure is methanated with hydrogen addition to e-methane. With this input of biogas in the system 0.21 TWh of e-methane was generated.

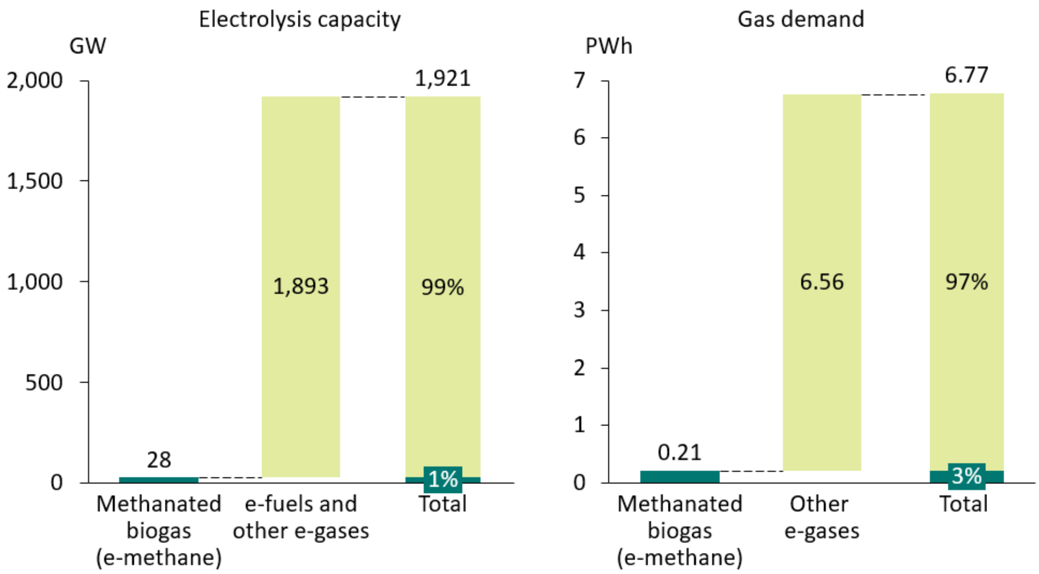

Figure 22. E-methane shares in the Smart Energy Europe 2050 in terms of electrolysis capacity and gas demands

From the Figure 22 we can see that the e-methane has a very small share in the total gas demand in the European energy system. The electrolysis share for the e-methane production is even lower and represents only 1% of the total electrolysis capacity in the system.

This level of e-methane in the European energy system, represents the level of 1.4 GJ/capita, while the levels of e-methane in Danish scenarios are 5-10 times higher per capita.

THE TRANSITION CUVERS FOR TECHNOLOGY IMPLEMENTATION

The transition curves or cumulative growth curves were created in order to determine the required investments for the electrolysis to meet the projections from today to 2050. This approach enables to highlight the time and scale of the proposed long term energy system projections and to illustrate the energy transition needed to reach targeted capacities.

Coupled with the growth of renewable energy towards 100% in 2050, the implementation of electrolysis requires significant expansion rates. It is important to note that all the scenarios rely on the inland production and self-security of supply, meeting all the country needs internally. Therefore in order to produce desired fuels for transport sector or industry, high uptake of electrolysis technology is needed.

The transition curves were created based on the three-system dimensions of transition: speed, size and time period [31]. Depending on the projected capacities in the future, some curves have higher speed of uptake over the shorter period of time.

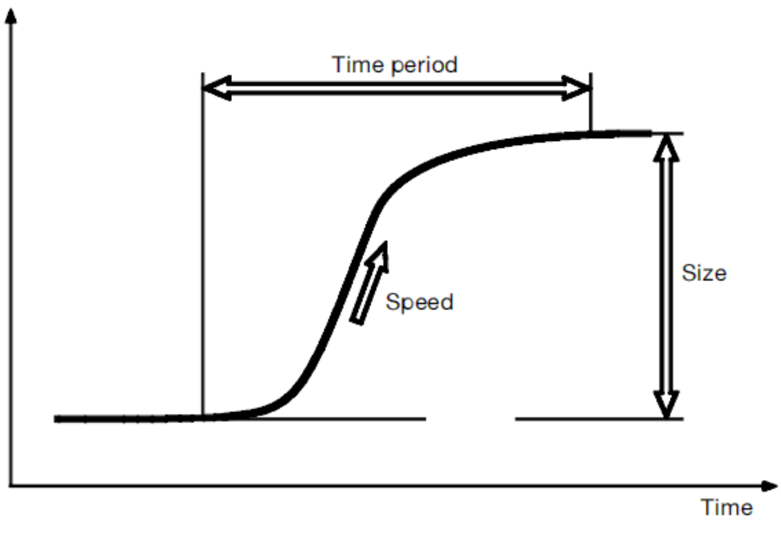

Figure 23. The three system dimensions of transition. Adapted from [31]

INVESTMENT'S PROJECTION FOR ELECTROLYSIS AND BIOGAS METHANATION IN DENMARK

The transition curve for electrolysis capacity from today to 2050 for Denmark is illustrated below. These growth curves enable reaching the projected capacities in 2035 and 2050. Starting from 1MW in 2020 to ~1GW in 2050 in case of e-methane and from 1MW to 5.7 GW in 2050 for liquid e-fuels. The uptake of electrolysis for liquid e-fuels is little bit faster in the first period until 2035 than for e-methane, in order to meet its high capacity in 2050. Stabilisation of capacities occurs after the 2038 where the capacity growth per year starts decreasing. The significant growth in capacities needs to happen in order to meet the high capacities projected for 2050.

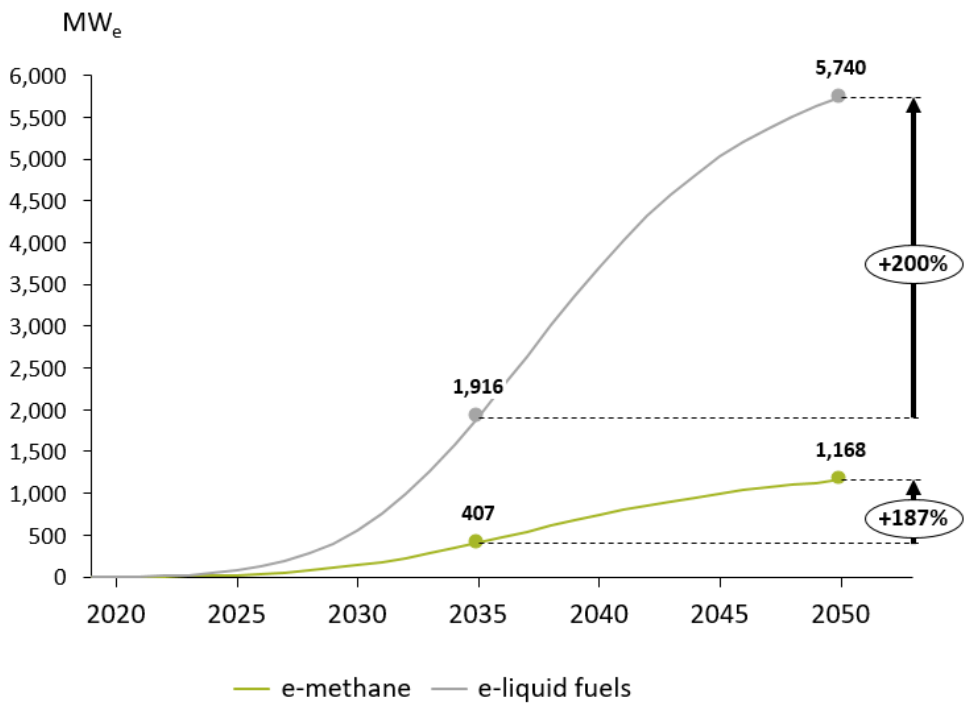

Figure 24. Cumulative growth curves of electrolysis capacities from today to 2050 in IDA

As the aim of this chapter is to focus on the investment strategies for e-methane or biogas methanation, further comparison and results will exclude the liquid e-fuels even though they are playing a major role in the future energy system. E-methane represents around 18% of the total electrolysis capacity both in 2035 and 2050, while the rest of the electrolysers in the system are used for the liquid fuel production mainly for the transport purposes.

The electrolysis capacity for e-methane from biogas methanation are rather similar in IDA and DEA scenarios as illustrated before, but the cumulative growth curves show a different speed of uptake due to the different capacities projected for 2035 and 2050 (see Figure 25). Even though the capacity growth in IDA is steeper in the years prior to 2035, the uptake stabilises a little bit before than DEA scenarios when approaching the year of 2050.

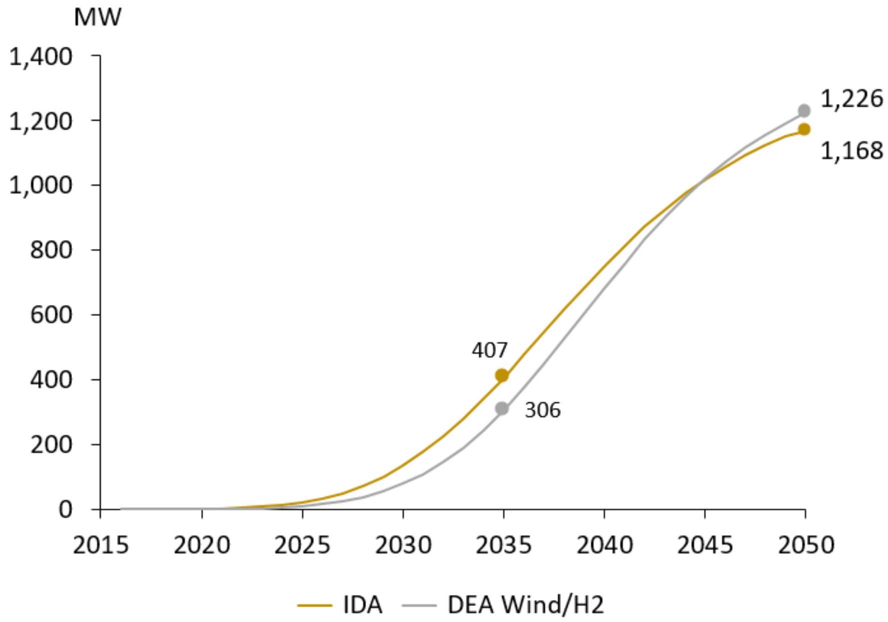

Figure 25. Cumulative growth curves of electrolysis capacity for e-methane production in DEA and IDA scenarios

To illustrate the needed investments for these technologies towards 2050, the price development for alkaline was used in case of DEA scenarios and SOEC price development for IDA scenarios (see Figure 26). All price developments were adapted from [19] and interpolated to reflect year by year price reduction towards 2050. The price reduction in case of SOEC is higher than in the case of alkaline electrolysis, due to the technology development expectations. Alkaline as a more mature technology and material used is expected to have higher costs in the year 2050 than SOEC, even though its starting price today is significantly lower than SOECs.

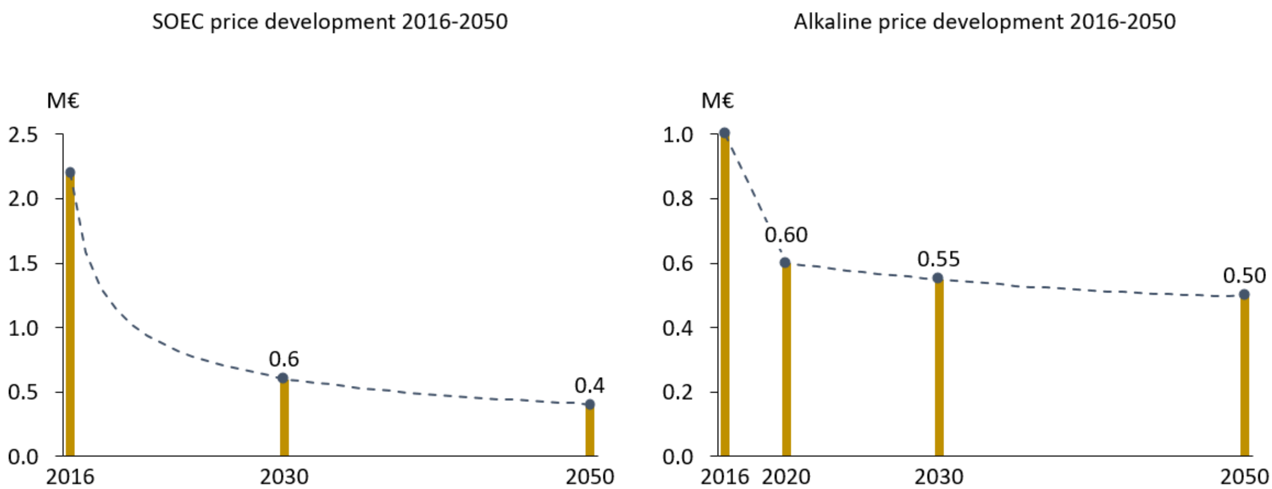

Figure 26.Price development for SOEC and alkaline electrolysis based on [15]

By applying the technology price development and the transition curve for the installed capacity projections it is possible to create the investment per year curve for both IDA and DEA scenarios. It is visible from the Figure 27 that most of the investments in IDA scenario need to be realised before 2036, and in case of DEA scenarios prior to reaching 2040. While IDA projection has higher costs until 2035, the DEA electrolysis investment costs increases and remains higher until 2050. The investments in DEA scenarios are higher due to the different transition curves and the cost projection change after 2030 for alkaline in comparison to SOEC.

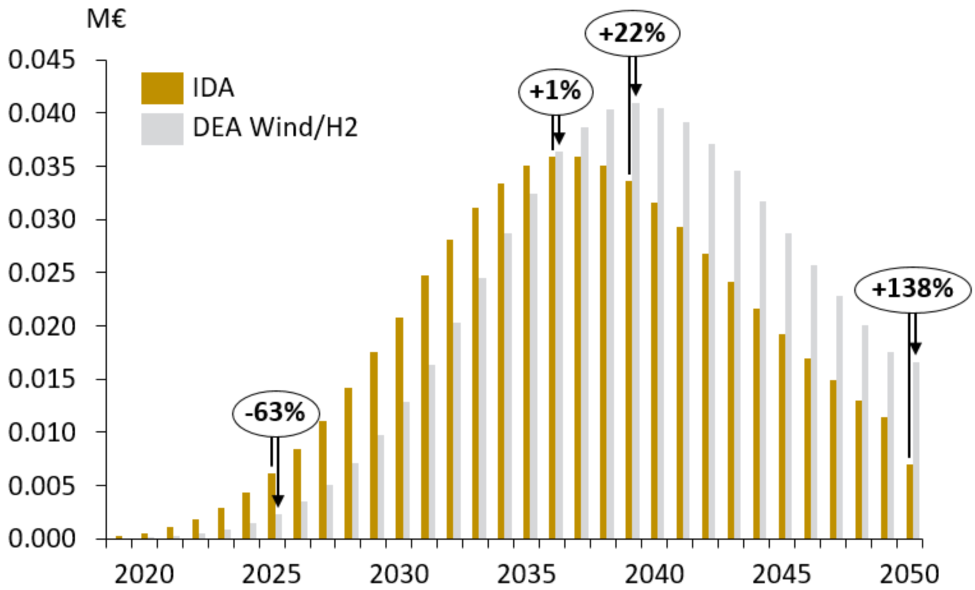

Figure 27. Electrolysis investment per year curve for IDA and DEA projections from today to 2050

The more detailed overview on biogas methanation investments and the sensitivity analysis of the costs will be presented only for IDA scenario. The price development for the methanation units was adapted from Brynolf *et al* [20] where the costs decrease from 0.9 M€/MW in 2016 to 0.2 M€/MW in 2050. The curve for the price development was created by interpolation of the available data points towards 2050. This cost distribution was applied to account for the investments needed in the biogas methanation itself.

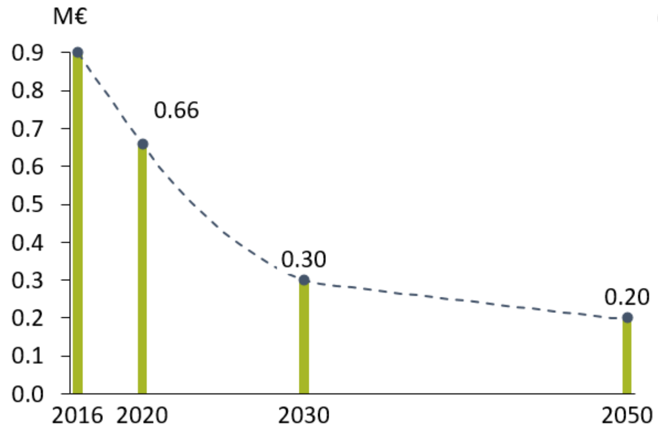

Figure 28. Price development for the methanation units based on [20]

The cumulative growth curve for the biogas methanation and the related costs are illustrated in Figure 29, the uptake speed is lower than in the case of electrolysis as well as the investment levels per year. The capacity needed in 2035 is little bit lower than half of the anticipated capacity in 2050, making the uptake after 2035 a bit steeper. The investment levels in the biogas methanation units are lower by almost half of the investments needed in the electrolysis units.

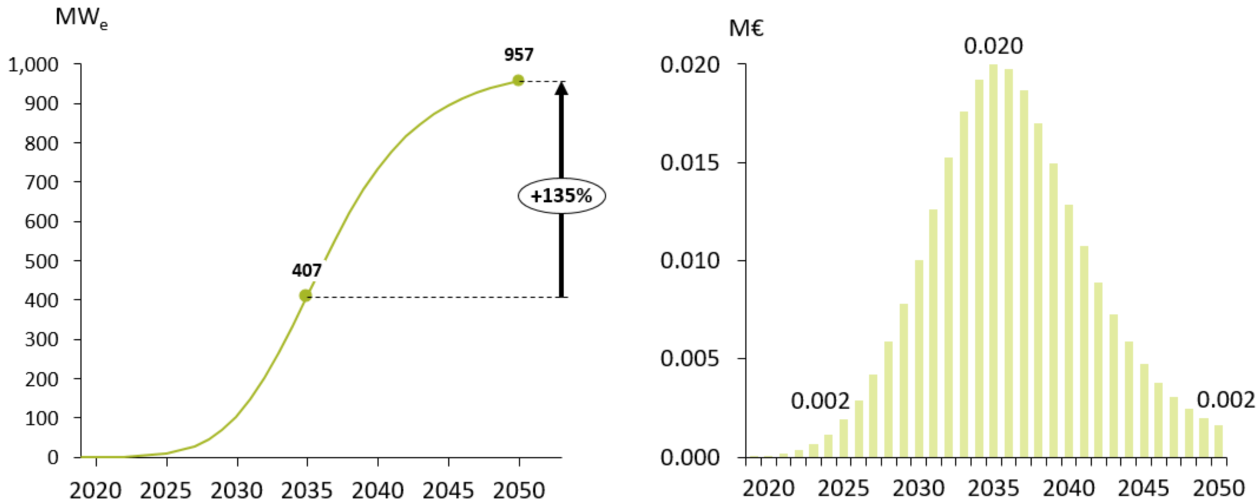

Figure 29.Transition curve for methanation capacity (cumulative growth curve) and the related investment per year curve for IDA.

Sensitivity analysis included increasing the cost for electrolysis in the IDA scenarios by 50% in 2030 and 2050. This resulted in distributed cost increase over the whole period of time as the costs levels evenly distributed over the years (see Figure 30).

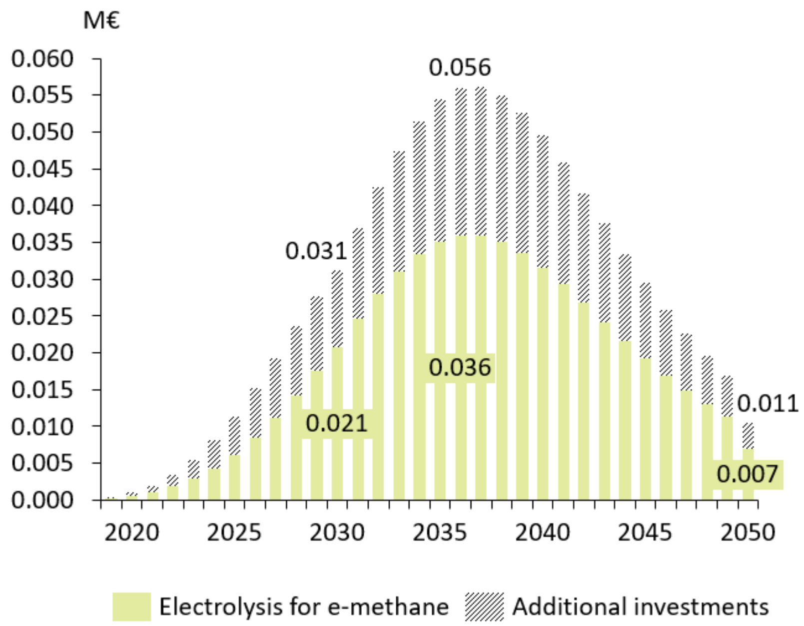

Figure 30. Cost change in case of price increase of electrolysis by 50% in 2030 and 2050 for IDA scenario

It was furthermore investigated how the investments would be influenced if IDA scenarios were using alkaline electrolysis instead of SOEC. Firstly electrolysis capacity needs to be adjusted due to the different efficiency of electrolysers resulting in increasing the capacity by 14% in 2035 and 16% in 2050 to compensate for the efficiency decrease (Figure 31). As alkaline electrolysis is significantly cheaper until 2030, even with the higher capacity it can result in savings in comparison to SOEC, but around the year of 2030 it becomes cheaper to invest in SOEC.

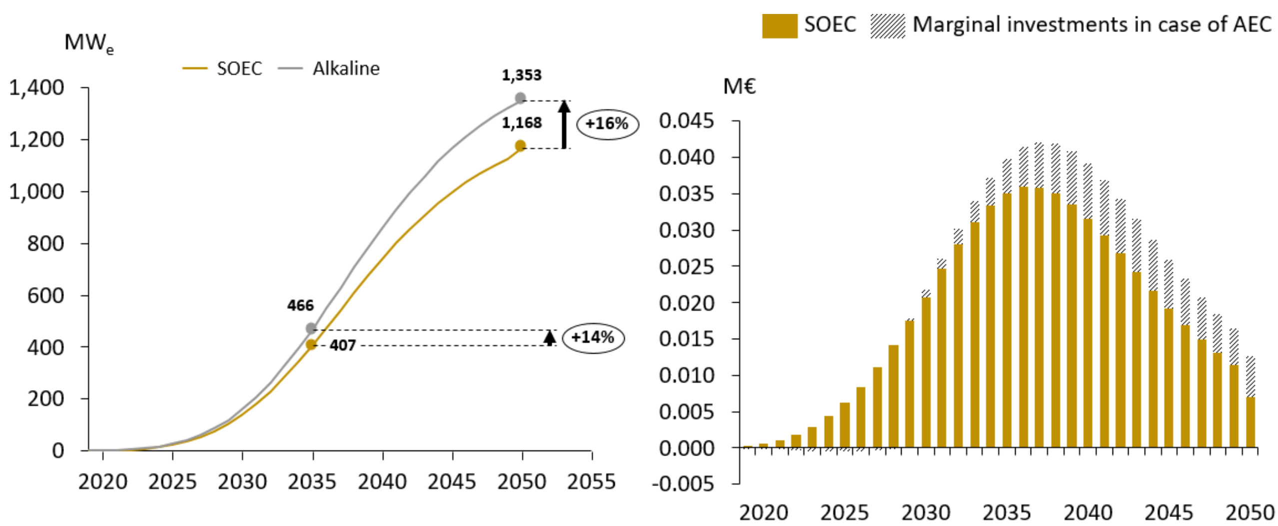

Figure 31. Cumulative growth capacity curves and cost difference of investments in alkaline versus SOEC

INVESTMENT'S PROJECTION FOR ELECTROLYSIS AND BIOGAS METHANATION IN EU

The same methodology, as for the Danish case, with transition curve and cost developments was applied for the EU analysis. The figure below presents the growth curve and the yearly investments in the electrolysis for biogas methanation.

The transition curve for the electrolysis capacity needed for producing e-methane is rather steep, much steeper than in the case of Denmark. The investments peak in 2038 with 1.1 M€ and decline afterwards. This is around 30 times more than the investment needed in Denmark to achieve the e-methane levels projected.

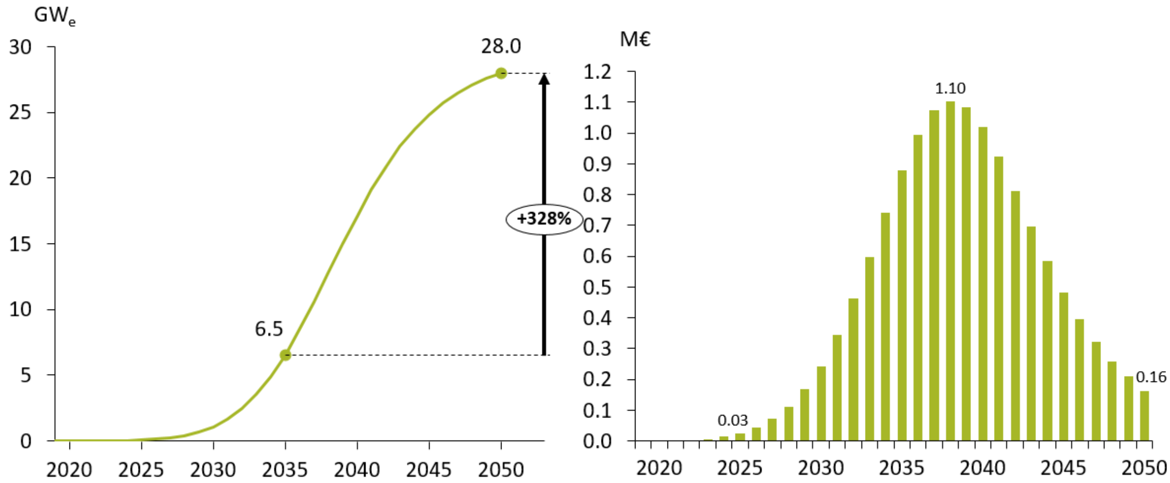

Figure 32. Investments in the electrolysis for e-methane in EU until year of 2050

Sensitivity analysis shows that the increase in electrolysis cost by 50% in 2030 and 2050 rises the investments significantly. Therefore the importance of technology cost reduction is crucial for maximizing its application in the future.

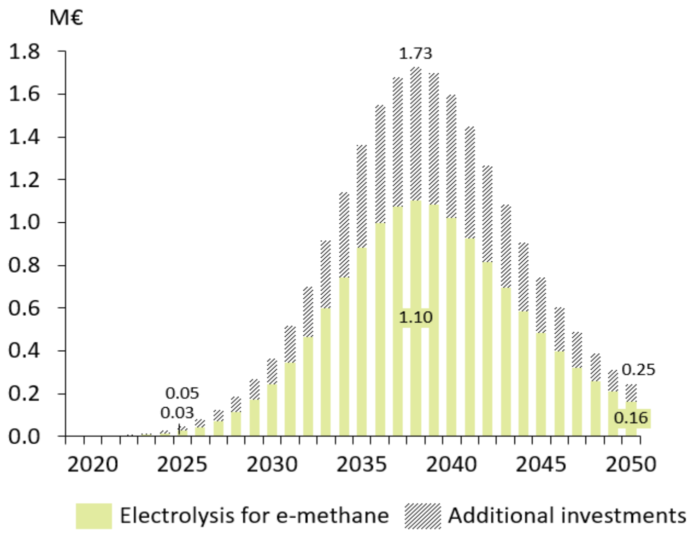

Figure 33. Cost change in case of price increase for electrolysis of 50% in 2030 and 2050 for EU scenario

The same trend is visible for the methanation capacity and the investment level needed as illustrated below.

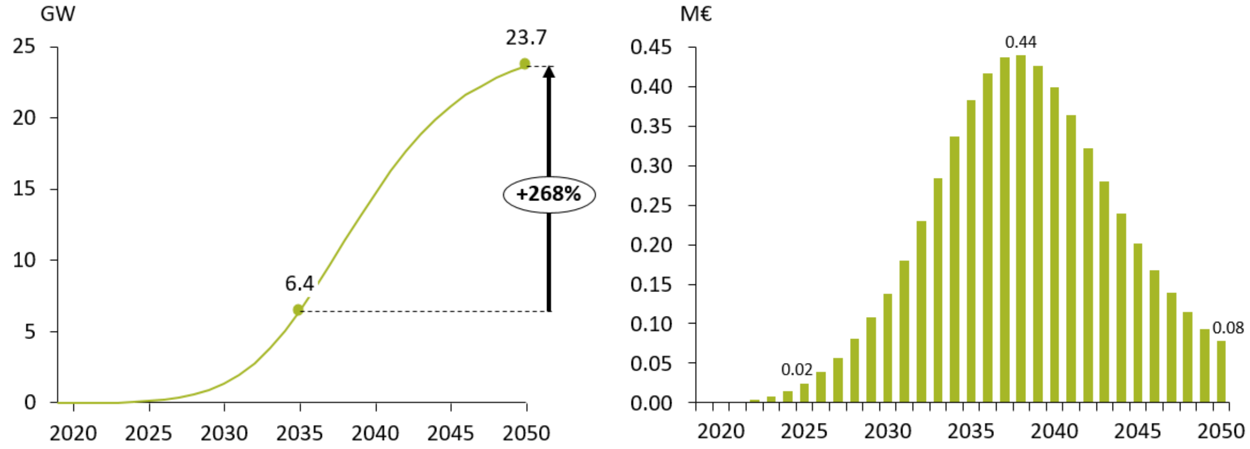

Figure 34. Transition curve for methanation capacity and the related investment per year curve for Smart Energy Europe

In comparison to the Smart Energy Europe scenario where there is no utilisation of biogas, implementation of biogas methanation results in same levels of bioenergy, with minimal cost increase of 0.1%. It also enables the reduction of the electrolysis capacity by 7 GW needed in the whole system as it has displaced the e-gas produced by methanation of gasified biomass.

The capacities analysed in the Smart Energy Europe scenarios are significantly lower than the capacities analysed by other researchers, where power-to-methane capacities reach up to ~550 GW in EU [32]. There is no doubt that the potential for this technology is high, however it is a question is the technology development and application pace capable to deliver high projected capacity.

DISCUSSION AND CONCLUSION

The sections aims to summarize the purpose of this chapter and to discuss is this type of technology growth feasible.

The transition towards 100% renewable energy systems in countries around the world require the fast growth of renewable technologies and storage capacities. In this chapter, the aim was to create cumulative growth curves for electrolysis and methanation that will support the transition towards the 100% renewable energy system. Further the growth curves were linked to the needed investments to obtain the capacity levels in the energy system modelling scenarios for 2035 and 2050. Similar type of analysis was done by [33], which points out that historically most of the technological growth curves are following S-shape growth.

Most of the electrolysers currently installed are part of the demo projects. Majority of the installed capacity are alkaline or PEM electrolysers, while there is still small share of SOECs even in the demonstration projects (Figure 35). With the total of

82.7 MW of the installed capacity and 172 demonstration projects this represents on average 0.5 MW per project. In relation to these levels it is clear that there is a need for steep growth curves to reach the targeted capacity from energy system analysis scenarios.

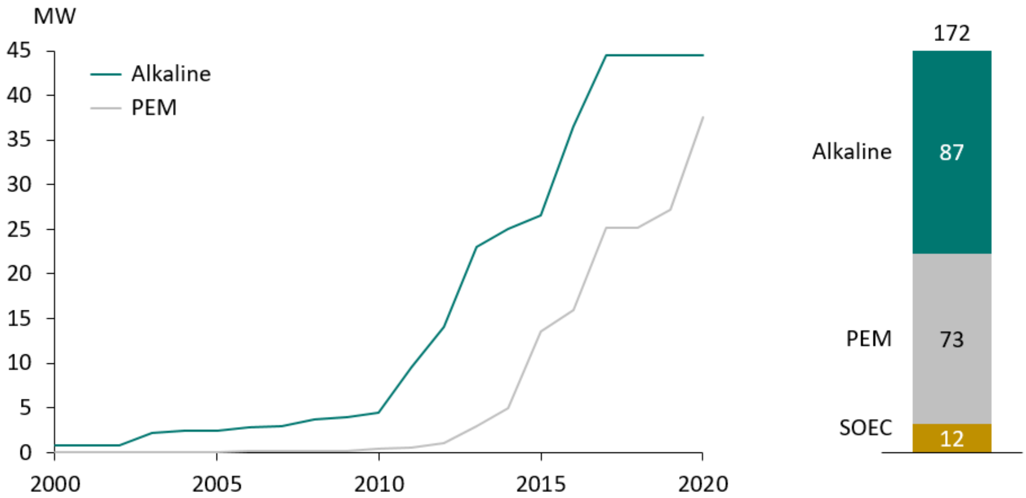

Figure 35. Cumulative electrolysis capacity installed in MW and number of demo projects per type of electrolysis. Adapted from [34]

Developed curves can be supplemented with investigating the possibility of producing these capacity levels in the proposed time frame and available resources. Smolinka *et al* [35] investigated electrolysis component demand. It is concluded that it is critical to reduce the amount of raw materials needed per kW of the installed capacity especially when it comes to PEM electrolysis. The Danish future scenarios include only alkaline or SOEC and Smart Energy Europe scenario includes only SOEC. Therefore the material concerns are not so critical. However, as the high temperature electrolysis is still on the early phase of commercialization this technology brings the biggest uncertainties when it comes to the future development. The future analysis could involve scenarios with the mix of different electrolysis technologies for reaching the hydrogen demand projected for 2035 and 2050 in order to eliminate the high dependency on the individual technology to deliver the high capacity needed. The results from energy system analysis with mix of electrolysis technology will lead towards increase in the electrolysis capacities, higher costs and higher electricity demand as both alkaline and PEM electrolysis have lower efficiency than SOEC. Similarly, the costs would increase as it was shown in the chapter when substituting SOEC with alkaline electrolysis due to the different investment projection levels. Technology mix would also result in a different component requirements and give more realistic market representation.

In order to reach the high capacities in the future, it is also important that the policy as well as the investment strategies are adjusted to the specific characteristic of different technologies and how they fit into the rest of the energy systems and goals that are planned to be achieved. Neij *et al* [36] assessed experience curves as a tool for policy assessment suggesting that these could be used as a complementary methods when looking into needed policies for any energy technology. As the study was based on the wind power that has experienced high growth, the outcomes of this study could be relevant when developing policies for the implementation of electrolysis. One thing is clear and that is that RD&D programmes are not enough and that there is a need for market pull measures in order to maximise the production and the use of new technologies.

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