Biogas, Biomethane and Electro-methane cost comparison

REPORT

TSP Report
December 2019

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Hørsholm 2019

Title	:	Biogas, Biomethane and Electro-methane cost comparison
Report Category	:	TSP Report
Author	:	Johan Bruun, Torben Kvist and Henrik Iskov
Date of issue	:	20.12.2019
Copyright	:	Danish Gas Technology Centre
File Number	:	417-20; h:\417\20 smart grid\p2g report\rapport\electrolyser and methanisation economics_final.docx

Table of Contents **Page**

1 Results and conclusion

This report gives an overview of cost and maturity of the technologies used for production of electro-methane.
Electro-methane: $CO_2 + 2H_2O$ + power → CH_4 (plus some oxygen)

Results, discussion and conclusions are presented in this section and further details can be found in the subsequent sections.

Cost estimates for electro-methane are made based on a literature study covering electrolysis, methanation and electricity prices. The hydrogen production cost dominates the total cost where electricity prices and efficiency are the key factors.
In 2020, the estimated production cost for electro-methane is found to be within 1200 – 1600 DKK_{2020}/MWh for alkaline, PEM and SOEC electrolysis. Alkaline electrolysis is currently the most cost-effective process for hydrogen production.
For comparison, the production cost of biomethane is estimated to be ~540 DKK/MWh as of today.

Main drivers for electro-methane to become relevant is lower electricity prices, integration with downstream market and reduced investment cost. Sensitivity calculations to electricity prices and potential revenue from excess heat and oxygen has been conducted. It was found that electro-methane can become cost-competitive to biomethane in a future scenario (2030) if average electricity prices (incl. transmission) are in the range of 120 DKK/MWh and revenues are made on excess heat and oxygen from the process. This could drive down the electro-methane production cost to 450 – 600 DKK_{2020}/MWh. This is in the same range as biomethane.

In section 4-3, the production cost of hydrogen is shown as a function of operating hours. It is shown that it is not cost effective to run an electrolysis plant for less than 1000 – 2000 hours. At least 3000 operating hours must be achieved to obtain an economically efficient production process given the relatively high CAPEX of the facility. Electricity prices in 2018 would only have allowed for operation in 100 hours to achieve an average price of 120 DKK/MWh (400 hours if transmission cost is neglected). The aggressive expansion of renewable energy in Northern Europe can maybe drive electricity prices down to an acceptable level and if also transmission cost is reduced significantly, the electricity price could allow electro-methane to become cost-competitive compared to biomethane.

In this report, the assumed investment costs for electrolysis and methanation are base case estimates. The investment costs found in the literature suggest a wide range. Using the lowest estimates on CAPEX would make a better business case but as the investment cost only constitutes 20 – 30 % of the total gas production cost, this is not expected to be able to change the conclusions.

An EUDP project managed by Haldor Topsøe concerning electrical upgrading of biogas was submitted in February 2018 (1). In this project, biogas was upgraded in a Sabatier methanation unit and SOEC electrolysis was used for hydrogen production. In the project report, PlanEnergi analysed the economics from a private investor perspective. With the following assumptions, it is concluded that electro-methane production can be economical:

- The electricity price to the SOEC is no higher than 250-350 DKK/MWh on an annual average basis
- The produced SNG can be sold at a price of 6.00 DKK/Nm^3 or higher
- The steam output from the methanation is utilized as an input for the SOEC process
- The SOEC unit should operate at full load for 4600 – 4800 hours per year where the average weighted electricity price is 109 DKK/MWh

The assumed CAPEX and OPEX for the SOEC plant are lower compared to the figures used in this report and the efficiencies for the SOEC process is higher (97.4%). Furthermore, the biogas fed to the process constitutes of 60% CH_4 and 40% CO_2. The purchase cost of biogas is assumed to 3.25 DKK/Nm^3 (~550 DKK/MWh). The methane molecules from the biogas are included in the final production cost of electro-methane and damp the higher cost of the electrolysis and methanation processes.

Accepting the above assumptions and the slight differences in the way the economics are calculated, the authors of this report arrive at a similar conclusion for the cost of electro-methane.

This report shows that for electro-methane to become relevant, many things must interact favourably in reducing the cost. Most importantly electricity prices must be reduced significantly. Furthermore, production of excess heat and oxygen has to be capitalized. Finally, the CAPEX must be reduced. If all these things are realised, electro-methane could play an important role in the future renewable energy system.

2 Introduction

The purpose of the present report is to compare the cost for producing either biogas (60% CH_4 and 40% CO_2), upgraded biogas (biomethane) or electro-methane. The focus of the report will be on the cost of electro-methane as the other technologies are more mature and well documented. Cost for biogas production and upgrading are, therefore, only treated.

Biogas is gas produced from anaerobic digestion of e.g. manure, household waste or other types of organic material.
Biomethane is upgraded biogas where CO_2, sulphur and other impurities are removed. Typically, biomethane is produced with the purpose of injection into the natural gas distribution or transmission grid.

Electro-methane is methane produced from CO_2 and H_2 by methanation. Today, CO_2 is a waste product from biomethane production and by combining this CO_2 and H_2 from electrolysis in a methanation reactor, electro-methane can be produced.

In general, the year 2020 is used as basis year for all economic calculations if not stated otherwise. Inflation of 2 % is used in calculations to get the 2020-cost.

3 Biogas and biomethane

Biogas is produced by anaerobic digestion of organic materials. Biogas systems use anaerobic digestion to recycle these organic materials, turning them into energy (biogas) and valuable soil products (liquids and solids), see Figure 3-1.

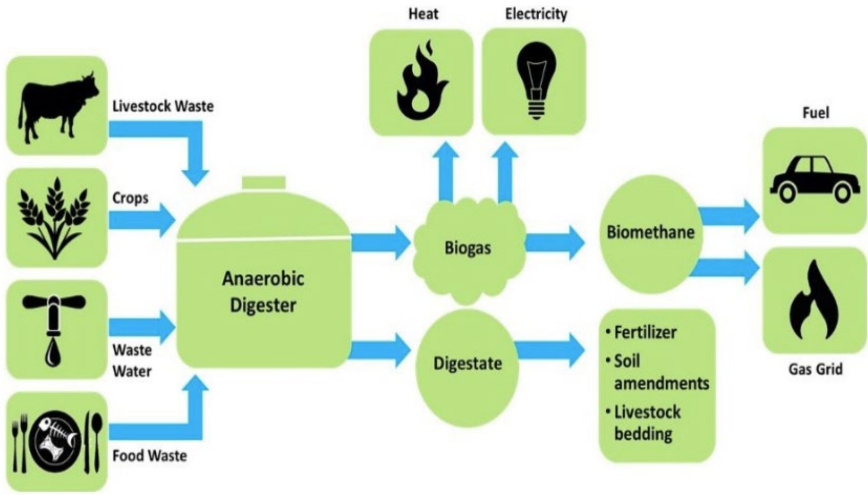

Figure 3-1 Anaerobic digestion process (2).

A typical biogas composition consists of ~60% CH_4, ~40% CO_2 and low concentrations of oxygen, nitrogen and sulphur compounds (primarily H_2S).

3.1 Estimated cost of biogas and biomethane production

A report concerning application of biogas for electricity and heat production by Ea Energianalyse (3) has been used to estimate the production cost of biogas. The upgrading cost is based on a DGC study from 2018 (4).

In the report by Ea Energianalyse (3), the production cost for biogas and biomethane (including purchase of biomass and transport) is estimated.
The estimated cost for biogas is reported to be in the range of 2.6 – 3.2[1] DKK/Nm^3 (400-490 DKK/MWh). Biogas is most often upgraded to a quality level which is suited for injection into the natural gas grid but there are also several cases where biogas is used directly in gas engines.

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[1] Assumed lower heating value for biogas (65 % CH4 and 35 % CO2) at 23.3 MJ/Nm^3, Gasfakta.dk.

DGC has recently investigated the cost for upgrading, and the cost for larger plants was found to be approx. 0.6 DKK/Nm^3 CH_4 (4). Adding this cost to the cost for biogas results in a biomethane cost of 4.6 – 5.5 DKK/Nm^3 CH_4 (460 – 550 DKK/MWh) dependent on the type of organic material used and production setup. Same approximate cost figures for biomethane are reported in the study by Ea Energianalyse (3).

The approximate cost figures for biogas and biomethane are used later for comparison to the production cost of electro-methane.

4 Electro-methane (Synthetic Natural Gas, SNG)

Production of hydrogen by electrolysis of water and synthetic natural gas (SNG) from methanation are the two core building blocks of power-to-gas (P2G).

A literature study of the electrolyser and methanation technology is presented along with cost estimates for the different technologies.
This forms the basis for an estimate of the production cost of electro-methane. The cost of electro-methane is compared to the cost of biomethane and biogas.

4.1 Background

As large-scale storage of fluctuating renewable energy will be an important part of the future energy system, hydrogen production and storage capacity are expected to be necessary. Scenario calculations (5) for the North European countries indicate that several GW_e electrolyser capacity and sufficient seasonal underground storage capacity may be needed sometime after 2030. Figure 4-1 shows that in 2035, 24 TWh may be consumed by PtX applications in Denmark alone based on a forecast by Energinet. Assuming 4000 equivalent full load operation hours per year, this corresponds to an electrolyser capacity of 6 GW_e.

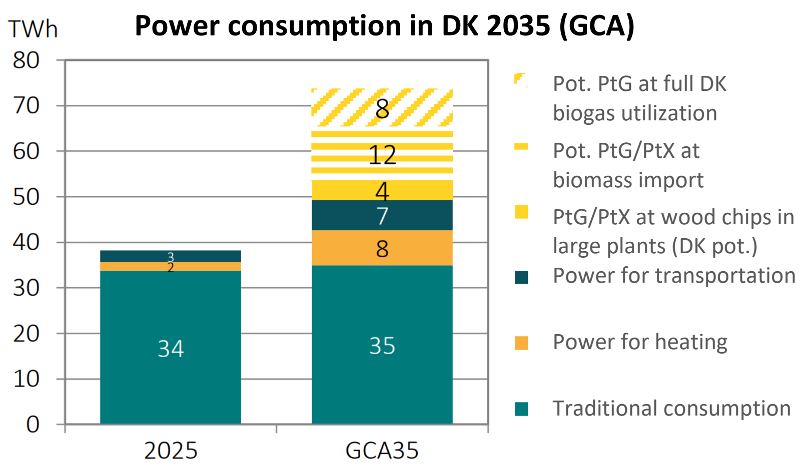

Figure 4-1 Power consumption in Denmark 2035 for a likely scenario in the report System perspectives 2035 by Energinet (5).

4.2 Electrolysers

There are three types of electrolysers, two of which are commercially available, PEM and alkaline. The maturity of the third type, solid oxide electrolyser (SOEC), is currently at laboratory/pilot stage.

4.2.1 Alkaline and PEM electrolysers

The alkaline type is the traditional type used in the process industry for more than 100 years. Figure 4-2 illustrates the alkaline cathode/anode reactions and an example of an electrolyser unit.

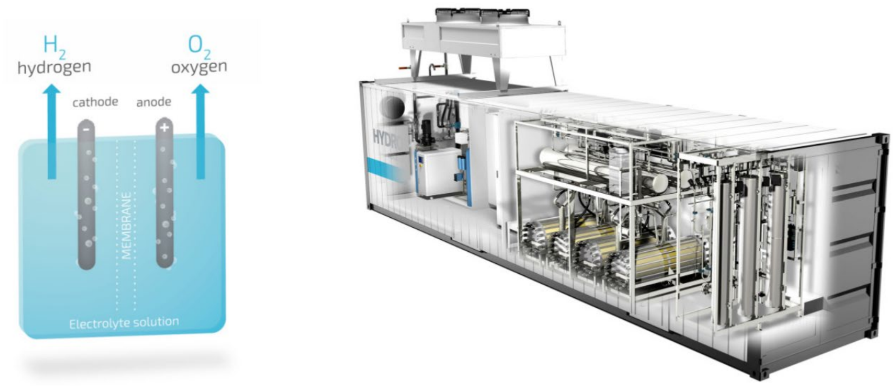

Figure 4-2 Representation of the water electrolysis reaction and example of a 60 Nm³/h electrolyser unit (6).

Compared to the new PEM type, alkaline electrolysis is much more space demanding. PEM has been commercial for around 30 years in sizes up to 100 kW (electric input), and alkaline has been available in stack sizes up to around 3 MW. In the last few years, a number of large-size (0.5 – 6 MW electric input) demonstration plants based on PEM technology have been tested for P2G applications in northern Europe, mainly Germany and Denmark. The PEM-based plants have shown efficiencies at the same level as alkaline electrolysis and the main advantages of the PEM technology is faster cold starts, higher flexibility and better coupling with dynamic and intermittent systems (7).

See Table 4-1 for reported parameters for alkaline electrolysis and PEM electrolysis.

Table 4-1 Overview on commercially available types of electrolysers, Alkaline (ALK) and proton exchange membrane electrolysis (PEM) (8).

		ALK						PEM					
		2017 @ P atm			2025 @ 15 bar			2017 @ 30 bar			2025 @ 60 bar		
Nominal Power	UNITS	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW	1 MW	5 MW	20 MW
Minimum power	% Pnom	15%			10%			5%			0%		
Peak power – for 10 min	% Pnom	100%			100%			160%			200%		
Pressure output	Bar	0 bar			15 bar			30 bar			60 bar		
Power consumption @ P nom	kWhe/kg	58	52	51	55	50	49	63	61	58	54	53	52
Water consumption	L/kg	15 L/kg											
Lifetime – System	Years	20 years											
Lifetime – Stack @ full charge	hr	80 000 h			90 000 h			40 000 h			50 000 h		
Degradation – System	%/1000 h	0,13%/ 1000 h			0,11%/ 1000 h			0,25%/ 1000 h			0,20%/ 1000 h		
Availability	%/year	>98%											
CAPEX – Total system Equipment	€/kW	1200	830	750	900	600	480	1500	1300	1200	1000	900	700
OPEX – Electrolyser system	%CAPEX	4%	3%	2%	4%	3%	2%	4%	3%	2%	4%	3%	2%
CAPEX – Stack replacement	€/kW	420	415	338	315	300	216	525	455	420	300	270	210

Estimates for CAPEX and OPEX are also stated in reference (8). The 2017 costs for a 10 MW alkaline og PEM electrolyser are estimated to ~60 million DKK and ~90 million DKK, respectively. Other authors have reported the same CAPEX range (500 – 1000 €/kW for alkaline) (9), (10). The lifetime of the electrolyser stacks is estimated to be 80,000 hours for the alkaline types and 40,000 hours for the PEM types.

Table 4-2 shows that the load range is wider and response time is faster for PEM electrolysers than for atmospheric alkaline electrolysers. Pressurized alkaline electrolysers do have a similar fast response time, but they are only available with small electrolyser stacks – up to around 100 kW_e. The reason is that large diameter pressurized alkaline stacks must be designed with very thick, heavy and costly steel plates to withstand the pressure.

Table 4-2 Dynamic performance of commercial electrolysers (8).

2017	ALK	PEM
Load range	15-100% nom. load	0-160% nom. load
Start-up	1 - 10 minutes	1 sec - 5 minutes
Ramp-up	0,2 - 20 % /s	100% /s
Ramp-down	0,2 - 20 % /s	100% /s
Shut down	1 - 10 minutes	Seconds

4.2.2 SOEC electrolyser

Compared to the other electrolyser technologies, SOEC is not a mature technology. TRL (Technical Readiness Level) is around 5 (11). SOEC technology is being tested and demonstrated in laboratories and a few pilot plants in Germany and Denmark. The potential is large due to high efficiencies. Limitations in the technology are scale-up possibilities and durability of electrolyser stacks. Lifetime is limited, due to the high operating temperature which leads to fast material degradation and limited long-term stability (11). Only small units in the kW size have been demonstrated. Furthermore, the technology is based on ceramic plates in the cell stack working at high temperatures around 600 – 800 °C, and it has not yet been demonstrated that it is possible to scale up these ceramic cell plates. Temperature related stress and corrosion are among the problems. Scalability is very important in the future energy system as there may be installed several GW_e in units of perhaps 100 MW_e each (5). Today, a typical SOEC stack is below 5 kW and stack lifetime is far below the alternative electrolyser technologies.

The SOEC technology is not commercial today – neither in kW_e nor the MW_e range, and this means that no valid economic data on SOEC is available today. The Danish Energy Agency has published predictions for the future economic data on SOEC (12), see Figure 4-3. The background for this impressive development is (quote from (12)): “The projection is based on the assumptions that major technological challenges are overcome by 2020 or shortly thereafter, to an extend which enables targeting an emerging and growing market in the period 2020-2030 resulting in an annual production volume of SOEC plants of ~300 MW per year (by 2030).”

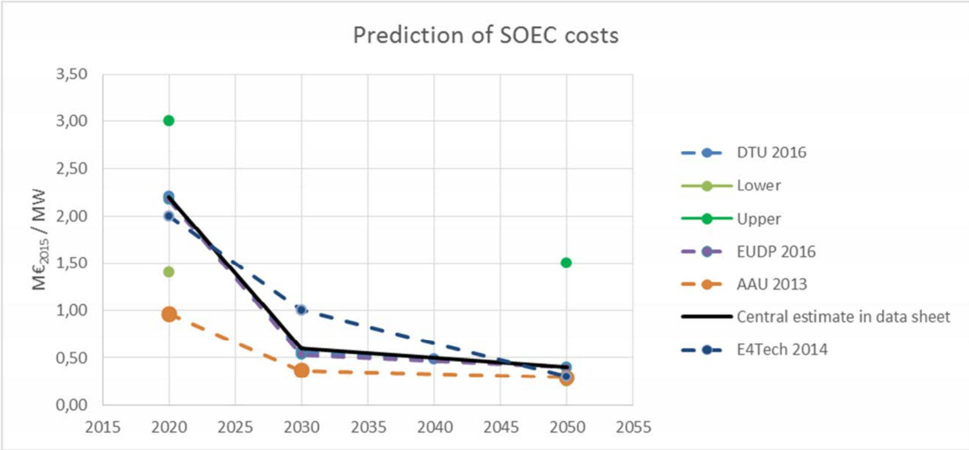

Figure 4-3 Expected development of SOEC plant costs (12).

Figure 4-3 shows the predictions for the development in SOEC costs. The actual market price will be higher in order to cover the large development costs, marketing, warranties and service costs.

The question is whether the assumed timeline for cost reduction is realistic or not. Comparing with fuel cell development the last 30 years indicate that the assumptions behind the SOEC predictions may be rather optimistic.

4.2.3 Economics of hydrogen production

Based on the Technology Catalogue (12) OPEX and CAPEX for Alkaline, PEM and SOEC electrolyser technologies have been estimated. The reported costs have been compared to other reports and seem relatively optimistic for some parameters, e.g. for alkaline electrolysers, the lifetime is assumed to be 25 years and the CAPEX is assumed to be 600 €/kW_e, whereas other reports assume 800 – 3000 €/kW_e (8), (10), (7).

The electricity price is a major factor in evaluating the cost for electrolysers. Figure 4-4 shows the electricity spot price in 2018 for Western Denmark. The average spot price was 328 DKK/MWh.

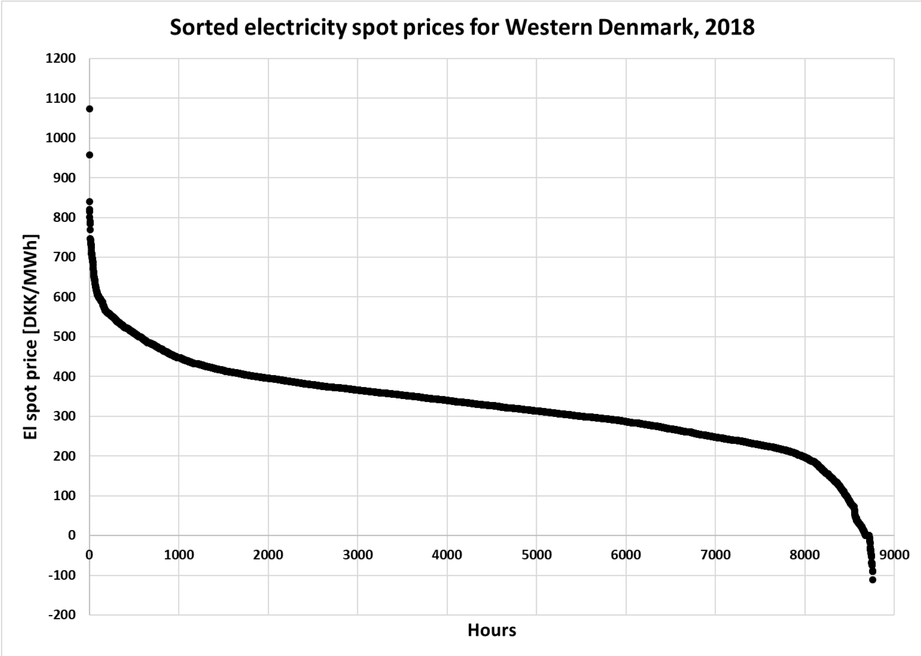

Figure 4-4 Spot prices for electricity in Western Denmark, 2018 (13).

Even though it is very difficult to predict the future prices for electricity, the forecast prices by Energinet is 248 DKK/MWh and 370 DKK/MWh in 2020 and 2030[2], respectively (14). For the following calculation examples in Table 4-3 it is assumed that the electrolyser operates in the 6000 hours with the lowest spot price. This results in average spot prices of 223 DKK/MWh and 341 DKK/MWh in 2020 and 2030, respectively. Assuming that the PSO-tariff is removed and that the total transmission cost is 70 DKK/MWh, the industry electricity price is 293 DKK_{2020}/MWh and 411 DKK_{2020}/MWh in 2020 and 2030, respectively.

A calculation of the production cost for hydrogen is shown in Table 4-3 for alkaline, PEM and SOEC electrolysis. The electrolyser in the below table all have the same hydrogen production capacity, which fits with the methaniser discussed in the next section.

[2] The 2030 cost for electricity is back-calculated to 2020-prices as 2020 is the reference year for the economic figures of this report if not stated otherwise.

Table 4-3 Calculation of production cost for hydrogen using alkaline, PEM[3] or SOEC electrolysis.

	Alkaline		PEM		SOEC			
Year	2020	2030	2020	2030	2020	2030	Unit	Comments/references
Economic assumptions								
Interest rate	5%	5%	5%	5%	5%	5%		
Exchange rate	7,45	7,45	7,45	7,45	7,45	7,45	DKK/EUR	
Technical assumptions								
Electrolyser capacity	10,2	9,9	11,2	10,5	7,3	7,0	MW_e	
Technical lifetime	25	25	15	15	20	20	years	Tech. Cat. Assumptions (12)
LHV Hydrogen	10,8	10,8	10,8	10,8	10,8	10,8	MJ/Nm^3	
Oprating hours	6000	6000	6000	6000	6000	6000	hrs/yr	
Conversion efficiency	63,9%	65,9%	58,0%	62,0%	89,0%	93,0%	$H_{2, LHV}/MW_e$	Tech. Cat. Assumptions (12)
Electricity cost*	293	411	293	411	293	411	DKK/MWh	
H_2 production	13,0	13,0	13,0	13,0	13,0	13,0	M Nm^3/year	
Investments and cost								
CAPEX*	50,2	44,8	101,3	51,8	132,1	34,5	M DKK	Tech. Cat. Assumptions (12)
Annualised CAPEX	3,6	3,2	9,8	5,0	10,6	2,8	MDKK/year	
OPEX*	2,5	2,2	4,6	2,4	5,5	1,5	MDKK/year	Tech. Cat. Assumptions (12)
Electricity cost*	17,8	24,4	19,7	25,9	12,8	17,3	MDKK/year	
Cost per Nm^3 H_2	**1,84**	**2,29**	**2,62**	**2,56**	**2,23**	**1,65**	**DKK/Nm^3 H_2**	

* Back-calculated to 2020 as basis year with 2% inflation

The alkaline production price of hydrogen from a large-scale electrolyser is calculated to be 1.84 DKK_{2020}/Nm^3 in 2020 and 2.29 DKK_{2020}/Nm^3 in 2030. As mentioned, the investment cost estimates from the Technology Catalogue (12) are comparable to the price estimate for onsite reformers reported in a Belgian study (6). PEM based electrolysers are more expensive, but their dynamic capabilities may counterbalance the higher cost as they are better suited for delivering balancing services to the electric grid.

SOEC electrolysers have a high estimated CAPEX in 2020 but the higher energy efficiency makes the SOEC technology comparable to the other technologies. In 2030, the SOEC production price is lower than alkaline electrolysis when assuming huge progress for the technology, which currently is at lab/pilot plant level. For the SOEC plant it is assumed that the energy for steam production comes from the methanation plant in order to achieve the very high efficiencies.

The production cost for hydrogen is investigated further by calculating the hydrogen production cost per cubic meter gas as a function of operating hours per year for alkaline electrolysis. It is assumed that the electrolyser is running when the electricity spot price is lowest, i.e. if the electrolyser is operating 1000 hours a year, the 1000 hours with the lowest spot price are used. Examples for 2018 (realised spot prices), 2020 (forecast) and 2030 (forecast) are shown in Figure 4-5.

[3] For the PEM electrolysis, grid connection is not part of the stated CAPEX assumption from the Technology Catalogue. For alkaline and SOEC, grid connection is part of the assumed CAPEX.

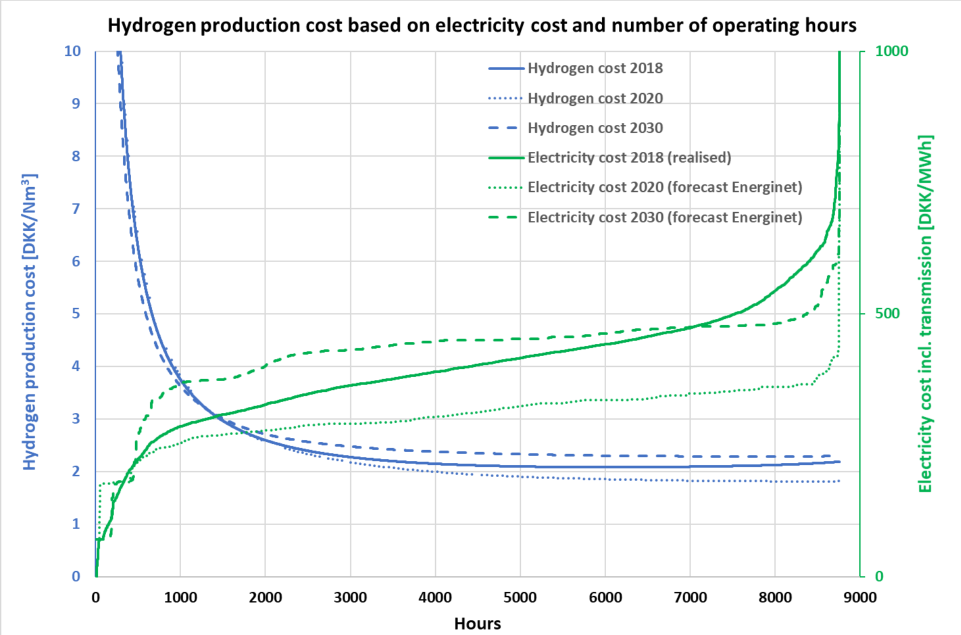

Figure 4-5 The production cost for hydrogen (alkaline) based on electricity cost and number of operating hours.

Figure 4-5 shows that an electrolyser plant must run for a relatively high number of hours in a year to amortize the CAPEX. Operation of a power-to-gas asset running for only 1000 or 2000 hours per year is economically inefficient given the relatively high CAPEX of the facility.

A start/stop analysis has been made for a strategy where the 6000 hours with lowest electricity prices are exploited for hydrogen production. The results from the analysis are shown in Figure 4-6. The analysis shows that the strategy results in ~300 starts during a year of operation. This means that the electrolysis plants need to start and stop almost every day.

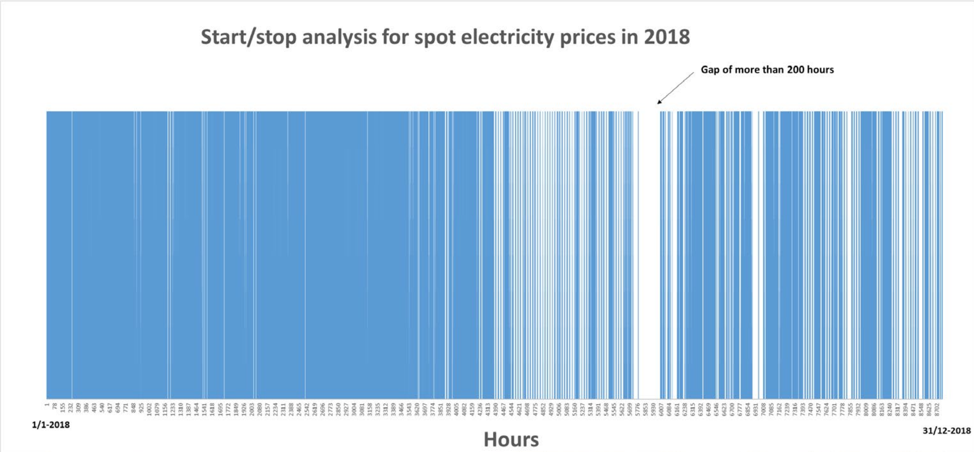

Figure 4-6 Results from start/stop analysis allowing for operation in the 6000 hours with lowest electricity prices (blue means the plant is operating and white means no operation).

Figure 4-7 shows the number of starts per week when using the same assumptions as used in Figure 4-6.

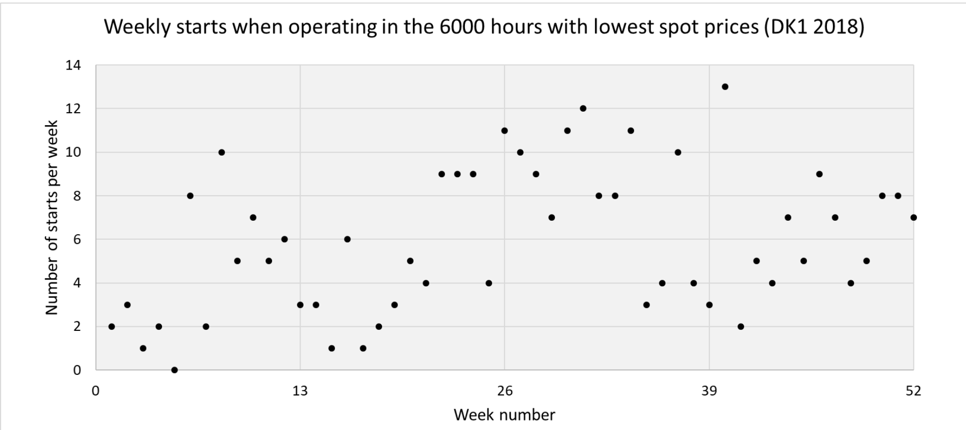

Figure 4-7 Resulting number of starts when operating in the 6000 hours with lowest spot prices in DK1 for 2018.

The analysis also shows that hours with lowest electricity price are not evenly distributed over the year. This has some practical implications when combining the electrolyser with a biogas plant and a methanation reactor. The biogas plant runs steadily throughout the year and a methanation reactor typically has best performance under steady-state conditions. The analysis shows that there is a gap of more than 200 hours where the electricity prices are too high for operating the electrolysis plant, when aiming for the 6000 hours with lowest costs. To overcome this challenge, a hydrogen storage facility can be established but this will also drive the total cost up.

Implications of combining the very dynamic production patterns of the electrolyser with the steady production pattern of a biogas plant and methanation reactors are discussed further in the next section.

4.3 Methanisers

4.3.1 Types of methanisers relevant for P2G

Catalytic methanation has been used in industry for more than 100 years in steady-state running large-scale processes. Power-to-gas applications include dynamic operation where the traditional commercial methanation process (adiabatic fixed-bed methanation) is the most sensitive reactor concept. A solution can be installation of large intermediate H_2 storage between electrolyser and methanation unit, but this is generally assumed too costly. Instead, new methanation concepts with better dynamic abilities have been developed over the last 10-20 years. These are biological or three-phase isothermal catalytic slurry bubble columns (7). These new concepts are at lab/pilot stage and therefore not yet commercial. Biological methanation is mostly suited for smaller plants as the reactor size needed for converting a certain feed gas is several orders of magnitude larger than for the commercial adiabatic fixed-bed methanation. Reactor size demand for the new three-phase catalytic methanation is somewhere between these two concepts. For large plants above 100 MW SNG, the commercial adiabatic fixed-bed methanation reactor is well suited but requires steady-state operation (7).

Combining a biogas plant with an electrolyser and methanation reactor to produce electro-methane will have some implications for the operation mode. Investing up front in an upgrade plant for biogas to produce a stream of CO_2 and a stream of biomethane (CH_4) will give the plant operator the freedom to only run the electrolyser when electricity prices are low. When electricity prices are high, the CO_2 stream from the upgrading plant can be vented to the atmosphere.

As mentioned above, the only mature technology for large scale methanation is fixed-bed reactors. These reactors have to be run in steady-state as control of the reactor temperature is a key parameter to avoid sintering and cracking of the catalyst. A steady-state methanation process requires a hydrogen storage to allow the electrolyser to take advantage of the hours with low price electricity. For large-scale projects, it is important to keep in mind that fixed-bed reactors are the only current mature technology. Steady-state operation is a requirement for this type of reactors and expenses for a hydrogen storage needs to be included in the economics.

4.3.2 Economics of methanisers

As CO_2 methanation projects related to biogas plants and Power-to-Gas applications is well below 100 MW SNG, it will mostly be methanation concepts under development, biological and three-phase isothermal catalytic methanation that will be used. That means that economic data will be based on experience with demonstration plants, estimates and expectations for the future developments of technology and P2G market.

Compared to electrolyser investment costs, methanation unit investment costs are much lower. An indication of this is shown in
Table 4-4 (7).

Table 4-4 Two investment cases for a P2G project: 36 MW electrolyser plus a steady-state running methanation unit in case 1 and a dynamic running methanation unit in case 2 (7).

Investment in M€	Electrolysis	Compressor	H_2 storage	Methanation	Total
Case 1	28.8	1	8.3	0.7	38.8
Case 2	28.8	1	4.8	1.2	35.8

In both cases, the average SNG production is around 340 Nm^3/h, but in case 2 with varying methanation load. The max load is 600 Nm^3/h. Methanation pressure is 20 bar. In these cases, the difference between electrolyser and methanation unit investment costs is a factor 30.

A literature review of CO_2 methanation costs for P2G applications shows specific investment costs ex works varying from 130-1500 €/kW SNG excluding installation etc., which is estimated to add typical further 50% to the cost. The variation covers different plant sizes (3-110 MW SNG) and projections. An overview of the review is shown in Table 4-5.

Table 4-5 Estimates of CAPEX and OPEX for methanation units for Power to gas applications by different reports.

Source	Year	Power MW	Pressure [bar]	CAPEX € / kW SNG	OPEX % of CAPEX per year	ref
Gassner and Maréchal	2009	14,8	15	175		(7)
Outotec GmbH	2014	5	20	400		(7)
Outotec GmbH	2014	110	20	130		(7)
Lehner et al. (three reports)	2014			300-500	8%	(7)
Ausfelder et al. (2015)	2050			600		(7)
E&E Consultant (2014)	2014			1500		(7)
E&E Consultant (2014)	2030			500		(7)
Ueckerdt et al.	2013			1000		(7)
Grahn & Jannasch	2018			600	4%	(9)
enea consulting	2016		10	1500	5-10%	(10)
enea consulting	2030		10	1000	5-10%	(10)
enea consulting	2050		10	700	5-10%	(10)
Danish Energy Agency	2020	3,3		910	6-8%	(12)
Danish Energy Agency	2030	8,3		760	6-8%	(12)
Danish Energy Agency	2050	23,1		450	6-8%	(12)
Haldor Topsøe	2017	25		670	3%	(1)

OPEX including catalytic exchanges but excluding energy costs are estimated by the various sources to 3-10% per year of CAPEX.

4.4 Estimated cost of electro-methane

In this section a base case calculation is presented along with a sensitivity analysis of the important factors.

4.4.1 Base case calculations

The calculations are based on hydrogen production from the three electrolysis technologies described previously, even though alkaline electrolysis is the only type which is fully commercial in MW_e scale today. Economic assumptions for the hydrogen production can be found in Table 4-3. It is assumed that both electrolyser and methaniser are suited for a dynamic operation pattern and operates 6000 equivalent full load hours per year.
CAPEX for methaniser systems in the size of around 5 MW SNG is estimated to 1005 $€_{2020}$/kW SNG based on data from the Technology Catalogue (12). As seen in Table 4-5, this includes installation and is in the mid-range of the different reported CAPEX estimates.
OPEX is also based on the Technologue Catalogue and amounts to ~7% of CAPEX per year. This is in line with OPEX figures from other reports as shown in Table 4-5.

In the following cost estimate for electro-methane, CO_2 is estimated to 31 $€_{2020}$/ton (9). Currently there are many big biogas plants in Denmark where the separated CO_2 is vented to the atmosphere after the upgrading plant which in theory makes the plant CO_2 free. A cost of 31 €/ton for CO_2 capture is included to show that it constitutes a minor share of the total cost. The cost of water for electrolysis is negligible compared to the cost of electricity (9).
An indirect cost is included to cover the engineering cost and additional cost spend on connecting the different plants, e.g. biogas, electrolysis and methaniser. The indirect cost is assumed equal to the CAPEX in 2020 and half of the CAPEX in 2030 due to gained experience with the technologies. The calculated indirect cost for alkaline electrolysis is used for all the electrolysers. The estimate for indirect cost is low compared to figures reported by Grahn and Jannasch (9) as they use a multiple of 3.14 for today and a future multiple of 2.0.

Figure 4-8 shows estimated production cost for electro-methane in 2020 and 2030 for three electrolysis technologies. The estimated production costs are compared to the production cost of biogas and biomethane. The figure shows that cost of electricity (i.e. power prices and system efficiency) is the most important factor.
Comparison to the production cost of biogas or biomethane shows that electro-methane is more than twice as costly to produce when comparing with the most mature electrolysis technology, which is alkaline electrolysis.

The analysis furthermore shows that SOEC electrolysis is the most expensive technology as of today but also has high potential for cost reductions as the efficiency is higher than alkaline and PEM electrolysis.

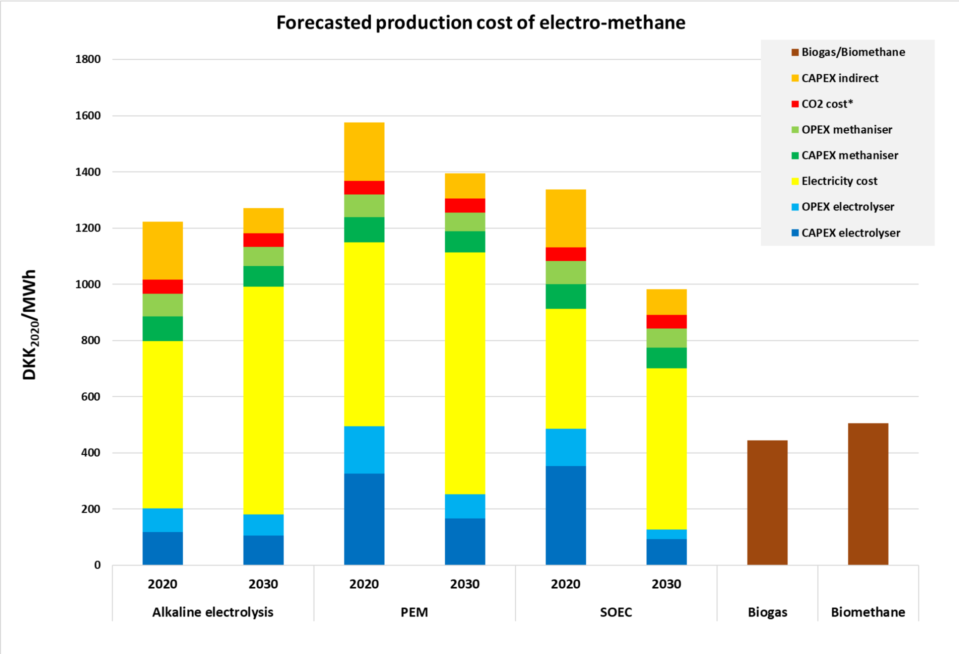

Figure 4-8 Cost estimates for electro-methane in 2020 and 2030.

Table 4-6 Break down of the cost estimates presented in Figure 4-8 for electro-methane in 2020 and 2030.

Electrolysis and catalytic methanation								
	Alkaline		PEM		SOEC			
Year	2020	2030	2020	2030	2020	2030	Unit	Comments/references
Economic assumptions								
Interest rate	5%	5%	5%	5%	5%	5%		
Exchange rate	7,45	7,45	7,45	7,45	7,45	7,45	DKK/EUR	
Technical assumptions								
Methaniser capacity	5	5	5	5	5	5	MW SNG	
Tech. lifetime methaniser	25	25	25	25	25	25	years	Reference (12), (9)
LHV SNG	35,9	35,9	35,9	35,9	35,9	35,9	MJ/Nm^3	
LHV Hydrogen	10,8	10,8	10,8	10,8	10,8	10,8	MJ/Nm^3	
Oprating hours	6000	6000	6000	6000	6000	6000	hrs/yr	
Conversion efficiency	77,0%	77,0%	77,0%	77,0%	77,0%	77,0%	$Methane_{, LHV}/H_{2,LHV\ input}$	Reference (9)
Demand H_2	130%	130%	130%	130%	130%	130%	$MWh_{H2,LHV}/MWh_{SNG,LHV}$	Reference (9)
Demand H_2	2165	2165	2165	2165	2165	2165	Nm3/h	
Demand CO2	0,21	0,21	0,21	0,21	0,21	0,21	ton_{CO2}/MWh_{CH4}	Reference (9)
Produced SNG	3,0	3,0	3,0	3,0	3,0	3,0	M Nm3/year	
Investments and cost								
CAPEX (methaniser)*	37,4	31,3	37,4	31,3	37,4	31,3	M DKK	Reference (12)
CAPEX (electrolyser)*	50,2	44,8	101,3	51,8	132,1	34,5	M DKK	Reference (12)
CAPEX (Indirect cost)	87,6	38,0	87,6	38,0	87,6	38,0	M DKK	Reference (9)
Annualised $CAPEX_{methaniser}$	2,7	2,2	2,7	2,2	2,7	2,2	MDKK/year	
Annualised $CAPEX_{electrolyser}$	3,6	3,2	9,8	5,0	10,6	2,8	MDKK/year	
Annualised $CAPEX_{indirect}$	6,2	2,7	6,2	2,7	6,2	2,7	MDKK/year	
OPEX (methaniser)*	2,4	2,0	2,4	2,0	2,4	2,0	MDKK/year	Reference (12)
Opex (Electrolyser)*	2,5	2,2	5,1	2,6	4,0	1,0	MDKK/year	Reference (12)
Electricity cost	17,8	24,3	19,7	25,8	12,8	17,2	MDKK/year	Table 3-3 assumptions
CO2 cost*	1,5	1,5	1,5	1,5	1,5	1,5	MDKK/year	31 €/ton CO_2
Cost per Nm^3 CH_4	12,2	**12,7**	15,7	**13,9**	13,3	**9,8**	**DKK/Nm^3 CH_4**	
Cost per MWh CH_4	**1223**	**1271**	**1576**	**1395**	**1338**	**982**	**DKK/MWh CH_4**	

* Back-calculated to 2020 as basis year with 2% inflation

4.4.2 Sensitivities

In this section, it is investigated if electro-methane can be cost-competitive to biogas and biomethane if a scenario with more than 70% renewable energy is assumed.

The most important factor is electricity price. A scenario made by Energinet for 2040 is shown in Figure 4-9. Here spot prices for DK1 are shown for scenarios with significant amounts of renewable energy in Northern Europe (more than 70% wind and solar energy). The green curve illustrates a scenario with limited P2G installed. The blue curve illustrates a scenario with significant P2G installed. Eyeballing of the green scenario indicates that an average spot price of 50 DKK_{2020}/MWh is possible for approx. 6000 hours (a rough estimate). Assuming that transmission cost is 70 DKK/MWh results in an average electricity price of 120 DKK/MWh for a very optimistic scenario with limited installation of P2G capacity.

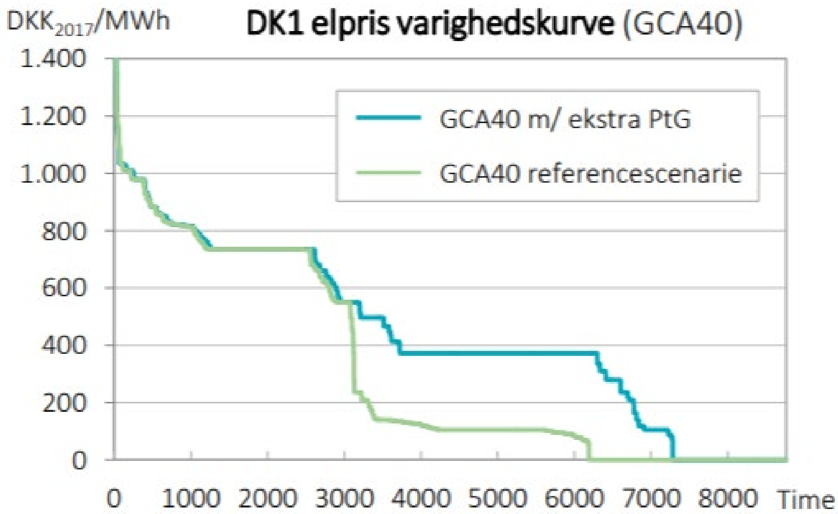

Figure 4-9 Spot prices for an ambitious renewable energy scenario for Northern Europe in 2040 reported in Systemperspektiv 2035 by Energinet (5) (green is prices with little or no P2G and the blue reflects potential P2G installation).

The effects by changing the electricity price to 120 DKK/MWh in the above base case calculations are shown in Figure 4-10. The figure shows that, even with very low electricity prices, the production cost of biogas and biomethane is significantly lower than electro-methane with current technology as of today. With the forecasted improvements in the different electrolysis technologies, the production cost of electro-methane is close to becoming competitive to biogas and biomethane in 2030 if the electricity price drops to 120 DKK/MWh.

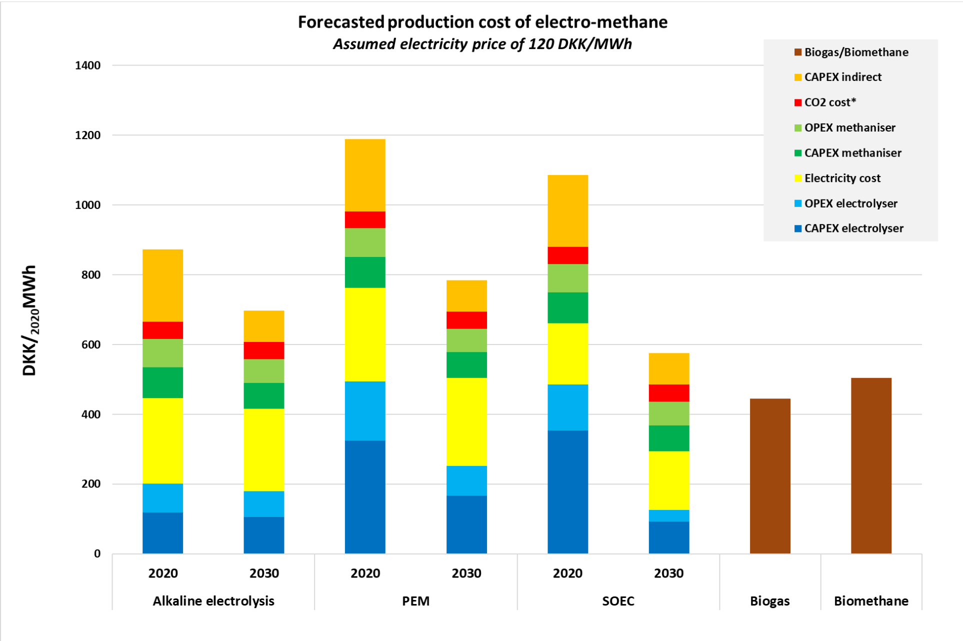

Figure 4-10 Same assumptions as in the base case except that the cost of electricity is reduced to 120 DKK/MWh (incl. tariffs).

Other initiatives to drive the price down for electro-methane are utilisation of excess heat and oxygen from the electrolysis process. Assuming a revenue of 230 DKK_{2020}/MWh_{heat} (9) for the excess heat and 390 DKK_{2020}/ton (9) for the oxygen can support the economy for electro-methane. Assumptions from the Technology Catalogue about excess heat from electrolysis and methanation are used. The results are shown in Figure 4-11 where the revenues have to be deducted from the cost. The final cost is shown with dots on the bar chart.

Figure 4-11 shows that electro-methane is not cost-competitive with biogas and biomethane in the base case scenario even if potential revenues from excess heat and oxygen sales are included.

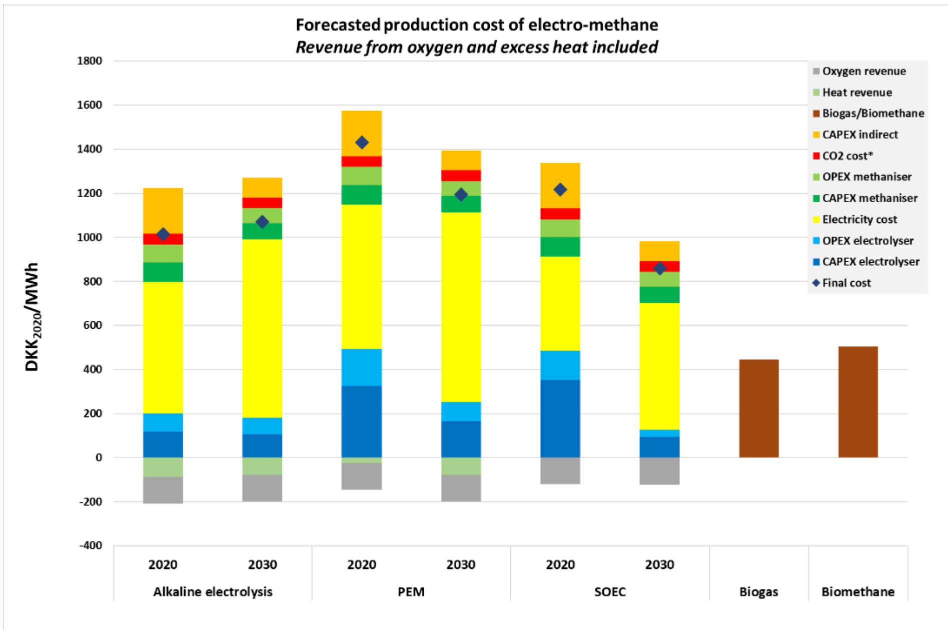

Figure 4-11 Base case results combined with revenues from excess heat and oxygen production.

A combined case with low electricity prices and revenues from oxygen and excess heat are generated and shown in Figure 4-12.

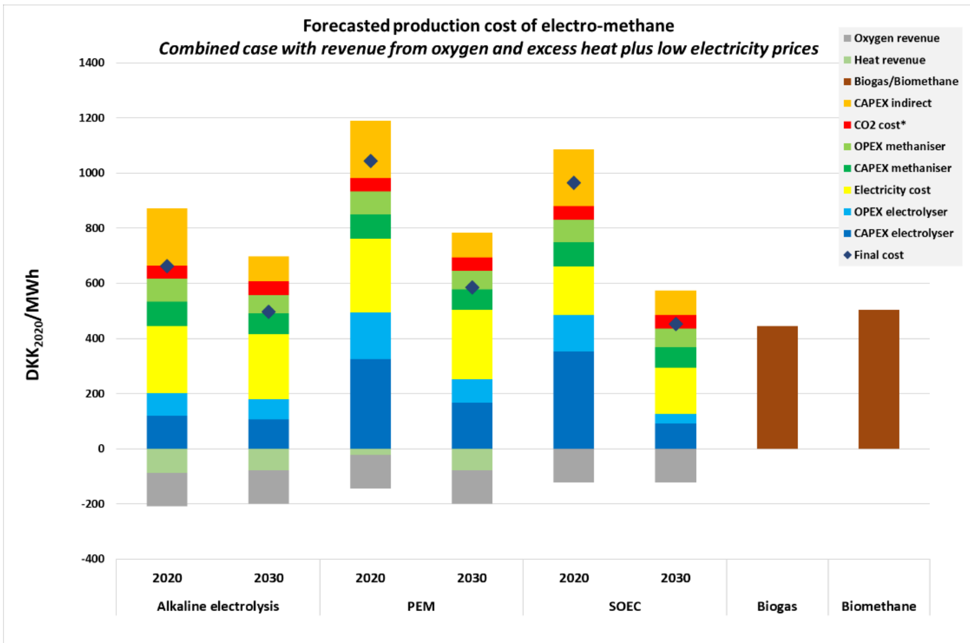

Figure 4-12: Combined case where low electricity prices are assumed (120 DKK/MWh), and revenue from oxygen and excess heat sales are included.

Figure 4-12 shows that electro-methane can become cost-competitive to biogas and biomethane if electricity prices are low and full integration with downstream market (heat and oxygen) is achieved.

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