Co-funded by the European Union's Horizon 2020 research and innovation programme under Grant Agreement no. 691797

STORE&GO

Innovative large-scale energy storage technologies and Power-to-Gas concepts after optimisation

D8.6

Report on the optimal time profile and operation of the conversion technology during a representative year, in the perspective of the available storage capacities

Due Date	31 December 2018 (M34)
Deliverable Number	D8.6
WP Number	WP8
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Status	Started / Draft / Consolidated / Review / Approved / Submitted / **Accepted by the EC** / Rework

Dissemination level

✘	**PU**	Public
	PP	Restricted to other programme participants (including the Commission Services)
	RE	Restricted to a group specified by the consortium (including the Commission Services)
	CO	Confidential, only for members of the consortium (including the Commission Services)

Document history

Version	Date	Author	Description
1.0	2018-08-06	C van Leeuwen	Started.
1.1	2018-10-26	Jachin Gorre	First draft
2.0	2018-12-19	Jachin Gorre	Second draft, after first review
2.1	2018-12-07	Jachin Gorre	First iteration
2.2	2018-12-12	Jachin Gorre	Second iteration
3.0	2019-02-11	Jachin Gorre	Final Version

Table of contents

Executive Summary

This report gives an overview on economics for various operating strategies of Power-to-Gas methanation plants during a representative year. Four different basic operating strategies considering the electricity and gas market were analysed (1–4). The operating strategies vary in whether or not electricity and gas are bought and sold according to hourly and daily varying price levels or via long-term contracts that are arranged on forehand and therefore ensure continuous operation of the plant (or parts of the plant). Besides the basic operating strategies, the authors see further opportunities for applying PtG in the near future (2030–2050). Therefore, eight additional strategies (5–12) have been analysed (Figure 1). In addition to long-term contracts and trading on the day-ahead market, these strategies consider direct coupling of the PtG plant with a renewable energy source and the seasonal use of surpluses (grid services) on the electricity purchase. These strategies are considered even though there are not yet appropriate incentives or support schemes in place, which enable economic benefits. Nevertheless, the regulatory framework will very likely be adapted in future, when the share of renewables will rise and electricity grid services will become more relevant.

		Electricity purchase			
		long term contracts	short term market	direct coupling RES	seasonal
Gas selling	long term contracts	1. Continuous operation Prices both fixed on forehand, continuous operation of the plant. No large storage facilities needed. Participation in electricity balancing market could be an option.	2. Flexible electricity Gas is continuously sold and injected in the gas grid. Electricity is purchased according to price levels. Hydrogen buffer tank is required.	7. Flexible electrolyser **Gas** is **continuously sold** and injected in the gas grid. **Electricity** is purchased according to **load of the RES**. Hydrogen buffer tank is required.	10. Seasonal electrolyser **Gas** is **continuously sold** and injected in the gas grid. **Electricity** is purchased according to **surplus** energy from RES from grid. Hydrogen buffer tank is required.
Gas selling	short term market	3. Flexible gas Electrolyser is operated continuously, participation in electricity balancing market could be an option. Gas is sold according to price levels, buffer tank for methane is needed.	4. All flexible Electricity is bought according to price levels and gas is sold according to price levels. Large buffer tanks for both hydrogen and methane are needed.	8. Flexible coupling Electricity is purchased according to load of the RES and **gas** is sold **according to price levels**. Large buffer tanks for both hydrogen and methane are needed.	11. Seasonal flexibility **Electricity** is purchased according to **surplus** energy from RES from grid and gas is sold according to price levels. Large buffer tanks for both hydrogen and methane are needed.
Gas selling	seasonal	5. Seasonal gas Electrolyser is operated continuously, participation in electricity balancing market could be an option. **Gas** is sold according to **requisition in winter season**, buffer tank for methane is needed.	6. Flexible and seasonal Electricity is bought according to price levels and **gas** is sold according to **requisition in winter season**. Large buffer tanks for both hydrogen and methane are needed.	9. Seasonal coupling Electricity is purchased according to load of the RES and **gas** is sold according to **requisition in winter season**. Large buffer tanks for both hydrogen and methane are needed.	12. Seasonal **Electricity** is purchased according to **surplus** energy from RES from grid and **gas** is sold according to **requisition in winter season**. Large buffer tanks for both hydrogen and methane are needed.

Figure 1: Schematic of electricity purchase and gas selling strategies for current and future markets

The **current market situation** relates to a gas price in the range of 10–25 €/MWh with an average per year of around 19.2 €/MWh. The average electricity prices (tax free) of various EU member states range between 20 and 50 €/MWh over one year. The prices are reduced about 50 % when only the low-priced 4,000 hours of a year are considered. The corresponding actual methane production costs (100 % FLH – long term contracts), including CAPEX and fixed + variable OPEX, result to 121–162 €/MWh, with feedstock costs of water, electricity and CO_2. of still 52–93 €/MWh. Present subsidiary schemes in EU member states allow for market prices of methane in the range of 19.20 €/MWh, which is basically the current NG price, up to 164 €/MWh, with strong governmental support, referring to the German case of biogas subsidy. Based on these figures, the Willingness-to-Pay (WTP) for electricity of a PtG plant is in the range of 5.3–77.1 €/MWh$_{el}$. The corresponding full load hours (FLH), which would enable to pay for these electricity prices, are rather low (< 1,000 FLH) and would therefore result in high investments for rather large PtG plants.

An opportunity to reduce gas production costs is to increase the workload of methanisation by operating electrolysis and methanisation separately. This is technically achieved by an intermediate storage tank for hydrogen. In this report, it is assumed that electrolysers are able to operate in a flexible way, switching on and off when required, whereas methanation reactors are less flexible and need to operate on a relatively continuous basis. Nevertheless, the cases considered have shown that under the current conditions the gas production costs only decrease slightly or not at all due to the rather high costs for on-site hydrogen storage. An analysis on the optimal storage size of an on-site hydrogen storage leads to optimum capacities in the range of less than one day.

Besides the current situation, the **potential of PtG in future markets**, e. g. when electricity prices increase and are more volatile, PtG plant components are mass-produced and investment costs and fixed operating costs fall as a result, were considered. Electricity price level is projected to remain either constant or showing a tendency to increase up to a level of around 80 €/MWh_{el} in future. Projected gas prices are within the range of constant to slight increase in 2030 and double the current price in 2040 as maximum.

In case of long-term electricity contracts (assuming continuous operation in 8,760 FLH) an operation with the expected future electricity price of 2030 (74 €/MWh_{el}) is not profitable. The maximum assumed future revenue for SNG (75 €/MWh) is achieved with a power price of less than 15 €/MWh_{el}. In 2050, there is a positive business case (with 75 €/MWh SNG revenue) for any size of the PtG plant with electricity prices lower than 50 €/MWh_{el}.

When the FLH are reduced, lower electricity prices can be acquired. The calculation results show that with an electricity price of 10 €/MWh and 4,000 FLH the methane production costs in 2030 are in the range of 70 €/MWh_{el}. The methane production costs in 2050 (with the same electricity costs) already come close to the projected natural gas price (40 €/MWh). Suchlike operating schemes can be achieved by offering positive and negative secondary control reserve via PtG. Nevertheless, the corresponding average electricity price projections for 4,000 FLH are higher, more likely in the range of 25 – 40 €/MWh_{el}. The difference still has to be paid on top of the methane production costs.

The opportunities of operating a PtG plant for seasonal storage of electricity have also been considered. The size of the SNG storage has been set to the yearly production capacity of the PtG plant. Such large storage capacities can only be realized when the natural gas grid is used as a storage. The results show that also seasonal electricity storage offers interesting market opportunities for PtG plants, which might even enable certain revenues by selling the produced gas in 2030 - 2050. Parts of the revenues must certainly still be spent on electricity purchase to realize a high number of operating hours but in both, the secondary control reserve and the seasonal electricity storage case, only low incentives are necessary to enable positive business case for PtG plants.

This report gives an overview of a cost-orientated operation of PtG methanation plants for 12 different PtG application cases. The provision of electricity via long-term contracts, short-term market or direct use of renewable energy without grid connection or the seasonal availability of surplus energy was considered. Gas selling was also considered at different levels: long-term contracts, short-term market and seasonal. It was shown that under the current conditions the operation of a PtG plant is not economically feasible. Only strong governmental support – such as is offered in Germany or in Italy – enable a profitable operation at present. Especially the cases with low electricity prices show that the gas production costs are below the expected future market prices for synthetic gas and biogas.

With the future expected development of CAPEX, OPEX, electricity prices, gas costs, efficiencies and optimized interaction and operation of the electrolyser and methanation, an economic production of SNG for the years 2030, especially for 2050 appear to be feasible. Figure 2 shows the gas production costs in the range of operating hours in which the twelve operating concepts can be found. The higher the number of operating hours, the lower the gas production costs without electricity costs; the higher the number of operating hours, the higher the (average) electricity price on the electricity market.

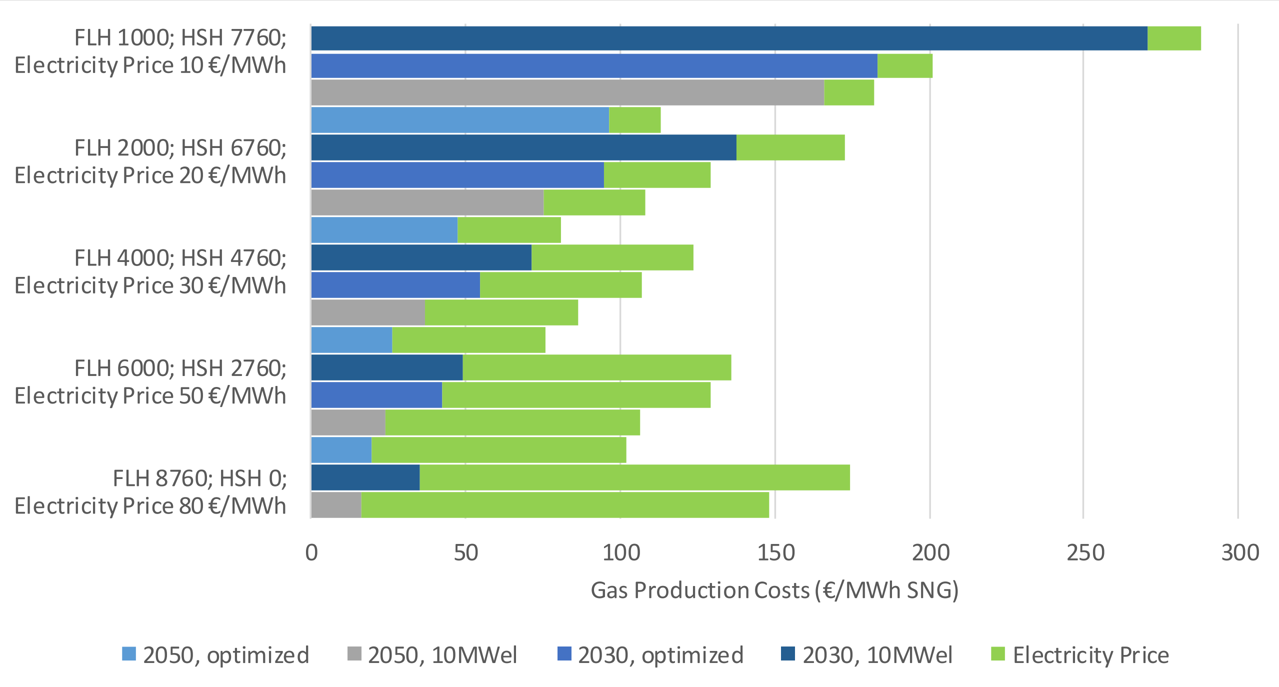

Figure 2: Gas production costs for the year 2030 and 2050, depending on the full load hours (FLH), hot standby hours (HSH) and electricity price. The gas production costs of the twelve cases considered are also dependent on the FLH, HSH, electricity price and the optimisation potential, which is influenced by the expected electricity load profile.

In 2050, the gap between the market driven business models and economic feasibility is rather narrow. Although governmental support schemes were not considered in any calculations performed in this report, the results allow for an estimation of the necessary amount of support for enabling economic feasibility of PtG operation. Based on these results, politicians have to decide whether regulatory measures are to be taken for enabling the systemic benefits (security of supply, support of electricity grid) of the large-scale sectoral coupling and energy storage capabilities of the PtG technology.

1 Introduction

In the technology power-to-gas (PtG), electricity is used to split water into hydrogen (H_2) and oxygen (O_2), whereby the electric energy is stored in the H_2. The conversion takes place in an electrolyser. The H_2 can be used directly but can also be further converted into methane (CH_4), thereby simplifying the transport, storage and usage of the energy. The additional conversion requires a methanation reactor in which the H_2 reacts with carbon dioxide (CO_2).

This report gives an overview of the operation of the PtG technology and its optimal time profile during a representative year, in perspective of the available storage capacities. Hereby we focus on PtG methanation plants. The main components of these plants are an electrolyser and methanation reactor and optionally (depending on the configuration and operating strategy) storage facilities for H_2, CO_2 and CH_4. A rough schematic of the plant is visible in Figure 3.

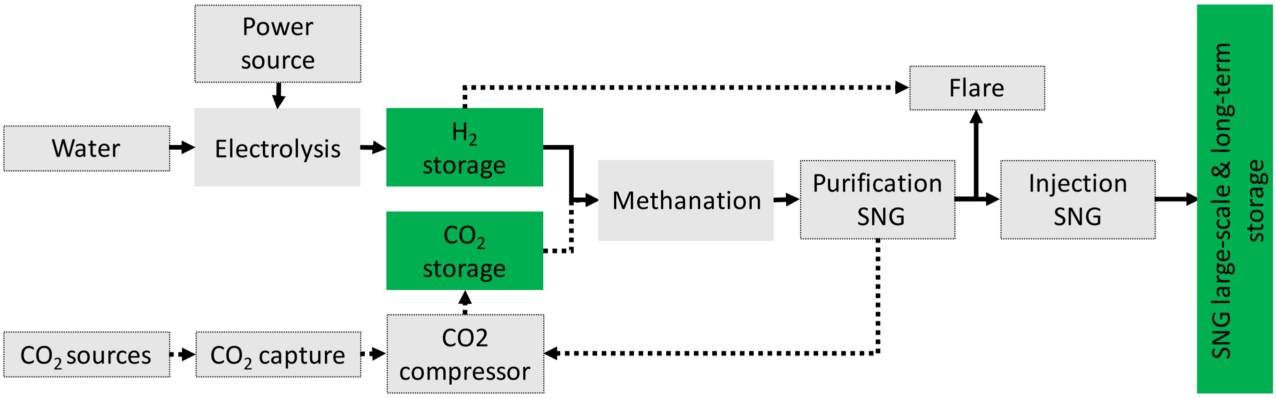

Figure 3: Very basic schematic of the PtG plant considered in this report

Four factors together determine the optimal time profile and operation of the PtG conversion technology:

- The market prices of electricity and the plant's willingness-to-pay (WTP) for electricity[a]
- The market prices of gas and the plant's willingness-to-accept (WTA) for gas
- The availability of CO_2
- The availability of storage capacity for CO_2 and H_2 to operate the sub-systems electrolysis and methanation independent

Besides these four factors, there are operational expenses (OPEX) for the different operating states of the sub-systems of the plant that need to be taken into account.

The markets of electricity and (fossil) natural gas are external factors that cannot significantly be influenced by a (single) PtG plant. However, the WTP for electricity and WTA for gas are determined by cost factors of the plant itself and influence each other. The size of the H_2 storage tank influences the application of the system, since its size can be chosen during the construction phase of the plant.

There are actually four different operating strategies of a PtG plant within the electricity and gas market, as displayed in Figure 4. The strategies vary in whether or not electricity and gas are bought and sold according to hourly and daily varying price levels or in long-term contracts that are arranged

[a] The method of using the WTP for electricity to evaluate the business case of a PtG plant originates from*: van Leeuwen, C and Mulder, M, Power-to-Gas in Electricity Markets dominated by Renewables*. Applied Energy; https://doi.org/10.1016/j.apenergy.2018.09.217

on forehand that ensure continuous operation of the plant (or parts of the plant). In the near future, the authors see further operating strategies of PtG (chapter 4, Figure 16). In this report, it is assumed that electrolysers are able to operate in a flexible way, switching on and off when required, whereas methanation reactors are less flexible and need to operate on a relatively continuous basis (chapter 2.4). A hydrogen storage tank can enable flexible operation of the electrolyser while still ensuring continuous operation of the methanation reactor.

In the first option in Figure 4 (continuous operation), both electricity purchase and gas selling are arranged on forehand in long-term contracts. The PtG plant is continuously operating and there is no need for a large hydrogen storage buffer. Optionally, the plant could participate in the electricity balancing market. In the second option (flexible electricity), the electricity is purchased in wholesale markets close to real time, whereby the PtG plant can adapt to low and high prices during times of high and low shares of renewable power generation respectively. A hydrogen storage facility is required to ensure continuous operation of the methanation reactor and continuous selling of gas, arranged in long-term contracts. In the third option (flexible gas), electricity purchase is arranged in long-term contracts, ensuring continuous operation of the electrolyser and subsequently continuous operation of the methanation reactor. The gas is sold in short-term markets. When the PtG plant is connected to the gas grid, methane storage is no critical aspect. In the fourth and last option (all flexible) both the electricity purchase as well as the gas selling is flexible and arranged in short-term markets. The plant needs a hydrogen storage facility to buffer the fluctuating output of the hydrogen and to ensure continuous operation of the methanation reactor.

		Electricity purchase	
		Long-term contracts	Short-term market
Gas selling	Long-term contracts	1. Continuous operation Prices both fixed on forehand, continuous operation of the plant. No large storage facilities needed. Participation in electricity balancing market could be an option.	2. Flexible electricity Gas is continuously sold and injected in the gas grid. Electricity is purchased according to price levels. Hydrogen buffer tank is required.
	Short-term market	3. Flexible gas Electrolyser is operated continuously, participation in electricity balancing market could be an option. Gas is sold according to price levels, buffer tank for methane is needed.	4. All flexible Electricity is bought according to price levels and gas is sold according to price levels. Large buffer tanks for both hydrogen and methane are needed.

Figure 4: Schematic of electricity purchase and gas selling strategies, assuming that the electrolyser can operate flexible whereas the methanation reactor needs to operate continuously.

The report investigates the four operating strategies presented in Figure 4 and the future applications that are expected. To do so, chapter 2 first describes the three factors that determine the optimal operation of a PtG plant: the electricity supply (section 2.1), gas selling (section 2.2), gas storage (section 2.3) and operation requirements of the sub-systems electrolyser and methanation (section 2.4). Using this information, operation of the PtG technology is first investigated for the current situation (chapter 3). Afterwards, chapter 4 explores future developments that could influence the PtG business case and the four operating strategies. The report ends with conclusions and discussion (chapter 5).

2 Economical basics of operating a PtG plant

This chapter describes the four factors that determine the optimal time profile and operation of the PtG conversion and storage technology: electricity supply (section 2.1), gas selling (section 2.2) and gas storage and availability (section 2.3). When planning the system, expected electricity prices and year-dependent gas prices are assumed. This data are used to design the electricity procurement concept for electrolysis. Then the need for a hydrogen buffer is determined and finally the size of the storage and methanation is optimised. The aim of the optimization is to reduce operational expenses (OPEX) (section 2.4) of the entire plant, excluding the electricity for the production of hydrogen. The OPEX are divided into fixed and flexible OPEX. The flexible OPEX are strongly dependent on the duration in the respective operating states. The following operating states are considered: Hot standby (HSH), cold standby (CSH) and production operation in terms of full load hours (FLH). This chapter focuses on the current situation only, which is used as an input for chapter 3. Future developments of the different aspects will be discussed in chapter 4.

2.1 Electricity supply

Electricity is the most important feedstock of a PtG plant. Section 2.1.1 first briefly describes the market design of European electricity markets. Section 2.1.2 then gives an overview of recent electricity prices in Europe by showing the prices in four countries: Germany, France, the Netherlands and Denmark.

2.1.1 European electricity markets

Electricity can be traded in forward markets already years before actually delivery. Most electricity is, however, traded closer to the actual delivery in the day-ahead (DA) market. In this market, power is usually traded on exchanges, where computer algorithms determine the market price for every hour based on all the bids of power consumers and producers. The DA market typically closes one day before actual delivery, when the intraday (ID) market starts. In this market, trading continues until very shortly – typically somewhere between 5 and 60 minutes – before actual delivery. ID markets are usually continuous markets where prices are set bilaterally. For every hour, the market price consists of a lowest, highest, latest and weighted average bid instead of a single market-clearing price (*EPEX SPOT*, 2018; *Nord Pool*, 2018). In Germany, the ID market also facilitates quarter-hourly trading of electricity, in addition to hourly trading (EPEX SPOT, 2014; *EPEX SPOT*, 2018; Neuhoff et al., 2016).

Besides the electricity markets where power is traded between consumers and producers, there are also markets for the provision of reserve capacity. Because the power system needs to be in balance all the time (power consumption must equal power production at every moment), the transmission system operator (TSO) needs to be able to activate reserve capacity when needed. There are several types of reserve capacities, varying in terms of activation time and duration.

2.1.2 Recent electricity prices

Electricity prices vary from country to country and from hour to hour. Besides the wholesale market price, most power consumers also have to pay fees (e.g. for the grid) and taxes. These are not considered here, but their existence should be kept in mind.

Figure 5 shows the average wholesale electricity price in Germany, France, the Netherlands and Denmark over the years 2013 – 2017 for 8760 FLH operation of a PtG plant. Denmark has two market zones: DK1 (west) and DK2 (east) and the figure therefore shows two electricity price curves for Denmark.

For power consumers that can be flexible, such as PtG plants, it is not only the average electricity price that is important, but also the volatility of the electricity price. A very constant electricity price throughout time does not give many possibilities to profit from low prices, whereas a very volatile profile does. Figure 6 presents 32 different electricity price profiles of the four countries over the years 2010 – 2017. The figure has been taken from STORE&GO Deliverable 8.4[b]. The curves show the average electricity price when electricity is only bought during the x-% cheapest hours of the year.

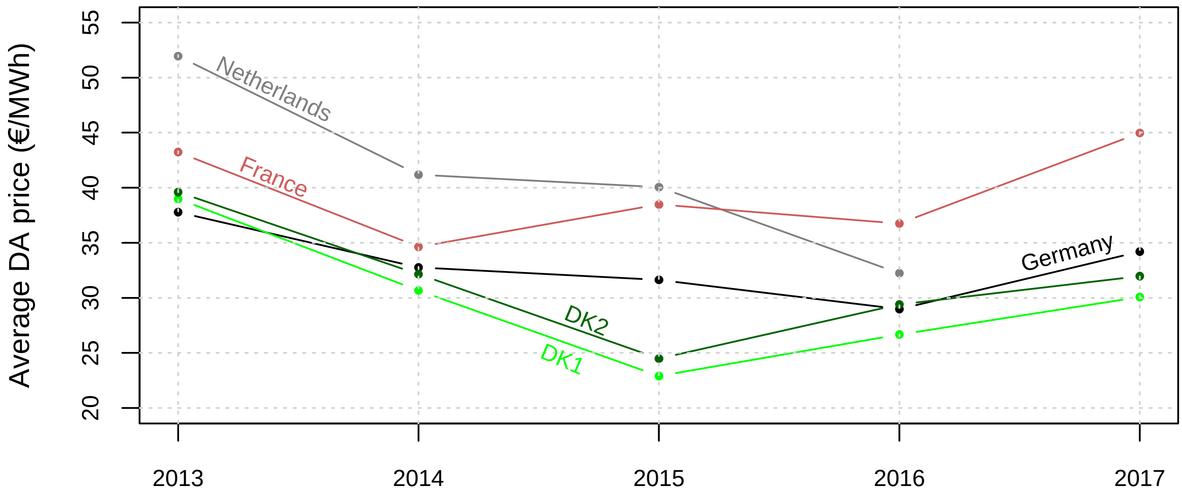

Figure 5: Average DA electricity prices 2013 – 2017 in France, Germany, the Netherlands and Denmark (DK1 and DK2). For the Netherlands, data for 2017 are not available. Sources: (Bloomberg LP, 2018a; *Nord Pool*, 2018)

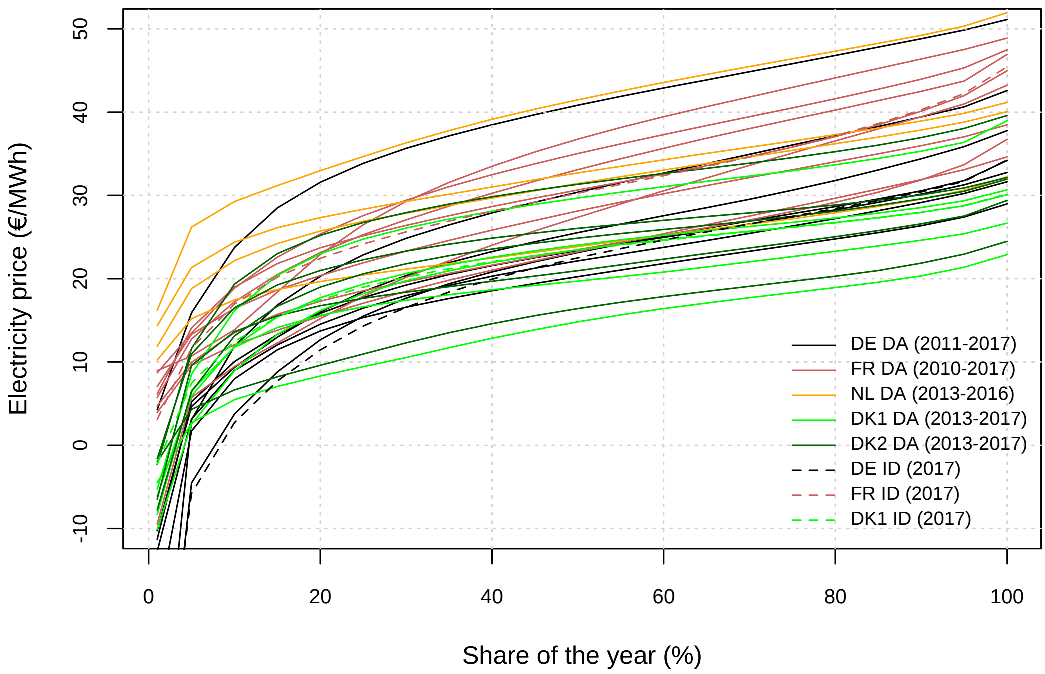

Figure 6: Electricity price profiles calculated from the DA and ID market data in Germany, the Netherlands, France and Denmark (both DK1 and DK2 zones) between 2010 and 2017. The average price is calculated for the cheapest x-% hours of the year. Sources: (Bloomberg LP, 2018a; *EPEX SPOT*, 2018; *Nord Pool*, 2018).

[b] D8.4: Software of the stochastic net present value (NPV) model for a bottom-up assessment of the feasibility of investment in the power-to-gas conversion and storage technology. Due date: 30 June 2018

2.2 Gas selling

Natural gas is currently widely used in the EU and elsewhere in the world. It is used for heating, electricity generation, as a building block for industry and for mobility. This section first briefly describes natural gas markets in Europe (section 2.2.1) and afterwards gives an overview of recent natural gas prices in these markets (section 2.2.2). Next, prices for green gas are discussed (section 2.2.3) as green gas can have a higher value than natural gas.

2.2.1 European natural gas markets

PEGAS is the central European gas trading platform with contracts in Austria, Belgium, the Czech Republic, Denmark, the Netherlands, France, Germany, Italy and the UK. Figure 7 gives an overview of the PEGAS trading platform with all the virtual trading hubs.

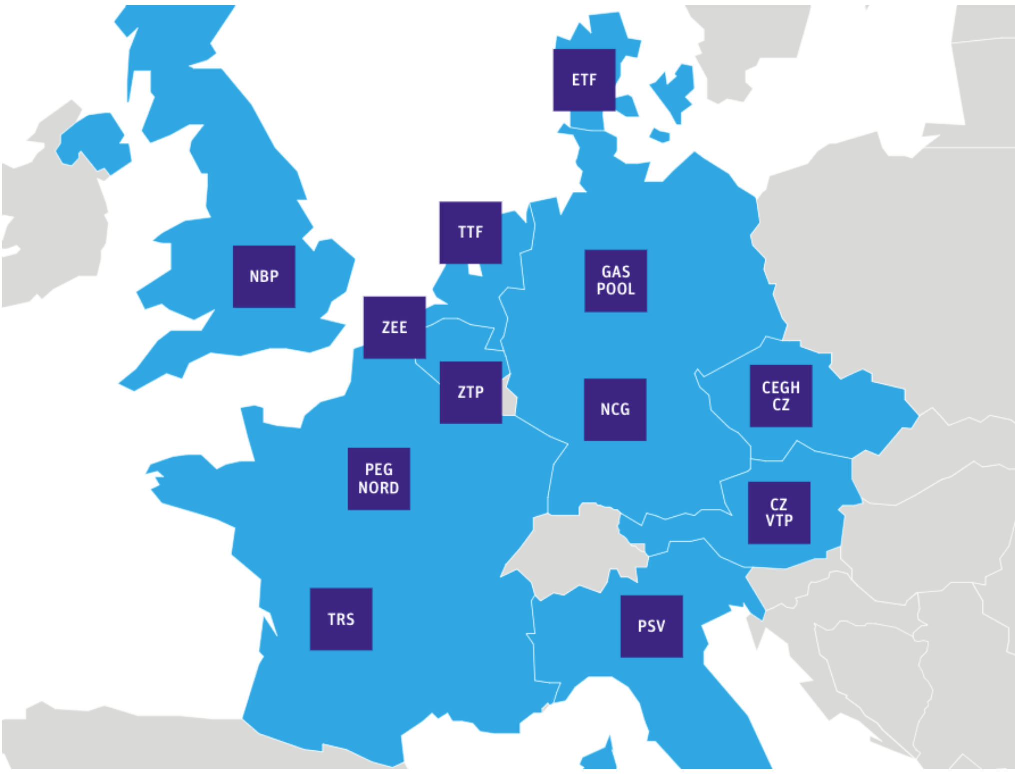

Figure 7: Overview of the PEGAS gas market platform. Source (PEGAS, 2018)

The gas market platform TTF (Title Transfer Facility) located in the Netherlands is the market with highest trading volume in Europe (PEGAS, 2018). Together with the British NBP trading hub, it has by far the largest trading volumes, dwarfing all the others (Heather and Petrovich, 2017). In this report, we therefore focus on the TTF gas market. Another fact that justifies this is the single-price behaviour of North West Europe (including TTF, NCG, Gas pool, ZEE and PEGN): there is strong price alignment and price level convergence within this zone (Heather and Petrovich, 2017).

At TTF, gas is traded in €/MWh and the contract volumes are in MWh. The virtual trading point TTF is operated by Gasunie Transport Services (GTS), the transmission system operator in the Netherlands. Trading occurs per day, whereby a delivery day is from 06:00 to 06:00 on the following calendar day. Day-ahead trading occurs from 3:00 am at D-1 until 3:00 am on the delivery day D. Besides day-ahead trading there is also within-day trading (from 2:00 am on the delivery day until 2:00 the next day), trading for whole weekends (48 hours) and future trading, with contracts established long before the delivery day (PEGAS, 2018).

2.2.2 Recent natural gas prices

The European Commission publishes quarterly reports on the European Gas Markets, including average wholesale spot prices at TTF. In the last quarter of 2017, this was equal to 19.20 €/MWh (European Commission, 2018). This price is taken as a reference in this report.

Figure 8 shows the DA wholesale natural gas prices at TTF in the years 2015-2018. Trading in this day-ahead market only occurs on weekdays. For weekends, there are special 48h contracts. The price generally fluctuates between roughly 10 and 25 €/MWh[c]. Very high prices suddenly appeared on 27 February – 1 March 2018: during these days, there was extremely cold weather in Europe. Besides the three exceptional days, gas prices generally do not vary very strongly.

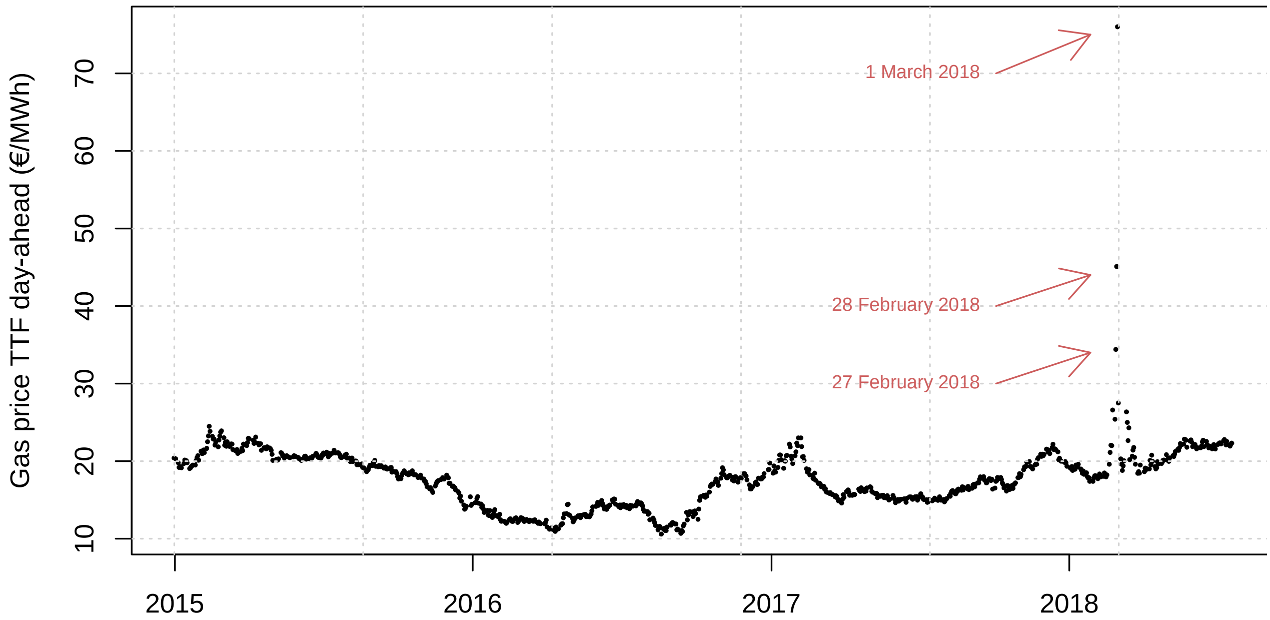

Figure 8: Day-ahead (weekdays) natural gas prices at TTF 2015 – 2018. Source: (Bloomberg LP, 2018b)

2.2.3 Green gas prices

Methane produced in a PtG plant could be considered "green" depending on the sources of electricity and CO_2 that are used (see for an evaluation of this definition of green gases STORE&GO Deliverable 8.1[d]). Methane produced in a PtG plant is chemically identical to fossil methane but since the origin of the two is very different, price differences will very likely arise. First of all, consumers might be willing to pay extra for green gas as opposed to fossil gas (see STORE&GO Deliverable D7.8[e]). Second, governments might want to stimulate the production of green gases through support schemes.

Consumers can prefer green gas to fossil gas and might be willing to pay extra for the green character of the gas. Once the produced biomethane (green gas, SNG) is injected into the natural gas grid, however, it is not possible anymore to distinguish it from the other methane molecules in the grid. The only way to sell green gas is the use of guarantees of origin (GoO).

[c] Average weekday prices for 2015, 2016 and 2017 were 19.82, 14.02 and 17.33 €/MWh respectively

[d] D8.1: Exploring the future for green gases. Due date: 31 August 2017.

[e] D7.8: Report on social and public acceptance determinants in selected EU-countries. Due date: 28 February 2019

The partners of the EU project CertifHy[f] delevoped a European system for hydrogen produced with low carbon emissions. The hydrogen has to be generated by renewable energy with carbon emissions 60% below the benchmark emissions intensity threshold or created by non-renewable energy with emissions below the same threshold. Some countries recently adopted certification schemes for renewable methane, but these systems are usually still immature without any common standard or regulatory frameworks (see STORE&GO Deliverable 8.2[g]).

STORE&GO Deliverable 8.1 gives some estimates for the WTP of consumers for green gas. The value of Dutch Vertogas green methane GoO is estimated based on experts in the field at a price of 0.03 – 0.11 €/kWh (LHV). Analysis of the electricity market reveals a WTP for green products of approximately 19% on top of the average electricity price.

A third estimate of the additional value of green gas can be made based on a new platform that was launched recently (June 2018) in the Netherlands on which consumers can purchase green gas certificates from real green gas producers (Oosterling et al., 2018). Consumers can choose between three products: “1 year green cooking”, “1 year green showering” or “1 year green heating”. The amount of green gas purchased varies, but the price is always 0.16 €/m^3, which is 18.20 €/MWh using the low calorific value of the Dutch Groningen Gas (31.65 MJ/m^3). This would mean roughly doubling of the wholesale market price of natural gas (which was on average 19.20 €/MWh in the last quarter of 2017 at TTF (European Commission, 2018)) for the green gas producer.

Even when consumers are hardly or not willing to pay extra for green gas, governments might will. STORE&GO Deliverable 7.3[h] gives an extensive overview of support schemes for the use of SNG (synthetic natural gas) in the three countries in which a PtG methanation plant is built under the flag of STORE&GO (Germany, Italy and Switzerland). The overview makes clear that support schemes can be very complicated with different requirements and exceptions to get support. The position of SNG produced in PtG plants is not always the same as that of SNG produced from biomass. To receive some kind of support there are often requirements to the origin of the electricity and/or the origin of the CO_2. Support is also often sector specific, e.g. targeting specifically on electricity generation, the transportation sector or heating.

The document stresses that methane production from renewable electricity in PtG plants is relatively new, which is why legislation and support schemes currently not always incorporate this. In most countries new support schemes are under development, which is why the situation can be different in the near future. Summarizing the findings in STOREG&GO Deliverable 7.3 on the current situation in the three countries:

- In Germany there is hardly any support for PtG plants, except for a remuneration of 0.007 €/kWh for feeding gas in the grid and avoid network costs. Other support cannot be received because of several reasons such as the definition of biomethane under the EEG 2017 (not for methane from PtG plants): the obligation to be connected directly to a renewable electricity source instead of to the grid or the need for re-electrification instead of feeding the gas into the grid to be used for other purposes. The picture is different for biogas. The Federal Network Agency has issued the second invitation to bid for biomass plants. The bid date was 1 September 2018. The average surcharge value of all bids was 14.73 ct/kWh. This is quite an extensive amount compared to the current market prices of natural gas.
- Italy is about to release a new decree on biomethane with a focus on the transportation sector, as the country is lagging behind the targets in this sector. Significant support can be

[f] EU project CertifHy; http://www.certifhy.eu/

[g] D8.2: Report on the acceptance and future acceptability of certificate-based green gases. Due date: 30 April 2018

[h] D7.3: Legislative and Regulatory Framework for PtG in Germany, Italy and Switzerland. Due date: 30 April 2018

received for “advanced biomethane” – which is also methane from PtG plants. The produced gas can be sold to the GSE (*Gestore Servizi Energetici*): a private company under the ministry of Economy and Finance that is responsible for coordination and execution of promoting and developing renewable energy. When sold to the GSE, the producer receives a premium in addition to a biomethane price equal to the weighted average price at the virtual trading point in the month of sale, reduced by 5%. The premium is equal to €375 per 5 Gcal (20,920 MJ), which equals to 64.53 €/MWh or 0.99 €/kg.

- In Switzerland it is not very clear what the amount of money could be that one could receive on top of the market price. It is possible to get a tax relief for biogenic fuels in the transportation sector. For SNG the origin of the electricity should be renewable but the origin of the CO_2 is not important. Besides the tax exemptions, there has also been a motion that car importers manufacturers receive CO_2 emission credits when vehicles are fuelled with Swiss-made synthetic CO_2 neutral fuels. This reduces their need to lower the CO_2 value of new cars. PtG plants can also be allowed to deliver these CO_2 neutral fuels, but for SNG it is demanded that the CO_2 is supplied through ambient air capture. It might also be possible for PtG plants to trade emission reduction certificates.

The above overview of possible additional revenues for green gas on top of the wholesale market price for natural gas is summarized in Table 1. The first row shows the average market price of natural gas at TTF in the fourth quarter of 2017 (European Commission, 2018). The other rows show the total revenue that could be received for green gas, defined as the basic market price plus a certain addition as discussed in this section. These possible revenues for green gases will be used in further analyses in this report.

Table 1: Possible methane revenues and WTP for electricity following from that

	Methane revenue (€/MWh)
Market price	19.20
Market price + Dutch GoO	19.31
Market price + WTP 20%	23.04
Market price + 0.007 €/kWh (support Germany)	26.20
Market price + Dutch certificate	37.40
Market price 95% + premium (support Italy)	82.77
Market price + 0.1472 €/kWh (support German biogas)	166.40

2.3 Gas storage

Methane and hydrogen can be stored in several ways. The most important storage facilities are high-pressure steel tanks, salt caverns and depleted natural gas reservoirs. This section will discuss all three storage options.

2.3.1 High-pressure steel tanks

High-pressure steel tanks are very suitable for storage or relatively small to medium volumes of gas. Most PtG plants that currently exist store their hydrogen in high-pressure steel tanks since this technology is state-of-the-art and widely available with high capacities and relatively low costs (Gahleitner, 2013).

The costs of high-pressure steel tanks for hydrogen storage are extensively discussed in STORE&GO Deliverable 8.3[i]. In this report we take into account the base case assumptions from this Deliverable of 100 €/m^3 capital expenditures (CAPEX), which translates into 1112 €/kg or 33.33 €/kWh (LHV).

2.3.2 Salt caverns

Geological formations are already widely used to store natural gas and bring flexibility in the gas system. Salt cavern storages are very flexible since they have very high withdrawal and injection rates and low cushion gas[j] requirements (Kepplinger et al., 2011; Ozarslan, 2012). Salt caverns are the most suitable geological formations for hydrogen storage as they are inert with respect to hydrogen and extremely gas tight (Crotogino et al., 2010). The technology of storing hydrogen in salt caverns is very similar to the storing of methane in salt caverns. The most important difference is the density of the gas, which is three times lower for hydrogen compared to methane meaning that a salt cavern can contain less hydrogen than methane in the same volume. This makes hydrogen storage more expensive than storage of natural gas. The advantage of salt caverns is that it allows rapid injection and withdrawal to respond to market conditions and other short-term events.

STORE&GO Deliverable 8.3 contains more information on hydrogen storage in salt caverns and includes cost estimates for the technology. In this report we take into account the base case assumptions from this Deliverable of CAPEX of 0.11 €/m^3 cavern space. It is possible to store about 280 kWh/m^3 hydrogen (Kepplinger et al., 2011), which means that for hydrogen costs are about 0.036 €/kWh. Since the energetic density of methane is roughly three times as high as that of hydrogen, we assume that we can store 866 kWh/m^3 methane in a salt cavern[k], which means that for methane the costs of storage are roughly 0.012 €/kWh. These values translate into storage costs of 1.19 €/kg for hydrogen and 0.16 €/kg for methane.

A typical salt cavern of 500,000 m^3 (Kepplinger et al., 2011) will cost €5 million and is able to store roughly 140 million and 433 million kWh of hydrogen or methane respectively. In terms of weight this means a typical cavern can store roughly 4,200t hydrogen or 31,000t methane. The yearly operational costs are estimated to be 2% of CAPEX.

2.3.3 Depleted natural gas reservoirs

Although salt caverns are relatively large compared to high-pressure steel tanks, their size is rather limited compared to what can be stored in depleted natural gas reservoirs. For seasonal storage of gas, salt caverns might not be large enough.

Although methane can be stored at large-scale in depleted natural gas reservoirs, this might be different for hydrogen. The hydrogen could interact with the minerals and microorganisms in the reservoir (Amid et al., 2016; Crotogino et al., 2010). Besides, in the configuration studied in this report, very large-scale (seasonal) storage of hydrogen is not considered, as we only study PtG methanation plants, whereby hydrogen is just stored as an intermediate product. The very large volumes that could be stored in depleted natural gas reservoirs are therefore potentially only interesting for methane, depending on the size of the plant and application of the technology.

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[i] D8.3: Report on the costs involved with PtG technologies and their potentials across the EU. Due date: 30 April 2018.

[j] Cushion gas is the gas volume required in the storage to maintain an adequate storage pressure. Although this gas is present in the reservoir, it cannot be used.

[k] Just as (Kepplinger et al., 2011) does, these calculations are based on the lower heating values (LHVs) of the gases, which are 3.00 kWh/Nm^3 for hydrogen and 9.28 kWh/Nm^3 (50.0 MJ/kg) for methane, indicating that the energetic density of methane is 3.1 times as high as that of hydrogen. Note that this is 2.9 in case the HHVs of the gases are used.

(Lord et al., 2014) give an extensive overview of costs for geological storage of hydrogen in geological formations. Their cost estimate for hydrogen storage in salt caverns was taken into account in STORE&GO Deliverable 8.3. The project "Underground Sun Storage" in Austria is the latest project, where hydrogen is stored underground[I]. For depleted oil and gas reservoirs, levelized costs for hydrogen storage are estimated to be 1.23 $/kg: about 24% cheaper than the 1.61 $/kg that was found for hydrogen storage in salt caverns. The IEA estimates cost of developing gas storage in depleted fields at up to 1.00 €/m^3 of working gas. The cost of developing salt cavern storage is higher, approximately twice the cost per cubic metre of working gas (IEA 2014).The reason for the difference is mainly the lower construction costs (no cavern development is needed) and lower compressor costs (but also lower injection and withdrawal rates). These outweigh the increased costs for cushion gas, which is 50% of the storage volume, where this is only 30% for salt caverns.

2.3.4 Summary of gas storage costs

Table 2 summarizes the findings of this section and gives the different values for the CAPEX of hydrogen and methane storage facilities. For depleted oil and gas reservoirs it is assumed that costs are 75% of the costs of salt caverns, following (Lord et al., 2014). This assumption might be, however, a bit rough. The table makes clear that geological storage of hydrogen or methane is much cheaper than storage in high-pressure steel tanks. It is important to note, however, that geological storage is only possible for very large volumes of gas. The existing natural gas network and the unrestricted addition of SNG to the natural gas network with suitable quality make it possible to physically separate the long-term and large-scale storage facilities from the PtG plant location. High-pressure steel tanks for H_2 are used for short-term intermediate storage within the plant.

Table 2: CAPEX of hydrogen and methane storages

	CAPEX				
		Hydrogen		Methane	
	€/m^3 (NTP)	€/kWh	€/kg	€/kWh	€/kg
High-pressure steel tanks	100	33.33	1112	10.78	150
Salt caverns	0.11	0.036	1.19	0.012	0.16
Depleted oil and gas reservoirs	0.08	-	-	0.009	0.12

STORE&GO Deliverable 8.3 also gives estimates for OPEX of both high-pressure steel tanks and salt caverns. These costs are estimated to be 1.5 and 2% of CAPEX respectively for the two storage techniques.

2.4 Power-to-Gas system parameters

A Power-to-Gas plant is composed of an electrolysis sub-system, connected to the electricity grid, and a methanation sub-system, connected to the H_2 supply of the electrolysis sub-system and the CO_2 supply from the CO_2 source. The two sub-systems can have different dimensioning and load changes and need to be operated accordingly. The operation for each sub-systems depends on the application and limits of the PtG system. The expected limits of the electrolysis sub-system and methanation sub-system are listed in section 2.4.1 and 2.4.2.

[I] Underground Sun Storage, RAG, Austria; https://www.underground-sun-storage.at/

In general, the operation of both systems can be split into three operating states: cold-standby, hot-standby and production. The correlation of the different operating states is shown in Figure 9. The system is designed and optimised for the expected operation.

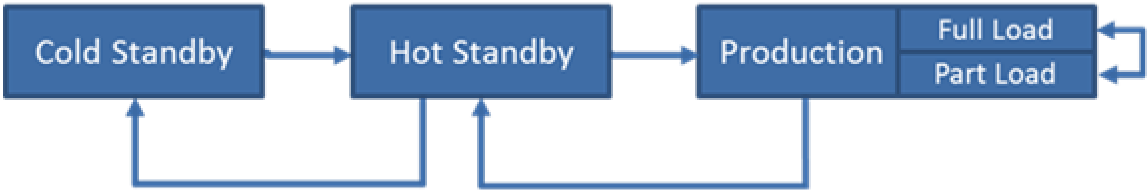

Figure 9: Different operation states of a PtG-plant and the possible changeover between states.

The changes between operation states of the electrolysis depend on the expected electricity load profile. The electricity source specifies the production of hydrogen. The minimum load of, the maximum possible load change rates of methanation without quality losses in the conversion are mostly not the same as for electrolysis. This results in the necessity of a hydrogen storage and enables options in systems design. The CAPEX and the operational expenses (OPEX) of the plant can be determined based on the system design, the electricity price and the resulting operating procedure. A comparison of OPEX with the daily gas price shows whether the operation is profitable.

For the following calculation a pressurized alkaline or PEM electrolysis is considered. The sub-system methanation can be either a chemical or a biological methanation. This report does not distinguish between different technologies for electrolysis and methanation, because the small differences between the technologies are neglected for this examination. The assumption does not apply to a solid oxide electrolysis (SOEC). The costs of CO_2 storage and compression, H_2 storage and compression, gas grid injection are listed separately.
The following technical parameters and costs are based on the STORE&GO deliverable D8.3[m], where a large literature study was done. The values are used for the simulation of the optimal time profile and operation of the conversion technology during a representative year, in the perspective of the available storage capacities

2.4.1 Electrolyser

Assuming that the electrical consumption of electrolysers is today 5.13 kWh_{AC}/m^3 (NTP) and due to processing of the technology the consumption will be 4.72 kWh_{AC}/m^3 (NTP) in 2030 and 4.54 kWh_{AC}/m^3 (NTP) in 2050, the efficiency is between 69 and 78%. The calculations for today's electrolysis are based on 69% electrolyser efficiency. The following parameters in Table 3 are guidelines referring to the performance of the electrolyser sub-system used for the simulation It should be noted that an extensive literature study was carried out in D8.3.

Table 3: Process parameters of the electrolysis sub-system

Requirement	Minimum	Maximum
Load	0 %	110 %
Load change rate electrolysis	± 6 %/ min	± 20 %/ s
Load change density	1 / h	720 / h
Load change spectrum	± 0.5 %	± 100 %

[m] STORE&GO, Deliverable D8.3 Report on the costs involved with PtG technologies and their potentials across the EU

2.4.2 Methanation

The current aim is to achieve a long and continuous full-load operation of methanation. In the future, methanation will also have to be more flexible due to new fields of application. The gas composition of the product of chemical methanation changes if the temperature and pressure in the reactor system are changed too quickly. These changes must be so slow that they have no effect on gas quality. Therefore it makes sense to add a hydrogen puffer tank in between the chemical methanation and the electrolysis. The methanation unit can then be designed independent in terms of possible load change rates from the electrolyser sub-system. Ideally, cost-intensive standby can be avoided by operating as long as possible, at full or partial load.

Most studies assume that the conversion rate of hydrogen and carbon dioxide to methane is 100%. This results in a theoretical efficiency of 78% based on the heating values of hydrogen and methane. The efficiency of methanation is only informative with the degree of conversion. The lower the degree of conversion, the higher the efficiency. In addition, heat utilization within the PtG process chain can increase the overall efficiency of the methane production. In the following, it is assumed that the degree of conversion is 100% and the efficiency refers only to gaseous input and output. Electrical consumption within methanation is considered on the cost side, but is not included in the efficiency. Table 4 gives an overview of actual process parameters of the sub-system methanation.

Table 4: Process parameters of the sub-system methanation

Requirement	Minimum	Maximum
Load	40 %	100 %
Load change rate electrolysis	± 0.5 % / min	± 10 % / min
Load change density	1 / h	60 / h
Load change spectrum	± 0.5 %	± 100 %

2.5 PtG plant costs

In D7.5[n] and D8.3[o], partners have evaluated the current CAPEX of PtG processes. The analysis includes data gathered from relevant literature, cost estimates and experience values from STORE&GO project partners as well as from the STORE&GO demo plants. D 8.3 is based on papers where the costs are derived from offers and price inquiries, manufacturers- and expert-elicitations. Literature sources, where only assumptions are made or only other literature sources are summarized, are not taken into account.

In D5.2[p] the OPEX of a Power-to-Gas plant are pointed out. The OPEX can be grouped into two main categories: fixed and variable OPEX, respectively. Fixed OPEX are independent on operation hours and can be expressed in €/a. Variable OPEX are related to the plant utilization and can be expressed in $€/kW_{el} * h$.

2.5.1 CAPEX

The costs in Table 5 refer to a 1 MW plant and are based on the results of D7.5, D8.3 and own empirical values for the current point in time. Larger plants are considered in chapters 4 and 5.

n D7.5: Report on experience curves and economies of scale
o D8.3: Report on the costs involved with PtG technologies and their potential across the EU
p D5.2: Interim report of benchmarks and analysis description and load profile definitions

Table 5: CAPEX for a PtG plant producing methane, based on a 1 MW electrolyser in 2017 and the literature research of STORE&GO D8.3[q].

	Component	1 MW_{el}/0.537 MW_{SNG} PtG System
1	Electrolyser system (€2017)	1'180'000
2	Hydrogen compressor[r] (€2017)	-
3	Hydrogen storage[s] (€2017)	77'966
4	Carbon dioxide compressor (€2017)	235'735
5	CO_2 storage[t] (€2017)	19'320
6	Methanation reactor (system) (€2017)	322'404
7	Gas grid injection station (€2017)	75'000
Total components (€2017)		**1'910'425**
Installation (10%) (€2017)		191'043
Planning & design (18%) (€2017)		343'876
Replacement costs (€2017)		197'672
Total (€2017)		**2'505'456**

For detailed research results and sources, please read the public Deliverable D7.5 and D8.3.

2.5.2 Variable OPEX

Variable OPEX include in particular the provision of consumption of raw materials and energy. These include electricity for the operation of machines, pumps and compressors, heat for temperature control, nitrogen, carbon dioxide and instrument air. In addition, there is the disposal of continuously produced media such as condensate (waste water) and, if necessary, the operation of a flare. Electricity for operating the electrolyser is included in the gas production costs via a separate matter of expense.

The variable OPEX depend on the operating status (see 2.4) and the prices for electricity, thermal energy, raw materials and auxiliaries. The safety-relevant elements are active in all states. The consumption is very low and can be neglected. In cold standby mode, no gas is produced and no media are circulated. Methanation is not ready to process carbon dioxide. The electrolysis can be put into operation in a few seconds or minutes from cold standby, depending on type and manufacturer. The OPEX in cold standby can be neglected. In the hot standby state no gas is produced, but all plant elements and media are at operating temperature and pressure. Methanation is ready to convert

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[q] STORE&GO, Deliverable D8.3 Report on the costs involved with PtG technologies and their potential across the EU
[r] Not necessary, due to operation of the electrolyser at a pressure of 30 bar
s The size is equivalent to the volume of hydrogen produced during four hours of full load operation (780 Nm^3).
t The size is a quarter of the volume of hydrogen produced during four hours of full load operation (195 Nm^3).

carbon dioxide into methane. The OPEX in hot standby are very high as heat losses have to be compensated and all media circuits are active. Hydrogen and methane are produced in operating mode. Both processes have sufficient waste heat to cover the losses and, if required, to dissipate heat. All media circuits and compressors are active. The OPEX in normal operation are lower than in hot standby because there is no or less need to compensate heat losses. While operation the rejected heat of the electrolysis and the exothermal reaction of the methanation exceed the need of thermal losses. Since in today's scenarios the plants are either in full load operation or switched off and have long continuous operating states, the variable OPEX of all trades were not included in the calculations. The variable OPEX were priced into the fixed OPEX. The most relevant OPEX of electrolysis, i.e. the consumption of water and electricity, were calculated and shown individually. For methanation, the consumption and costs for the provision of carbon dioxide were listed. For future operating concepts, a distinction is made between variable and fixed OPEX.

The price for electricity is depending on the electricity market and the WTP. Thermal energy is classified into low-temperature and high-temperature heat. This covers both the purchase of heat requirements and the selling and supplying of heat for external heat sinks.
The water need of the electrolyser is calculated separately to show the less influence on the hydrogen and methanation production costs. It is assumed, that water costs 0.00069 €/kg and a water need of 200% of the stoichiometric need. Assumptions all originate from STORE&GO Deliverable 8.3[u].

CAPEX and OPEX for carbon capture and use technology are not easy to define in general. The costs strongly depend on concentration of carbon dioxide in the source stream. CO_2 sources are energy industry, chemical industry, iron and steel production, cement production paper production and biogenic CO_2 sources. The costs differ a lot depending on the source and capture technology. It seems more practical to value the needed CO_2 as an operating supply and therefor represent its costs as per ton CO_2 depending on its source and sequestration technology, respectively. A detailed overview of the average capture costs for CO_2 related to industrial sectors will be available in Deliverable D7.5[v]. For the calculations in our publication the costs of CO_2 are fixed at 50 €/tCO_2.

[u] D8.3: Report on the costs involved with PtG technologies and their potentials across the EU. Due date: 30 April 2018

v D7.5: Report on experience curves and economies of scale

2.5.3 Fixed OPEX

The costs of guaranteeing operational readiness are fixed OPEX. These include, among other things, personnel costs, insurances, room costs and maintenance costs for the production facilities. Depending on the complexity and moving party of each unit, the fixed OPEX can vary. Table 6 gives an overview of the fixed OPEX for the relevant components of a complete PtG system.

Table 6: Fixed OPEX for a PtG plant in 2017. The costs are defined as a percentage of the CAPEX. The CAPEX are taken from Table 5.

Component	**% of CAPEX**	**1 MW_{el}/0.537 MW_{SNG} PtG System**
Electrolyser system	4	47'200
Hydrogen com-pressor	3	-
Hydrogen storage	1.5	1'169
Carbon dioxide compressor	3.5	8'251
Carbon dioxide storage	3.5	676
Methanation reac-tor (system)	10	32'240
Gas grid injection station	2	1'500
Total yearly fixed OPEX (€/a)		**91'037**

3 Economical Operation of PtG: Current situation

In this chapter we describe the current situation of the PtG technology and the optimal time profile and operation of the conversion technology during a representative year. Each of the four operating strategies that were presented in Figure 4 will be discussed.

3.1 Continuous operation of electrolyser and methanation plant

In the “continuous operation” mode, the plant purchases electricity and sells gas through long-term contracts. Costs and revenues are known on forehand and (large) storage facilities are not needed. Optionally, the PtG plant can participate in the electricity balancing markets by offering (part of) the capacity as balancing reserve. When the plant is operated at full load, only positive control reserve can be offered (that is, the plant can reduce its electricity consumption when required). To offer negative (secondary or tertiary) control, or primary control (which should be symmetrical) the plant cannot run at full load since it has to be able to increase its consumption when required.

In this report it is assumed that the long-term electricity contract has the same price as the yearly average day-ahead market price. Table 7 shows the calculated methane production price for different electricity prices from different countries in recent years. For the calculations, the default values given in STORE&GO Deliverable 8.4[w] are used, taken from STORE&GO Deliverable 8.3[x]. The calculations assume the plant is operated continuously throughout the year and buys electricity at the average price in the respective day-ahead electricity markets.

Table 7: The total methane production costs for different electricity prices.

Day-ahead market	Power price (€/MWh)	Methane costs (€/MWh)	Methane costs (€/m^3)
Denmark (DK1) 2015	22.90	120.21	1.24
Germany 2016	28.98	131.53	1.35
Netherlands 2016	32.24	137.59	1.42
France 2017	44.97	161.28	1.66

As can be seen in Table 7, the methane production costs vary between 1.24 and 1.66 €/m^3 or 120 €/MWh and 161 €/MWh, depending on the electricity price. To break-even, the plant must sell the methane for at least the production price. The potential methane revenues were discussed in chapter 2.2.3. As can be seen in Table 1, the maximum revenue was estimated to be about 166 €/MWh, which is enough to recover all costs of the continuously operating PtG methanation plant, if SNG is treated like biogas in Germany. The basic revenues on the natural gas wholesale market (19.20 €/MWh) are even almost a whole order of magnitude lower than the production costs in the PtG plant.

Looking only at the marginal costs and revenues, the plant needs to pay €0.40 for water and €8.90 for CO_2 for every MWh of methane that is produced. The marginal costs of the plant does not include any additional CAPEX and fixed OPEX. The marginal costs depend on the feedstock costs of water, electricity and CO_2. Electricity vary depending on the country, market and year. Table 8 shows the marginal production costs of methane in a PtG plant. Although roughly half of the costs disappear when the CAPEX and fixed OPEX are not taken into account, the production costs remain too high to be covered by the market price of natural gas. In addition, the revenues for green gas are not

[w] D8.4: Software of the stochastic net present value (NPV) model for a bottom-up assessment of the feasibility of investment in the power-to-gas conversion and storage technology. Due date: 30 June 2018

[x] D8.3: Report on the costs involved with PtG technologies and their potentials across the EU. Due date: 30 April 2018.

sufficient (see Table 1). Only with substantial governmental support as can be received in Italy or Germany for biogas, the marginal revenues can outweigh the marginal costs.

Table 8: The marginal methane production costs for different electricity prices.

Day-ahead market	Power price (€/MWh)	Methane costs (€/MWh)	Methane costs (€/m^3)
Denmark (DK1) 2015	22.90	51.91	0.53
Germany 2016	28.98	63.24	0.65
Netherlands 2016	32.24	69.31	0.71
France 2017	44.97	92.98	0.96

3.2 Flexible operation of electrolyser and continuous operation of methanation plant

In the “flexible operation” mode of operation, gas is sold on forehand in long-term contracts whereas the electricity is purchased in short-term markets. Since the revenue of the gas is known on forehand, it is possible to determine the willingness-to-pay (WTP) for electricity – following the methodology presented in a paper at the journal Applied Energy[y]. The authors figured out, that there are currently not enough hours with sufficiently low electricity prices to become profitable. For optimistic future scenarios it is shown, those power-to-gas plants can become profitable with higher revenues and lower costs.

Table 9: Possible methane revenues and corresponding WTP for electricity

	Methane revenue (€/MWh)	WTP for electricity (€/MWh)
Market price	19.20	5.32
Market price + GoO	19.31	5.38
Market price + WTP 20%	23.04	7.38
Market price + 0.007 €/kWh (Germany)	26.20	9.08
Market price + Dutch certificate	37.40	15.10
Market price 95% + premium (Italy)	82.77	39.48
Market price + 0.1472 €/kWh (support German biogas)	166.40	84.44

As can be seen in the table, the WTP for electricity is highly dependent on the revenue of the methane. In case the revenue is only based on the wholesale natural gas market, the WTP for electricity is very low with only 5.32 €/MWh electricity. With very strong governmental support such as in Italy or Germany for biogas, the WTP for electricity can increase up to almost 40 €/MWh respectively 84 €/MWh.

The WTP for electricity can be compared to electricity prices in certain markets in certain years to determine the yearly amount of operating hours. Table 10 shows the amount of hours in a year the PtG methanation plant is able to buy electricity, using the WTP for electricity values determined in Table 9 and data from DA markets in Germany, Denmark and the Netherlands in 2015 and 2016.

[y] van Leeuwen, C and Mulder, M, Power-to-Gas in Electricity Markets dominated by Renewables; https://doi.org/10.1016/j.apenergy.2018.09.217

Table 10: Hours in the year the electricity price in the DA market is lower than a given WTP for electricity (values taken from Table 9). Sources: (Bloomberg LP, 2018a; *Nord Pool*, 2018)

WTP (€/MWh)	Hours per year electricity price in DA market is lower than the WTP					
	DE 2015	DE 2016	DK1 2015	DK1 2016	NL 2015	NL 2016
5.32	208	193	292	141	4	5
5.38	208	195	294	141	4	5
7.38	224	234	515	164	10	11
9.08	247	312	792	209	15	21
15.10	677	740	2224	430	80	164
39.48	6514	7529	8050	8164	4197	6965

As can be seen in Table 10, the possible amount of yearly operating hours is quite low when the WTP for electricity is below 10 €/MWh, especially in the Netherlands. Even with a WTP of 15.10 €/MWh, the yearly operating hours are limited, with Denmark 2015 as an exception where a plant could have been operated for a quarter of the time. With a WTP for electricity of almost 40 €/MWh caused by strong governmental support, the amount of operating hours becomes significant and investment in a PtG methanation plant might become worthwhile. One has to note, however, that these calculations assume the plant only needs to pay the wholesale market price for electricity, and is exempted from electricity taxes and grid tariffs. In reality, this might not be the case. For now, we continue with the assumption that electricity costs are limited to the wholesale market.

Figure 10 shows the hydrogen storage level (in terms of hours production stored) of a PtG plant with a WTP for electricity of 39.48 €/MWh in the German DA market in 2015. It is assumed that the methanation capacity is 74% of the output of the electrolysis. The methanation is running 8760 hours per year to sell a constant amount. As can be seen in the graph, the minimum storage level is -91, meaning that – ideally – this should be the starting level of the storage facility. The maximum level is 196, meaning that the storage facility should – ideally – be able to store 196 + 91 = 287 hours of production.

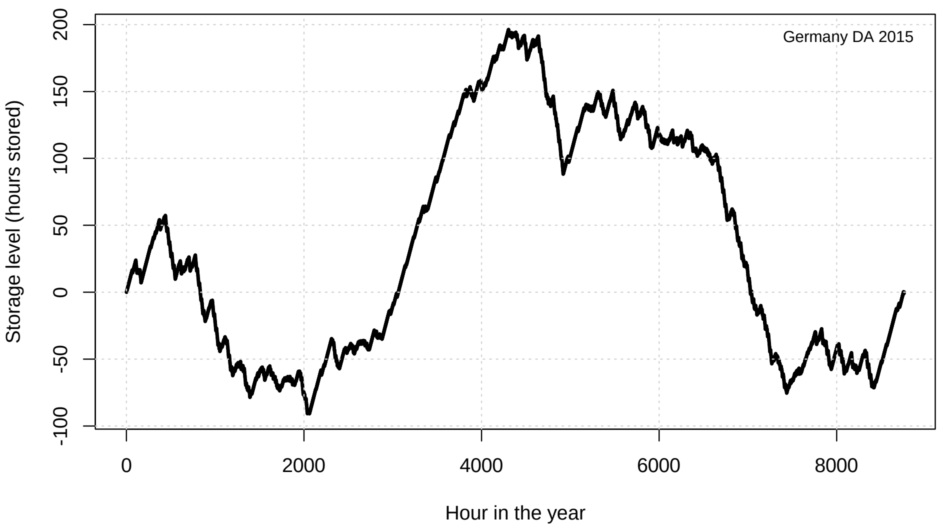

Figure 10: Level of the storage (in terms of hours production stored) throughout the year assuming a WTP for electricity of 39.48 €/MWh in the German DA market 2015 with the hourly gas selling adapted exactly to the yearly operating hours in this market (74% of the time).

Assuming that the plant operator has a long-term contract for selling the gas, he always needs to make sure the customer receives the amount of gas that was promised, during every hour of the year. Figure 10 shows that there are 91 hours in which the plant cannot deliver gas. Figure 11 shows the storage level throughout time, assuming that the plant has to produce gas when the storage is empty, even when the electricity price is above its WTP, to fulfil its obligations. Following this strategy, the plant has some gas left in the storage after the whole year: 91 hours of production are left, which is equal to the ideal starting level of the storage facility (see Figure 10).

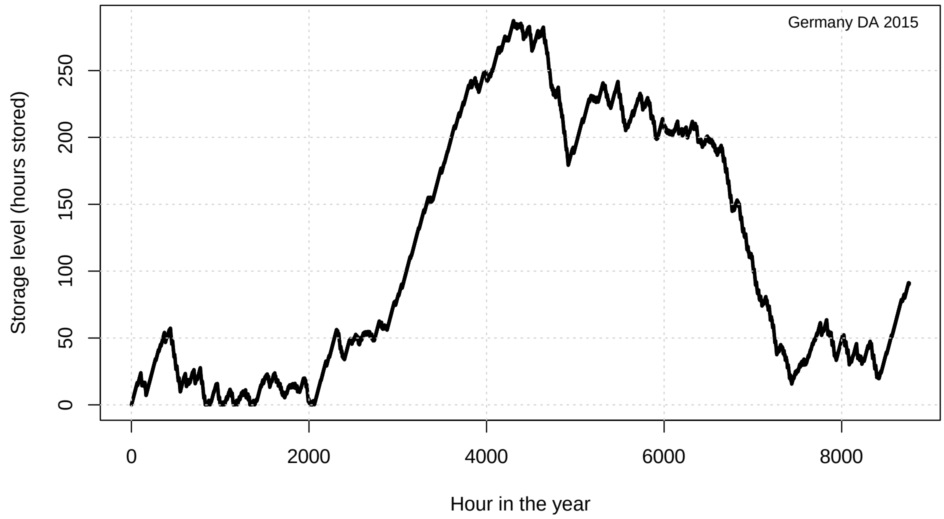

Figure 11: Level of the storage (in terms of hours production stored) throughout the year assuming a WTP for electricity of 39.48 €/MWh in the German DA market 2015 with the hourly gas selling adapted exactly to the yearly operating hours in this market (74% of the time) and assuming gas should always be produced when the storage facility is empty, ensuring gas is delivered to the customer during all hours.

The previous exercises still assume an unlimited storage size. In the situation presented in Figure 11, this means that the storage facility should be able to store at least 288 hours of production. In reality, the storage facility has a specific size that is determined during the building of the plant. This means that during some hours, production would not be possible even though the electricity price is low, because the storage is full. Figure 12 shows this principle for a PtG methanation plant with a storage capacity of 150 hours of hydrogen production.

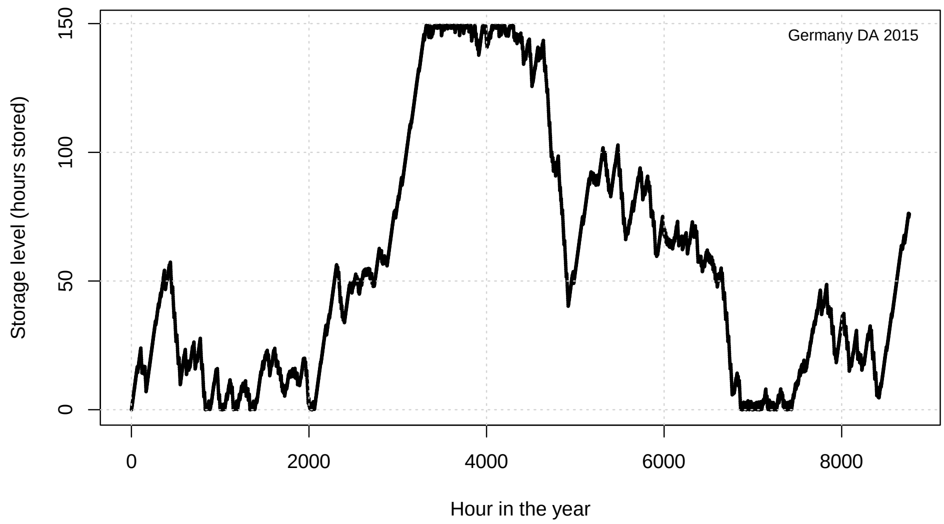

Figure 12: Level of the storage (in terms of hours production stored) throughout the year assuming a WTP for electricity of 39.48 €/MWh in the German DA market 2015 with continuous gas selling every hour equal to 74% of hourly gas production and a storage capacity limited to 150 hours production.

The operation of the PtG plant in the German DA market of 2015 can be modelled for different storage limits. For all storage limits it is possible to calculate the yearly revenues and yearly cost of the PtG plant and in this way determine the value of the storage facility.

In this example the plant is continuously selling methane at a price of 82.77 €/MWh (Italian case). The WTP for electricity of the plant is therefore 39.48 €/MWh. The plant is therefore selling an amount of methane every hour that is equal to 74.36% of the hourly production of the electrolysis.

The case without any storage is not much worse in terms of net revenue than the case with an optimal storage capacity of about one day. Very low storage volumes should not be considered: the limited savings that can be achieved in terms of electricity costs do not outweigh the higher costs (both CAPEX and OPEX) for the larger electrolyser that is needed.

Figure 13 shows the results plotted as a bar plot. The figure shows the total yearly costs for the three feedstock and the OPEX for the three main components of the plant for different storage volumes. The yearly revenues of the plant are indicated in the figure through a horizontal line: only when the yearly costs are lower than the yearly revenues, the plant makes a profit. As was indicated, this is only the case for plants with a storage volume of roughly one day production or no storage volume at all. The figure also clearly shows that electricity is the largest contributor to the yearly costs of the plant, with a share of 50 – 70% of total costs.

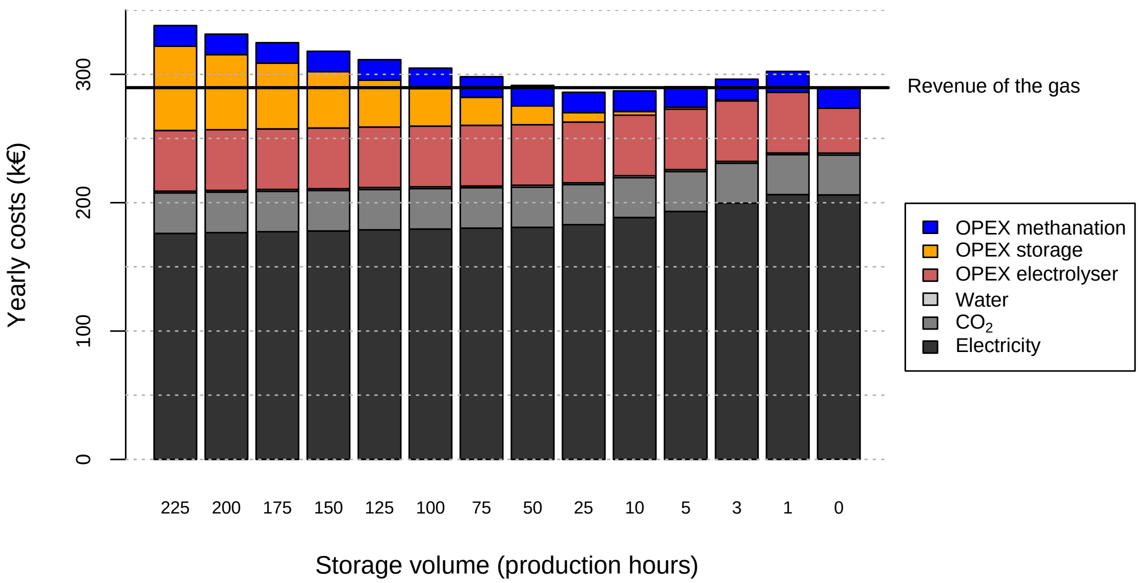

Figure 13: Bar plot of the yearly costs of a 1 MW PtG plant (0.74 MW for the no storage case) operating in the DA market in Germany in 2015 with a WTP for electricity of 39.48 €/MWh, an obligation to deliver gas every hour (74% of hourly production, or 100% in the no storage case), plotted against the available storage capacity (in hours production). The yearly revenue is drawn as a horizontal line.

The same exercise can be done for other electricity markets, other methane revenues and other assumptions with regard to the plant characteristics. This exercise just shows one of multiple outcomes, but is very illustrative.

Now it is assumed that – based on the previous analysis – it is decided to build a PtG methanation plant with an electrolyser of 1 MW, a hydrogen storage capacity of one day (24 hours), and a methanation reactor that is scaled such that it continuously uses 74.36% of the hourly output of the 1 MW electrolyser. The plant has a contract to deliver 0.40 MWh of methane at every hour throughout the year at a price of €33.07 leading to a total revenue of €289,717.

The following analysis show what will happen when this plant that is designed based on 2015 electricity market characteristics is operated in the German DA market in 2016 and subsequently in 2017.

The storage tank still has 22 hours of production left at the first day of 2016. Figure 14 shows the level in the storage tank throughout the years.

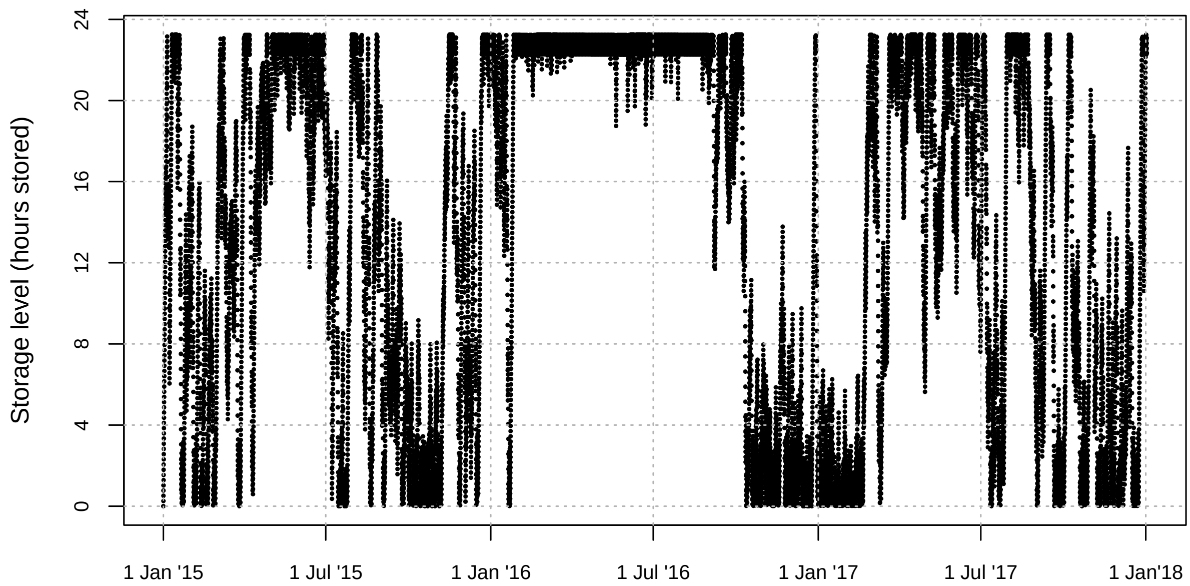

Figure 14: Level of the storage (in terms of hours production stored) throughout the years 2015 – 2017, assuming a WTP for electricity of 39.48 €/MWh in the German DA market in the years 2015, 2016 and 2017.

As can be seen in the figure, the storage tank is completely full for most of the year 2016. In this year, wholesale electricity prices were low. The electricity price was below the PtG plant's WTP for almost 86% of the time, meaning that with the configuration of the plant (selling 74% of the hourly production every hour and a 24 hour storage tank), opportunities for revenues are missed. Net revenues were found to be about €9,000 (compared to about €4,000 in 2015). In 2017 electricity prices were much higher again and the plant needs to operate for many hours even though the electricity price is higher than the WTP. The plant makes a loss of about €16,000 – cancelling out the revenues of 2015 and 2016 and making an overall loss over the three year period. The difference in making a loss or revenue is solely determined by the electricity prices.

3.3 Continuous operation of electrolyser and flexible operation of methanation plant

In the operation mode of "flexible gas", the electricity is purchased by long-term contracts and the plant is operating continuously. The gas, however, is not sold continuously, but stored and sold at times with high gas prices. For this option to be beneficial, the benefits of selling the gas at times with high prices should be higher than the costs of the gas storage.

Since the costs of the plant are known on forehand, it is possible to determine the willingness-to-accept (WTA) for the gas. This is equal to its production costs – which were determined already in section 3.1 for different electricity prices (Table 7 and Table 8). Different from the continuous operating mode that was discussed in section 3.1, the PtG plant is now not continuously selling the produced gas at a fixed average market price, but adapting to the fluctuating wholesale gas market. When calculating the gas production costs, the gas is stored in high-pressure steel tanks and only sold if the gas price is correspondingly high. The case for storage in a salt cavern is discussed in the future scenarios if the PtG plant is 10 or 50 MW in size.

For these calculations we take into account the country and year with the lowest electricity prices that were recently observed in Europe: Denmark (DK1) 2015. We assume that the plant is continuously operating throughout the year and the plant thus pays the average electricity price of 22.90

€/MWh at which the marginal production costs of methane become 51.91 €/MWh (see Table 8). This is thus the WTA of the gas. As can be seen in Figure 8, the price of natural gas at the wholesale market generally fluctuates between roughly 10 and 25 €/MWh, which is significantly lower than the WTA. Under the Italian support scheme (see section 2.2.3), the plant receives 95% of the wholesale market price plus an additional bonus of 64.53 €/MWh. The bonus alone is already more than enough to compensate the marginal production costs of the gas. The second best support for green gas production listed in Table 1, the Dutch certificate with a value of 18.20 €/MWh, is not enough to compensate the production costs, also not in combination with the wholesale market price of natural gas, which is in principle never above the required 33.71 €/MWh (51.91 – 18.20).

It is possible to do some calculations to find the additional revenues a storage facility can bring, similar as what was performed in the previous section "flexible electricity". Table 11 gives some statistics on the wholesale natural gas market prices at TTF in the years 2015 – 2017 (as presented in Figure 8). The table shows for every year the average price and the share of the year that the price was above a certain threshold.

Table 11: Some statistics on the wholesale natural gas weekday TTF prices per year: the average price and the share of the days that the price was higher than a certain threshold. Source: (Bloomberg LP, 2018b)

	Average (€/MWh)	>20 €/MWh	>18.5 €/MWh	>15 €/MWh
2015	19.82	55%	76%	97%
2016	14.02	0%	2%	25%
2017	17.33	17%	28%	93%

The table makes clear that there are significant year-to-year variations, making it very difficult to design a plant that can optimally profit from fluctuating natural gas prices. Another factor that makes it difficult to profit from fluctuating prices in the gas market is the fact that prices do not vary strongly from day-to-day, but vary more on a monthly or even seasonal basis (see Figure 8). Because gas prices are settled per day, there are no hourly variations. This all means that the plant cannot really profit from a small-sized storage (e.g. 1 – 3 days of production) but only profits from different market prices when the storage facility is much larger (weeks, months). The larger the storage, however, the higher the costs, and the variations in gas prices are not that large that these high costs will be covered.

A 1 MW PtG plant produces 17.5 kg hydrogen per hour (195 Nm^3/h), which is further converted into 34.9 kg (0.54 MWh) methane. Table 12 gives an overview of different storage capacities, its costs in terms of CAPEX and OPEX (see section 2.3) and the price difference that is required: i.e. the amount of money that should be earned extra for every MWh methane that is sold to compensate for the yearly OPEX.

Table 12: Required price difference (i.e. the amount of money that should be earned extra for every MWh methane that is sold) to compensate the yearly OPEX of the methane storage

	Hour	Day	Week	Month	Year
Storage volume (kg CH_4)	35	837	5,856	25,095	305,326
Storage volume (MWh CH_4)	0.54	13	90	387	4,707
Storage CAPEX (k€)	5	125	878	3,764	45,799
Storage OPEX (€/year)	78	1,882	13,175	56,464	686,983
Required price difference (€/MWh)	0.11	2.70	18.97	81.31	989.34

One hour methane storage does not make much sense since the price of natural gas at the whole-sale market is set per day – and not per hour as is the case in the electricity market. So, although the plant needs to earn only €0.11 more for every produced MWh methane to pay for the yearly OPEX, this is difficult to reach in practice. If the plant builds a storage facility to store production of one month, it should earn an additional 81.31 €/MWh methane produced. The prices do not vary this much, as is visible in Figure 8 and Table 11.

3.4 Flexible operation of electrolyser and methanation plant

In the “all flexible” operation mode, both electricity purchasing and gas selling are not arranged on forehand but are arranged in the short-term markets. The difficulty in this option is that the WTP for electricity and the WTA for gas depend on each other and are therefore hard to determine for a given point in time.

There are several ways to operate the plant within this mode. The most straightforward one is a simplification of the “*flexible electricity*” mode that was discussed in section 3.2: instead of being obligated to sell the gas continuously throughout the year, the plant can decide not to operate the plant and not deliver gas when electricity is too expensive. The main problem of this operating strategy is the need for the methanation reactor to switch on and off when required. Assuming that this is possible without restrictions and additional OPEX we can run the plant again in the year 2015 in the German day-ahead market, as was done in section 3.2. It is found that the plant will not sell gas during 598 hours that year. Due to this, the income decreases by €19,778 (from €289,717 to €269,940) but the savings in electricity are larger with €22,077. Because there are also less expenses for water and CO_2, overall the revenues are more than €4,500 higher than in the case where methane must be sold continuously (€8,281 versus €3,762).

3.5 Conclusion on operating concepts of today's plants

In the previous sections, the effects of different operating concepts on gas production costs were examined. The price of electricity for electrolysis and the sale of synthetic natural gas were either traded on the short-term market or determined by long-term contracts. All four operating concepts show that economic plant operation (low gas production costs) is possible for very low electricity prices and simultaneously high operating hours.

The high number of operating hours cannot be achieved with a flexible power supply concept (operation at low electricity costs) under current market conditions. There are only a few hours a year when electricity is traded on the market at low prices. An opportunity to reduce gas production costs is to increase the workload of methanisation by operating electrolysis and methanisation separately. This is achieved by an intermediate storage tank for hydrogen. Nevertheless, the cases considered have shown that under the current conditions the gas production costs only decrease slightly or not at all. In addition, a storage for the synthetic methane on site was examined to have the opportunity to sell the gas in times of high prices. The gas productions costs are not influenced positive. One reason for this is that the investment costs for the storage facility are too high and the operating costs of the main elements electrolysis and methanisation are currently very high. The investment costs for electrolysis and methanisation are very high due to individual production and site-specific adaptations.

The following chapters show the potential of PtG in the future when electricity prices fall and are variable, PtG is mass-produced and investment costs and fixed operating costs fall as a result.

4 Development of future conditions

Chapter 3 discussed the operation of a PtG methanation plant in different operating modes under current market conditions. This chapter will discuss the future market conditions and in chapter 4.4 the production costs of different future PtG plant sizes and operating szenarios.

The share of energy from renewable energy sources will increase in all sectors. However, complete electrification of all sectors is hardly possible. The EU even expects the share of liquid and gaseous fuels to stay high or even increase. It is not yet possible to say what share of liquid and gaseous energy sources is produced synthetically. The start of industrial production of synthetic fuels in continuous operation, the rising cost of CO_2 certificates, temporary surplus of renewable energy and seasonal fluctuation of electricity and gas demand, will help to have profitable business cases for PtG plants in future. The future of green gases is explored in the public STORE&GO Deliverable D8.1[z].

Regarding energy imports, a modest trend is projected and shown in Table 13. The import dependence peaks in 2040-45 under 59% and declines marginally to just under 58 % in 2050. With regard to the EU28 domestic gas production, the scenario reveals persistently decreasing production in most countries following historic trends and exhaustion of resources (particularly in the UK and in the Netherlands). At the same time, gas imports will increase considerably both in the form of pipeline and LNG. The highest rises in import dependency between 2010 and 2030 are observed in the regions of Central-West EU (GE, FR, NL, BE, LX) and in UK+Ireland mainly determined by the decrease in local gas extraction in Netherlands and UK respectively and continuous gas demand (European Commission 2016).

Table 13: EU energy net imports and import dependency (European Commission 2016)

		2015	2020	2025	2030	2035	2040	2045	2050
Solids	ktoe	129,695	116,099	98,394	83,855	62,251	42,781	30,886	21,705
Oil	ktoe	556,140	532,001	529,826	523,615	525,540	528,066	532,091	536,465
Natural gas	ktoe	269,292	279,116	296,557	295,088	319,712	339,699	343,969	332,706
Electricity	ktoe	1,761	1,501	779	175	147	23	16	-21
Import dependency	%	55,9	55,4	56,7	56,6	58,0	58,8	58,9	57,6

With the further development of PtG technology and changes in prices and costs, part of the imported natural gas could be produced synthetically. In the future, seasonal storage of methane from large plants might enable the use of salt caverns for storage. Salt caverns are much cheaper than high-pressure steel tanks in terms of energy stored (see Table 2). The main changes that can be expected in the different cost and revenue parameters will be discussed (section 4.1, 4.2 and 4.3), just as their consequences for the PtG plant operation (section 4.4).

4.1 Power-to-Gas system parameters

It is expected that the future systems will hardly differ from today's systems in terms of design and functionality. A slight decrease in the specific energy consumption of hydrogen production is expected. Full conversion of CO_2 into CH_4 is still assumed to simplify the calculation. A change in the

[z] D8.1: Exploring the future for green gases. Due date: 31 August 2017

limit values for the maximum H_2 concentration in the SNG feeding into the natural gas network would reduce the CAPEX and the OPEX. Future limits and requirements for synthetic gas were discussed in detail in D8.2[aa].

The lifetime of the plant is expected to be 20 years. The lifetime of 20 years is valid for all system components except the electrolysis stacks and SNG storage. The lifetime of the electrolysis stacks is only 10 years and of the SNG storage 60 years.
The PtG system of the future will consist of an electrolyser with a hydrogen storage to decouple the operation of the electrolysis and the methanation. To be independent from the CO_2 source, a CO_2 storage according to the size of the hydrogen storage is necessary. A storage tank was provided, as the CO_2 separation technology would otherwise have to be run with the load curve of the methanisation in order to avoid CO_2 waste. So PtG can be used as CCU and then no CO_2 should be emitted into the atmosphere. The size is depending on the electricity supply for the electrolyser and cost improvement.

4.1.1 Electrolyser

Due to the further development of electrolysis technology, an increasing efficiency from today 69% (5.09 kW_{AC}/m^3) up to 75% (4.72 kW_{AC}/m^3) in 2030 and up to 78% (4.54 kW_{AC}/m^3) in 2050 is assumed for alkaline and PEM electrolysis in the years 2030 and 2050. SOEC can also play a role in the future electrolysis market. Currently SOEC is still new on the market and in research projects efficiencies of up to 80% have been measured for the SOEC system (Sunfire 2018). With an existing heat source to generate steam for SOEC, even higher efficiencies are expected in the future.

The investment costs decrease over the years as the electrolysis stacks are manufactured in series and the electrolyser systems are supplied in standardised sizes. In this way the overall investment can be reduced. The electrolyser stack has compared to the other components a lifetime of 10 years. The costs for exchange of stacks are 30% of the electrolyser system CAPEX.

4.1.2 Methanation

The cost of the methanation system is expected to decrease in the future due to standardisation and series production. Costly gas processing can also be eliminated if the feed-in conditions for the synthetic gas change. The following assumptions were made for the assessment of gas production costs: The conversion from CO_2 to CH_4 is 100% without gas losses in gas processing units. This results in an efficiency of 78% (HHV) if only the combustible gases at the inlet and outlet are considered. The efficiency increases with increasing H_2 content in the process gas. An internal (and external) use of the waste heat of the methanation increases the efficiency.

4.2 PtG plant costs

To evaluate PtG plant operation in the future, it is important to discuss the developments that can be expected in all cost and revenue parameters that influence PtG plant operation.

4.2.1 CAPEX

The PtG technology is almost fully developed when estimating the costs for the years 2030 and 2050. and serious cost reductions and efficiency improvements are expected. STORE&GO Deliverable 8.3[bb] gives an overview of actual costs and STORE&GO Deliverable 7.5[cc] gives an overview of cost reductions of the main PtG plant components (electrolyser, methanation reactor and CO_2 capture) for 2030 and 2050 that can be expected due to technological learning curves. To get a detailed

[aa] D8.2 Report on the acceptance and future acceptability of certificate-based green gases. Due date: 30 April 2018
[bb] D8.3: Report on the costs involved with PtG technologies and their potentials across the EU

[cc] D7.5: Report on experience curves and economies of scale. Due date: 31 October 2018

view on technological learning, a component-based approach was developed with the model CoL-LeCT - Component Level Learning Curve Tool. The costs are thereby stated as real costs (reference year 2017, €2017). In D7.5 no significant changes in technology, like an implementation of additional functions or efficiency improvements, have been taken into account for calculating the future CAPEX. Reductions for specific CAPEX for individual power-to-gas plants in consequence of up-scaling of nominal power, according to the reference value used in the experience curve analysis, have not been considered in Deliverable D7.5. These effects will be handled separately in Deliverable 7.7[dd]

On basis of D7.5 and a preliminary report of D7.7 the CAPEX of the electrolyser and the methanation system are expected. Basis for the calculation of the technology learning curves are a 5 MW_{el} system. The cost calculation for 2030 and 2050 is based on PEM electrolysis and chemical methanation. The costs are calculated with the cost predictions of D7.5, up-scaling calculations from D7.7 and own assumptions.

Technology learning curves of AEC systems show lower potential for cost reductions compared to the other investigated electrolysis technologies. With calculated specific CAPEX in 2050 of about 440 $€_{2017}/kW_{el}$ for a 5 MW_{el} electrolyser unit they are expected to be significantly higher than stated for PEMEC systems with about 275 $€_{2017}/kW_{el}$.

The experience curves for catalytic and biological methanation systems show similar trends for cost reductions. The CAPEX for biological methanation reach lower levels in the long term. This is mainly driven by the fact that the relative increase in cumulative produced volume has to be substantially higher compared to catalytic application to reach presumed technology production share levels. Additionally, biological methanation misses the catalyst component in contrast to catalytic reactor, which is expected to gain relatively low learning effects compared to other components in the reactor module. Despite this, CAPEX for both technologies are on a similar level throughout the investigated period reaching values of 250 €2017/kW_{SNG} (catalytic) and 200 €2017/kW_{SNG} (biological) in 2050 under the presumed conditions (2.69 MW_{SNG}). However, note that specific costs imply the same system scale, while biological methanation is actually not suitable for large scale application. Thus, these cost advantages will be inverted then by expectable scaling effects. The specific costs for a 1, 10 and 50 MW_{el} electrolyser system and an equivalent methanation system is shown in Table 14 for 2030 and 2050.

Table 14: Cost parameters of the sub-system electrolyser and methanation

	2017	**2030**			**2050**		
	Electrical input of the electrolyser ($MW_{el,AC}$)						
	1	**1**	**10**	**50**	**1**	**10**	**50**
Electrolyser system ($€_{2017}/kW_{el}$)	1180	665	470	415	350	245	220
Energy output of the methanation reactor (MW_{SNG})	0.538	0.585	5.85	29.25	0.608	6.084	30.42
Methanation system ($€_{2017}/kW_{SNG}$)	600	530	375	295	335	235	185

Compared to the calculations in D7.5, D7.7, the PtG system and the calculation of the future gas production costs are expanded and covers a hydrogen storage, carbon dioxide compressor and

[dd] D7.7 Analysis on future technology options and on techno economic optimization

storage, injection station and SNG storage. The discount rate is 6 % for all units. However, it has to be pointed out that the development of the power-to-gas technology is subject to fundamental energy and climate policy decisions. As a result, the development of the CAPEX for power-to-gas systems is uncertain. The expected CAPEX of balance of plants and additional costs for the sub-systems electrolyser and methanation are listed in Table 15.

Table 15: CAPEX of balance of plants and additional costs for the sub-systems electrolyser and methanation

	2017	**2030**			**2050**		
Size ($MW_{el,AC}$)	**1**	**1**	**10**	**50**	**1**	**10**	**50**
Hydrogen storage ($€_{2017}/m^3$ H_2)	100	75	75	75	50	50	50
CO_2 storage ($€_{2017}/m^3$)	100	50	50	50	50	50	50
CO_2 compressor ($€_{2017}$/kg)	2465	1232.5	1232.5	1’000	1'000	750	750
Gas grid injection station ($€_{2017}$)	75’000	75'000	75'000	75'000	50'000	50'000	50'000
SNG storage ($€_{2017}/m^3$)	100	50.00	50.00	0.08	50.00	50.00	0.08
Additional costs for installation (% of CAPEX)	28%	10%	10%	10%	10%	10%	10%
Additional costs for planning, design, etc. ($€_{2017}$)	0	100'000	140'000	160'000	100'000	140'000	160'000

4.2.2 Variable OPEX

The variable OPEX consist of the provision of heat for hot standby and the consumption of electrical energy for all equipment in cold and hot standby as well as operation mode. The electrical energy for the electrolyser sub-system in operation is listed separately. All safety-relevant elements of the electrolyser and the methanation sub-system are in operation in all states. In cold standby, antifreeze mode is added if required. In hot standby operation, the plant is kept at operating temperature and all media are circulated. The methanation is ready for the admixture of CO_2. The heat can be provided by external heat sources or electrically. No heat needs to be provided during operation, as the electrolysis produces waste heat and the methanation process is exothermal. The electrical consumption in operation is the same as in hot standby.

Table 16 shows the variable OPEX for a PtG plant in the years 2030 and 2050 depending on the electrical and thermal energy demand in each state. The variable operating costs were calculated with a price for thermal energy of 50 €/MWh and for electricity of 25 €/MWh. Variable OPEX in 2050 is slightly lower than in 2030 due to the assumption of efficiency improvements. The electricity prices for the operation of the electrolysis are depending on the operation concept and conditions of purchase.

Table 16: Future variable OPEX for a PtG plant in 2030 and 2050. The costs are defined as € per operation hour per installed MW_{el}.

	variable OPEX (€$_{2017}$/h/MW_{el})		
Component	**Cold Standby**	**Hot Standby**	**Operation**
Electrolyser system 2030	0.05	1.50	0.50
Electrolyser system 2050	0.05	1.13.	0.38
Methanation system 2030	0.05	3.125	0.625
Methanation system 2050	0.05	2.50	0.50

Table 17: Assumption of the thermal and electrical energy consumptions for a PtG plant in 2030 and 2050. The energies are defined as kWh per operation hour per installed MW_{el}.

	Energy consumption (kWh/h/MW_{el})		
Component	**Cold Standby**	**Hot Standby**	**Operation**
Electrolyser system 2030			
Thermal	0	20	0
electrical	20	20	20
Electrolyser system 2050			
Thermal	0	15	0
electrical	15	15	15
Methanation system 2030			
Thermal	0	50	0
electrical	20	25	25
Methanation system 2050			
Thermal	0	40	0
electrical	20	20	20

4.2.3 Fixed OPEX

For future operating concepts, a distinction was made between variable and fixed OPEX. This is necessary because the systems have very different times of presence in the respective operating modes, depending on the power supply concept. In particular, the additional OPEX for hot standby and the discarding of off-spec gas during start-up are of importance for the variable OPEX. The discarding of off-spec gas can be neglected here, since the systems remain in hot standby and the discard for the electrolysis is zero and for the methanation it depends on the plant concept (recirculation or membrane). The discard time is around 15 minutes.

STORE&GO Deliverable 8.3 also gives estimates for OPEX of both high-pressure steel tanks and salt caverns. These costs are estimated to be 1.5 and 2% of CAPEX respectively for the two storage techniques.

Table 18: Fixed OPEX in % of CAPEX

	2017	2030			2050		
	Plant Size / MW_{el}						
	1	1	10	50	1	10	50
Electrolyser system (% of CAPEX)	4	3	3	3	2	2	2
Hydrogen storage (% of CAPEX)	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Methanation system (% of CAPEX)	10	5	5	5	3	3	3
CO_2 storage (% of CAPEX)	3.5	1.5	1.5	1.5	1.0	1.0	1.0
CO_2 compressor (% of CAPEX)	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Gas grid injection (% of CAPEX)	0.0	1.0	1.0	1.0	1.0	1.0	1.0
SNG storage (% of CAPEX)	0.0	1.0	1.0	2.0	1.0	1.0	2.0

4.3 Energy and CO_2 market

The costs for the feedstocks are included in the variable OPEX. The feedstock costs of the PtG methanation plant consist of costs for water, CO_2 and electricity, whereby water costs are almost negligible (at least in Western Europe).

4.3.1 Technical CO_2 provision costs

In the calculations for the current market conditions (chapter 3) we assume CO_2 costs are 50 €/tCO_2. For future development, the EU ETS market will influence the CO_2 supply for PtG systems. In the long-term, and in particular from 2040 onwards, the level of the ETS price increases significantly (see Figure 15 and Table 19). This is the consequence of a decreasing supply of allowances in line with the yearly linear reduction factor that reduces the cap substantially over time and a combination of energy supply factors (European Commission 2016).

Figure 15: Development of ETS emissions and ETS carbon prices (European Commission 2016)

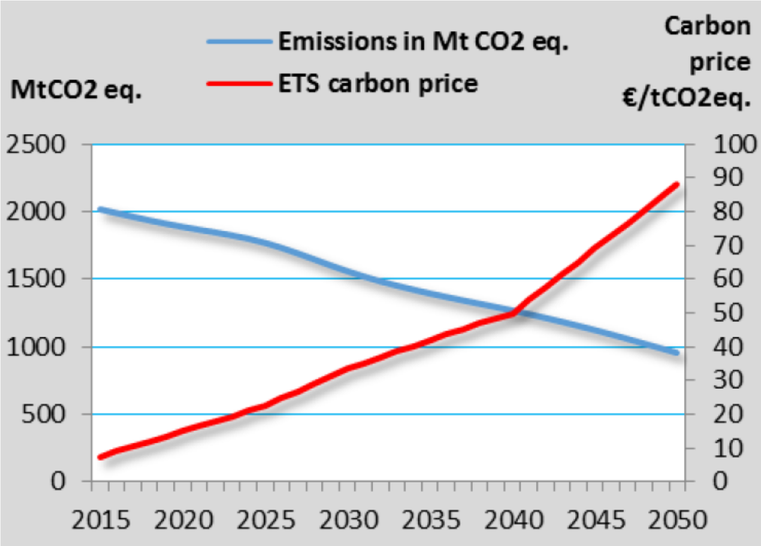

Table 19: Development of ETS emissions and ETS carbon prices, own calculations based on (European Commission 2016)

	ETS Emissions / $MtCO_2eq$	**ETS Carbon Prices / €/tCO_2eq**
2015	2017	10
2020	1887	18
2025	1769	26
2030	1559	34
2035	1395	42
2040	1269	50
2045	1124	70
2050	955	90

For the calculation of future scenarios, the following assumptions are made. As a basis, costs of 50 €/t for the extraction of CO_2 by separation from exhaust gases and logistic to the PtG plant are assumed. If the cost for one ETS certificate is less than 50 €/t, a separation and sale makes no sense from an economic point of view. If the ETS certificate price exceed the costs for extraction of CO_2, then it may make sense to capture and sell CO_2. For the year 2030 and 2050, 50 €/t CO_2 is still expected to be the costs for CO_2 separation and logistic. In the year 2050 a certificate price of approx. 90 €/t is reached and only the assumed logistic costs for CO_2 supply of 10 €/t CO_2 has to be achieved. The expected CO2 prices for the year 2030 and 2050 are summarized in Table 20.

Table 20: Future CO_2 prices for the years 2030 and 2050.

	2030	**2050**
CO_2 price (€/tCO_2eq)	50	10

4.3.2 Electricity market

Electricity prices are determined by a combination of power generation portfolio, interconnection capacity and market design. Especially power generation portfolios are changing strongly at the moment and will continue to do so in the coming decades.

(European Commission 2016) summarized in the EU reference scenario 2016, that from 2010 to 2020, average electricity prices increase by 13%. This is due to increased capital costs, which more than compensate the observed decrease in fuel costs. Beyond 2020, average electricity prices will increase up to 2030 and then remain broadly stable beyond 2030, as the benefits, in terms of fuel cost savings, resulting from the restructuring investments in electricity supply come increasingly to the fore. In addition, lower technology costs from technology progress and learning over time will help to contain electricity prices. Prices of electricity across the EU tend to converge towards the EU average in the projection period; this convergence is driven by a combination of factors including the elimination of subsidies where these are still present, an increased penetration of RES in all countries, as well as wider market coupling. Over time, the structure of costs slightly changes; capital intensive investments (RES and CCS) and increasing grid costs bring a decrease of the share of variable cost components and a corresponding increase in the capital cost components. The prices for households and services are projected to increase moderately in the medium term and to decrease slightly in the long term. Prices for industry on the contrary are stable or decrease over time as industry maintains base-load profile and bears a small fraction of grid costs and taxes. Taxes apply mainly on prices for households and services.

In the power-to-gas roadmap to Flanders, (Thomas et al., 2016) performed calculations on the future electricity prices in Belgium. Power price duration curves are estimated for the years 2030 and 2050, showing that the share of hours with very low prices increases, just as the share of hours with very high prices. In other words, the electricity prices are expected to become more volatile. (Sijm et al., 2017) find the same for the electricity prices in the Netherlands in their report on the supply of flexibility for the power system in the Netherlands in the period 2015-2050.

Brainpool simulates the electricity price trend until 2050 for an electricity market study. The electricity price for the years 2020-2030 follows the growing primary energy and CO_2 prices. From the year 2040 there will be a decline in electricity prices due to high power supplies from wind and solar power plants. This also increasingly results in low and often negative electricity prices. The average electricity price in 2030 is approximately 74 €/MWh and 88.5 €/MWh in 2050.

(Agora Verkehrswende et al., 2018) recently published a report in which they state, amongst others, that PtG plants need cheap electricity and high full-load hours, which means that they cannot be operated with excess power. Renewable electricity plants therefore have to be built explicitly for the purpose of gas production in PtG plants and the produced fuels therefore always have to bear the costs of the required electricity generation.

Electricity prices vary in the different countries of the European Union. Therefore, a sensitivity analysis with different electricity prices and full load hours is carried out in the following calculations to cover a wide field.

4.3.3 Natural and synthetic/biological gas market

In future, the revenues of a PtG methanation plant will depend on the CO_2 footprint of the sold gas. Thus, a CO_2 price will come on top or a green gas quota will be introduced. The revenues of a PtG methanation plant consist of the selling of the produced gas with potentially a bonus on top of that for the green character of the gas. Additional revenues could exist in the form of selling of the by-products oxygen and heat. The latter can be low-temperature (from the electrolyser and biological methanation) or high-temperature (from chemical methanation). Revenues for the by-products would increase the WTP for electricity and / or decrease the WTA for gas.

The revenue of the produced methane itself will be strongly influenced by the prices of natural gas and CO_2 and CO_2 footprint. The future development of natural gas prices is therefore very relevant for PtG methanation plants. Several studies and reports analyse the future development of natural gas demand and natural gas prices, some of them will be shortly summarized here.

The World Bank does not expect any significant changes in the natural gas price in their forecast up till the year 2030 (the World Bank, 2018).

(Agora Verkehrswende et al., 2018) writes that there are still large crude oil and natural gas reserves that can be mined at low cost. If the demand for these fuels decreases, due to increased electricity generation with wind and solar power, their reserves are not expected to become scarce. PtG will probably never be cheaper than crude oil and natural gas. Only political measures can ensure the use of PtG, they state. This can be done through pricing of CO_2 emissions or through other measures such as blending requirements. It is stated that the abundant reserves of oil and gas need to remain largely underground, to be able to combat climate change.

A study done by the Lappeenranta University of Technology and the Energy Watch Group (Ram et al., 2017) claims that a global transition to a 100% renewable electricity system is feasible at every hour of the year, at lower costs than the current system. Their future scenario shows that in 2050, over two third (69%) of the electricity in the world will be generated by solar power. Wind power will generate 18% of electricity and hydropower 8%. The remaining power will be generated by geothermal, biomass, gas and a little bit of nuclear that will be phased out a bit after 2050. Storage is predicted to increase from roughly 33 TWh_{el} in 2015 (largely based on hydro) to over 15,000 TWh_{el} that is largely (95%) based on batteries for short-term storage. Gas (only renewable based) will be used for long-term storage.

Other reports show very different future scenarios. An example is the World Energy Outlook 2017 (IEA, 2017) according to the natural gas use is predicted to strongly increase in the coming 25 years. In both the current policies and new policies scenario, gas demand is expected to continue to increase at the same pace as in the last decades. In the sustainable development scenario gas demand is expected to stabilize after 2025, but remains important in 2040. The document also provides a prediction for the natural gas prices in different regions in the world, including the EU. Here, prices are expected to increase from 2016 levels to roughly double by 2040 (from about 4.9 to 9.6 $/MBtu in the new policies scenario), which is, however, still below levels seen around 2010. The predicted increasing share of liquefied natural gas (LNG) in the global trade has an important influence on the natural gas prices. Power generation in 2040 is still expected to rely for a large part on fossil fuels. In all regions in the world, coal and gas still have a large share of the power generation, whereby lowest shares of fossils will be found in the EU.

Table 21: Future prices for natural gas based on (European Commission 2016) and for the biogas, SNG, LSNG on the gas market in 2030 and 2050 based on assumptions.

Product	**Price 2030 / €/MWh**	**Price 2050 / €/MWh**
Biogas/ SNG/ LSNG	75 €/MWh	125 €/MWh
Natural gas (European Commission 2016)	30 $€_{2013}$/MWh	36 $€_{2013}$/MWh

(European Commission 2016) summarized in the EU reference scenario 2016, that in the short term, low gas import prices are projected to be maintained, with prices in 2020 remaining well below recent peaks and even 2014 prices. The world oil price landscape affects European gas import contracts that are indexed to oil prices, while the pressure on global LNG market is relaxed due to the expected rise in nuclear energy use in Japan (implying lower requirements for gas imports) and the emergence of shale gas in USA with potential LNG exports. Moreover, the transition away from long-term oil-indexed gas contracts and towards indices linked to the prices prevailing in gas trading hubs leads to fewer restrictions in gas supply contracts and higher flexibility in international gas spot markets. In the period after 2020, the average EU gas import price increases constantly reaching 69 $2013/ boe in 2030 (30.52 €2013/MWh) and 79 $2013 in 2050 (35.75 €2013/MWh). This increase is driven by high growth in natural gas consumption in developing economies, mainly in China, India and the MENA region, and the constantly increasing international oil prices (that influence oil-indexed EU gas import contracts). Additional unconventional gas resources, mainly shale gas, are assumed to become massively available at the global level after 2020, expanding the gas supply base. On the other hand, these resources are characterised by higher production costs compared to conventional low-cost reserves that will gradually deplete.

4.4 Future markets and operation concepts

Due to future developments in the gas and electricity market, as well as the reduction targets for CO_2 emissions, PtG will play an important role in the future. Deliverable 6.1[ee] investigated the role of PtG in the electrical system, in particular drawing its possible use in the different sectors of the electrical system. The authors indicated the potential applications of PtG on the electricity generation side, electricity transmission and electricity distribution grid. From an electricity system point of view PtG can be used to add additional flexibility, to provide arbitrage opportunities, ancillary services or system management and to integrate an energy system based on renewables by storing bulk or excess energy. On distribution side PtG can help to avoid reverse power flow, to regulate the voltage level and to contract synergy with heat or gas networks.

From a comprehensive perspective, PtG can link the heat, mobility and electricity sectors. In the future PtG plants can provide long-term (seasonal) storage of electricity, if the price incentives are right. The produced gas is stored until the point when it becomes profitable to sell it. Prices differences must be large enough to cover the storage costs. Seasonal long-term storage of renewable energy is achieved by feeding synthetic natural gas into salt caverns, which are cheaper than local gas tanks. The stored gas can be used for providing heat, electricity or both energies.

Mobility is the least diverse sector of energy demand: Deliverable D8.1[ff] examines the current status and developments for a future demand for green gas. Currently 93% of the total energy consumption in the mobility sector is produced from petroleum products. In recent decades, the efficiency of traditional cars has improved, but a reduction in emissions in the area of mobility has not been achieved. In order to significantly reduce GHG emissions in the transport sector, oil products must be replaced by alternative fuels. The European Union is committed to reducing CO_2 emissions from cars. Regulation (EC) No 443/2009[gg], as last revised by Regulation (EC) No 333/2014[hh], sets a limit of 130 g CO_2/km for fleet consumption. This will be reduced to 95 g CO_2/km by 2021. Car manufacturers will compensate for the CO_2 emissions of their vehicle fleets (passenger and heavy duty) by producing synthetic fuels. (Otten Reinhard 2016).

[ee] D6.1: Report on opportunities and options for PtG in power systems
[ff] D8.1: Econometric analysis of the future demand for 'green gases' and related flexibility
[gg] https://eur-lex.europa.eu/legal-content/DE/TXT/PDF/?uri=CELEX:32009R0443
[hh] https://eur-lex.europa.eu/legal-content/DE/TXT/PDF/?uri=CELEX:32014R0333

5 Economical Operation of PtG: Future situation

This section will highlight some important points that influence the operating strategies discussed in chapter 3 and taking into account the developments described in section 4. Depending on the application, there are different operating strategies. These strategies are shown in Figure 16.

		Electricity purchase			
		long term contracts	short term market	direct coupling RES	seasonal
Gas selling	long term contracts	1. Continuous operation Prices both fixed on forehand, continuous operation of the plant. No large storage facilities needed. Participation in electricity balancing market could be an option.	2. Flexible electricity Gas is continuously sold and injected in the gas grid. Electricity is purchased according to price levels. Hydrogen buffer tank is required.	7. Flexible electrolyser **Gas** is **continuously sold** and injected in the gas grid. **Electricity** is purchased according to **load of the RES**. Hydrogen buffer tank is required.	10. Seasonal electrolyser **Gas** is **continuously sold** and injected in the gas grid. **Electricity** is purchased according to **surplus** energy from RES from grid. Hydrogen buffer tank is required.
	short term market	3. Flexible gas Electrolyser is operated continuously, participation in electricity balancing market could be an option. Gas is sold according to price levels, buffer tank for methane is needed.	4. All flexible Electricity is bought according to price levels and gas is sold according to price levels. Large buffer tanks for both hydrogen and methane are needed.	8. Flexible coupling Electricity is purchased according to load of the RES and **gas** is sold **according to price levels**. Large buffer tanks for both hydrogen and methane are needed.	11. Seasonal flexibility **Electricity** is purchased according to **surplus** energy from RES from grid and gas is sold according to price levels. Large buffer tanks for both hydrogen and methane are needed.
	seasonal	5. Seasonal gas Electrolyser is operated continuously, participation in electricity balancing market could be an option. **Gas** is sold according to **requisition in winter season**, buffer tank for methane is needed.	6. Flexible and seasonal Electricity is bought according to price levels and **gas** is sold according to **requisition in winter season**. Large buffer tanks for both hydrogen and methane are needed.	9. Seasonal coupling Electricity is purchased according to load of the RES and **gas** is sold according to **requisition in winter season**. Large buffer tanks for both hydrogen and methane are needed.	12. Seasonal **Electricity** is purchased according to **surplus** energy from RES from grid and **gas** is sold according to **requisition in winter season**. Large buffer tanks for both hydrogen and methane are needed.

Figure 16: Schematic of electricity purchase and gas selling strategies for future market, assuming that the electrolyser can operate flexible whereas the methanation reactor needs to operate less flexible.

Eight more have been added to the current four operating strategies shown in Figure 4. In addition to long-term contracts and trading on the day-ahead market, there is also the direct coupling of the PtG plant with a renewable energy source and the seasonal use of surpluses (grid services) on the electricity purchase. The seasonal supply of synthetic gas on the gas selling increases the operating variants. The 12 variants and the gas production costs are explained in the following subchapters.

The CAPEX, fixed as well as variable OPEX of an installation in 2030 and 2050 are shown in Table 14 to Table 18. Estimates of future CO_2 prices are given in Table 20. Expected prices on the gas market are listed in Table 21. The prices for gas storages are given in Table 2. The calculations are based on the assumptions of 75% (2030) and 78% (2050) electrolyser efficiency, 100% methanation conversion, water costs of 0.00069 €/kg and a water need of 200% the stoichiometric need.

5.1 Continuous operation of electrolyser and methanation plant

A sensitivity analysis is done for future long-term electricity contract. The calculations assume the plant is operated continuously throughout the year (8760 hours) and buys electricity at the average price in the electricity markets. The gas is also sold for a fixed price continuously throughout the year. There is no need for hydrogen and methane storage on the site. Table 22 shows the calculated methane production price for different electricity prices. As can be seen for the year 2030, the maximum revenue for SNG was estimated to be about 75 €/MWh, which can be enough to recover all costs of the continuously operating PtG methanation plant if the power price is less than 15 €/MWh. An operation with the expected electricity price of 74 €/MWh for 2030 is not profitable.

Table 22: The total methane production costs for different electricity prices and expected plant costs for 2030. The production costs are marked green if the production costs are below the expected market price for SNG of 75€/MWh or 0.83€/m³.

	Methane production costs 2030 / €/MWh			**Methane production costs 2030 / €/m³**		
	Plant Size / MW_{el}					
Power price / €/MWh	**1**	**10**	**50**	**1**	**10**	**50**
0.00	46.19	35.39	31.64	0.51	0.39	0.35
1.00	47.90	37.10	33.35	0.53	0.41	0.37
2.00	49.61	38.81	35.06	0.55	0.43	0.39
3.00	51.32	40.52	36.78	0.57	0.45	0.41
4.00	53.04	42.24	38.49	0.59	0.47	0.43
5.00	54.75	43.95	40.20	0.61	0.49	0.45
10.00	63.31	52.51	48.76	0.70	0.58	0.54
15.00	71.87	61.07	57.32	0.80	0.68	0.64
20.00	80.43	69.63	65.88	0.89	0.77	0.73
25.00	88.99	78.19	74.44	0.99	0.87	0.83
50.00	131.79	121.00	117.25	1.46	1.34	1.30
74.00	172.89	162.09	158.34	1.92	1.80	1.76
100.00	217.40	206.60	202.85	2.41	2.29	2.25

As can be seen in Table 22, the methane production costs vary for the assumption of 2030 between 31.64 and 217.40 €/MWh or 0.35 and 2.41 €/m³, depending on the electricity price. To break-even, the plant must sell the methane for at least the production price.

For the year 2050 a SNG/ biogas price of 125 €/MWh for 2050 is assumed. If the electricity price is less than 50 €/MWh_{el} a positive business case is possible for each size of the PtG plant, if the system runs 8760 hours per year. The production costs reported in Table 22 to Table 27 include all costs over the lifetime of the plant, including CAPEX, yearly fixed and flexible OPEX depending on the operating mode and duration. An operation with the expected electricity price of 88.50 €/MWh for 2050 is not profitable as shown in Table 23.

Table 23: The total methane production costs for different electricity prices and expected plant costs for 2050. The production costs are marked green if the production costs are below the expected market price for SNG of 125€/MWh or 1.38€/m³.

	Methane production costs 2050 / €/MWh			**Methane production costs 2050 / €/m³**		
	Plant Size / MW_{el}					
Power price / €/MWh	**1**	**10**	**50**	**1**	**10**	**50**
0.00	23.30	16.33	14.74	0.26	0.18	0.16
1.00	24.95	17.98	16.39	0.28	0.20	0.18
2.00	26.60	19.62	18.04	0.30	0.22	0.20
3.00	28.24	21.27	19.68	0.31	0.24	0.22
4.00	29.89	22.92	21.33	0.33	0.25	0.24
5.00	31.54	24.56	22.98	0.35	0.27	0.26
10.00	39.77	32.80	31.21	0.44	0.36	0.35
15.00	48.00	41.03	39.44	0.53	0.46	0.44
20.00	56.23	49.26	47.67	0.62	0.55	0.53
25.00	64.46	57.49	55.90	0.72	0.64	0.62
50.00	105.62	98.64	97.06	1.17	1.09	1.08
88.50	169.00	162.03	160.44	1.88	1.80	1.78
100.00	187.93	180.96	179.37	2.09	2.01	1.99

5.2 Flexible operation of electrolyser and methanation plant

In the “flexible operation” mode of operation, electricity is bought on the short-term market and gas is sold either on the short-term market (option 4) or long-term market (option 2). The willingness-to-pay (WTP) for electricity can be determined and based on the trend in the electricity price. The duration of the period spent in the respective operating state can be determined over an operating year. Due to the high proportion of fluctuating generation capacities, electricity prices are becoming more volatile. In addition, extremely high and extremely low prices arise on the electricity exchange. Extreme prices are understood to be electricity prices equal to or less than 0 EUR/MWh and more than 100 EUR/MWh. The expected relation between the two extreme prices brings market opportunities for new market participants and technologies, such as storage systems. Figure 17 shows from 2026 onwards, extreme prices are expected to rise sharply in Europe (Carlos Perez-Linkenheil 2017).

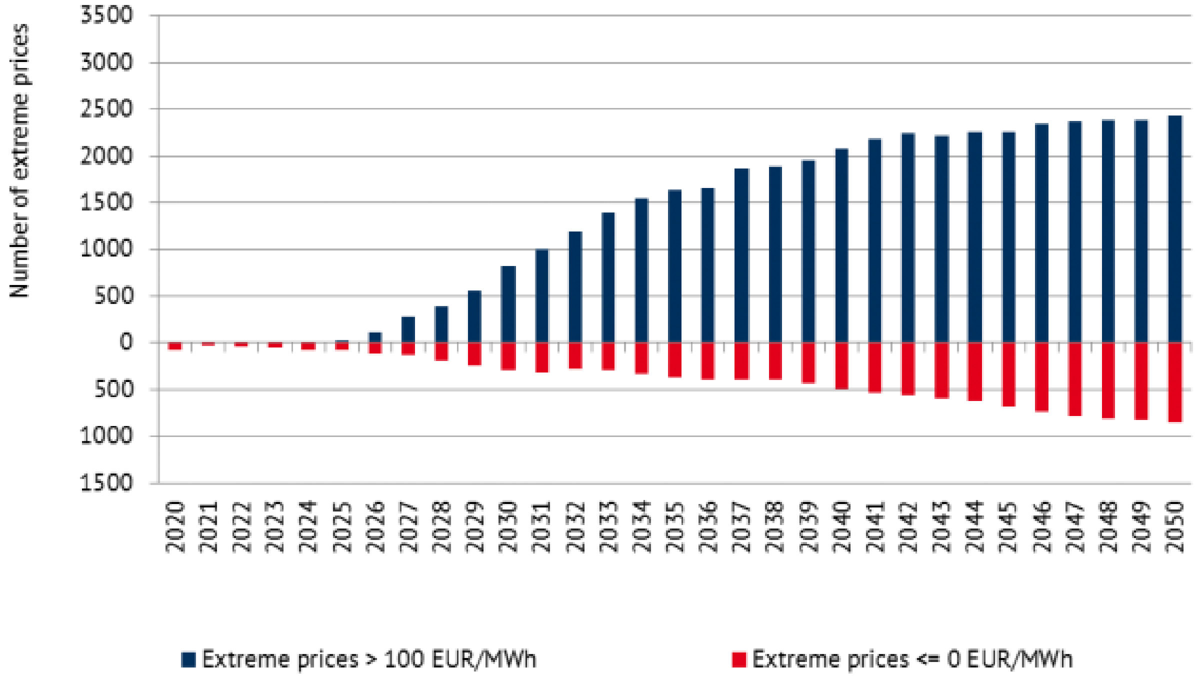

Figure 17: Number of positive and negative extreme prices EU-28 (Carlos Perez-Linkenheil 2017)

5.2.1 Methane production costs

The methane production costs depend on the electricity price, the operating time of the electrolysis and the methanation. Variable OPEX, which were not taken into account in the calculations in chapter 3, play a significant role in the calculations of future scenarios. It is assumed that the methanation processes the entire hydrogen quantity of the electrolysis and that only a small intermediate storage separates the two systems in order to compensate for the different rate of load changes of the subsystems.

Table 24 shows the methane production costs with the expected WTP for electricity of the electrolyser and the expected duration in the operation modes of the electrolyser and methanation. The methane production costs are calculated for different electricity prices. For each electricity price, four cases with different operating hours of electrolysis are considered. The methanation has the size to convert in one hour the whole output of the electrolyser of one hour. The basis is a 10 MW_{el} PtG plant. In variable OPEX is calculated as mentioned in 4.2.2.

Table 24: The total methane production costs in €/MWh_{SNG} for different electricity prices, expected plant costs for a 10 MW_{el} plant in 2030 and 2050 and for different full load operation hours (FLH). The rest of the year, the plant is in hot standby (HSH).

Operation mode / h		Methane production costs €/MWh_{SNG}									
		Electricity prices									
		0 €/MWh_{el}		1 €/MWh_{el}		5 €/MWh_{el}		10 €/MWh_{el}		25 €/MWh_{el}	
		Year									
FLH	**HSH**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
1000	7760	270.39	165.83	272.11	166.01	278.95	166.72	287.51	167.61	313.20	170.28
2000	6760	137.75	75.05	139.46	76.70	146.31	83.28	154.87	91.52	180.55	94.19
4000	4760	71.43	37.01	73.14	38.65	79.98	42.24	88.55	53.47	114.23	78.16
6000	2760	49.32	24.32	51.03	25.97	57.88	32.56	66.44	40.79	92.12	65.58

With an optimized size of the hydrogen storage and the methanation, the fluctuated load of the electrolyser can be flattened and longer continuous operation of the methanation is possible. It results in an optimization problem.

5.2.2 Optimised methane production costs

The size of the hydrogen storage depends on the load profile of the electrolyser and the size of the downstream methanation. The optimization problem is examined in more detail in another publication by the author, which has not yet been published at the time of submission. The optimisation was calculated with the following boundary conditions.

The size of the hydrogen storage tank is determined on the basis of the expected current load profile for the electrolyser. The aim is to ensure that methanation can achieve the longest possible continuous operating times. Methanation does not have to run at full load. The load can fluctuate between 40 and 100%. The number of hours at full load is determined by the load and the operating hours. If the hydrogen storage tank is empty, the methanation is carried out in hot standby mode. The flexibility of the electrolysis is limited by the hydrogen storage and the smaller methanation. When the hydrogen storage tank is full, the electrolysis can run at maximum with the full methanation power, even if the electricity is cheap.

Table 25 shows the methane production costs with the expected WTP for electricity and the expected duration in the operation modes of the electrolyser and methanation. The operating hours of the electrolysis are spread over the year on a periodic basis. The size of the hydrogen storage between electrolyser and methanation is sized, that the methanation is running 8500 hours per year and a constant supply of methane is possible. The load is fixed to 100 %. The methane production costs are calculated for different electricity prices. For each electricity price, four cases with different operating hours of electrolysis are considered. The hydrogen storage and the methanation were optimized accordingly. The basis is a 10 MW_{el} electrolyser and cost estimation from 2030.

Table 25: The total methane production costs in €/MWh_{SNG} for different electricity prices, expected plant costs for a 10 MW_{el} plant in 2030 and 2050 and for different full load operation hours (FLH) of the electrolyser and methanation subsystem. The rest of the year, the plant is in hot standby (HSH).The hydrogen storage and methanation size is optimized according to electricity load profile and full load hours of the electrolysis. Green marked methane production costs are lower than the non-optimised calculation in Table 24.

Electrolyser		H_2 storage / h	Methanation			Methane production costs €/MWh_{SNG}					
						Electricity prices					
						0 €/MWh_{el}		10 €/MWh_{el}		25 €/MWh_{el}	
FLH	**HSH**		**Size MW_{SNG} 2030/2050**	**FLH**	**HSH**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
1000	7760	8.5	0.68/0.71	8500	260	183.46	96.58	200.59	113.05	226.27	137.74
2000	6760	4.3	1.37/1.42	8500	260	94.55	47.69	111.67	64.15	137.36	88.85
4000	4760	2.2	2.73/2.84	8500	260	54.85	26.41	71.97	42.88	97.65	67.57
6000	2760	1.5	4.1/4.26	8500	260	42.32	19.79	59.44	36.25	85.12	60.95

Figure 18 shows the methane production costs of Table 24 and Table 25 under the assumption that the operating time of the PtG system depends on the availability of the assumed electricity price. In general, the gas production costs of operating concepts are all in this range: The higher the number of operating hours, the lower the gas production costs without electricity costs; the higher the number of operating hours, the higher the (average) electricity price on the electricity market.

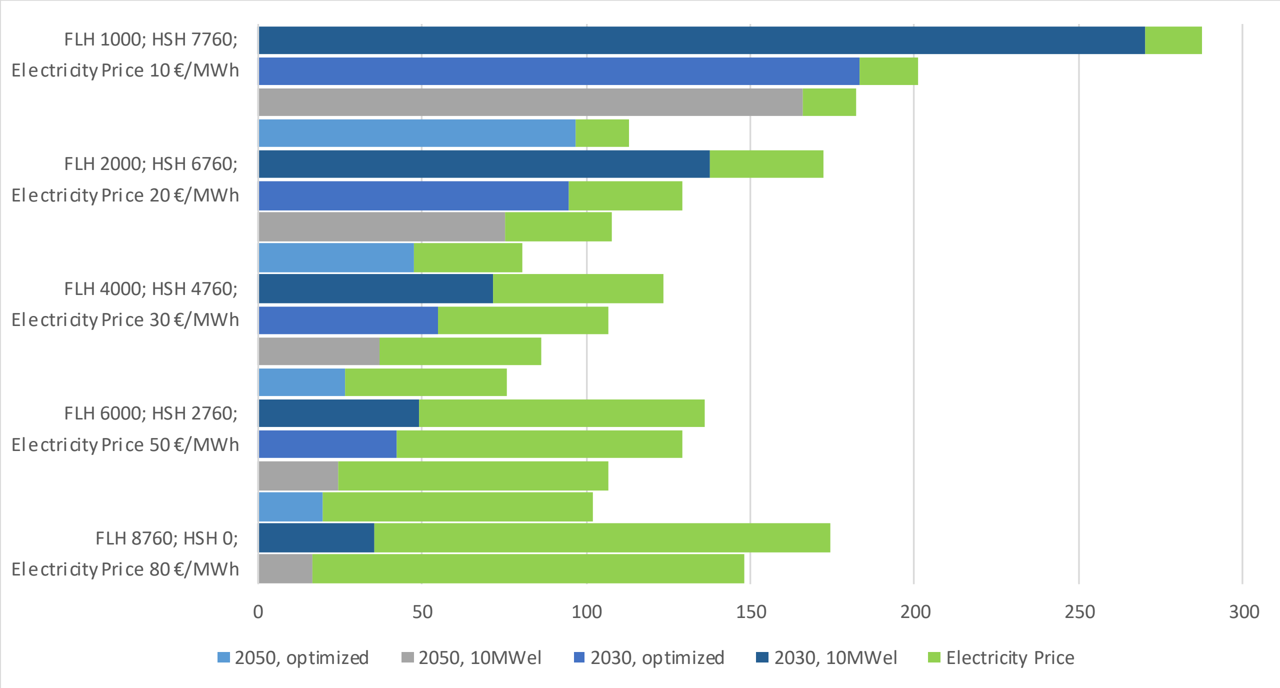

Figure 18: Methane production costs (€/MWh) for different full load operations (FLH) of the electrolyser sub-system. For the optimized cases, the FLH of the methanation is different from the electrolysis, due to a hydrogen storage. The methane production costs depend on the electricity price. The WTP for the electricity determines the operating time of the plant.

If the supply of the electricity is not constant or on a periodic basis, the hydrogen storage must be sized bigger if a constant supply of methane is required. Alternative the methane can be temporarily stored (see case 2, 7 and 10 in Figure 16). If the electricity supply is not constant or assured with a long term contract a specific percentage of the maximum production quantity is purchased. The remains are stored temporarily in a methane storage on site. Same solution for option 4: If the gas cannot be sold on the short-term market, it must also be stored on site. Therefore see chapter 5.4.

5.3 Direct coupling RES and seasonal electricity purchase

The direct connection of the PtG plant with a renewable energy source (option 7, 8 and 9) or the seasonal purchase of excess electricity (option 10, 11 and 12) result in large fluctuations in the load for electrolysis. The load profile of the electrolyser depends on the renewable energy source (RES) or on the frequency of seasonal electricity purchase. Seasonal purchase is defined as providing grid services and active capping of surpluses from renewable energy sources.

The load fluctuations of the electrolysis can be separated from the maximum possible load change of the methanation by a hydrogen storage. The constant supply of SNG is a major challenge when power supply is not constant. The options selling gas with long term contracts will be used if there are no significant variations in gas prices throughout the year. So on site long-term storage of methane makes no sense for plant operators to benefit from large price differences. The gas is continuously sold and injected in the gas grid. To provide a constant SNG flow (option 7 and 10) a large hydrogen buffer tank and methane storage on site is required. If the gas is sold according to price levels from short term markets, also buffer tanks for hydrogen and methane are needed (Option 8 and 11).

In Table 26 the gas production costs for direct coupling of a PtG plant with RES and the use of PtG for offering secondary control reserve are shown. The calculations are done for the years 2030 and 2050. The examples are a 10 MW_{el} PtG, which is directly coupled to a PV field, to a wind park and is offering symmetrical secondary control power. The main goal is low gas production costs. The gas is supplied to the grid, depending on the operational load of the methanation. To have a constant flow of gas, the storage size of the H_2 storage must be bigger or an additional SNG storage is necessary.

Table 26: Gas production costs (GPC) for option 7, direct coupling with renewable energy source and for option 10, seasonal purchase of excess electricity in form of secondary control reserve. The gas production costs are calculated for the year 2030 and 2050 with an electricity price of 0 €/MWh$_{el}$. The part load and full load operation hours (OPH) are converted in full load hours (FLH).

	Electrolyser			H_2 storage / h	Methanation				GPC (€/MW$_{SNG}$)	
	FLH	OPH	HSH		Size MW$_{SNG}$ 2030/ 2050	FLH	OPH	HSH	2030	2050
PV field	1012	4445	4315	9.3	1.95/ 2.03	3028	6378	2382	199.38	106.10
Wind park	1592	6708	2056	6.6	5.72/ 5.95	1625	2437	6323	168.66	92.44
Secondary Control reserve	4459	8760	0	3	3.71/ 3.86	7014	8760	0	52.05	24.86

5.4 Seasonal Gas selling

The integration of large amounts of renewable energy sources poses technological difficulties. Thus, at times there will be high demand when there is not enough renewable energy available. Storing large amounts of electric energy from renewable sources will enable countries to deal with long periods without sufficient wind and sun available, as e.g. during a dull November. One storage possibility is synthetic natural gas. The produced gas can be stored in underground caverns of the plant operator and can be sold seasonal. The electricity purchase and the gas selling strategies for future market (Figure 16) shows four options (5, 6, 9 ad 12) for the production of gas and the seasonal sale of the produced gas.

Option 5 comprises a long-term contract with an electricity supplier in order to obtain a high degree of planning security. The sub-system electrolyser will be operated continuously.

Electricity prices vary strongly on a short-term basis and not really in a long-term basis while methane prices are lower in summer than in winter. Then it makes sense to operate the PtG plant throughout the year and purchase the electricity on the short term market (option 6). If the price is temporarily too high, a small hydrogen storage (24 hours, couple of days) can help to bridge the gap. When both electricity prices and methane prices become very low in summer and very high in winter (option 12), it makes sense to operate a PtG plant in summer, store the produced methane.

The supply of electricity in direct coupling to a renewable energy source (option 9) can also be very volatile. For this reason, the operation of methanation must be decoupled from electrolysis by means of a hydrogen storage tank.

For all four options methane is stored in a geological formation to sell it according to requisition in winter season or when the price is high. All four options demonstrate the potential of long-term and large-scale storage of renewable energies. The options are calculated with a size of the SNG storage of the yearly production capacity. The yearly production capacity of the methanation depends on the electricity supply for the electrolysis.

Table 27: Gas production costs (GPC) with seasonal gas storage and an electricity price of 0 €/MWh$_{el}$ in the years 2030 and 2050

	Electrolyser		H_2 storage / h	Methanation			SNG storage / h	GPC (€/MW$_{SNG}$)	
	FLH	HSH		Size MW$_{SNG}$ 2030/ 2050	FLH	HSH		2030	2050
Option 5 (long term electricity contract)	8500	260	2	5.80/ 6.04	8500	260	5760	35.73	16.52
Option 6 (Short term market)	4500	4260	9	5.22/ 5.47	5000	3670	5760	65.73	30.34
Option 9 (direct coupling with a windpark)	1592	2056	6.6	5.72/ 5.95	1625	2437	6323	168.66	92.44
Option 12 (Seasonal electricity)	4459	0	3	3.71/ 3.86	7014	8760	0	52.05	24.86

6 Discussion and conclusions

This report gave an overview of a cost-orientated operation of PtG methanation plants. Various power purchase concepts and selling strategies for synthetic natural gas were investigated.

Four different basic operating strategies considering the electricity and gas market were analysed (1–4) for the current state of the art. The operating strategies vary in whether or not electricity and gas are bought and sold according to hourly and daily varying price levels or via long-term contracts that are arranged on forehand and therefore ensure continuous operation of the plant (or parts of the plant). With varying load of the electrolyser and an intermediate storage tank for hydrogen, the workload of methanisation is increased by operating electrolysis and methanisation separately. Nevertheless, the cases considered have shown that under the current conditions the gas production costs only decrease slightly or not at all due to the rather high costs for on-site hydrogen storage. The scenarios show that the current framework conditions are not sufficient to bring gas production costs to a comparable level of fossil gas prices. By evaluating SNG as a renewable gas, subsidies - such as is offered in Italy or Germany for biogas-, lower electricity prices or higher prices for synthetic natural gas,can lead to an attractive operation.

For the near future (2030-2050) further operating strategies of PtG, like direct coupling of the PtG plant with a renewable energy source and the seasonal use of surpluses (grid services) on the electricity purchase, are considered. The operation for 12 different applications was investigated. The provision of electricity via long-term contracts, short-term market or direct use of renewable energy without grid connection or the seasonal availability of surplus energy was investigated. Gas selling was also considered at different levels: long-term contracts, short-term market and seasonal. The new cases have shown under the future conditions the gas production costs decrease slightly although the electricity supply is less constant due to variable electricity prices. The mass-production of PtG plant components and increasing availability will reduce investment costs and fixed operating costs. With the expected development for CAPEX, OPEX, electricity prices, gas costs and efficiencies, an economic production of SNG for the years 2030 and 2050 can be illustrated. Particularly, for a plant with high operating hours of the methanation due to optimisation, enable a good business case in 2050. These power profiles are achieved by offering secondary control reserve symmetrically. Further assumptions are rising prices for synthetic and renewable natural gas and associated electricity prices.

The results show that PtG can be used for long-term, large-scale seasonal storage of renewable energy. Seasonal electricity storage will become interesting market opportunities for PtG plants, which might even enable certain revenues by selling the produced gas. The revenues can vice versa be spent on electricity purchase. In these cases, only low incentives are necessary to enable positive business cases for PtG plants. Especially the cases with high operating hours show that the gas production costs are below the expected market prices for synthetic gas and biogas. The optimisation of the plant layout by means of intermediate storage of hydrogen and carbon dioxide shows that the methanation standby times can be reduced and thus the gas production costs are decreased.
With the future expected development of CAPEX, OPEX, electricity prices, gas costs and efficiencies, an economic production of SNG for the years 2030, especially for 2050 should be feasible. In 2050, the gap between the market driven business models and economic feasibility is rather narrow.

All calculations were carried out without the implementation of systemic advantages (e.g. reduction of grid load, security of supply). These aspects can have a positive effect on economic efficiency with appropriate incentives or support schemes. Nevertheless, the regulatory framework will very likely be adapted in future, when the share of renewables will rise and electricity grid services will become more relevant.

Although governmental support schemes were not considered in any calculations performed in this report, the results allow for an estimation of the necessary amount of support for enabling economic feasibility of PtG operation. Based on these results, politicians have to decide whether regulatory measures are to be taken for enabling the systemic benefits (security of supply, support of electricity grid) of the large-scale sectoral coupling and energy storage capabilities of the PtG technology.

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