Applied Energy 253 (2019) 113594

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Production costs for synthetic methane in 2030 and 2050 of an optimized Power-to-Gas plant with intermediate hydrogen storage

Jachin Gorre[a,*], Felix Ortloff[b], Charlotte van Leeuwen[c]

[a] University of Applied Science Rapperswil, Institute for Energy Technology, Oberseestrasse 10, CH-8640 Rapperswil, Switzerland
[b] DVGW Research Centre at Engler-Bunte-Institute (EBI) of Karlsruhe Institute of Technology (KIT), Engler-Bunte-Ring 1, 76131 Karlsruhe, Germany
[c] Faculty of Economics and Business, University of Groningen, Nettelbosje 2, 9747 AE Groningen, the Netherlands

HIGHLIGHTS

- Expected development of CAPEX and OPEX of Power-to-Gas technology.
- Different electricity purchase and gas selling strategies for plant operation.
- Optimization of plant operation and dimension depending on the electricity supply.
- Production cost for synthetic natural gas (methane) in 2030 and 2050.
- Proof of cost-efficient, long-term and large-scale storage of renewable energies.

ARTICLE INFO

Keywords:
Power-to-Gas
Optimisation
Operation strategy
Production cost
SNG

ABSTRACT

The publication gives an overview of the production costs of synthetic methane in a Power-to-Gas process. The production costs depend in particularly on the electricity price and the full load hours of the plant sub-systems electrolysis and methanation. The full-load hours of electrolysis are given by the electricity supply concept. In order to increase the full-load hours of methanation, the size of the intermediate hydrogen storage tank and the size of the methanation are optimised on the basis of the availability of hydrogen. The calculation of the production costs for synthetic methane are done with economics for 2030 and 2050 and the expenditures are calculated for one year of operation. The sources of volume of purchased electricity are the short-term market, long-term contracts, direct-coupled renewable energy sources or seasonal use of surpluses. Gas sales are either traded on the short-term market or guaranteed by long-term contracts. The calculations show, that an intermediate storage tank for hydrogen, adjustment of the methanation size and operating electrolysis and methanation separately, increase the workload of the sub-system methanation. The gas production costs can be significantly reduced. With the future expected development of capital expenditures, operational expenditure, electricity prices, gas costs and efficiencies, an economic production of synthetic natural gas for the years 2030, especially for 2050, is feasible. The results show that Power-to-Gas is an option for long-term, large-scale seasonal storage of renewable energy. Especially the cases with high operating hours for the sub-system methanation and low electricity prices show gas production costs below the expected market prices for synthetic gas and biogas.

1. Introduction

With an increasing share of renewable energies in the form of electrons, technologies that convert electrons into molecules must make a complete energy transition in all sectors possible. There is a large number of pathways for the transformation of energy from renewable sources into gaseous or liquid energy carrier. An overview of the so-called Power-to-Gas (PtG) and Power-to-X (PtX) technologies and worldwide existing projects which deal with this technologies is given by [1]. A PtG plant is composed of an electrolysis sub-system, connected to the electricity grid, and a methanation sub-system, connected to the H_2 supply, the electrolysis sub-system, and the CO_2 supply from the CO_2 source. Process chains of different PtG paths and the evaluation with regard to their suitability for applications, including the sub-systems electrolysis and methanation are given in [2]. In many PtG projects it was concluded that the design and sizing, control strategy and

* Corresponding author.
E-mail address: jachin.gorre@hsr.ch (J. Gorre).

https://doi.org/10.1016/j.apenergy.2019.113594
Received 2 April 2019; Received in revised form 20 June 2019; Accepted 19 July 2019
Available online 07 August 2019

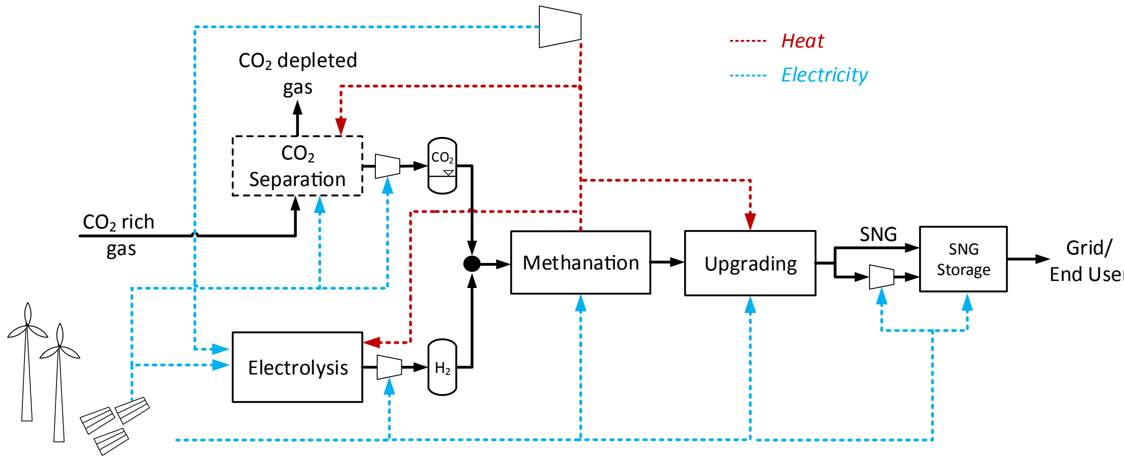

Fig. 1. Overview of a PtG plant with sub-system electrolysis for production of H_2, sub-system methanation to convert H_2 and CO_2 into CH_4 and H_2O. Before the gas is fed into the natural gas network or used for final purposes, it is upgraded and, if necessary, compressed. The dotted lines show the heat (red) and electricity flow (blue).

system integration of the PtG plants have a great influence on efficiency, reliability and economics [3]. The latest review of PtG projects in Europe is given by [4]. The main application for PtG is the injection of hydrogen or methane into the natural gas grid for storing renewable energy or substitute fossil fuel with synthetic natural gas (SNG).

The technology for the first step of a PtG process is the electrolysis. The electrolysis uses electricity to split water into hydrogen (H_2) and oxygen (O_2), whereby the electric energy is stored in the H_2. The electrolysis technologies available on the market on an industrial scale are alkaline electrolysis [5] and proton exchange membrane electrolysis [6]. A basis of the parameters required for a techno-economic analysis of water electrolysis-based concepts for evaluation of PtG and PtL processes in energy system is given by [7]. A strong focus on projects with methane as a product was placed in [8]'s review to give an overview of methanation technology and research.

Generally, H_2 can be used as a fuel or as a raw material for other products. When converted into SNG, the H_2 reacts with carbon dioxide (CO_2) in a second reaction step to methane (CH_4). The main benefits of SNG is that this gas allows renewable energy to be stored in, and transported through, the extensive existing natural gas system with less restriction then H_2 [9]. CH_4 has also a higher volumetric energy density.

On the hydrogen side, the main components of a Power-to-Methane plant are an electrolysis, H_2 compressor, if necessary, and H_2 storage. The second process step, producing methane, respectively SNG, needs a CO_2 separation, CO_2 compressor, CO_2 storage and a methanation reactor. For further use of the SNG an upgrading unit, a SNG compressor and a SNG storage are needed. The size of the H_2, CO_2 and SNG storage facilities and the capacity of the methanation reactor are depending on the configuration and operating strategy. The main unit of a PtG system and the connections of electricity and the flow of heat are shown in Fig. 1.

Three economic factors determine the operation strategy of a PtG plant:

- The (market) price of electricity and the willingness-to-pay (WTP) for electricity[1]
- The market price of SNG and the willingness-to-accept (WTA) for SNG
- The market price of CO_2 and the availability

[1] 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.

A technical factor, the availability of storage capacity for CO_2 and H_2 to operate the sub-systems electrolysis and methanation independent, has an effect on the dwell time of the operational states. The dwell time in operation states has a direct impact on the gas production costs.

The publication shows the the potential of reducing the production costs of SNG produced by PtG process for different operating strategies. First the characteristics, economical basics and operation strategies of the PtG process are introduced. An overview of the operating strategies is provided in Table 8. The results can also be transferred to components of the PtX technology. The operating period examined is one year and the economics are based on assumptions for the years 2030 and 2050. The basic operating strategies vary in whether or not electricity and gas are bought and sold according varying price levels. A further option are 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 study includes direct coupling of the PtG plant with a renewable energy source and the seasonal use of surpluses (grid services) on the electricity purchase.

2. PtG system characteristics

The requirements for operation of the two sub-systems electrolysis and methanation depend on application and certain limits. In general, the operation of both systems can be assigned to three states: cold standby (CS), hot standby (HS) and production (OP). The correlation of the different operating states is shown in Fig. 2.

In CS state, no gas is produced and no media is circulating. Methanation is not ready to process carbon dioxide. The electrolysis can be switched to OP mode in seconds to minutes from CS (depending on type and manufacturer), whereas the methanation needs a few hours to warm up.

In HS state, no gas is produced, but all plant units and media are at operating temperature and pressure, the methanation is ready for the admixture of CO_2. The heat for keeping the plant in HS can be provided by external heat sources or electrically.

In OP state, the electrolysis produces hydrogen and the methanation synthetic natural gas (SNG). Both processes have sufficient waste heat to cover the losses and, if required, to dissipate heat. All media circuits and compressors are active.

The changes between states of the electrolysis depend on the present electricity load profile. The minimum load and the possible load change rates of methanation without significant quality losses in the conversion are typically not the same as for electrolysis. It may happen that methanation cannot follow the hydrogen generation profile of electrolysis.

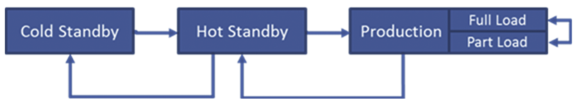

Fig. 2. Main operation states of a PtG-plant and the possible changeover between states: Cold standby, hot standby and production with different loads.

Therefore, the two subsystems electrolyser and methanation must be decoupled and operated separately if the electricity load profile fluctuates strongly. In addition, the maximum hydrogen processing rate of the methanation reactor may be lower than the maximum production rate of the electrolysis. A hydrogen storage system can help to maintain a load interval and load change rates that keep the gas quality constant. The independent operation of the subsystems can lead to a constant and continuous production phase of methanation. The size of the intermediate hydrogen storage needs to be optimized on a case-by-case basis for the chosen PtG technologies and operating strategies.

The following parameters and boundary conditions are used to develop the optimal PtG plant design and to simulate the operation of the sub-system electrolyser and methanation during an operating period of one year, in the perspective of the electricity supply. It is assumed that electrolysers are able to operate in a flexible load, switching on and off when required. The size of the electrolyser is set to 1, 10 or 50 MW. For optimization of the sub-system methanation, the maximum demand is set to the maximum output of the electrolyser and the minimum demand is set to process the produced hydrogen of 8760 h of electrolyser operation with 100% load of methanation over 8760 h.

The aim of the optimization is to reduce gas production costs and to ensure that methanation can achieve the longest possible continuous operating times, to reduce the number of shutdowns. The methanation load can vary between 40 and 100% depending on the level of the hydrogen storage. If the hydrogen storage tank is empty, the methanation is carried out in HS. The level of hydrogen storage has to reach 60% of the maximum level before operation of the methanation is started again. It is assumed, that no hydrogen or produced gas is discharged while start-up.

Due to further developments in electrolysis technology, it is estimated that the efficiency will increase from today between 61% [10] and 64% [11] (5.53–5.80 kWh_{AC}/m^3) up to 75% [12] (4.72 kW_{AC}/m^3) until 2030 and up to 78% (4.54 kW_{AC}/m^3) in 2050.

For the sub-system methanation, it is assumed that the degree of conversion is 100% and the efficiency refers only to gaseous input and output. The theoretical efficiency is 78% based on the heating values of hydrogen and methane. Electrical consumption within methanation is considered on the cost side, but is not included in the efficiency (see Table 1).

3. Economical basics of PtG system and operation

The actual costs of PtG plants are reported in [13] and developments of cost projections and estimates for electrolysers are investigated in [14]. The expected cost reductions of the main components (electrolyser, methanation reactor and CO_2 separation units) due to technological learning curve effects for 2030 and 2050 are given in [15]. No significant changes in technology, like an implementation of additional functions or efficiency improvements, have been taken into account for calculating the future CAPEX in that report. Additional reductions for specific CAPEX of individual PtG plants in consequence of up-scaled nominal power have been considered [16].

This publication does not distinguish different electrolysis and methanation processes in order to their minor technological differences. Furthermore, the assumptions do not apply to a solid oxide electrolysis (SOEC), which might play a role in the future electrolysis market but currently is still in R&D. Nevertheless, system efficiencies of up to 80% have already been measured [17] and can even be increased with a suitable heat source for steam production.

Table 1
Minimum and maximum demand, load and load change rate of electrolysis and methanation.

Requirement	Set Point	Minimum	Maximum
Demand of electrolyser ($P_{1.0}$)	1, 10 or 50 MW_{el}	–	–
Efficiency ($\eta_{1.0}$)	2030: 75% 2050: 78%	–	–
Load of electrolysis ($L_{1.0}$)	variable	0%	100%
Load change rate of electrolysis	variable	–	± 20%/s
Demand of methanation ($P_{2.0}$)	variable	–	2030: 0.585 * $P_{1.0}$ MW_{SNG} 2050: 0.608 * $P_{1.0}$ MW_{SNG}
Specific efficiency ($\eta_{2.0}$) with 100% conversion	78%	–	–
Load of methanation ($L_{2.0}$)	variable	40%	100%
Load change rate of methanation	variable	–	± 10%/min

Compared to the business case analysis of a PtG plant in electricity markets dominated by renewables in [18–20] this article considers the methanation stage as well as future market and cost developments. The following analysis for the year 2030 and 2050 bases upon data gathered from relevant literature [18], cost estimates [14] and experience values from the European Union's Horizon 2020 research project STORE&GO[2] deliverables [15,16] as well as from STORE&GO demo plants and own assumption. Compared to the calculations in [15,16,18], the PtG system and calculations of future gas production costs are expanded.

In order to validate the profitability of the PtG process techno-economic analysis [21] and feasibility studies [22,23] of the plant are done. One approach for validating the gas production costs is to calculate the present value of the total costs for the construction and operation of a plant over its economic life, divided into equal annual payments. Another approach is to calculate the levelized costs of energy (LCOE) [24] or as levelized costs of storage (LCOS) for energy storage applications [25]. In the case of LCOS, the focus of the economic valuation is on the costs per unit of stored energy [26]. LCOS include energy-related and capacity-related cost. In this publication the approach of LCOE is used. In the following the approach of LCOE is adapt for calculating the gas production costs GPC of SNG (see Eq. (1) and Table 2 based on [24]). The GPC allow a cost comparison of technologies with different system configurations and modes of operation to produce SNG.

$$GPC = \frac{\sum_{t=1}^{n} \frac{CAPEX_t + OPEX_t + Energy_t + Decommissioning_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{SNG_t}{(1+r)^t}} \tag{1}$$

[27] presented the cost model of Levelized Cost of X (LCOX) for the mode of operation of the PtP plant for the production of a product similar to the PtG process. It is a general approach to calculate the Levelized Cost of Product (LCOX) for all potential products of a PtP plant operation, see Eq. (2).

$$LCOX = \frac{\sum_{t=1}^{n} \frac{Costsinyears_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{Number\ \ of\ \ X\ \ units\ \ produced\ \ in\ \ year\ \ t}{(1+r)^t}} \tag{2}$$

The LCOX and GPC calculation based on the LCOE approach show a general method for calculating the costs of production through PtX systems.

[2] The European Union's Horizon 2020 research project STORE&GO, grant agreement No 691797. The project is supported by the State Secretariat for Education, Research and Innovation (SERI) under contract number 15.0333.

Table 2
Variables of the GPC calculation.

$CAPEX_t$	capital expenditure in year "t"
$OPEX_t$	Operation and maintenance expenditure in year "t"
Energy:	Electricity and heat costs in year "t"
$Decommissioning_t$	Decommissioning cost in year "t"
$(1 + r)^t$	The discount factor for year "t"
SNG	The amount of SNG produced in year "t"

3.1. Capital expenditure

Today's capital expenditure (CAPEX) for PtG systems are high, but a decreasing trend due to size and experience is visible [14]. However, it has to be pointed out that the development of the PtG technology is subject to fundamental energy and climate policy decisions. If PtG systems be manufactured in standardized sizes and series, the CAPEX for PtG systems will further decrease. In addition, technological development will lead to better efficiencies. The expected CAPEX of the sub-systems electrolyser and methanation, balance of plant (storages, compressor and grid injection) and additional costs for planning and installation are listed in Table 3. The discount rate is 6% for all units and the costs are stated as real costs (reference year 2017, $€_{2017}$).

3.2. OPEX

The operation expenditures (OPEX) of PtG plants can be grouped into two main categories: fixed and variable OPEX [32]. 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*h).

3.2.1. Fixed OPEX

Fixed OPEX are costs to guarantee operational readiness, including personnel costs, occupancy costs, fees for maintenance agreements and insurance for the production facilities. Depending on the complexity and moving parts of each unit, the fixed OPEX can vary. The fixed OPEX of the methanation system also includes the costs of a catalyst change. Table 4 gives an overview of the fixed OPEX.

3.2.2. Variable OPEX

The variable OPEX depends on the operating state, the price and consumption of electricity, thermal energy, raw materials and auxiliaries. In particular, it includes the costs for the balance of plant (BoP), namely electricity for the operation of pumps, compressors, heat for temperature control, nitrogen, carbon dioxide and instrument air. In addition, there is the disposal of continuously produced media such as condensate (wastewater) and, if necessary, the operation of a flare.

Table 4
Fixed OPEX in % of CAPEX. The data are based on own assumptions and project experience from STORE&GO and other PtG projects where the authors are involved.

	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

All safety-relevant elements of the sub-systems electrolysis and methanation are in operation in all states, spending 2 kWh/(MW_{el}*h) energy. For PtG plants in areas with ambient temperatures around the freezing point a trace heating is necessary. The trace heating protects pipes containing water from freezing at sub-zero temperatures. The energy consumption is neglected in energy consumption. Keeping the methanation reactor and the electrolyte of the electrolyser at operating temperature and electricity for media circuits dominate the operating costs of HS. The electrical consumption in operation is the same as in hot standby. The OPEX in normal operation are lower than in hot standby because there is no or less need to compensate heat losses. Table 5 gives an overview of the assumptions of the thermal and electrical energy demands.

Table 6 shows the variable OPEX for PtG plants in 2030 and 2050 depending on the electrical and thermal energy demand in each state as listed in Table 5. The costs were calculated with a price for thermal energy of 50 €/MWh and for electricity of 25 €/MWh. The values for 2050 are slightly lower than in 2030 due to the estimated efficiency improvements.

Like the electricity costs for electrolysis operation, the costs for water and carbon dioxide are listed separately. A water consumption of 200% of the stoichiometric requirement at a cost of 0.69 €/m^3 is assumed [13]. Specific costs for CO_2 supply are not easy to define in general, because they strongly depend on the concentration in the source stream [33]. It seems more practical to value the needed CO_2 as

Table 3
Specific CAPEX of the sub-system electrolyser, methanation and further units of a PtG plant for the year 2017, 2030 and 2050.

	2017	2030			2050			
	Electrical input of the electrolyser ($MW_{el,AC}$)							
	1	1	10	50	1	10	50	
Electrolyser system ($€_{2017}/kW_{el}$)	1′180	665	470	415	350	245	220	[7,15,16,18]
Methanation system ($€_{2017}/kW_{SNG}$)	600	530	375	295	335	235	185	[13]
Hydrogen storage ($€_{2017}/m^3$ H_2)	100	75	75	75	50	50	50	[28]
CO_2 storage ($€_{2017}/m^3$)	100	50	50	50	50	50	50	[13]
CO_2 compressor ($€_{2017}$/kg)	2′465	1′233	1′233	1′000	1′000	750	750	[1]
Gas grid injection station ($k€_{2017}$)	75	75	75	75	50	50	50	[13]
SNG storage ($€_{2017}/m^3$)	100	50	50	0.08	50	50	0.08	[29,30]
Additional costs for installation (% of CAPEX)	28%	10%	10%	10%	10%	10%	10%	[2]
Additional costs for design, planning, etc. ($k€_{2017}$)	0	100	140	160	100	140	160	[2]
Replacement costs ($k€_{2017}$)[2]	354	199.5	141	124.5	105	73.5	66	[31]

[1] Own assumption and project experience from European Union's Horizon 2020 research project STORE&GO, grant agreement No 691797, and other PtG projects where the authors are involved.

[2] The lifetime of the plant is expected to be 20 years, except the electrolysis stacks and SNG storage. The lifetime of the electrolysis stacks is only 10 years and has to be replaced during lifetime. The lifetime of the SNG storage is 60 years.

Table 5
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 and per installed MW_{el}.

	Energy demand/kWh/(MW_{el}*h)		
Component	Cold Standby	Hot Standby	Production
Electrolysis system 2030			
• Thermal	0	20	0
• Electrical	2	20	20*
Electrolysis system 2050			
• Thermal	0	15	0
• Electrical	2	15	15*
Methanation system 2030			
• Thermal	0	50	0
• Electrical	2	25	25
Methanation system 2050			
• Thermal	0	40	0
• Electrical	2	20	20

* The electricity consumption of the electrolyser is depending on the application, operation concept and conditions of purchase and is therefore excluded in Table 5. The values refer to the demand for BoP in production mode.

Table 6
Variable OPEX in 2030 and 2050 for the sub-system electrolysis and methanation in the status cold standby, hot standby and production. The costs are calculated from the energy consumption of Table 5 and prices of 25 €/MWh_{el} for electrical and 50 €/MWh_{th} for thermal energy. The costs are defined as $€_{2017}$ per operation hour and per installed MW_{el}.

	variable OPEX/$€_{2017}$/(MW_{el}*h)		
Component	Cold Standby	Hot Standby	Production
Electrolysis system 2030	0.05	1.50	0.50
Electrolysis system 2050	0.05	1.13	0.38
Methanation system 2030	0.05	3.13	0.63
Methanation system 2050	0.05	2.50	0.50

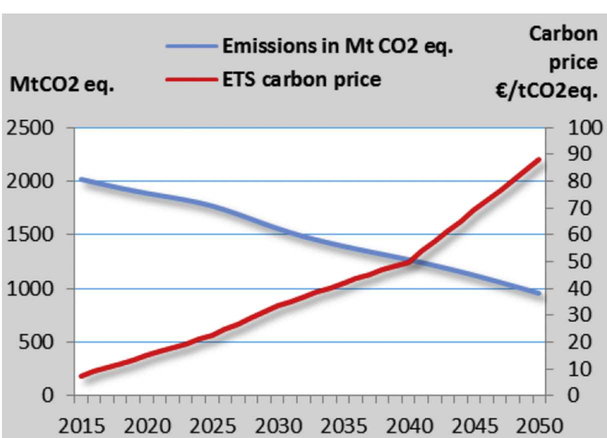

Fig. 3. Development of ETS emissions and ETS carbon prices [34].

an operating supply and therefore represent its costs per ton CO_2 depending on its source and sequestration technology. A detailed overview of the average capture costs for CO_2 related to industrial sectors is available in [15]. For future development, the EU ETS market will influence the CO_2 supply for PtG systems. In long-term, particularly from 2040 onwards, the level of the ETS price increases significantly (see Fig. 3). 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 [34].

The costs for the provision of CO_2 are assumed to be 40€/t and for transport 10€/t. Since the costs of 50€/t for separation and transport are below the certificate prices of 2030, they will be charged in full. For the year 2050 the certificate prices of 90€/t are higher than the separation. Therefore for 2050 only a flat rate of 10€/t is charged for transport. In the following an exemplary list of potential, unavoidable CO_2 sources, which are also available after a transition to renewable energies: carbon intensive chemical industry [35], iron and steel production, cement production [36,37], paper production, biogenic CO_2 sources [38,39] and the atmosphere [40].

3.3. Natural and synthetic/biological gas market

Methane produced in a PtG plant could be considered "green" depending on the sources of electricity and CO_2 that are used [41]. Consumers can prefer green gas to fossil gas and might be willing to pay extra for it. Governments can introduce a market incentive programme to promote the switch from fossil gas to synthetic gas. An extensive overview of support schemes for the use of SNG in the three countries in which a PtG methanation plant is built within the STORE&GO project (Germany, Italy and Switzerland) is given in [9]. It makes clear that these schemes can be very complicated with different requirements and exceptions to get support. 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.

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. The future development of natural gas prices is therefore highly relevant for PtG methanation plants. No significant changes in the natural gas price are expected until 2030 by [42]. [43] states that there are still large crude oil and natural gas reserves that can be mined at low cost. Only political measures can ensure the use of PtG. This can be done through pricing of CO_2 emissions or through other measures such as blending requirements.

Other reports show very different future scenarios. An example is the World Energy Outlook 2017 [44] according to which the natural gas use will strongly increase in the upcoming 25 years. The document also provides a prediction for the natural gas prices in different regions in the world, including the EU, where prices are expected to increase from 2016 levels to roughly double by 2040 (from about 4.9 to 9.6 $/MBtu or roughly 28.8 €/MWh in the new policies scenario).

[34] 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 and 79 $\$_{2013}$/boe (27.07 and 30.99 $€_{2017}$/MWh) in 2030 and 2050, respectively. This price increase is driven by growing 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 available in large quantities on a 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. Application and operation strategy of PtG in future

The analysis on economics for various operating strategies of PtG plants is done for one year of operation. Four different basic operating strategies considering the electricity and gas market were analysed (1, 2, 5 and 6). 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, which are arranged on forehand and therefore ensure continuous operation of the plant (or parts of the plant). Besides the basic operating strategies, the authors perceive further opportunities for PtG applications in the near future. These strategies consider direct coupling of the PtG plant with a renewable energy source and the seasonal use of surplus energy from RES or participation in electricity balancing market. These strategies are considered even though there are not yet appropriate incentives or support schemes in place, which enable economic benefits.

In the flexible modes, electricity is bought on the short-term market and gas is sold on either the short-term market (option 6) or long-term contract (option 2). 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 €/MWh and more than 100 €/MWh. The expected relation between these extreme price ranges, which are expected to rise sharply from 2026 onwards [45], bring opportunities for new participants and technologies on the market, such as storage systems. The dwell time for a PtG system in a respective operating state can be investigated over a year of operation.

The eight combinations of electricity purchase and gas selling strategies according to Table 8 were analysed with a 1, 10 and 50 MW_{el} PtG plant for 2030 and 2050. Furthermore, a sensitivity analysis was carried out for case one (Continuous operation) and two (Flexible electricity).

5. Results

The GPC reported in this section include all costs over the lifetime of the plant, including CAPEX, yearly fixed and flexible OPEX, which strongly depend on the operating mode and the full load hours (FLH).

Some results are calculated with an electricity price of 0 €/MWh for the operation of the electrolysis. Eq. (3) can be used to check the influence of an individually determined electricity price (EP) on the calculated GPC by using the efficiency $\eta_{0.0}$ of the PtG system.

$$GPC_{EP} = GPC_{0€} + \frac{EP}{\eta_{0.0}} \tag{3}$$

1 "Continuous operation"

This operating strategy assumes a continuous operation of the plant over a year (8760 FLH) with an average electricity price. The gas is produced and sold constantly for a fixed price. In this operating strategy, there is no need for hydrogen or methane storage on-site. Fig. 4 shows the calculated methane production costs for different electricity prices. The methane production costs in 2030 are in the range of 33.60 €/MWh for an electricity price of 0 €/MWh and 204.82 €/MWh for an electricity price of 100 €/MWh. As indicated in Table 7, the maximum revenue for SNG in 2030 was estimated to be about 75 €/MWh, which is enough to cover the costs of continuously operating a PtG methanation plant when the electricity price is lower than 24 €/MWh. With higher electricity prices, an operation is not profitable.

For 2050 a higher perspective SNG/biogas price of 125 €/MWh is assumed. In this case a positive business case is possible for each size of the PtG plant, if the electricity price is less than approximately 70 €/MWh.

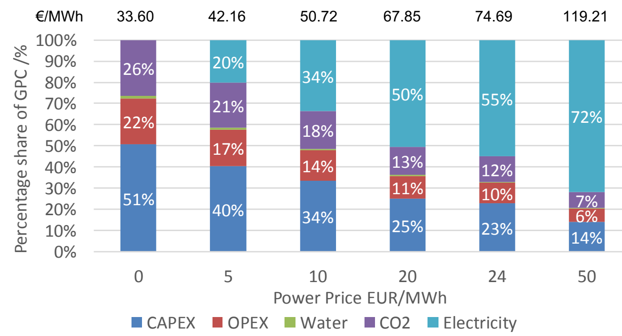

Fig. 4. Percentage share of CAPEX, OPEX, water, CO_2 price and electricity of the GPC of a 10 MW_{el} PtG with perspective cost parameters for 2030 and different power prices.

Table 7
Future prices for natural gas based on [34] and for biogas, SNG, LSNG on the gas market in 2030 and 2050 based on assumptions.

Product	Price 2030	Price 2050
Biogas/SNG/LSNG	75 €/MWh	125 €/MWh
Natural gas [34]	30 $€_{2013}$/MWh	36 $€_{2013}$/MWh

2 "Flexible Operation"

The methane production costs strongly depend on the electricity price and the operating time of the electrolysis and the methanation. In the calculations for the case "2. Flexible Operation", the operating hours of the electrolysis are assumed to be distributed evenly over the entire year. If no electricity is available, the electrolysis is maintained in hot standby. For the methanation, two operation strategies are discussed as follows. In both cases the entire hydrogen quantity produced by the electrolyser is processed by the methanation unit.

I. Only a small hydrogen storage separates the electrolyser and the methanation unit in order to compensate for the different rate of load changes of the two sub-systems. Both sub-systems have the same FLH and HSH.
II. A larger hydrogen storage separates the two sub-systems. The intermediate storage guarantees that SNG is delivered constantly over the 8500 h. Depending on the pressure level of the hydrogen storage, the load of the methanation is varied between 40 and 100%.

Table 9 shows the methane production costs when operating the PtG plant based on strategy I. For each electricity price, four dwell times in production mode of the electrolyser and methanation are calculated on a basis of a 10 MW_{el} PtG plant.

The results shows that the FLH have a strong impact on the economic feasibility of SNG production via a PtG plant. The higher the operating hours, the larger the product volume and the fixed costs are distributed.

With operation strategy II, the fluctuating load of the electrolyser can decoupled from the load of the methanation. This enables slower load changes and longer continuous operation of the methanation unit. The size of the hydrogen storage depends on the load profile of the electrolyser and the size of the downstream methanation.

Table 10 shows the methane production costs for strategy II with the expected operation hours of the electrolyser and methanation. The size of the hydrogen storage between electrolyser enables 8500 h of operation of the methanation unit per year and therefore a constant supply of methane. 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

Table 8
Overview of electricity purchase and gas selling strategies for future markets.

Gas selling	Electricity purchase: long term contracts	short term market	direct coupling RES	seasonal
long term contracts	1. Continuous operation **Prices** both **fixed** on forehand, **continuous operation** of the plant. No large storage facilities needed.	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.	3. 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.	4. Seasonal electrolyser **Gas** is **continuously sold** and injected in the gas grid. **Electricity** is purchased according to **surplus** energy from RES or participation in electricity balancing market. Hydrogen buffer tank is required.
short term market	5. Flexible gas **Electrolyser** is **operated continuously**. **Gas** is sold **according to price levels**, buffer tank for methane is needed.	6. 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.	7. 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.	8. Seasonal flexibility **Electricity** is purchased according to **surplus** energy from RES from grid or participation in electricity balancing market. **Gas** is sold **according to price levels**. Large buffer tanks for both hydrogen and methane are needed.

storage size and the capacity of the methanation were optimized accordingly. The basis is a 10 MW_{el} electrolyser and cost estimation for the years 2030 and 2050.

Fig. 5 shows the results of the GPC of Table 9 under the assumption that the FLH of the PtG system depends on the electricity price. The lower the electricity price (willingness to pay), the lower the FLH. When electricity costs are not considered, the gas production costs reduce with higher numbers of operating hours. Contra productive for economic feasibility is the higher (average) electricity price on the electricity market for the cases with higher number of operating hours.

The results show that an optimization of the intermediate hydrogen storage size offers the potential for improvement of the PtG economics. Furthermore, (with the given correlation of FLH and electricity prices) there is a cost optimum for the SNG production via PtG for FLH in the range of 2000–4000 h/a.

3 Flexible electrolyser

In the case of flexible, irregular and unpredictable electricity supply, the hydrogen storage tank must be designed larger if frequent start-ups and shut-downs of methanation are to be avoided. The size of the methanation process is also a crucial factor. When optimising both systems, it must be asked in advance whether electricity can be interrupted or hydrogen rejected at peak times, if the H_2 storage is filled to the maximum. In these cases (Table 8, cases 3 and 7), the size of the H_2 storage and methanation was chosen so that no hydrogen is rejected. In Table 11, the corresponding GPCs are shown for a 10 MW_{el} PtG plant, which is directly coupled to a PV field with data from [46] in 2015 and to a wind park from [47] in 2016. Other than the previous calculation, the methanation is flexible and able to produce in part load (40 to 100%), depending on the charge-state of the hydrogen storage tank.

4 Seasonal electrolyser

The same conclusions can be drawn for seasonal purchase of excess electricity as well as participation in electricity balancing market (Table 8, case 4) as for case 3 “flexible electrolyser”. In Table 11, the corresponding GPCs are shown for a 10 MW_{el} PtG plant, which offers symmetrical secondary control power in Switzerland [48]. In the case of symmetrical control reserve, i.e. offering positive and negative control reserve, methanation can be designed for the output of electrolysis if no control reserve is called up. The fluctuations caused by the control reserve are absorbed by the H_2 storage and can be compensated by changing the methanation load. Thus the methanation can reach 8760 OPH and very high FLH according to the control reserve request.

Table 9
Methane production costs for operating strategy I based on a PtG plant size of 10 $MW_{el.}$

Operation strategy I		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

Table 10
Methane production costs operating strategy II based on a PtG plant size of 10 $MW_{el.}$

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	4.10 4.26	8500	260	42.32	19.79	59.44	36.25	85.12	60.95

5.1. Short-term vs. long-term markets

If the gas shall be sold on the short-term market, SNG storages have to be used for the cases 5–8 in Table 8. The produced gas can be stored in steel tanks on site or in underground caverns. In case steel tanks are used, the gas production costs become very high with the size of the storage volume. However, for caverns, additional volume lead to rather marginal extra cost. For all four options, SNG should therefore be stored in geological formations to sell it according to requisition in winter season or in times where there is a high selling price on the market (see Table 12). Natural gas prices fluctuated by up to 30% in 2018 (see Fig. 6). In order to profit from price fluctuations, electricity trading must be used. The price fluctuations on the intraday and day-ahead markets are more volatile, more frequent and less seasonal. In 2018, the electricity price in the intraday and day-ahead markets fluctuated over 100% [49].

The fifth case is based on a long-term contract for electricity purchase. In this case, the electrolysis and the methanation can be operated over 8500 h per year. The delivery volume to SNG is constant throughout the year and the sales volume can be estimated well on the basis of the storage level and the quantity produced and high prices can be fully exploited.

Electricity prices vary strongly on a short-term basis while methane prices are lower in summer than in winter. Therefore, it makes sense to purchase the electricity on the short-term market (Table 8, case 6, results Table 12) and sell the stored SNG, when the price is high. If the electricity price is temporarily too high and the electrolysis do not supply hydrogen, a small hydrogen storage (hours up to days) can help to bridge the gap for guarantee a constant SNG production.

The supply of electricity in direct coupling to a renewable energy source (Table 8, case 7, results Table 12) or using surpluses (Table 8, case 8, results Table 12) can also be very volatile. For this reason, the operation of methanation must be decoupled from electrolysis by means of a hydrogen storage tank.

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 GPC of case 7 increase for the electricity supply from wind compared to case 3

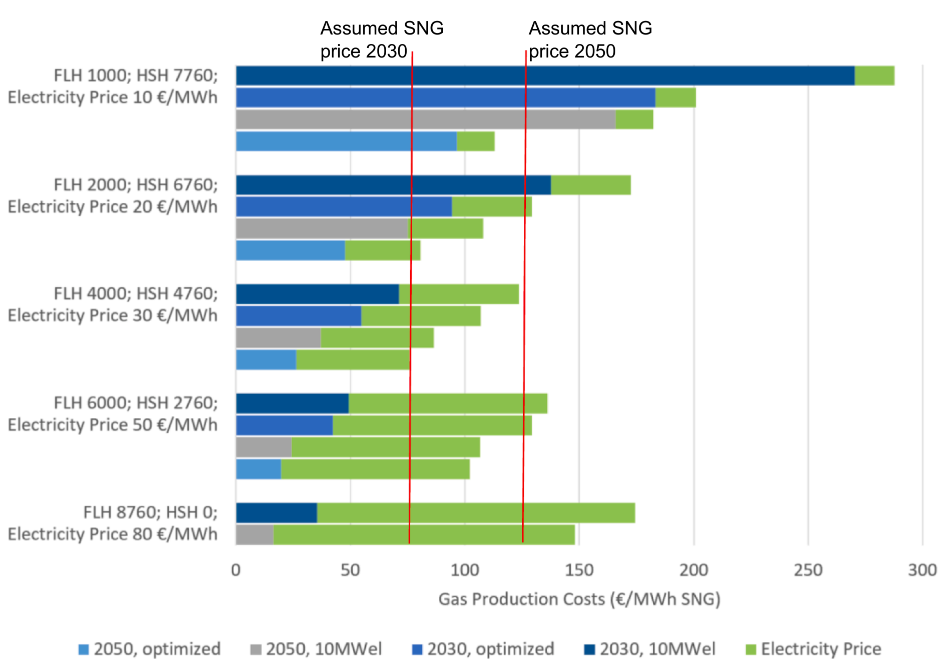

Fig. 5. Methane production costs (€/MWh) for different full load hours (FLH) of the electrolyser and methanation sub-system. The FLH of the PtG system depends on the electricity price. The lower the electricity price (willingness to pay), the lower the FLH.

Table 11
Methane production costs (MPC) for case 3 (direct coupling with RES) and 4 (seasonal purchase of excess electricity in form of secondary control reserve) with an electricity price of 0 €/MWh_{el}. The operation hours (OPH) with varying loads are cumulated to full load hours (FLH).

	Electrolyser			H_2 storage/h		Methanation			MPC (€/MW_{SNG})	
	FLH	OPH	HSH		Size MW_{SNG} 2030/ 2050	FLH	OPH	HSH	2030	2050
Case 3 (direct coupling with PV)	1012	4445	4315	9.3	1.95/2.03	3028	6378	2382	198.61	124.98
Case 3 (direct coupling with wind)	1592	6704	2056	6.6	5.72/5.95	1625	2437	6323	167.69	91.75
Case 4 (Secondary Control reserve)	4459	8760	0	3	3.71/3.86	7014	8760	0	51.83	27.03

Table 12
Methane production costs (MPC) with seasonal gas storage fees (0.11 €/m^3) and an electricity price of 0 €/MWh_{el} in 2030 and 2050.

	Electrolyser		H_2 storage/h	Methanation			SNG storage/h	MPC (€/MW_{SNG})	
	FLH	HSH		Size MW_{SNG} 2030/ 2050	FLH	HSH		2030	2050
Case 5 (long term electricity contract)	8500	260	2	5.80/6.04	8500	260	8500	36.07	16.87
Case 6 (Short term electricity market)	4500	4260	9	5.22/5.47	5000	3760	5000	65.69	34.94
Case 7 (direct coupling with a windpark)	1592	2056	6.6	5.72/5.95	1625	2437	1625	168.59	92.62
Case 8 (Secondary control reserve)	4459	0	3	3.71/3.86	7014	0	7014	52.70	27.90

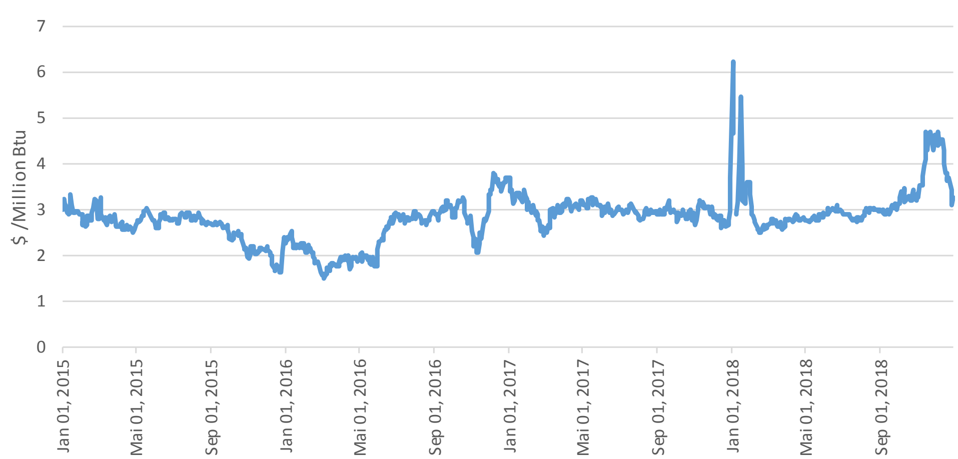

Fig. 6. Historical prices of natural gas (Henry Hub) in USD from January 2015 to December 2018 [50].

around 0.5% for 2030 and 0.9% for 2050, if an underground storage for the production capacity of one year is provided (compare case 3 and case 7 in Table 8). If the plant provides secondary control reserve, the GPC increases 1.7% in 2030 and 3.2% in 2050, due to the additional underground storage fees.

6. Discussion

This publication gives an overview of the effects of operating strategies and configuration on economics of PtG plants for the year 2030 and 2050. Four electricity supply concepts were combined with two selling strategies for synthetic natural gas. The operating schemes vary between the provision of electricity via long-term contracts, short-term markets or direct-use of renewable energy without grid connection or the seasonal availability of surplus energy. Gas selling is considered for long-term contracts and short-term markets.

The calculations have shown that adapting the system configuration can significantly reduce the methane production costs. With an intermediate storage tank for hydrogen and adjustment of the methanation demand, the workload of methanation can be increased by operating electrolysis and methanation separately. The optimised system configuration with the expected developments for CAPEX, OPEX, electricity prices, gas costs and efficiencies attain viable production of SNG in 2030, but especially in 2050 and electricity costs of 20–30 €/MWh, where the GPC become comparable to biogas. In 2050, the gap between the market driven business models and economic feasibility is rather narrow.

The results show that power to gas can be used for long-term, large-scale seasonal storage of renewable energy. Seasonal electricity storage will become an interesting market opportunity for PtG plants. Especially the cases with high operating hours and low electricity prices show GPC below the expected market prices for SNG and biogas. The optimization of the system configuration by means of intermediate hydrogen storage and methanation size show that the standby times can be reduced and thus the methane production costs are decreased.

In addition to system optimization, other aspects may contribute to a reduction of GPCs in the future. A change in the limit values for the maximum H_2 concentration in the SNG feeding into the natural gas network would reduce the CAPEX and OPEX due to a reduction of costs for subsequent gas processing (H_2 recycling). Future limits and requirements for synthetic gas were discussed in detail in [51].

In the case of volatile electricity supply, the optimization must run over a cycle of at least two years in order to allow the variance of different years to influence the optimization. The system configuration must be optimized on a case-by-case basis and a sensitivity analysis carried out.

The implementation of systemic advantages, e.g. reduction of grid load, security of supply or governmental support schemes were not considered in any calculations performed in this publication. These aspects can have a positive effect on economic efficiency with appropriate incentives or support schemes. Regulatory measures for enabling the benefits (security of supply, support of electricity grid) of large-scale sectoral coupling and energy storage capabilities of the PtG technology are still missing. 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.

Acknowledgments

This contribution has received funding from the European Union's Horizon 2020 research, innovation programme under grant agreement No. 691797. The project is supported by the State Secretariat for Education, Research and Innovation (SERI) under contract number 15.0333. The paper reflects only the authors' view and the Union is not liable for any use that may be made of the information contained therein.

References

[1] Bailera Manuel, Lisbona Pilar, Romeo Luis M, Espatolero Sergio. Power to gas projects review: lab, pilot and demo plants for storing renewable energy and CO2. Renew Susta Energy Rev 2017;69:292–312.
[2] Schiebahn Sebastian, Grube Thomas, Robinius Martin, Tietze Vanessa, Kumar Bhunesh, Detlef Stolten. Power to gas: Technological overview, systems analysis and economic assessment for a case study in Germany. Int J Hydrogen Energy 2015;40(12):4285–94.
[3] Gahleitner Gerda. Hydrogen from renewable electricity: an international review of power-to-gas pilot plants for stationary applications. Int J Hydrogen Energy 2013;38(5):2039–61.
[4] Wulf Christina, Linßen Jochen, Petra Zapp. Review of power-to-gas projects in Europe. Energy Procedia 2018;155:367–78.
[5] David Martín, Ocampo-Martínez Carlos, Ricardo Sánchez-Peña. Advances in alkaline water electrolyzers: a review. J Storage Mater 2019;23:392–403.
[6] Carmo Marcelo, Fritz David L, Mergel Jürgen, Stolten Detlef. A comprehensive review on PEM water electrolysis. Int J Hydrogen Energy 2013;38(12):4901–34.
[7] Buttler Alexander, Hartmut Spliethoff. Current status of water electrolysis for energy storage, grid balancing and sector coupling via power-to-gas and power-to-liquids: a review. Renew Sustain Energy Rev 2018;82:2440–54.
[8] Rönsch Stefan, Schneider Jens, Matthischke Steffi, Schlüter Michael, Götz Manuel, Lefebvre Jonathan, et al. Review on methanation – from fundamentals to current projects. Fuel 2016;166:276–96.
[9] Kreeft Gijs. D7.3 – Legislative and Regulatory Framework for Power-to-Gas in Germany, Italy and Switzerland. EU Project Horizon 2020 STORE&GO. Brussels; 04/2018.
[10] Vock H. DiamondLite (Proton, USA). Manual, Hogen C-Serie, 30Nm3/30bar, Container Layout; 2013.
[11] Kopp M, Coleman D, Stiller C, Scheffer K, Aichinger J, Scheppat B. Energiepark Mainz: technical and economic analysis of the worldwide largest Power-to-Gas plant with PEM electrolysis. Int J Hydrogen Energy 2017;42(19):13311–20.
[12] Hydrogenics: Hystat Hydrogen Generators (HyLYZER(R) 600). URL: https://www.hydrogenics.com/ [access date: 2019-02-12].
[13] Van Leeuwen Charlotte, Zauner Andreas. D8.3 – Report on the costs involved with PtG technologies and their potentials across the EU. EU Horizon 2020 Project STORE&GO. Brussels; 04/2018.
[14] Saba Sayed M, Müller Martin, Robinius Martin, Stolten Detlef. The investment costs of electrolysis – a comparison of cost studies from the past 30 years. Int J Hydrogen Energy 2018;43(3):1209–23.
[15] Böhm H, Zauner A, Goers S, Tichler R, Kroon P. D7.5 – Report on experience curves and economics of scale. EU Horizon 2020 Project STORE&GO. Brussels; 10/2018.
[16] Zauner A, Böhm H, Rosenfeld D, Tichler R. D7.7 – Analysis on future technology options and on techno-economic optimization. EU Horizon 2020 Project STORE&GO. Brussels; 02/2019.
[17] Sunfire Helmeth. Report on the overall system design and operational tests of the combined system: Deliverable 4.2. 1. März; 2018.
[18] Van Leeuwen Charlotte, Mulder Machiel. Power-to-gas in electricity markets dominated by renewables. Appl Energy 2018;232:258–72.
[19] Jorgensen C, Ropenus S. Production price of hydrogen from grid connected electrolysis in a power market with high wind penetration. Int J Hydrogen Energy 2008;33(20):5335–44.
[20] Baumann C, Schuster R, Moser A. Economic potential of power-to-gas energy storages. EEM 13: 10th international conference on the European energy market: Stockholm, Sweden, 27-31 May 2013. Piscataway, NJ: IEEE; 2013. p. 1–6.
[21] Schnuelle Christian, Thoeming Jorg, Wassermann Timo, Their Pablo, von Gleich Arnim, Goessling-Reisemann Stefan. Socio-technical-economic assessment of power-to-X: potentials and limitations for an integration into the German energy system. Energy Res Soc Sci 2019;51:187–97.
[22] Tsupari Eemeli, Kärki Janne, Vakkilainen Esa. Economic feasibility of power-to-gas integrated with biomass fired CHP plant. J Energy Storage 2016;5:62–9.
[23] Leonzio Grazia. Design and feasibility analysis of a Power-to-Gas plant in Germany. J Cleaner Prod 2017;162:609–23.
[24] Mcdonagh Shane, O'shea Richard, Wall David M, Deane JP, Murphy Jerry D. Modelling of a power-to-gas system to predict the levelised cost of energy of an advanced renewable gaseous transport fuel. Appl Energy 2018;215:444–56.
[25] Smallbone Andrew, Jülch Verena, Wardle Robin, Roskilly Anthony Paul. Levelised cost of storage for pumped heat energy storage in comparison with other energy storage technologies. Energy Convers Manage 2017;152:221–8.
[26] Jülch Verena. Comparison of electricity storage options using levelized cost of storage (LCOS) method. Appl Energy 2016;183:1594–606.
[27] ENEA consulting: The potential of Power-to-Gas: Technology review and economic potential assessment; 2016.
[28] Linnemann J, Steinbergerwilckens R. Realistic costs of wind-hydrogen vehicle fuel production. Int J Hydrogen Energy 2007;32(10–11):1492–9.
[29] Lord Anna S, Kobos Peter H, Borns David J. Geologic storage of hydrogen: Scaling up to meet city transportation demands. Int J Hydrogen Energy 2014;39(28):15570–82.
[30] Le Duigou Alain, Bader Anne-Gaëlle, Lanoix Jean-Christophe, Nadau Lionel. Relevance and costs of large scale underground hydrogen storage in France. Int J Hydrogen Energy 2017;42(36):22987–3003.
[31] Bertuccioli et al. Development of Water Electrolysis in the European Union; 2014.
[32] Gorre Jachin, Lydement Justin, Felix Ortloff, Jens Hüttenrauch, Ettore Bompard, Andrea Mazza, et al. Alessio: D5.2 – Interim report of benchmarks and analysis description and load profile definitions. EU Horizon 2020 Project STORE&GO. Brussels, 10/2017.
[33] Koytsoumpa Efthymia Ioanna, Bergins Christian, Kakaras Emmanouil. The CO2 economy: review of CO2 capture and reuse technologies. J Supercrit Fluids 2018;132:3–16.
[34] European Commission: EU Reference Scenario 2016: Energy, transport and GHG emissions Trends to 2050; 2016.
[35] Kuramochi Takeshi, Ramírez Andrea, Turkenburg Wim, Faaij André. Comparative assessment of CO2 capture technologies for carbon-intensive industrial processes. Prog Energy Combust Sci 2012;38(1):87–112.
[36] Farfan Javier, Fasihi Mahdi, Breyer Christian. Trends in the global cement industry and opportunities for long-term sustainable CCU potential for Power-to-X. J Cleaner Prod 2019;217:821–35.
[37] Baier Jens, Schneider Gabriel, Heel Andre. A cost estimation for CO2 reduction and reuse by methanation from cement industry sources in Switzerland. Front Energy Res 2018;6:17.
[38] Inkeria Eero, Sihvonenb Teemu, Karjunena Hannu, Tynjäläa Tero, Tähtinenb Matti, Weiss Robert. Integration of Power-to-Gas-Process to wastewater treatment plant with biogas production. Poster, 10th international renewable energy storage conference IRES, Düsseldorf. 2016.
[39] Laude A, Ricci O, Bureau G, Royer-Adnot J, Fabbri A. CO2 capture and storage from a bioethanol plant: Carbon and energy footprint and economic assessment. Int J Greenhouse Gas Control 2011;5(5):1220–31.
[40] CLIMEWORKS: Climeworks Capturing CO2 from Air. Leaflet of Launch Event. 31; Mai 2017.
[41] Jepma Catrinus, Van Leeuwen Charlotte, Hulshof Daan. D8.1 – Econometric analysis of the future demand for 'green gases' and related flexibility. EU Horizon 2020 Project STORE&GO. Brussels; 08/2017.
[42] World Bank Group: Natural Gas Prices Forecast: Long Term 2018 to 2030. URL http://comstat.comesa.int/ncszerf/natural-gas-prices-forecast-long-term-2018-to-2030-data-and-charts – Überprüfungsdatum 2019-02-20.
[43] Perner Jens, Unteutsch Michaela, Lövenich Andrea. Frontier Economics Ltd. (Mitarb.): The Future Cost of Electricity-Based Synthetic Fuels. Berlin; April 2018.

[44] IEA, International Energy Agency: World Energy Outlook 2017. Paris; 11/2017.

[45] CARLOS PEREZ-LINKENHEIL: Trends in the development of electricity prices - EU Energy Outlook 2050. URL https://blog.energybrainpool.com/en/trends-in-the-development-of-electricity-prices-eu-energy-outlook-2050/ – Überprüfungsdatum 2018-01-06.

[46] Pfenninger Stefan, Staffell Iain. Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. Energy 2016;114:1251–65.

[47] Staffell Iain, Pfenninger Stefan. Using bias-corrected reanalysis to simulate current and future wind power output. Energy 2016;114:1224–39.

[48] Swissgrid AG. Grid data reserve market. URL https://www.swissgrid.ch/ [access date: 2019-06-18].

[49] EPEX SPOT. Market data intraday and day-ahead market. URL https://www.epexspot.com/en/ [access date: 2019-06-18].

[50] EIA U.S. – Energy Information Administration: Price History of Natural Gas (Henry Hub). URL https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm [access date 2019-06-19].

[51] Hulshof Daan. D8.2 - Report on the acceptance and future acceptability of certificate-based green gases. EU Horizon 2020 Project STORE&GO. Brussels; 04/2018.