Projecting Cost Development for Future Large-Scale Power-to-Gas Implementations

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Abstract

Power-to-gas (PtG) is widely expected to play a valuable role in future renewable energy systems. In addition to partly allowing a further utilization of the existing gas infrastructure for energy transport and storage, hydrogen or synthetic natural gas (SNG) from electric power represents a high-density energy carrier and important feedstock material for further processing. This premise leads to a significant demand for large-scale PtG plants, which was evaluated with an amount of up to 14.2 TW_{el} at a global scale. Together with the upscaling of single-MW plants available today, this will enable to achieve appropriate cost reduction effects through technological learning. These effects were evaluated in the present paper via a holistic techno-economic assessment of different PtG plant configurations, resulting in the reduction of SNG production costs down to 100 €/MWh_{SNG} by 2030 and below 60 €/MWh_{SNG} by 2050, according to the supplying electricity source.

Keywords

Power-to-Gas, Electrolysis, Methanation, Scaling Effects, Technological Learning, SNG Production Costs

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1 Introduction

With switching from fossil fuels to renewable energy sources (RES) a transformation of existing energy systems to alternative energy carriers will be unavoidable. However, although an electrification of energy supply and its utilization to the greatest possible extent is generally reasonable in terms of energy efficiency, there will still be a significant demand for “green” gases, like hydrogen or synthetic natural gas (SNG) from renewables. Industrial processes, in particular, are expected to be reliant on these gases, be it for reduction processes (e.g. steel industry), high-density energy carriers or as feedstock material for chemicals and synthetic fuels. Besides that, power-to-gas (PtG) is often considered as a long-term storage and balancing technology for fluctuating RES or energy transport media, with the ability to use existing natural gas infrastructure, thereby potentially lowering infrastructure transition costs.

To estimate economic feasibility of different PtG concepts and evaluate impacts of regulatory measures, such as CO_2 taxes [1], the knowledge of the current state and expected development of technology and gas production costs is mandatory. Since power-to-gas still represents a relatively novel technology, at a technology readiness level (TRL) of 5-7 [2], appropriate data for commercial systems are hardly available. Thema et al. [3] analyzed cost development for electrolysis and methanation projects from 1988 onwards and provided cost projections up to 2050, assuming a continuous exponential decrease. Another approach is the estimation of future cost reduction according to technological learning [4]. Nicodemus [5] investigated the impact of policy support on technological learning for PV powered PEM electrolysis resulting in the production costs of < 3 \$/kg H_2 by 2030. Similar results could be reached using high-temperature electrolysis [6]. For the production costs of synthetic methane, Gorre et al. [7] tried to identify optimized PtG plant operation scenarios according to gas selling strategies and electricity purchase. Presuming significant reductions for CAPEX and OPEX of PtG plants, methane production costs could reach 50-90 €/MWh_{SNG} by 2030 and 25-65 €/MWh_{SNG} by 2050, under optimal conditions for plant scales of 10 MW_{el}.

In order to satisfy local demand, future demand for renewable gases will require the implementation of large-scale PtG plants for centralized production (e.g. in the steel industry [8]) and thus it will be necessary to utilize additional scaling effects. Significant cost reduction potential through up-scaling of plant production capacities for different PtG technologies were already identified by Parra et al. [9,10] (alkaline and PEM electrolysis and methanation) and Anghilante et al. [11] (solid-oxide electrolysis), and also considered the impacts of mass production. Gutiérrez-Martín et al. [12] evaluated power-to-SNG technology in general for large-scale storage applications, indicating levelized costs of energy (LCoE) for SNG of 30-80 €/MWh, depending on presumed electricity costs.

However, the existing studies generally only consider economies of scale either in terms of unit scale (increase in typical plant size) or technological learning (increase in number of produced units). For a holistic examination of future production costs for renewable SNG both aspects have a significant impact on overall cost reductions. Hence, our study investigates both scaling effects using component-based approach that considers the differences between common technologies and takes care of spillover effects from concurrent usage [4]. To allow this comprehensive analysis of production-related learning effects, we also include a literature review on future demand potentials for renewable gases to evaluate the according demands on cumulative productions for PtG technology components.

Since, besides the investment costs, future price for renewable electricity is a substantial factor for the suitability of this power-intense technology, we assessed the cost development for power-to-gas applications based on the resulting SNG production costs in different power supply scenarios. Hence, a comprehensive techno-economic assessment for different

configurations of large-scale PtG plants (≥ 50 MW_{el}) was performed. The study aims to allow the estimation of future costs of power-to-gas as a potentially valuable technology contributing to the future renewable energy systems. As such, it aims to facilitate the development of regulatory policies and measures that would be mandatory for the technology to be competitive against fossil-based technologies and processes.

2 Methodology

2.1 Demand potentials for PtG products

Since the cumulative production of related technology equipment is the main driving factor for technological learning and hence for the reduction of future investment costs on the technology, the evaluation of future demand potentials for PtG products is of major relevance for the assessment of the costs of generating PtG products. The review of relevant literature has shown that estimation on future demand potentials for Power-to-Gas differs, depending on focused targets and sectors.

2.1.1 Assessment of literature data

Different studies conducted for the German power sector reveal a demand potential for electrolysis plants of 26 to 36 GW_{el}, depending on the amount of parallelly installed short-term energy storage capacities (e.g. battery energy storages) until year 2050 [13,14]. Another assessment estimate a significantly higher demand on PtG as a flexibility option in the German energy system of 89 and 134 GW_{el}, with and without short-term storage options, respectively, in the same timeframe [15]. Targeting economic aspects in a 100% RES based German electricity system, Breyer et al. [16] discovered a need for 43-45 GW_{el} of installed electrolysis capacity until 2040. The incorporation of mobility, industry and (residential) heat sectors reveals electrolysis capacity demands of about 130 up to 280 GW_{el} for the production of hydrogen and subsequent renewable energy carriers and feedstock materials through Power-to-Methane (PtM) and Power-to-X processes [16–18]. While comparable studies estimate a significantly lower demand, they also show that the potentials for PtG and PtX in the mobility and industrial sectors are expected to outperform the needs for long-term storage capabilities [19]. This is also confirmed in studies focusing on the mobility sector only [20,21].

When studying the transition of the energy system to RES in Spain by 2050, Bailera et al. [22] discovered a demand for PtG storage capabilities for excess RES of 7-19.5 GW_{el}. For a complete decarbonization of the energy system this demand could be even more than four times higher, according to Lisbona et al. [23]. Expected demands for the Italian energy system are in a comparable range of 30 GW_{el} by 2050 [24].

At the European level Blanco et al. simulated the demands for PtM [25] as well as for hydrogen and Power-to-Liquid [26] in a low-carbon EU energy system, using cost optimizations. Depending on the boundary conditions, like underground carbon storage options and positive drivers for PtM, the resulting potentials are almost equal in both cases, PtM and hydrogen, covering a wide range from 70-1,000 GW_{el} of installed electrolysis capacity. For the PtM path the upper boundary indicates a methane production of 546 GW, which implies a coverage of 75% of the expected gas demand in the EU by 2050 [25].

At a global scale, the availability of relevant studies is rather limited. Pleßmann et al. [27] evaluated the demand for power plant and storage capacities for a global, decentralized and 100% RES-based electricity supply scenario, including long-term storage through renewable power methane (RPM) using PtG processes. The results showed a global demand for RPM storage of about 2,360 GW_{el} electric input. Though the produced SNG can be injected to existing gas grids and used to provide renewable gas to other sectors besides power

generation, the calculated demands only consider the needs for transformation of excess energy from volatile RES.

However, a large-scale roll-out of PtG plants also requires a significant increase of RES for the production of renewable gases, including the associated impacts on future energy systems (cf. Zappa et al. [28]). **Fehler! Verweisquelle konnte nicht gefunden werden.** summarizes the findings stated above. As the Figure shows, the comparability of these studies is restricted due to the variations in their regional and sectoral scopes, as well as the underlying constraints and boundary conditions.

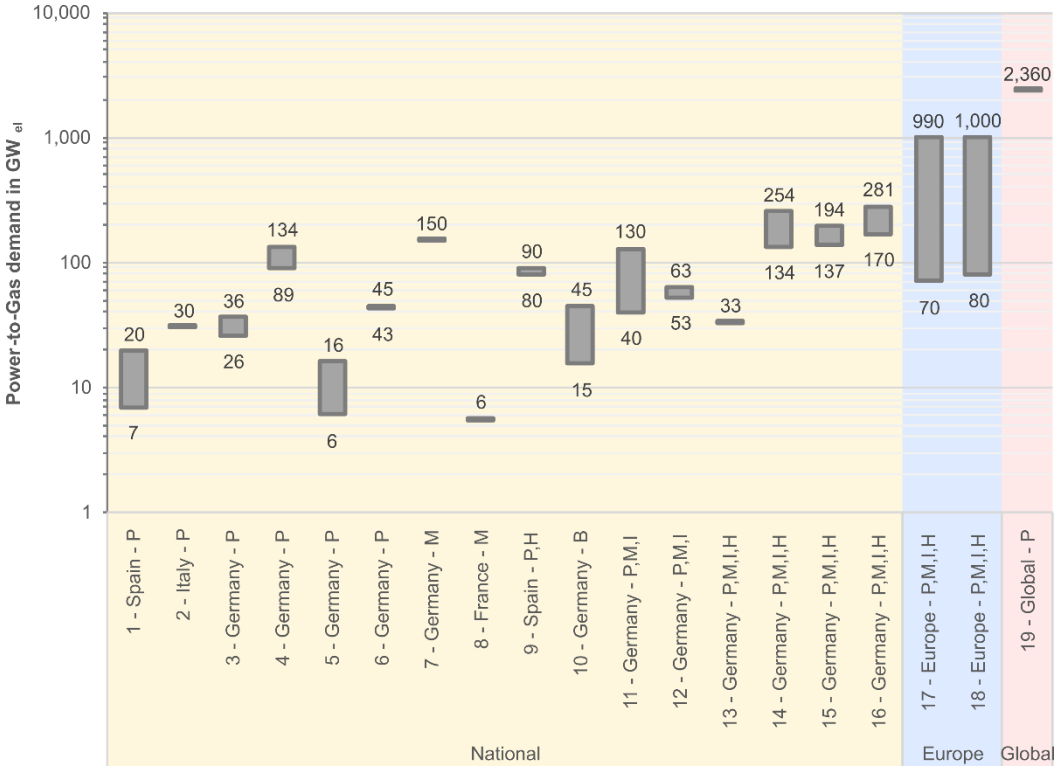

Figure 1: National and international PtG demand potentials for year 2050 according to relevant literature; based on [13–27,29–32] and own calculations
(P…power sector, M…mobility sector, H…heat sector, I…industry sector, B…based on biogas)

2.1.2 Deduction of global PtG demands

To apply the theory of technological learning to the Power-to-Gas technology, and thus evaluate potential future cost reductions for the relevant technologies, the examination of its overall market potential is mandatory. Due to the lack of appropriate data, especially at a European and global scale, our literature review only provides a limited idea of PtG demand potentials by 2050. According to the World Energy Council [33], there are additional uncertainties such as the pace of innovation and productivity, development of international governance and geopolitical change, prioritization of sustainability and climate change, and the balance between the use of markets and state directive policy which are critical for describing the future energy systems. These circumstances and the underlying framework conditions (e.g. RES policies, CO_2 reduction targets, cost optimization) often result in a wide range of possible scenarios. Most of the studies dealing with energy scenarios use simulation tools, based on many different variables, in order to predict a possible development path and describe an alternative future. For example, the EU Reference Scenario 2016 [34] acts as a benchmark of current policy and market trends and provides a model-derived simulation (e.g. PRIMES) trend projection in certain conditions (e.g. legally binding greenhouse gases (GHG) and RES targets). Additionally, Blanco et al. [35] analyzed different scenarios for the European

potential of the use of PtM by 2050 using the JRC-EU-TIMES model. The World Energy Council [33] uses its global multi-regional MARKAL model (GMM) for quantifying the scenarios, by accounting for the technical and economic parameters, driven by input assumptions and optimization algorithms to provide forecasts. These methods can be summarized as a bottom-up approach.

In contrast, this study utilizes a simple top-down approach to evaluate future demand potentials for PtG. In order to achieve a reduction of GHG emissions in the EU by 80% to 95% by 2050 compared to the 1990 levels (as indicated in the transition roadmap published by the European Commission [36]), the predominant use of RES is essential in all energy sectors. Hence, for each sector – power, industrial, mobility, and residential/heating – we defined three scenarios with different shares of renewable energy sources (50% = low, 75% = moderate, 90% = high). The proportion of the individual energy carriers, especially hydrogen and SNG required to achieve these RES proportions were estimated for an energy system in the year 2050, based on the EU reference scenarios [34] (see Appendix A). Regarding the amount of RES, these scenarios are more ambitious compared to the abovementioned EU and World reference scenarios [33,34], which mainly represent proposed trends of current policies to 2050, without focusing on achieving an environmentally sustainable energy supply and climate targets.

Based on the estimated proportions of SNG and hydrogen in each sector for the three investigated scenarios, we evaluated European and global demand potentials for renewable gases from PtG. The corresponding final energy demands for each sector and the evaluated proportions of hydrogen and SNG are presented in **Fehler! Verweisquelle konnte nicht gefunden werden.**. In addition, following assumptions were made to determine the required capacities of electrolysis and methanation of plants:

- Average efficiency of electrolysis by 2050: 75% (based on [37–40])
- Average efficiency of methanation by 2050: 85% (based on [41,42])
- Average full load hours of PtG plant operation: 6,000 h/a

Table 1: Final energy demands for EU and global and sectoral PtG product shares in investigated scenarios

Sector	Final energy demand in TWh		Sectoral PtG shares					
			Low (50% RES)		Moderate (75% RES)		High (90% RES)	
	EU[1)]	Global[2)]	H_2	SNG	H_2	SNG	H_2	SNG
Mobility	4,166	37,169	10%	15%	20%	20%	25%	20%
Industry	3,059	40,914	4%	15%	9%	24%	11%	29%
Residential	3,390	42,066	2%	10%	4%	21%	5%	28%
Power	3,920	39,843	0%	0%	1%	5%	2%	8%

[1)] acc. to EU Reference Scenarios [34]
[2)] acc. to World Energy Scenarios [33]

Based on these assumptions we expect a demand for up to 1,240 GW_{el} of installed electrolysis power and about 600 GW_{SNG} of SNG production at the EU scale in 2050 (see **Fehler! Verweisquelle konnte nicht gefunden werden.**). These values are at least comparable to the cost optimization approaches presented by Blanco et al. [25,26] in optimistic scenarios, estimating capacities up to 1,000 GW_{el} for Power-to-Hydrogen and 550 GW_{SNG} for Power-to-

Methane. Expanded to the global scale, the results show a demand for 6,500 to 14,200 GW_{el} of electrolysis and 3,400 to 7,100 GW_{SNG} of methanation capacities installed by 2050. While this demand seem relatively high, especially compared to the demand estimated by Pleßmann et al. [27], it has to be kept in mind, that the chosen scenarios presume a broad substitution of fossil energy carriers by renewables over all sectors. This also implies the adaption of (industrial) processes, which in many cases cannot be directly electrified and are dependent on alternative fuels. Similar arguments account for the transition of existing heating grids as well as heavy-duty and long-range transport sector. For the annual distribution of electrolysis capacities this would imply an annual growth of 20-23% globally, based on an overall global capacity of around 8 GW_{el}, as of 2014 [43]. To put that in context, power generation from wind experienced an average growth of 19% per year in the period 2007–2017, whereas PV has seen an even higher growth rate of nearly 48% from 2012–2017, especially driven by Asian regions [44,45]. Compared to these, the proposed growth rates for PtG seem reasonable, even though a constant high growth throughout, up to 2050, still seems optimistic. According to methanation, currently PtG plants with a total capacity of 14.5 MW_{el} globally produce methane [3]. This would result in an average growth rate of

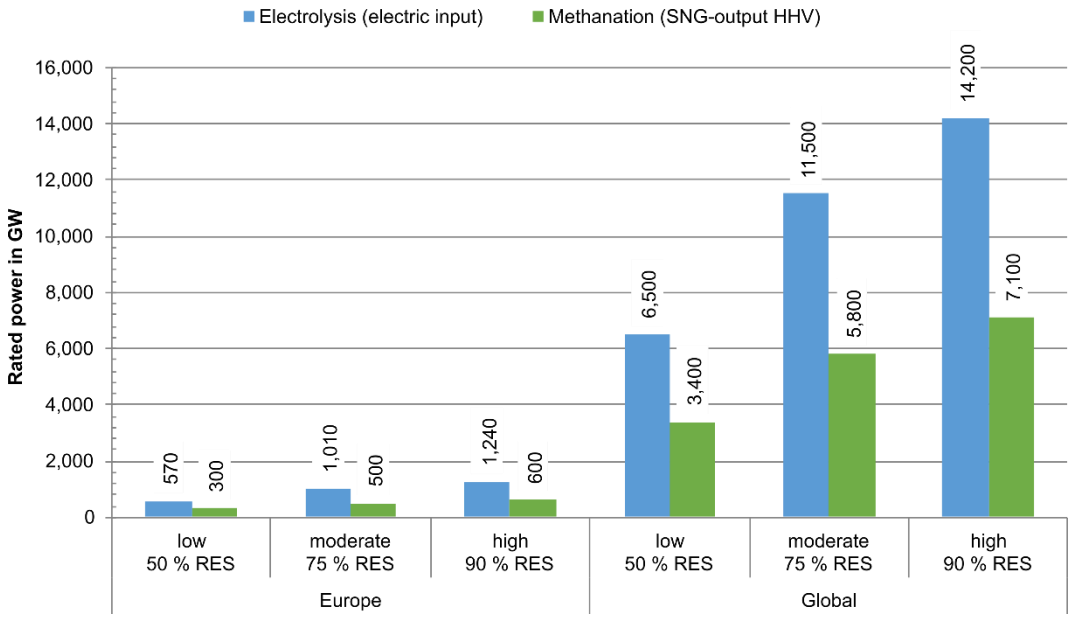

Figure 2: Scenario related demand potentials for PtG capacities by 2050

2.2 Current technology costs

A review of relevant literature on the investment costs for Power-to-Gas appliances showed that cost estimations vary a lot depending on the technology, system size and the year of installation (see Figure 3 for electrolysis and Figure 4 for methanation). It also showed that a comparison of available data is difficult, since it often misses significant information concerning system size, included peripherals (e.g. gas conditioning) or capacity reference (electric input, the lower heating value (LHV) output, the higher heating value (HHV) output). A recent review study on the investment costs of electrolysis by Saba et al. [46] which considered 30 years of cost studies, confirms the abovementioned mentioned issues. However, the study also reveals a continuous reduction of projected nominal investment costs for electrolysis since the 1990s.

To get an estimation on current technology costs, data for years of installation from 2015–2020 were analyzed in more detail. For alkaline electrolysis (AEC) this resulted in a cost range of 1,090–2,000 €/kW_{el} for capacities <1 MW_{el} [46–48] and 800–1,400 €/kWel for 1–10 MW_{el} [37,48–51], while other references for the given period, ranging at 630–1,000 €/kW_{el}, do not specify a dedicated system size [38,39,49,52]. For the proton exchange membrane (PEMEC)

technology, the available data proposes costs of about 1,500 €/kW$_{el}$ for systems below 1 MW$_{el}$ of installed capacity [46,47]. At average size of 1–10 MW$_{el}$, the current data has a significantly wide range from 960 €/kW$_{el}$ to 2,100 €/kW$_{el}$ [37,48,50,51], which is the same range as for the rest of the analyzed data with unspecified capacity [38,39,47,49,52]. For high-temperature electrolysis (solid oxide electrolysis cell or SOEC) there is hardly any data available on the actual investment costs, especially at sizes of 1 MW$_{el}$ and above, due to the limited amount of installations up to now. The reviewed literature estimates actual costs of 2250–2500 kW$_{el}$ for system sizes of 5–10 MW$_{el}$ [38,48,51], excluding outliers of <600 €/kW$_{el}$ [49,53,54]. For the methanation part the evaluation period was extended to the years 2012–2020, due to the lack of recent relevant data. Hence, the analysis resulted in a cost range of 160–1,970 €/kW$_{SNG}$ (related to the LHV of SNG output) for chemical methanation [41,55–57], including nominal capacities of 1–30 MW$_{SNG}$. For biological methanation in the same category of size, the revealed cost are even lower at approximately 100–1,430 €/kW$_{el}$ [41,55,58–61]. On the contrary, recent state-of-the-art analysis in Germany presumes costs for biological methanation being higher in general [62].

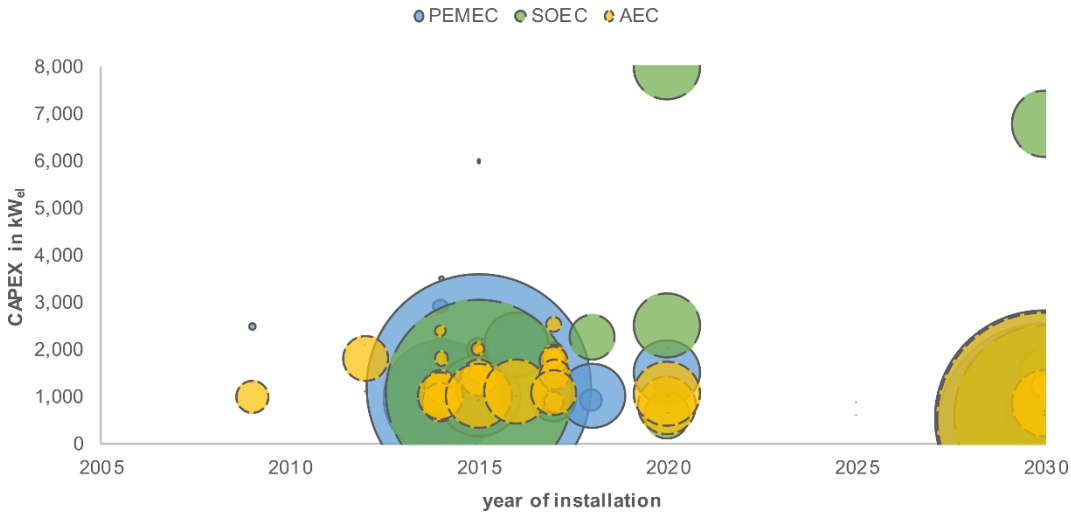

Figure 3: Collected data on specific investment costs for different electrolysis installations related to the year of installation (bubble area indicates the rated power from 0.1 to 100 MW$_{el}$); based on [37,38,46–54,63–68]

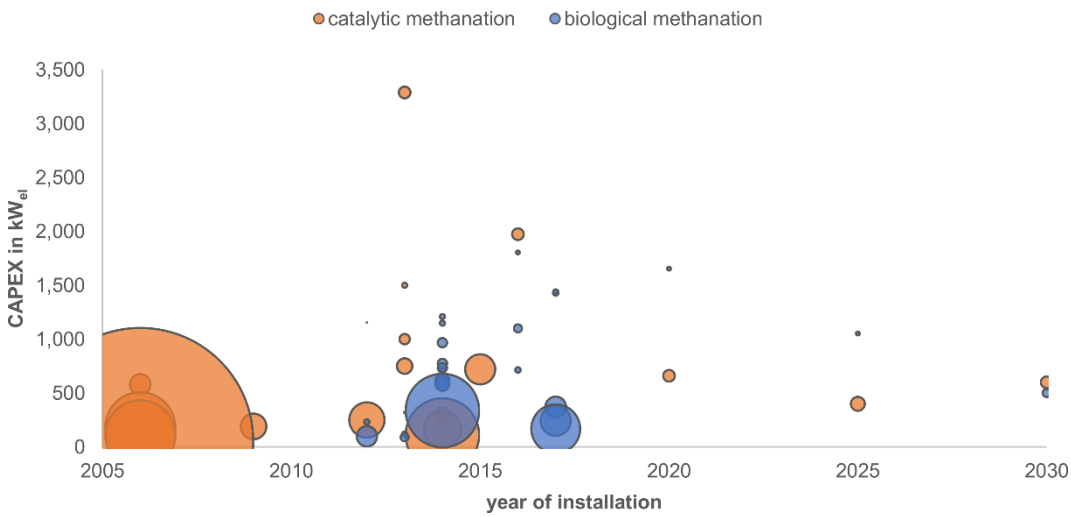

Figure 4: Collected data on specific investment costs for different methanation installations related to the year of installation (bubble area indicates the rated power from 0.1 to 1,000 MW$_{SNG}$); based on [41,55–61,63,68–73]

For the subsequent calculations on learning and scaling effects, initial costs were defined for a reference size of 5 MW for both, electrolysis (related to electric input) and methanation (related to the lower heating value of SNG output), based on the data given above and average scaling factors. The resulting specific CAPEX for each technology, using 2017 as reference year, are summarized in Table 2.

Table 2: Initial specific CAPEX for electrolysis and methanation defined for calculations (reference year 2017)

Technology	Initial CAPEX	Reference power
Electrolysis		
AEC	1,100 $€_{2017}/kW_{el}$	5 MW_{el} (electric input)
PEMEC	1,200 $€_{2017}/kW_{el}$	
SOEC	2,500 $€_{2017}/kW_{el}$	
Methanation		
catalytic	600 $€_{2017}/kW_{SNG}$	5 MW_{SNG} (LHV gas output)
biological	650 $€_{2017}/kW_{SNG}$	

2.3 Consideration of dynamic learning and scaling effects

For the evaluation of Power-to-Gas technology costs for different combinations of installation time and capacity, an appropriate analysis of scaling effects is necessary. This study includes a detailed evaluation of two different aspects of cost reduction by economies of scale: numbering-up of produced units and sizing-up of installed system capacities.

2.3.1 Technological learning – economies of manufacturing scale

To evaluate the individual learning curves of the investigated PtG technologies, we used a component-based approach described in preceding paper dedicated to technological learning effects of electrolysis systems [4]. The model allows an investigation of learning effects on a component or manufacturing process/material level to evaluate aggregated effects for the overall system, described by Eq. 1.

$$C(X_t) = \sum_{i=1}^{n} C_{0i} \left(\frac{X_t}{X_0}\right)^{-r_i} = C_{01}\left(\frac{X_t}{X_0}\right)^{-r_1} + C_{02}\left(\frac{X_t}{X_0}\right)^{-r_2} + \cdots + C_{0n}\left(\frac{X_t}{X_0}\right)^{-r_n} \qquad \textbf{Eq. 1}$$

with:

X_0 … cumulative number of produced units at time $t = 0$
X_t … cumulative number of produced units at time t
C_{0i} … costs of component i at time $t = 0$
$C(X_t)$ … total costs at time t
r_i … learning parameter for component i (where $lr_i = 1 - 2^{-r_i}$)

The model also allows to take into account the learning effects for individual properties related to the specific components and hence indirectly influence their general learning curve, acc. to Eq. 2 and Eq. 3.

$$P_t = P_0 \left(\frac{X_t}{X_0}\right)^{-r_p} \quad \textbf{Eq. 2}$$

$$C(X_t) = \sum_{i=1}^{m} \left\{ C_{0i} \cdot \prod_{j_i=1}^{n_i} \left[\left(\frac{P_{0j_i}}{P_{tj_i}}\right)^{ex_j} \right] \left(\frac{X_t}{X_0}\right)^{-r_i} \right\} \quad \textbf{Eq. 3}$$

with:

P_{0j_i} … initial value of property P_j of component i at time $t = 0$
P_{tj_i} … value of property P_j of component i at time t
r_p … learning parameter for property P
ex_j … influence exponent for property P

In addition, the component-based approach supports the incorporation and evaluation of spill-over effects of technological learning from complementary technology usage on a system level. Hence, the potentials of cost reductions for peripheral components is shared between investigated technologies. This approach also considers technological learning that already occurred in the past.

- For the investigated electrolysis technologies, the calculation parameters defined in [4] were used for the calculations executed in this paper. The methanation systems were also set up including 4 modules each in the learning curve model: (i) Reactor, (ii) Electric Installation & Control, (iii) Gas Conditioning and (iv) Balance of Plant. The Reactor module, which represented the core part of the methanation system, was further separated to additional Learning Components (cf. [4]) to treat different learning rates for the Reactor itself (incl. vessel and catalyst carrier), the Heat Management and the Catalyst (representing the catalytic coating in catalytic methanation). These are summarized in Table 3.

There are different methanation concepts for catalytic methanation according to Rönsch et al. [74], which can be roughly classified into fixed-bed, fluidized-bed, structured reactors, and slurry reactors. Due to this high range of technologies, the reactor is not classified further in the present investigations. Due to the lack of studies on methanation specific technological learning, only very rough estimates of learning rates were possible. While the steam methane reforming, as another Ni-based catalytic process, shows learning rates of 11%±6% [75], Anandarajah et al. [76] suggest using learning rates from 15% to 20% for novel technologies in general. Hence, we assumed a moderate learning rate of 15% as a starting value for the methanation reactor for both catalytic and biological technology.

While the methanation reactor component contains the carrier material for the catalytic material, the catalyst itself is treated independently within the model. This component can be roughly compared to the catalyst used in the definitions for the electrolysis cells, at least in terms of learning rates. While the catalyst material itself is different (methanation primarily uses Ni-catalysts), cost reduction effects will be similar assuming that material costs stay constant, while only coating thickness is reduced. Hence, the same learning rate of 8%, which provided good results for electrolysis cells, was used for the methanation catalyst as well.

Another essential component in the methanation reactor is heat management. Since operating temperature and heat management are highly dependent on the technology and the operation mode used in the individual reactors [74] and therefore tightly integrated with the reactor concept itself, a learning rate of 15% was assumed in this case, referring to the values used for the reactor component and provided for developing technologies by Anandarajah et al. [76].

Table 3: Learning Components in the Reactor modules of the catalytic and biological methanation learning curve models

Reactor module	Initial cost share	Learning rate
Catalytic		
Reactor	57%	15%
Catalyst	26%	8%
Heat management	17%	15%
Biological		
Reactor	77%	15%
Heat management	23%	15%

The peripheral modules of the methanation system models (Electric Installation & Control System, Gas Conditioning and Balance of Plant) are treated equally to their counterparts in the electrolysis systems (cf. [4]). Since Electric Installation & Control System are expected to be similar for both technologies, i.e. catalytic and biological methanation, spillover learning effects between these are taken into account by not directly coupling the technological learning of this module to the cumulative productions of each individual technology, but rather to the cumulative production of methanation systems as a whole. Hence, the modules are set to an "independent" learning characteristic. Same accounts for the Gas Conditioning module, which does additionally consider past learning effects. Since processing of the methanation product gases (e.g. gas cleaning and drying, compression) is assumed to be similar to the processing of natural gas in general, the cumulative treatment of natural gas in the overall timeframe from 1900 to 2050 was used as a basis to evaluate learning effects of the Gas Conditioning module (cf. [77,78]). The resulting Learning Modules, initial cost shares and cumulative production dependency are summarized in Table 5 (electrolysis) and Table 6 (methanation).

2.3.2 Scaling effects – economies of unit scale

In addition to cost reductions by technological learning, economies of scale are considered as well in the assessment of CAPEX development for PtG technologies, by sizing-up of nominal plant power. A common method to describe these scaling effects is the use of a logarithmic relationship (cf. Eq. 4), where C_b stands for the questioned equipment costs at the scale S_b (size, capacity, nominal power) of the component, and $C_a$and S_a represent the costs and scale of the known reference component, respectively. f is the scale factor applied to the technology in question. Since $f = 0.6$ can be used as a guideline scale factor for an initial approximate cost estimation of chemical appliances, this approach is also called the "six-tenth-factor rule" [79].

$$C_b = C_a * \left(\frac{S_b}{S_a}\right)^f \qquad \textbf{Eq. 4}$$

Applied to the technology costs found in literature (see section 2.1), the resulting scale factor for electrolysis varies a lot, reaching values of 0.51–0.96 for AEC or 0.53–0.97 for PEMEC technology, respectively. Categorized according to the appropriate system size, it can also be seen that scale factors are generally increasing with increased scale. While for capacities < 5 MWel mean scale factors are around 0.69 (AEC) and 0.72 (PEMEC), for larger scale

applications values of 0.9 and above are reached [48,63,65,66,68,80,81]. This can partially be explained by the fact that the electrolysis stack does not show potential for large cost reduction via EoS because of its modular design [82]. An increase in stack power due to an upscaling of the electrolysis cell is unlikely for many reasons (e.g. problems with leakage); therefore, the cell is limited in size. Similar effects are observed for scaling of methanation systems, while resulting scale factors are generally lower compared to electrolysis – ranging from 0.58 to 0.71 for catalytic and 0.39 to 0.73 for biological methanation, respectively – and the variation with different sizes is not as significant [41,55,59,73,83].

Since the approach used to analyze learning curve effects does already provide a modular disaggregation of the investigated systems, a similar approach was used to evaluate scaling effects on a more detailed level, rather than for the system as a whole. Scale factors were evaluated per component based on relevant literature values [79,82,84,85]. The weighted mean values per module are summarized in Table 5 for electrolysis and in Table 6 for methanation.

While this approach allows to evaluate unit scaling effects on a component basis with a dynamic dependency on changing cost structures over time, it is still static according to the actual scale of the unit. Specifically, electrolysis stacks are expected to be limited in size, or rather their nominal power per unit, for various reasons (e.g., problems with leakage); thus, they are expected to be scaled by modularity (scaling by numbers) [82]. However, the maximum cell stack size is expected to increase as TRL and technological advances increase. To take those effects into account, a dynamic scale factor was implemented for the electrolysis cell stack based on an exponential function:

$$f = 1 - (1 - f_0) \cdot e^{-\frac{S+S_0}{S_{max}}} \qquad \textbf{Eq. 5}$$

where f_0 represents the before mentioned basic scale factor, S the questioned scale, and S_0 the S_{max}average maximum stack size for the period under study. This provides a scale factor that is dependent on the system scale itself and minimizes scaling effects for large-scale applications. The same effect was also applied to the reactor modules of the investigated methanation systems. The presumed maximum stack and reactor sizes related to the year of installation are presented in Table 4.

Table 4: Presumed maximum electrolysis stack and methanation reactor sizes related to the year of installation, based on [38] & [41]

Year of installation	electrolysis			methanation	
	avg. max. stack size S_0 in MW_{el}			avg. max. reactor size S_0 in MW_{SNG}	
	AEC	PEMEC	SOEC	catalytic	biological
2020	3	1.2	0.5	10	2
2030	4	2	1	25	5
2040	5	3.5	2	100	5
2050	5	5	3	500	5

Even though scaling limits are to be expected for almost any component in the systems, this dynamic scaling effect was neglected for the other modules except for the electrolysis stacks and methanation reactors, due to the number of included components. Component and costs structures and corresponding scale factors are summarized in Appendix A.

Table 5: Summary of learning curve and scaling effects calculation parameters for electrolysis

Module	# components			initial cost share			learning curve dependency			scale factor		
	AEC	PEMEC	SOEC	AEC	PEMEC	SOEC	AEC	PEMEC	SOEC	AEC	PEMEC	SOEC
Cell Stack	9[1)]	11[1)]	9[1)]	50%	60%	30%		direct		0.88[2)]	0.89[2)]	0.87[2)]
Power Electronics	1 (lr=12%)	1 (lr=12%)	1 (lr=12%)	15%	15%	30%		independent			0.75	
Gas Conditioning	1 (lr=7%)	1 (lr=7%)	1 (lr=7%)	15%	10%	6%		independent			0.60	
Balance of Plant	1 (lr=13%)	1 (lr=13%)	1 (lr=13%)	20%	15%	34%		direct		0.68	0.73	0.73

[1)] variable learning rate calculated through the model
[2)] value for reference size and year

Table 6: Summary of learning curve and scaling effects calculation parameters for methanation

Module	# components		initial cost share		learning curve dependency		scale factor	
	catalytic	biological	catalytic	biological	catalytic	biological	catalytic	biological
Methanation Reactor	3[1)]	2[1)]	21%	17%	direct		0.67[2)]	0.51[2)]
Electric Installation & Control System	1 (lr=12%)	1 (lr=12%)	20%	21%	independent		0.75 0.60	0.67
Gas Conditioning	1 (lr=7%)	1 (lr=7%)	12%	13%	independent			
Balance of Plant	1 (lr=7%)	1 (lr=7%)	47%	49%	direct			

[1)] variable learning rate calculated through the model
[2)] value for reference size and year

2.4 Techno-economic assessment

To evaluate the effects of technological learning and plant scaling on production costs of renewable gases from power-to-gas plants, a techno-economic assessment for different plant configurations and capacities was performed. These costs were calculated by assessing the annual total plant costs related to the energy content (LHV) of the annually produced gas. This approach is comparable to the calculation of LCoE [86,87]. The methodology used to calculate the total annual costs is based on the calculation of economic efficiency using the annuity method [88]. The annuity of total annual payments A is stated as the difference between the annuity of proceeds A_p and the sum of the annuities of capital-related A_C, demand-related A_D, operation-related A_O and other A_M costs (see Eq. 6).

$$A = A_P - (A_C + A_D + A_O + A_M) \qquad \textbf{Eq. 6}$$

The executed calculations presume a general interest rate of 4% and an observation period of 20 years. By contrast to the guideline [88], price change factors and price-dynamic cash values were omitted. For detailed information on individual factors and values used in the techno-economic evaluation see Appendix A.

Variable costs (and proceeds) C_{var} that are dependent on input and output streams related to the time of operation (electricity and CO_2 input costs, proceeds from by-products like oxygen or heat) are added according to their occurrence. The levelized costs of PtG (LCoP), representing the generation costs for SNG (or hydrogen) related energy content, are then calculated as follows:

$$LCoP = \frac{-A + \sum_i C_{var,i}}{E_{out}} \qquad \textbf{Eq. 7}$$

2.4.1 Capital and operational costs

The capital-related costs mainly include investment costs for system components and expected replacements during the observation period T:

$$A_C = (I_0 + I_1 + \cdots + I_n - R) \cdot a \qquad \textbf{Eq. 8}$$

where I_0 represents the initial investment amount, $I_1 \ldots I_n$ the cash values of first to n-th procured replacement, R the residual value of the investment, or last replacement, respectively, and a the annuity factor. Replacements and the residual value are hence dependent on the interest-rate factor q and the deprecation period T_N.

$$I_n = \frac{I_0}{q^{n \cdot T_N}} \qquad \textbf{Eq. 9}$$

$$R = I_0 \cdot \frac{(n+1) \cdot T_N - T}{T_N \cdot q^T} \qquad \textbf{Eq. 10}$$

The annuity factor a can be derived as follows:

$$a = \frac{q^T \cdot (q-1)}{q^T - 1} \qquad \textbf{Eq. 11}$$

Besides direct capital costs of the main equipment (electrolyzer, methanation, storage tank), annuity of additional costs A_M for the construction and commissioning of the PtG plants was considered by using overhead factors, also known as *Lang* or *Chilton* factors [79,84,89] (see Appendix A).

Operation-related costs include costs for maintenance and inspection O_M as well as insurance and administration O_I. The according annuity is calculated as:

$$A_O = (O_M + O_I) \cdot a \qquad \textbf{Eq. 12}$$

Demand-related costs cover expenses for operational materials, like water and CO_2. Together with proceeds that are expected to arise from the sale of by-products, such as heat and oxygen, these were considered as variable costs C_{var} in the techno-economic evaluation.

Electric power supplyFor the evaluation of electricity supply costs three different power sources were considered:

1. supply from wind power plant (PtG-wind),
2. supply from PV power plant (PtG-PV) and
3. supply from public grid (PtG-grid)

The production profiles for wind and PV driven scenarios are based on profiles of existing plants located in Austria (14 $MW_{el,peak}$ wind park, 3 $MW_{el,peak}$ PV plant), scaled up to a theoretic nominal size of $MW_{el,peak}$ to cover investigated large-scale scenarios for the PtG plant. Since PtG is often deemed as an option for grid balancing and peak load storage, this study analyzes different scenarios of peak load utilization. Hence, peak load utilization from 50% (generated power beyond a base load 50% of the nominal power plant capacity is used in the PtG plant) to 100% (100% of the generated power is used for PtG operation) are considered (cf. Figure 5).

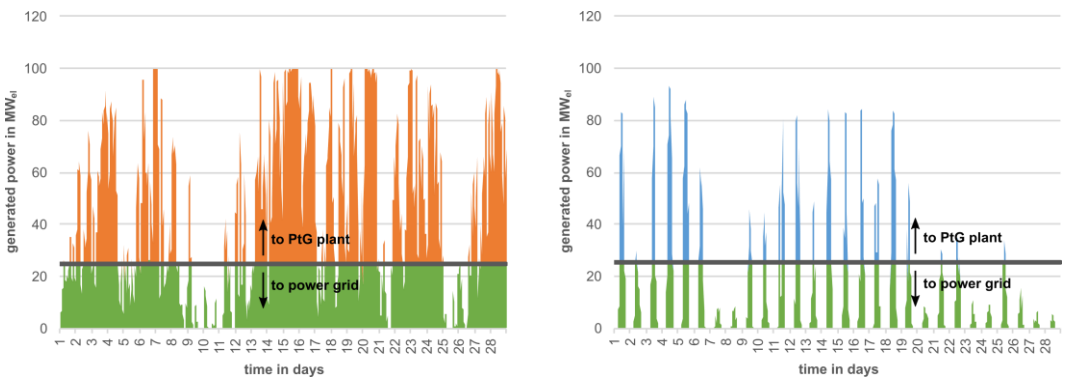

Figure 5: Sample 75% peak load utilization scenarios (upper 75% of nominal power utilized for PtG plant) for 100 $MW_{el,peak}$ wind (left) and PV (right) power source

According to Kost et al. [90], current (2018) LCoE from onshore wind farms in Germany are ranging from 40-82 €/MWh depending on the location. Despite providing a higher amount of FLH, electricity costs from offshore generation are stated significantly higher, at about 75-138 €/MWh. These costs are expected to decline in the medium term, reaching 35-71 €/MWh (onshore) and 57-101 €/MWh (offshore), respectively, until year 2035. Another

study executed by Agora Energiewende [91] expects even lower costs for electricity from onshore wind farms estimating 30-60 €/MWh by 2030 to 25-50 €/MWh by 2050, for plants located in Germany. Assuming a more optimistic scenario with a higher potential for cost reduction, these costs could also decline to 25-45 €/MWh (2030) and 20-35 €/MWh (2050). The LCoE from open space PV power plants in Germany currently (2018) reach costs of about 37-68 €/MWh, depending on the location. These costs are expected to decline to 21-39 €/MWh by 2035 [90]. An extended study by Fraunhofer ISE [92] estimated potential long-term LCoE of about 25-44 €/MWh for southern Germany, and 18-31 €/MWh in southern Spain by 2050, based on a proposed learning curve and scaling effects. The electricity costs presumed for wind and PV in the techno-economic assessment in different periods of observation are presented in Appendix A.

In addition to the direct supply from renewable energy sources, we assessed scenarios based on the participation in the electricity spot market. These calculations presume that the PtG plant is always operated at times with the lowest electricity prices, mean costs for electric power supply, a price limit for purchase of electricity, and is dependent on the annual full load hours (FLH) of operation. The price curves used for the evaluation of electricity supply costs are based on the Austrian spot market data for the year 2017, at a time periods of 15 minutes [93]. This data was also used for the year 2020 assessment with an annual mean value of approx. 34.5 €/MWh. For the estimation of future spot market prices, the annual mean value as well as the volatility of electricity prices was adapted. Therefore, each price value in the data set was transformed ($c_{i,y}$) by calculation of the derivation from the mean value in the reference year (2017) $d_{i,2017}$, multiplied by a presumed volatility factor $x_{v,y}$ representing the change of volatility according to the reference year 2017. This new volatility is then added to the year-related mean value $c_{mean,y}$ (see Eq. 13).

$$c_{i,y} = c_{mean,y} + d_{i,2017} \cdot x_{v,y} \qquad \textbf{Eq. 13}$$

The volatility factors were set to 1.5 (+50%) for 2030 ($x_{v,2030}$) and 2.0 (+100%) for 2050 ($x_{v,2050}$), respectively. The mean values for future scenarios were estimated based on the data obtained from the literature. According to [94], wholesale electricity prices in Germany are expected to rise to 67 €/MWh in 2030 and 87 €/MWh in 2050, due to CO_2 taxes and nuclear phase-out. A study on potential long-term development of spot market electricity prices in Austria [95] arrives at similar conclusions, estimating price ranges between 56 €/MWh (2025) and 76 €/MWh (2035) for 2030, and about 77 €/MWh for 2050. While these values are generally supported by additional studies, especially for 2030 [96,97], a Greenpeace study discussing a comprehensive renewable energy concept for Germany [98] proposes a significantly lower future electricity cost reaching 45 €/MWh in 2030 and declining to 22 €/MWh in 2050. However, in this study average future spot market electricity prices are presumed to be 65 €/MWh by 2030 and 80 €/MWh by 2050, respectively. The resulting price limits and mean prices for PtG plant operation, in relation to full load operating hours, are summarized in Table 7.

Table 7: Electricity mean prices and price limits for spot market scenarios related to full load hours of operation

Year			Full load hours (FLH) in h/a							
			1,000	2,000	3,000	4,000	5,000	6,000	7,000	8,000
2020	Price limit	€/MWh	17.6	25.2	29.5	33.0	36.7	40.6	45.2	54.6
	Mean price	€/MWh	0.7	3.2	6.4	9.9	13.9	18.3	23.2	28.8
2030	Price limit	€/MWh	38.8	50.4	56.8	62.0	67.5	73.3	80.3	94.3
	Mean price	€/MWh	2.5	7.7	13.9	20.6	28.0	36.0	44.8	54.6
2050	Price limit	€/MWh	45.1	60.5	69.0	76.0	83.3	91.1	100.4	119.1
	Mean price	€/MWh	2.6	8.7	16.2	24.5	33.6	43.5	54.4	66.7

3 Results and discussion

3.1 Resulting investment costs

- Based on the evaluated demand potentials for PtG production capacities, we calculated learning curves related to the year of installation, presuming that cumulative production matched the demand potential by year 2050. For annual interim values a logistic growth function was assumed for the overall production capacities. The total annual productions for electrolysis and methanation capacities were then subdivided into the individual technologies. For electrolysis these production shares were presumed based on the estimations given in [39], targeting about 40% each for PEMEC and SOEC and around 20% for AEC technology by 2050. For methanation an initial division of 90% vs. 10% (catalytic vs. biological methanation) was presumed, changing to 60% vs. 40% by 2050 (see Appendix A).

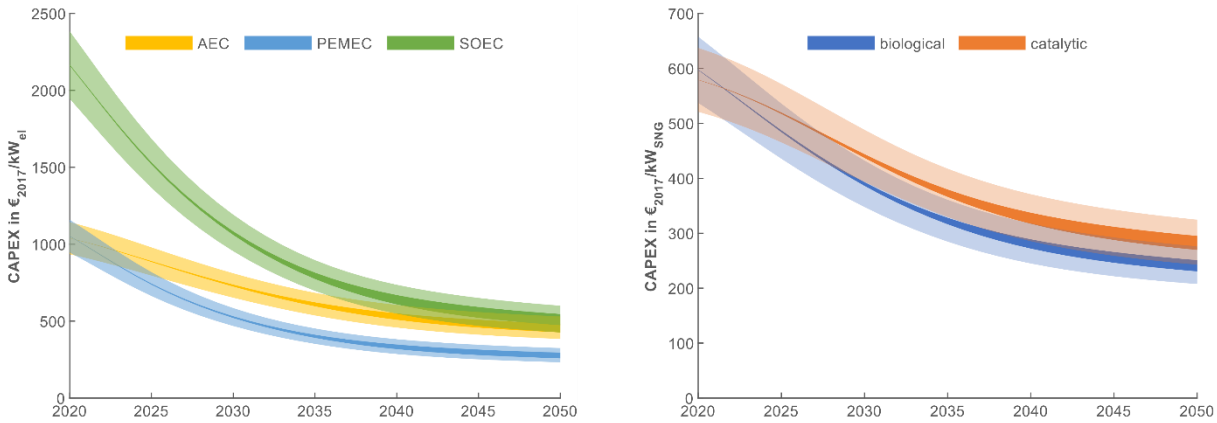

Figure 6: Estimated ranges for technological learning for electrolysis (left) and methanation (right) technologies
(dark-coloured areas: variation through demand potential ranges;
light-coloured areas: consideration of a ±10% uncertainty in initial CAPEX)

The results show that under presumed conditions, CAPEX are expected to decline significantly for all investigated technologies due to technological learning (see Figure 6). Solid-oxide electrolysis is about to compete with alkaline cells in terms of capital costs in the long-term, while PEMEC are about to undercut AEC in near future and establish the lowest cost solution. This is in line with the findings in [4] at a relative cumulative production of $5 \cdot 10^2$, considering

the difference in initial costs based on the literature review. Especially For methanation, bio-based technologies are expected to reach lower cost levels compared to its chemical counterpart at the referenced size of installation. The learning rates decrease only slightly over time, from 12.1% to 11.7% (catalytic) and 12.3 to 11.8 (biological), respectively. Concerning methanation technologies, there is a lack of relevant literature on technological learning. Looking at steam methane reforming (SMR) as another Ni-catalyst based chemical process compared to catalytic methanation, it shows similar learning rates of 11±6% [75]. To assess the values for biological methanation, the process of biogas methanation can be referred to, for which similar experience rates of about 12% were found by Junginger et al. [99]. Since variation in resulting cost development curves depending on demand potential scenarios is relatively low, mean values are used for each technology in subsequent calculations.

The evaluation of scaling effect (in terms of unit scaling) revealed additional cost reduction potentials for future PtG plants. Due to the component-based application of scaling factors the characteristics of these effects vary noticeably between the investigated technologies. Compared to the reference size values, these scaling effects abate relatively fast for AEC and PEMEC based electrolysis systems with an increasing order of magnitude, whereas SOEC based systems provide a more significant dependency of CAPEX to system scale. This is explained by higher cost share of better scalable peripheral (e.g. Power Electronics, BoP) over the Stack module, with limited scalability in the SOEC system (cf. Figure 7). Related to the year of installation, average scaling factors for the investigated electrolysis systems are generally decreasing – resulting in higher scaling effects – as better scalable modules show lower potentials for technological learning compared to the stack modules, which results in increasing cost shares and thus higher influence on scaling for these parts. At least for PEM and alkaline electrolysis systems, these results are close to the few values found in the literature for capacities of 50 MW_{el} and above [10,50].

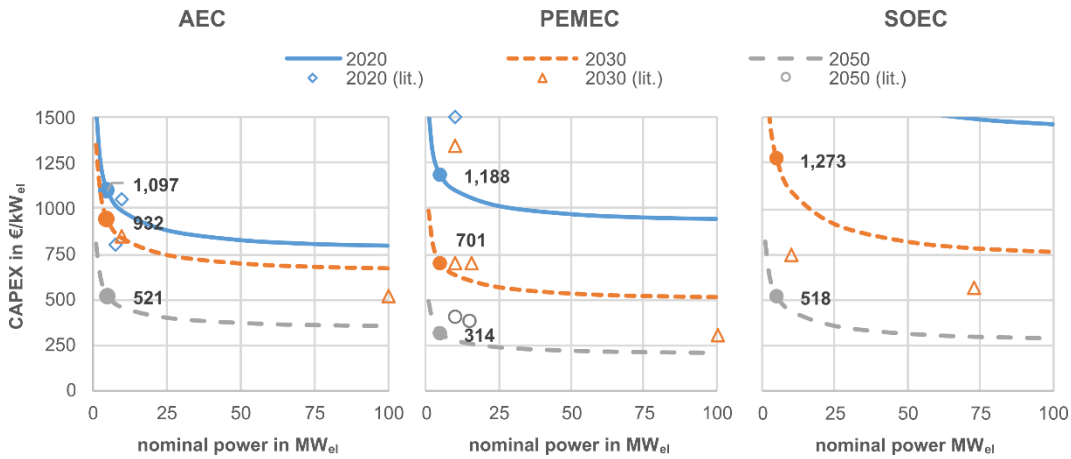

Figure 7: CAPEX development for electrolysis systems compared to projections from the literature study (lit.) for installations ≥ 10 MW_{el} (marked and labelled values refer to reference size of 5 MW_{el})

For the methanation technologies, scaling effects are more significant due to rather low scaling factors through all modules (cf. Table 6), being at about 0.73 (2020) to 0.68 (2050) on average, for both technologies. However, these investigations suggest that scale factors < 0.6, which were also found in the literature study [41,73], seem to be rather low. Therefore, we have to assume that these values do incorporate additional effects, like technological learning, besides pure unit scaling. For both technologies, the estimations are similar to the predictions for large scale applications of 50-100 kW that were gathered in the literature study [55,59,70,73].

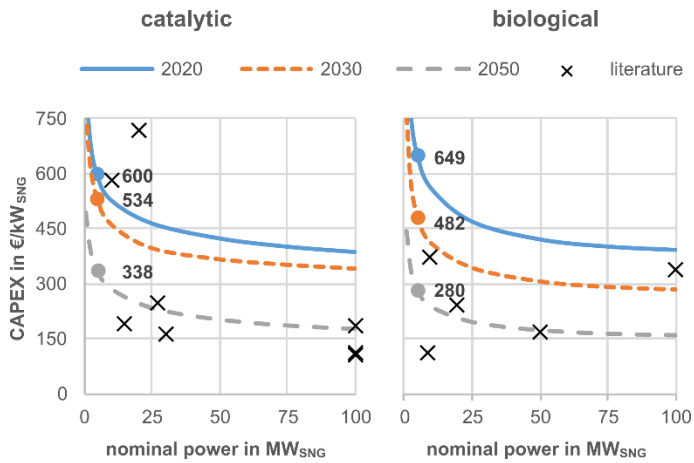

Figure 8: CAPEX development for methanation systems compared to projections from the literature review for installations ≥ 10 MW$_{SNG}$ (no target time frames available; marked and labelled values refer to reference size of 5 MW$_{SNG}$)

PtG powered by wind or PV

Considering a directly coupled wind form or PV plant as a single input source for the PtG plant, its operating conditions (annual FLH, total hours of operation, efficiency, start/stop cycles) are defined by the electricity generation profile. The following calculations presume a 100 MW$_{peak}$ wind or PV power plant, coupled to three different PtG systems with capacities of 50 / 75 / 100 MW$_{el}$ (cf. section 0). The resulting operating conditions for the year 2050 are summarized in Table 8. These characteristics show clear differences in the PtG plant operation especially concerning the amount of available FLH and therefore the energy supplied in total.

Table 8: Calculated operation characteristics for direct coupling of a 50 / 75 / 100 MW$_{el}$ PtG plant to a 100 MW$_{peak}$ wind or PV power plant

General parameters	Unit	Scenarios		
Share grid supply [a)]	%	50	25	0
Nominal power PtG plant	MW$_{el}$	50	75	100
PtG – wind farm		PtG-wind-50%	PtG-wind-75%	PtG-wind-100%
Energy supplied to electrolysis	MWh	80,948	168,079	309,624
Full load hours (equivalent)	h/a	1,619	2,241	3,096
Start/stop cycles	cycles/a	1,015	1,054	553
Hours of supply > 0	h/a	2,718	4,206	7,201
Average electrolysis load	%	60	53	43
PtG – PV power plant		PtG-PV-50%	PtG-PV-75%	PtG-PV-100%
Energy supplied to electrolysis	MWh	28,270	68,839	139,075
Full load hours (equivalent)	h/a	565	918	1,391
Start/stop cycles	cycles/a	542	545	373
Hours of supply > 0	h/a	1,240	1,978	3,826
Average electrolysis load	%	46	46	36

[a)] share of the nominal power plant capacity that is fed-in to the power grid (only generation beyond this share is supplied to the PtG plant

The results illustrated in Figure 9 for the year 2050 indicate that SNG production costs for PV supply are dominated by investment costs due to the low amount of annual full load hours. In

turn, for a wind powered PtG plant, the share of specific CAPEX, at same scale, is significantly lower, whereas these scenarios are dominated by the higher electricity supply costs. However, overall SNG production costs are in a similar range for both power sources, especially at larger scales. In comparison to the year 2050, the impact of higher CAPEX is stronger in short- and mid-term observations, when learning effects are still low, and thus the differences between wind and PV supply scenarios become more significant (see Figure 10). Nonetheless, the results show that the operation of a PtG plant using surplus electricity from PV or wind power plants by direct coupling is not feasible at reasonable production costs, especially in early applications (2030, 2050). Depending on market conditions, a utilization of the upper 75% of the nominal power plant capacity for PtG applications may become viable by 2050, since production costs are not expected to be significantly higher than for 100% utilization, especially in the wind scenarios.

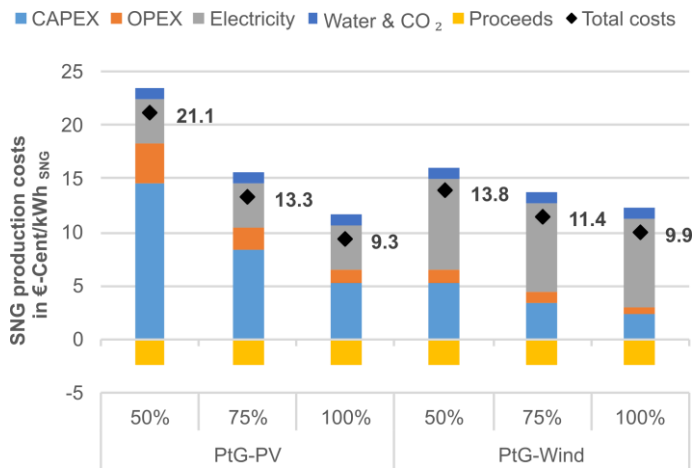

Figure 9: Specific SNG production costs for PV and wind supply scenarios with different PtG plant capacities for the reference year 2050

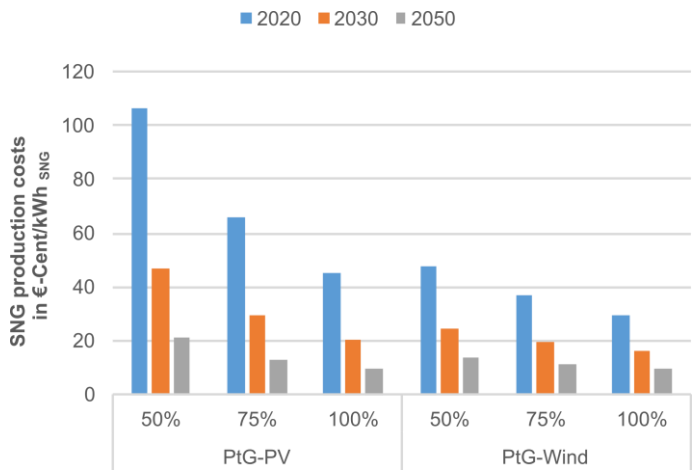

Figure 10: Comparison of short-, mid-, and long-term projection of SNG production costs for PV and wind supply scenarios with different PtG plant capacities

3.2 PtG powered by electricity grid

Assuming an operation of the PtG plant supplied with electricity from the public grid, generation costs for SNG could be reduced significantly compared to wind and PV scenarios, depending on the annual FLH, and thus the average costs of purchased energy (see Table 7). This also impacts the costs' optimum, which is mainly affected by the balance of specific CAPEX, dominating at low FLH, and electricity costs. The results for a 100 MW_{SNG} plant for the reference year 2050 indicate a cost optimum of around 2,500 operation hours under given

conditions (see Figure 11). According to these results, large scale PtG are able to reach SNG production costs of about 10 €-cent/kWh$_{SNG}$ in the mid- (2030) and long-term (2050) over a broad range of operating hours, using an optimized electricity purchasing strategy. However, even at lowest costs of about 6 €-cent/kWh, these are still well above natural gas prices in the EU in recent years (< 3 €-cent/kWh for non-household consumers) [100] and thus additional measures will be mandatory to promote PtG over fossil gases. In addition, considering the high demand for renewable gases in future energy systems as elaborated in section 0, an operation strategy targeting low numbers of annual FLH will not be desirable to cover that demand, or rather, require additional PtG capacities. However, considering power-to-gas in terms of sector coupling, supporting the power grid through load-balancing capabilities or seasonal storage of surplus energy from RES, a partial operation in periods with low electricity supply costs could still be reasonable.

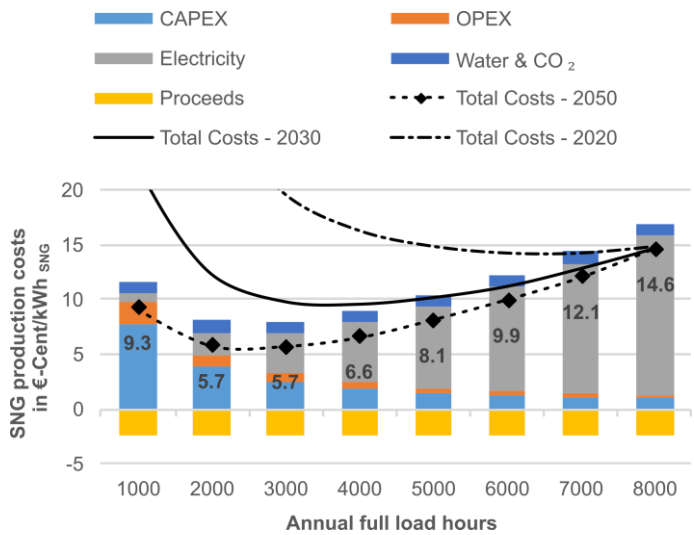

Figure 11: Specific SNG production costs for grid supply for the reference year 2050 (incl. comparative total cost curves for 2020 & 2030)

3.3 Comparison of technologies

To analyze techno-economic advantages of different PtG technologies, potential combinations of electrolysis and methanation technologies were compared in this study (see Figure 12). This comparison indicated that all investigated technologies are on a similar level for short-term examinations, with slightly higher costs for PEM based systems. Due to the lower cost reductions for alkaline electrolysis from technological learning, systems using this technology are expected to have significantly higher production costs compared to using PEM electrolyzers. Moreover, solid-oxide electrolysis (paired with catalytic methanation) provides the lowest production costs with economic advantages of up to 30% at high numbers of annual FLH, considering optimized thermal integration of the exothermal methanation process and therefore maximizing overall efficiency of the PtG system [101–103]. In contrast to electrolysis, the methanation technology used seemed to have only a minor influence on the SNG production costs. However, acc. to Götz et al. [83], biological methanation may not be an option for a large scale implementation due to the need for large specific reactor volumes and fewer possibilities for waste heat utilization.

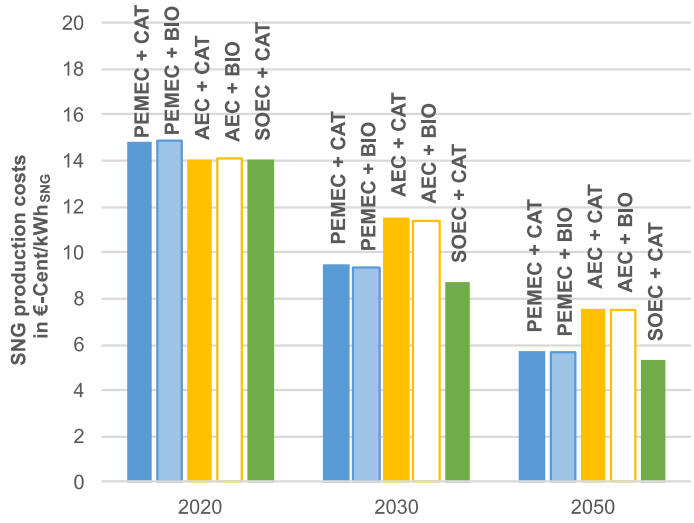

Figure 12: Comparison of SNG production costs for different technologies (power source: grid supply @ 5,000 FLH)

3.4 Sensitivity analysis

3.4.1 Effects on learning curves

The results of the learning curve calculations presume that the influence of cumulative production is only marginal at the given overall market potentials. Comparing low and high potential scenarios, the differences in expected CAPEX for electrolysis are at 11-13% for a variation of cumulative productions of a factor 2. For methanation effects these are even lower. Hence, the consideration of system lifetime in terms of replacements, which would increase cumulative productions of electrolysis stack and methanation reactor modules by about 30% and overall system production by < 1%[1], affects target costs in 2050 by < 3%. Therefore, the initial cost values for the calculation present the main uncertainty in estimating future CAPEX.

Application of presumed technology shares to more conservative technologies (higher values for PEM electrolysis and catalytic methanation, lower shares for SOEC) showed that influences of overall cumulative production volumes on evaluated learning curves are negligible at given scales (see Appendix A). Beyond that, the presumed learning rates itself are the most relevant impact factor for the development of the calculated learning curves. Sensitivity analysis have shown that a variation of the underlying learning curves for peripheral components (e.g. Gas Conditioning, BoP) by ±25%, influences the overall learning curves by -13% to +18% in high volume scenarios depending on the technology. Hence, a continuous observation of cost development over future productions is a mandatory aspect for the validation and adoption of PtG-related learning curves and corresponding measures.

3.4.2 Effects on SNG production costs

To assess the effects of the main techno-economic parameters incorporated in the evaluation of SNG production costs, an appropriate sensitivity analysis was carried out. The three scenarios – “Ptg-PV-100%”, “PtG-Wind-100%” and “PtG-Grid” at 3,000 annual FLH (6,000 FLH for 2020, 4,000 FLH for 2030) – were analyzed representatively. The impacts were derived for individual parameter variations of ±25% with respect to the reference values for the

[1] presuming a stack/reactor lifetime of 10 years and system lifetime of 25 years based on [38,39].

given scenarios. The results for the year 2050 are shown in Figure 13, additional results for the years 2020 and 2030 can be found in Appendix A.

According to the results of the analysis, the investigated scenarios behave similarly on changes of individual base parameters. Hence, variations of the overall plant efficiency by ±25%, especially reductions, lead to changes in calculated production cost of up to 30% and above. Nevertheless, a decrease of PtG efficiencies in future implementation is not expected. Impacts of electricity costs are higher in grid and wind supply scenarios, due to the higher base values compared to PV supply, though for the grid supply the influence is generally increasing at higher numbers of annual FLH, according to the elevated mean prices. The sensitivity of SNG production costs to variations in CAPEX correlates negatively with the amount of annual FLH and is therefore more significant in PV and wind supply scenarios. However, the impact of CAPEX increases with reduced plant scales according to the analyzed scaling effects and hence higher shares on overall production costs. However, given the uncertainties in CAPEX development, and based on the sensitivity analysis of the learning curves, the overall impact of that parameter on SNG production costs is comparably low. Nonetheless, the sensitivity analysis also showed that additional cost reductions can be expected through an optimization of operating conditions, which is also found in comparative studies [104].

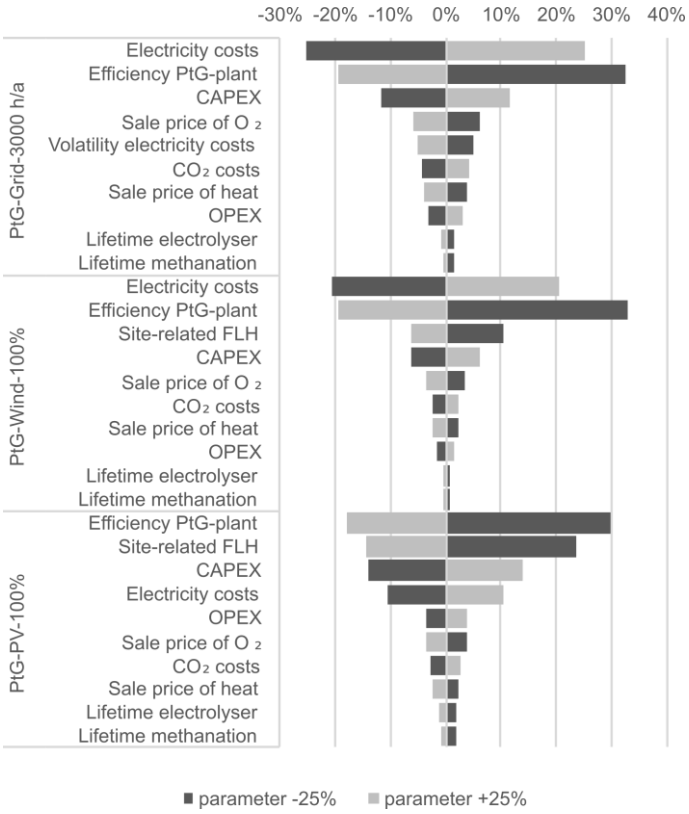

Figure 13: Sensitivity of SNG production costs to variation of techno-economic parameters by ±25% for different scenarios in the reference year 2050

4 Conclusions

This study evaluates a cost development of large-scale power-to-gas (PtG) applications in short-, mid- and long-term scenarios, based on a holistic techno-economic assessment. Our investigated into a future demand for renewable gases, primarily hydrogen and renewable methane (SNG). has revealed substantial demands for electrolysis and methanation capacities till 2050 to achieve a sustainable transition of European and global energy systems to renewable energy sources. The effects of technological learning, caused by the need to

significantly increase production rates for corresponding technologies and thus increase the cumulative production by several orders of magnitude, are expected to significantly reduce specific CAPEX for future implementations. However, an upscaling of average plant capacities to multi-MW scales will additionally be necessary for future PtG plants to be economically competitive to incumbent technologies. In that context, presented calculations revealed cost reduction potentials of >75% for the investigated technologies for capacities of 50 MW and beyond (from a 5 MW reference scale).

In addition to CAPEX development, a variety of parameters could have an impact on the economic feasibility of the PtG process chain. These effects were evaluated by assessing production costs for SNG for different PtG technologies and operation scenarios. The calculated results showed that the product costs are mainly driven by electricity supply costs, besides CAPEX and overall plant efficiency. However, the levelized costs of SNG are highly dependent on the annual FLH, despite showing different impacts based on the evaluated scenario. While scenarios with constantly low electricity prices, as presumed in PV and wind supply scenarios, would achieve lowest production costs at high FLH, their supply profiles, especially for peak load coverage, do not support an according operation. For the operation based on the actual spot market prices generation costs are dependent on average electricity prices and their future development. An expected increase in average grid supply costs together with still available hours at lowest prices will move best cost operation from high (~ 6,000 h/a in 2020) to low (~ 2,500 h/a in 2050) numbers of FLH.

Beyond that, it could be shown that future generation costs for SNG from PtG can reach values of around 10 €-cent/kWh$_{SNG}$ and below in large scale plants. However, even in the lowest cost considerations, resulting production costs are still around 6 €-cent/kWh$_{SNG}$ in a long-term perspective and thus significantly higher than today's energy costs for natural gas, representing an obvious benchmark for future PtG plants. Hence, beyond supporting investment and therefore enabling scaling effects for PtG technologies, it will be essential to introduce additional measures and facilitative regulatory frameworks in order to establish power-to-gas as a competitive technology to fossil energy sources.

Acknowledgement

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Appendix A. Supplementary material

The appendix is provided separately as supplementary material.

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