Gerda Reiter, MSc

Ecological and techno-economic evaluation of the integration of power-to-gas into the energy system

DOCTORAL THESIS

to achieve the university degree of

Doktorin der technischen Wissenschaften

submitted to

Graz University of Technology

Supervisor

Ao.Univ.-Prof. Dipl.-Ing. Dr.techn. Michael Narodoslawsky

Institute of Process and Particle Engineering

A. Univ.-Prof. Dr. Reinhold Priewasser
Institut für Betriebliche und Regionale Umweltwirtschaft, JKU Linz

Graz, September 2015

AFFIDAVIT

I declare that I have authored this thesis independently, that I have not used other than the declared sources/resources, and that I have explicitly indicated all material which has been quoted either literally or by content from the sources used. The text document uploaded to TUGRAZonline is identical to the present doctoral thesis.

Date

Signature

Preface

After completing my Master studies in Eco-Energy Technologies at the University of Applied Sciences Upper Austria in 2011, I started working as a research associate at the Energieinstitut an der Johannes Kepler Universität Linz. For almost four years now, my research focus lies on power-to-gas and energy storage and I have already participated in several national and international research projects in the field of power-to-gas.

Energy storage technologies will be important for enabling a more sustainable energy system in the future, as renewable power sources such as wind power or photovoltaics have strongly fluctuating and intermittent characteristics. To ensure a sustainable and at the same time secure energy supply, the fluctuations in power generation have to be compensated. The technology power-to-gas utilizes electricity for production of hydrogen or methane. The produced energy carriers can be applied in industrial processes, as transport fuels for mobility purposes or could be reconverted into electricity if required. Due to the versatile applications, power-to-gas could enable both, a higher percentage of renewable power sources in electricity generation as well as generation of environmentally friendly transport fuels and materials for industry. Furthermore, the produced energy carriers hydrogen or methane could be integrated into the existing gas distribution grid. Power-to-gas thereby connects the power grid with the natural gas network and provides high flexibility to the energy system.

However, the production of hydrogen or methane out of electricity via power-to-gas technology is also associated with significant energy losses along the process chain. For the environmental performance it is therefore decisive how the electricity has been generated beforehand. Generally, the production of hydrogen out of water and electricity in a water electrolyser is more efficient than the further synthesis of methane. However, the integration of hydrogen into the existing natural gas network is limited. As methane from power-to-gas is very similar to natural gas, it could directly replace it without the need for further adaptations in the infrastructure. For synthesis of methane, a carbon dioxide source is required. Carbon dioxide is produced in many industrial processes and is usually emitted to the atmosphere, where it contributes to global warming. Utilizing it in the power-to-gas process would thus be beneficial, although it has to be mentioned that carbon dioxide separation is always accompanied by a certain additional energy demand. Due to the early development stage, the investment costs of this technology are high and so appropriate applications have to be identified.

In my doctoral thesis I integrated different dimensions of process evaluation, as power-to-gas is a very versatile technology with numerous potential applications and benefits for the energy system. Apart from the technical evaluation of the power-to-gas concept and its integration into the energy system, I also focused on the ecological and economic aspects to get a most comprehensive picture. Additionally, aspects and influences on the overall potential for the implementation of the power-to-gas technology are included in this thesis.

I would like to express my gratitude to all the people that supported me during the years I worked on this thesis:

My supervisor Ao.Univ.-Prof. Dipl.-Ing. Dr.techn. Michael Narodoslawsky for his advice and for the interesting discussions.

A. Univ.-Prof. Dr. Reinhold Priewasser for reviewing and evaluating this thesis.

Dipl.-Ing. Dr. Horst Steinmüller and the association *Energieinstitut an der Johannes Kepler Universität Linz* for providing the required resources and giving me the opportunity to attend national and international conferences and present my research there.

Land Oberösterreich for the financial support of the doctoral thesis.

My colleagues at the *Energieinstitut an der Johannes Kepler Universität Linz* for their support and the pleasant working environment, with special thanks to Mag. Dr. Robert Tichler and Dipl.Ing. (FH) Johannes Lindorfer who is Co-Author of most of my published articles.

My husband Florian, my parents Inge and Augustin, my sister and brother and my friends for their moral support.

Gerda Reiter

September 2015

Table of Contents

Abstract

Coupling of the power grid and the natural gas grid via power-to-gas enables increased implementation of fluctuating renewable power sources (wind power and photovoltaics) by providing a long-term energy storage and transport opportunities. With the potential application of produced H_2 and CH_4 for mobility purposes or industrial processes, power-to-gas enables a hybridization of the energy system and provides increased flexibility. A sustainable implementation of the technology system power-to-gas should bring benefits to the environment and the society in terms of reduction of global warming, increasing or maintaining security of energy supply and provision of an affordable energy system. Thus different dimensions of process evaluation have been addressed in this thesis, including a life cycle assessment, economic evaluations and technical issues of components and system integration. To obtain a most comprehensive picture of the technology power-to-gas, influences on the overall potential for its implementation are included.

The main influencing parameter on the implementation of power-to-gas have been identified to be the environmental performance, the economic viability, the demand for energy storage and the demand for the renewable products H_2 and CH_4 in the transport and industry sectors.

The demand for energy storage and the surplus production from fluctuating renewable power sources will strongly increase in the next years as high growth rates are expected for wind power and photovoltaics. For reasons of higher overall efficiency, it is recommended to utilize the produced H_2 and CH_4 from power-to-gas as transport fuels or in industrial applications instead of reconverting them into electricity. However, the times with low renewable power supply then must be balanced by other technologies or by an increased installation of renewable power generation. This would on the one hand offer more electricity in times of high demand and would produce more surpluses for production of renewable fuels via power-to-gas.

The potential amount of H_2 injection into the Austrian natural gas grid may be a limiting factor for the implementation of power-to-gas as energy transport option as the H_2 content may not exceed 4 vol.-% in natural gas and the different gas consumption profiles of each grid segment show strong daily and seasonal fluctuations. Nevertheless, there are other options for power-to-gas plants such as direct utilization at the production site, transport in pressurized storage tanks or methanation. The availability of sufficient amounts of CO_2 for synthesis of CH_4 is on the other hand not a limiting parameter for the implementation of power-to-gas technology in Austria. The whole natural gas consumption could be covered by CH_4 produced with CO_2 from bioethanol production, biogas upgrading, power plants and industrial processes.

The theoretical potential for H_2 and CH_4 as renewable products for mobility or industrial purposes is huge, but the available amount of electricity from renewable power sources may limit this potential. As production costs of H_2 and CH_4 from power-to-gas are higher than for conventional production from fossil resources, the real future demand for green H_2 and CH_4 will strongly depend on the demand for green products in general and on political targets for share of renewables in all energy sectors.

The environmental performance of H_2 production via power-to-gas is strongly depending on the electricity input, which should have a global warming potential of less than 190 g CO_2 per kWh. In other words, a reduction of greenhouse gas emissions compared to fossil reference technologies can only be achieved if electricity is produced mainly from renewable power sources. Utilization of the greenhouse gas CO_2 for CH_4 synthesis via power-to-gas would substitute natural gas and is thus beneficial from an ecological point of view. Nevertheless, the CO_2 separation from industrial processes or power plants is accompanied by a certain additional energy demand related with additional greenhouse gas emissions. These emissions are characterized by the CO_2 penalty in g CO_2 additionally emitted per kg CO_2 captured. If the CO_2 originates from biogenic sources (no CO_2 penalty), the environmental break-even for CH_4 synthesis is 113 g CO_2 per kWh of utilized electricity. When CO_2 is separated for instance from cement production, the additional primary energy demand is comparably high and the environmental break-even decreases to 63 g per kWh electricity input.

The economic performance of power-to-gas is mainly influenced by reached full load hours and total efficiency of the process. Due to the early stage of development, learning and scaling effects could bring significant investment cost reductions. Electricity costs are strongly depending on the type of application which is again influencing the achievable full load hours. At 4 000 full load hours, doubling of electricity costs leads to an increase in specific production costs of +35%. Additional proceeds for oxygen and heat utilization as well as costs of CO_2 have hardly any influence on the specific production costs. Provision of negative balancing power could lead to a significant decrease in specific production costs due to a high achievable proceed for the utilization of electricity. Nevertheless, the participation of power-to-gas plants at the control energy market is connected with a considerable risk, as average prices are fluctuating significantly and cannot be predicted reliably. In comparison to the direct economic benchmarks, the specific H_2 and CH_4 production costs of the presented exemplary power-to-gas plants are higher, even when considering higher full load hours and a potential future investment cost reduction. However, power-to-gas has other benefits such as the possibility of long-term energy storage, the hybridization of the energy system leading to a higher flexibility and the reduction of greenhouse gas emissions when renewable electricity is applied.

One main issue to be considered for further research is the additional power demand in the energy system induced by H_2 and CH_4 production for transport and industry applications with high full load hours. This could increase the burden on the power grid and the additionally required power generation technologies would influence the ecological performance. For improvement of the economic viability of power-to-gas systems, future research should focus on the improvement of the applied technologies and systems in terms of lower costs and higher system efficiency, especially in part load and dynamic operation.

1 Introduction

Striving for a more sustainable and environmentally friendly energy system is accompanied by an increased installation of fluctuating renewable power sources such as wind power and photovoltaics. Apart from their large potential for reduction of greenhouse gas emissions in power generation, these technologies are characterized by a strongly fluctuating and intermittent power output. To enable increased installation of these renewable power sources and at the same time secure energy supply, energy storage technologies will be required.

Power-to-Gas (PtG) utilizes electricity from fluctuating renewable power sources for splitting water into hydrogen (H_2) and oxygen (O_2) in an electrolyser. The H_2 produced could further be synthesized to methane (CH_4), which is an optional process step in the power-to-gas system. The concept of “renewable power methane” was first proposed by M. Sterner in 2009 [1]. However, the idea of applying H_2 production for energy storage purposes exists much longer and pilot plants have been built since 1991 (see for instance Gahleitner [2] for more information).

The main process steps of power-to-gas are illustrated in Figure 1. An overview of the power-to-gas technology including technical information about the main process steps is provided by Reiter [3]. This includes also information on the transport and potential application of the H_2 and CH_4 produced.

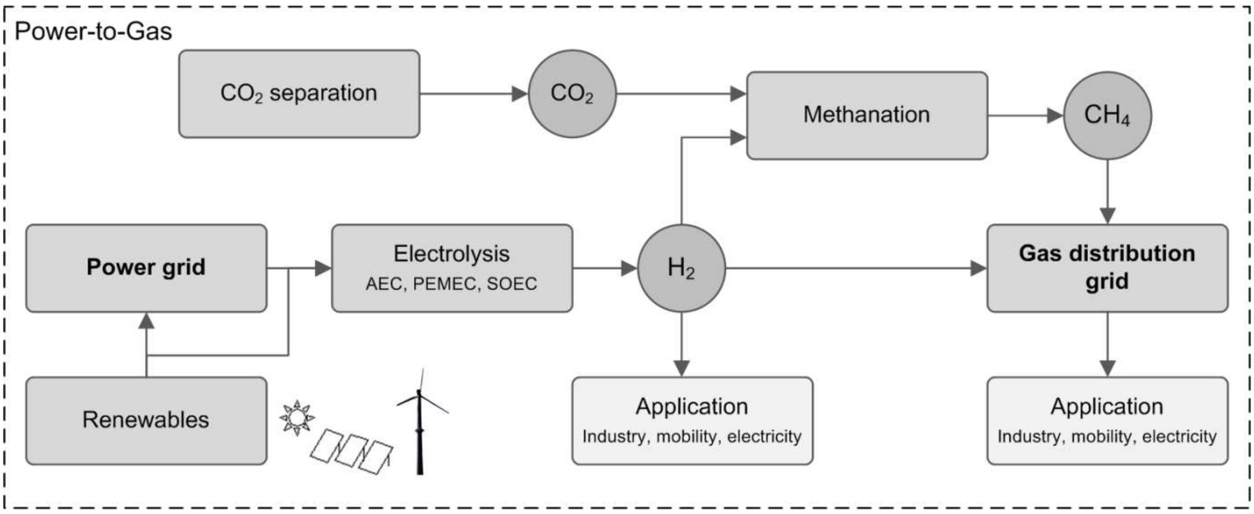

Figure 1. Main process step of the power-to-gas system, from [3]

Numerous power-to-gas pilot plants with increasing capacity have been built in the last decade especially in Europe and North America. Gahleitner [2] provides detailed information on technical specifications of these pilot plants in a review on international power-to-gas pilot plants. Furthermore, experiences from the operation of the power-to-gas plants and the subsequent application of the energy carriers are summarized. Figure 2 shows the power-to-gas pilot plants that are installed all over the world.

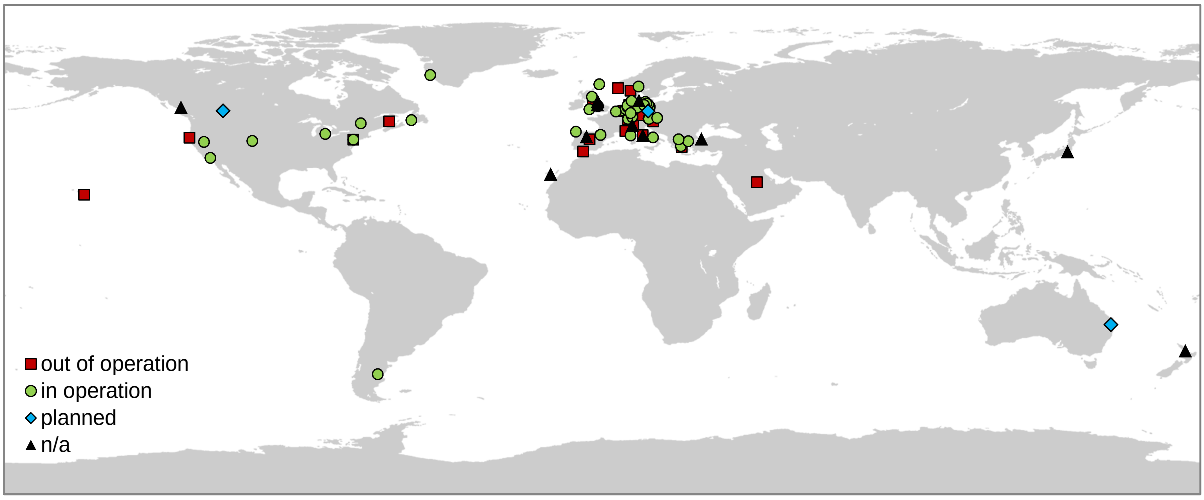

Figure 2. International power-to-gas pilot plants, with information from Gahleitner [1] and Reiter [3]

Figure 2 indicates that there is a strong focus on power-to-gas pilot plants in Europe. Thus the power-to-gas pilot plants in Europe are shown in more detail in Figure 3. As fluctuating renewable power sources such as wind power and photovoltaics are strongly growing in Germany, there is a strong focus on power-to-gas projects there.

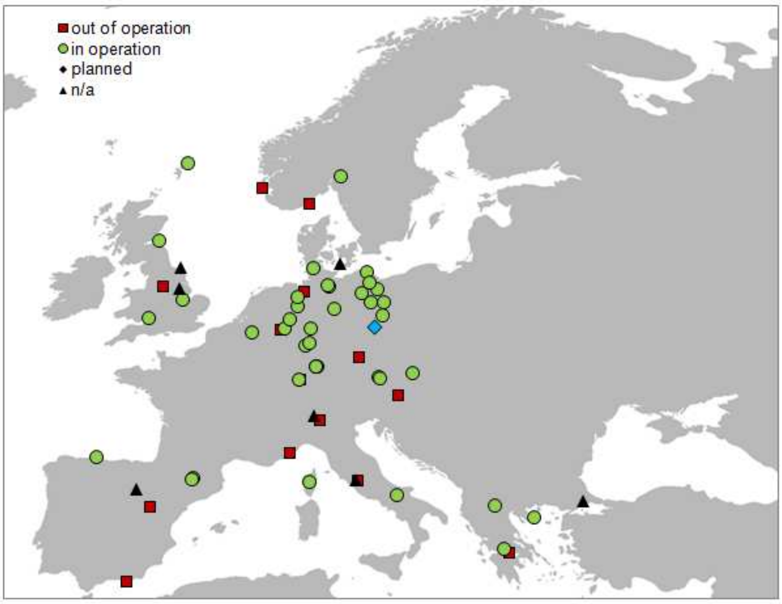

Figure 3. Power-to-gas pilot plants in Europe, with information from Gahleitner [1] and Reiter [3]

Due to the versatile applications, power-to-gas could fulfill several functions in the energy system, which have been characterized for instance in Reiter et al. [4], Steinmüller et al. [5], or Tichler et al. [6]. The identified functions are listed here.

- H_2 and CH_4 produced via power-to-gas could be applied for mobility purposes or industrial processes. If electricity from renewable power sources is utilized and the CO_2 for methanation originates from biogenic sources, the H_2 and CH_4 produced are renewable energy carriers. One function of power-to-gas technology could thus be the **provision of renewable energy carriers** for mobility purposes or industrial processes.

- Converting electricity into H_2 or CH_4 via power-to-gas and feeding these energy carriers into the gas distribution grid enables the coupling of energy infrastructures. The existing gas distribution grid could thereby be applied for **transporting energy** over large distances without significant losses. With its enormous storage capacity, the gas infrastructure could additionally be utilized for **seasonal storage of energy** from fluctuating power sources. The coupling of the power grid and the natural gas distribution system via the technology power-to-gas enables a **hybridization of the energy infrastructures** and provides more flexibility to enable higher integration of renewable power sources.
- In regions with high percentage of renewable power generation but low electricity demand, there are times with surplus electricity that could not always be directly utilized by consumers. As the power generation from some renewable power sources such as wind or solar is strongly fluctuating and could not be adapted to the actual demand, options for electricity storage or utilization are required. With power-to-gas, **electricity could be utilized for production of H_2 or CH_4 in times with low electricity demand but high generation from renewables**.
- In regions without access to the public power grid, electricity is very often provided by diesel generators that have several negative side effects such as high energy costs, air pollution, noise and high dependency on fossil fuels. Such abundant regions often also have a high potential for renewable electricity generation via wind power plants or photovoltaics. However, these renewable power sources are strongly fluctuating and cannot adapt their production to the actual demand. With power-to-gas technology, the electricity could be utilized for H_2 or CH_4 generation in times when the electricity demand is low. The produced energy carriers could be stored and reconverted into electricity when demand is high. Alternatively, these energy carriers could also be applied for heat generation or provision of transport fuels for mobility purposes. Power-to-gas together with renewable power sources could thus provide **self-sufficient energy supply for regions without access to the public energy infrastructure**.
- The methanation step within the power-to-gas system requires CO_2, which could be gathered from various industrial processes where it is produced as by-product. CO_2 could be separated from the flue gas of power plants, from industrial processes such as steel, cement or lime production and is also generated in bioethanol production or biogas upgrading. **Utilization of the greenhouse gas CO_2** for production of synthetic CH_4 via power-to-gas would thus create an additional benefit per kg CO_2. Alternatively to CO_2 utilization, the captured CO_2 could also be stored in underground geological reservoirs such as depleted oil and gas fields or saline aquifers. However, carbon capture and storage (CCS) is related to high costs, high additional energy requirement and ecological problems due to leakages. [8]

Power-to-gas technology could thus enable higher percentages of renewables not only in power generation, but also in the transport and industry sector. Furthermore, the technology system could contribute to maintain the high level of energy supply security for instance in Europe or North America and could provide energy supply to remote regions.

However, the production of H_2 or CH_4 out of electricity via power-to-gas technology is also associated with significant energy losses along the process chain. In general, the production of H_2 is more efficient than the further synthesis of CH_4, but the integration of H_2 into the existing natural gas network is limited. As CH_4 from power-to-gas is very similar to natural gas, it could directly replace it without the need for further adaptations in the infrastructure. For synthesis of CH_4, a carbon dioxide source is required. CO_2 is produced in many industrial processes and is usually emitted to the atmosphere, where it contributes to global warming. Utilizing it in the power-to-gas process would thus be beneficial, although it has to be mentioned that CO_2 separation is always accompanied by a certain additional energy demand. Major challenges for power-to-gas are the high investment costs and the early stage of development.

2 Thesis Approach

The primary goal of the implementation of a new technology should always be the improvement of the viability of a system. This should be achieved in both, an environmental and a sociel dimension. The improvement of the impact of energy generation and supply on the environment is often characterized by a certain reduction in greenhouse gas emissions. A reduction in greenhouse gas emissions of power generation could be achieved by a higher implementation of renewable power generation technologies such as wind power or photovoltaics. However, these power generation technologies are characterized by a strongly fluctuating energy supply and an increased implementation requires balancing options, such as energy storage via power-to-gas. Apart from energy storage, power-to-gas could also be utilized to produce renewable H_2 or CH_4 for utilization in the transport and industry sector. The technology could thus enable both, a higher implementation of renewable technologies for power generation as well as provision of renewable products for other energy sectors. Apart from a positive impact on the environment, a new technology must be affordable for a society in terms of overall lifecycle costs and should contribute to obtain or even increase the security of energy supply.

With the aim of improving the energy system in a technical, ecological, economic as well as social dimension, this doctoral thesis evaluates the integration of power-to-gas into the energy system. Thereby it addresses technical issues of components and system integration, environmental impact and economic considerations. To obtain a most comprehensive picture of the technology power-to-gas the thesis additionally includes aspects and influences on the overall potential for the implementation of power-to-gas. One main research question of the thesis is the determination of these influencing parameters and the identification of limitations and barriers. It should also be found out in the course of this thesis, how the various parameters influence the economic and ecological performance and if these two dimensions are contradictory. The doctoral thesis thus discusses the following main research questions:

1) Which parameters influence the implementation of power-to-gas?
2) Are any of these parameters limiting the implementation of power-to-gas in a significant order of magnitude?
3) Do economic power-to-gas applications always have a positive environmental impact?

The doctoral thesis discusses these three main research questions and addresses further technical, economic and ecological issues in various research articles. The following articles were published in peer-reviewed international journals and are the basis of this doctoral thesis.

I. G. Gahleitner (2013) *Hydrogen from renewable electricity: An international review of power-to-gas pilot plants for stationary applications*. International Journal of Hydrogen Energy 38 (5): 2039-2061. DOI:10.1016/j.ijhydene.2012.12.010

II. G. Reiter, J. Lindorfer (2015) *Global warming potential of hydrogen and methane production from renewable electricity via power-to-gas technology.* International Journal of Life Cycle Assessment 20 (4): 477-489. DOI:10.1007/s11367-015-0848-0

III. G. Reiter, J. Lindorfer (2015) *Evaluating carbon dioxide sources for power-to-gas applications – A case study for Austria.* Journal of CO_2 Utilization 10: 40-49. DOI:10.1016/j.jcou.2015.03.003

I was sole author of the first article and thus I am responsible for the whole content of the paper. The second and third article was written together with my colleague Johannes Lindorfer. I was responsible for the life cycle assessment (data collection, calculations, interpretation) and writing of the second article. My co-author contributed with corrections and recommendations to the article and supported me in methodological issues. In the third article, I was responsible for the general description of the power-to-gas technology and the various CO_2 separation technologies. I calculated the specific costs, CO_2 emissions and energy demand of various CO_2 sources and did the case study for Austria. Johannes Lindorfer contributed with recommendations on the article, supported me in data collection and article writing. I was main author of all three papers and thus was also responsible for submission and revision of the articles.

The following papers are also relevant for the doctoral thesis and have been published at international conferences or as chapters in books:

IV. G. Gahleitner, J. Lindorfer (2013) *Alternative fuels for mobility and transport: Harnessing excess electricity from renewable power sources with power-to-gas.* eceee 2013 Summer Study, France.

V. G. Reiter, J. Lindorfer (2013) *Möglichkeiten der Integration von Power-to-Gas in das bestehende Energiesystem.* Jahrbuch Energiewirtschaft 2013, NWV-Verlag.

VI. G. Reiter, J. Lindorfer (2014) *Ökonomische und ökologische Prozessbewertung des Technologiekonzeptes Power-to-Gas.* Minisymposium Verfahrenstechnik, Wien.

VII. G. Reiter (2015) *Power-to-Gas.* In: D. Stolten (Ed.) Data, Facts and Figures on Fuel Cells. Wiley-Verlag, Forthcoming.

3 Influences on the potential for implementation

A new energy technology can only be designated sustainable, if it brings benefits to the environment and the society with the primary goal of improving the viability of a system. This is achieved by decreasing the environmental impact in terms of greenhouse gas emissions, water demand, resource consumption etc. At the same time, the new technology must be affordable for a society in terms of overall lifecycle costs. Another important goal is to obtain or even increase the security of energy supply. The quality of energy supply depends strongly on the availability of energy infrastructure that should enable transport and storage of energy in an efficient way.

Figure 4 shows the parameters that are strongly influencing the potential for the implementation of power-to-gas plants. The superordinate influencing parameters are the economic viability, the environmental performance, the demand for products (H_2 and CH_4), and the demand for energy storage and energy transport. These parameters are coloured blue in Figure 4. Each of these main parameters is again influenced by other factors, which are coloured green in Figure 4.

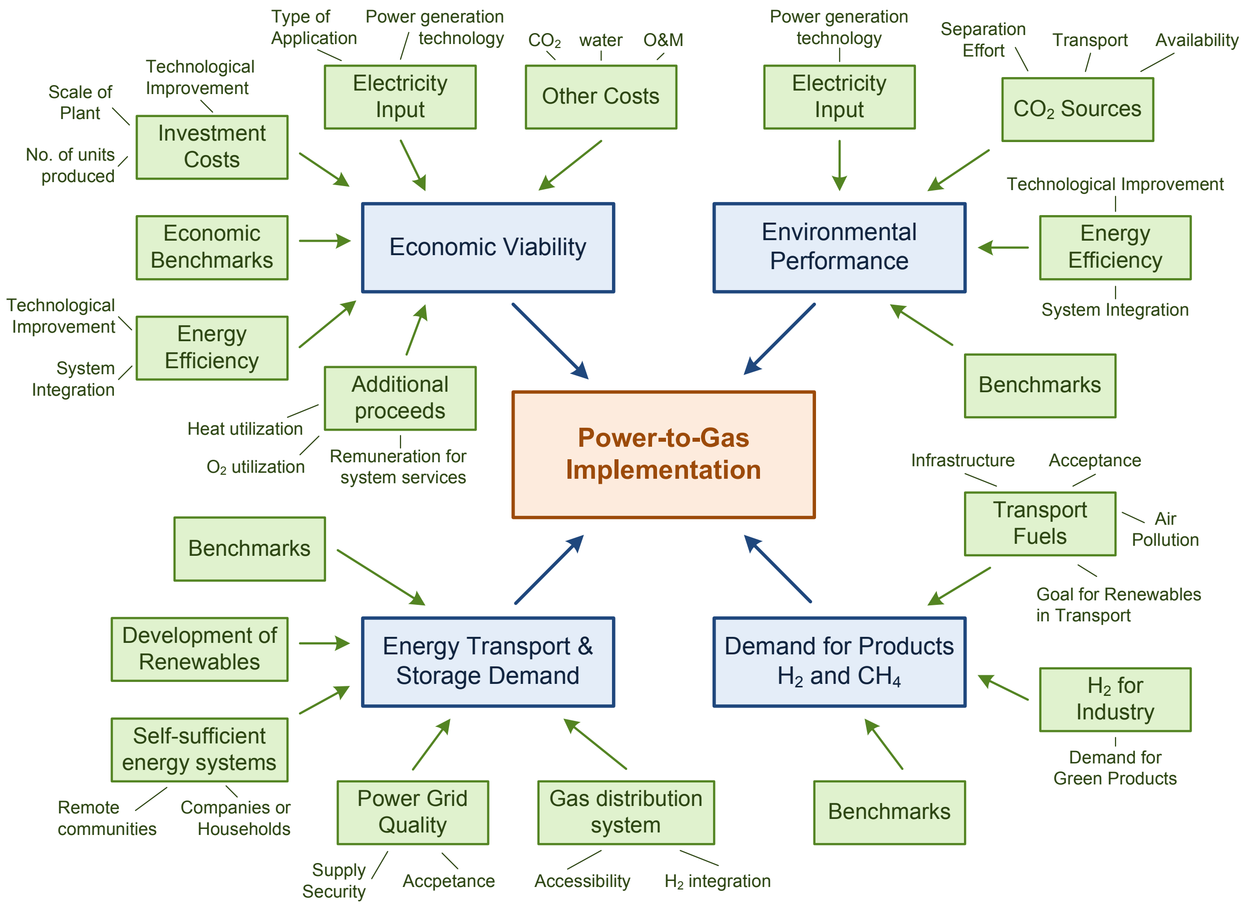

Figure 4. Influencing parameter on the implementation of power-to-gas

Power-to-gas technology could enable a higher integration of renewable power sources in electricity generation and at the same time provide renewable fuels for mobility purposes, heat generation or industrial applications. Main objective of the implementation of power-to-gas technology is to reduce overall greenhouse gas emissions of the energy system. Thus it is crucial to consider the **environmental performance** of the technology and its applications. According to results presented in Reiter et al. [7], the most influencing parameters on global warming potential are the type of electricity generation and the additional impact of CO_2 separation. The so-called CO_2 penalty[1] of various CO_2 sources has been analyzed in more detail in [8]. The biggest barrier for an environmentally friendly application of the power-to-gas technology is the high percentage of fossil-generated electricity in the energy system. A reduction in greenhouse gas emissions in comparison to reference technologies can only be achieved, if the utilized electricity for H_2 production is mainly generated by renewable power sources (see section 5.1 for more information). The improvement of the energy efficiency of power-to-gas could also improve the environmental performance.

The **economic viability** of power-to-gas is strongly influenced by the investment costs of power-to-gas plants, which are determined by technological development of the main components as well as by learning and scaling effects of the technology. Depending on the type of application, the electricity input costs as well as full load hours vary significantly and influence the specific production costs of H_2 and CH_4. Additional revenues for fulfilling system services such as provision of balancing power could significantly improve the economics of power-to-gas. However, the decisive parameter for the economic viability is the relevant benchmark technology. Depending on the function that power-to-gas fulfills in the energy system, the costs of the benchmark may vary significantly. If H_2 or CH_4 from power-to-gas are utilized as transport fuels, other transport fuels such as diesel, gasoline, ethanol or biodiesel are the relevant benchmarks. However, if the power-to-gas plant additionally provides balancing power, this has to be considered too. Since issues of economic viability have also a high impact on the environmental performance of power-to-gas, these two parameters are discussed together in section 5.

From its primary intention, power-to-gas should enable increased integration of fluctuating renewable power sources such as wind or photovoltaics. Thus the development and percentage of these renewable power sources in electricity generation is crucial for the implementation of power-to-gas. Striving for a more sustainable energy system, most countries have goals for high shares of renewable power sources and so both photovoltaics and wind power have strong growth rates. However, apart from renewables share in national power generation especially the local developments of renewable power sources have to be considered. High penetration of wind power in regions with low electricity demand may already require energy storage although the share of wind power in the national electricity generation is still of small importance. The **demand for energy storage and transport** is also considerably influenced by the quality of the power grid in these regions. Transporting large amounts of electricity from regions with high renewable power generation but low electricity demand to regions with higher demand often requires substantial

[1] Analogous to the term energy penalty, the additional CO_2 emission incurred by CO_2 capture is termed the **CO_2 penalty** in Reiter et al. [8]. CO_2 capture technologies mostly require primary energy input, which lowers the total efficiency of the power plant. Thus, for production of the same amount of electricity, more primary energy input is required. This additional primary energy input causes additional greenhouse gas emissions. These additional greenhouse gas emissions related to the captured CO_2 are called the **CO_2 penalty**.

expansion of power grids. Usually this is accompanied by strong public resistance, high costs and extensive authorization procedures. The implementation of power-to-gas as energy storage and energy transport technology is thus strongly depending on the power grid quality especially in regions with high renewable power generation. If the H_2 or CH_4 produced via power-to-gas should be transported via the gas distribution system, the distance and potential capacity of the gas grid is decisive. This is especially important for the integration of H_2 into the gas distribution grid, as the allowed volumetric fraction of H_2 in natural gas is limited. Further influencing parameter on the potential for H_2 integration are described and quantified in section 4.3. Synthetic CH_4 from power-to-gas can be easier integrated into the gas distribution grid, but a CO_2 source is required for the synthesis. The availability of CO_2 for the methanation process is therefore another influencing parameter. A case study for Austria shows the available amounts and evaluates the sites of these CO_2 sources in comparison to the regions with high fluctuating renewable power generation. The aggregated results are presented in section 4.4.

The H_2 or CH_4 produced via power-to-gas technology could be utilized for mobility purposes or as input in industrial processes. The **demand for renewable products** in these two sectors is therefore decisive for the implementation of power-to-gas. If renewable electricity is utilized as input for the power-to-gas process, H_2 and CH_4 can be considered to be “green products” and thus substitute fossil alternatives in both the transport and the industrial sector. The demand for such green products from power-to-gas is strongly depending on the national and global goals for renewables in these sectors and also depends on the economic and environmental performance of other green alternatives.

4 Demand for energy storage and renewable products

According to the IEA [9], global electricity generation is currently (2014) covered by 22.8% of renewable power sources, with water power being the most important (16.6%). Variable or fluctuating renewable power sources such as wind and photovoltaics only account for 3.1% and 0.9%, respectively. However, the installed capacity of wind power and photovoltaics grew very fast in the last decade. Currently, 370 GW of wind power and 177 GW of photovoltaics are installed globally. Figure 5 shows the expected future capacity of fluctuating renewable power sources for selected countries and the rest of the world. High growth rates are especially expected for China and the European Union. Installed power of photovoltaics is projected to be strongly increasing in China and the rest of the world.

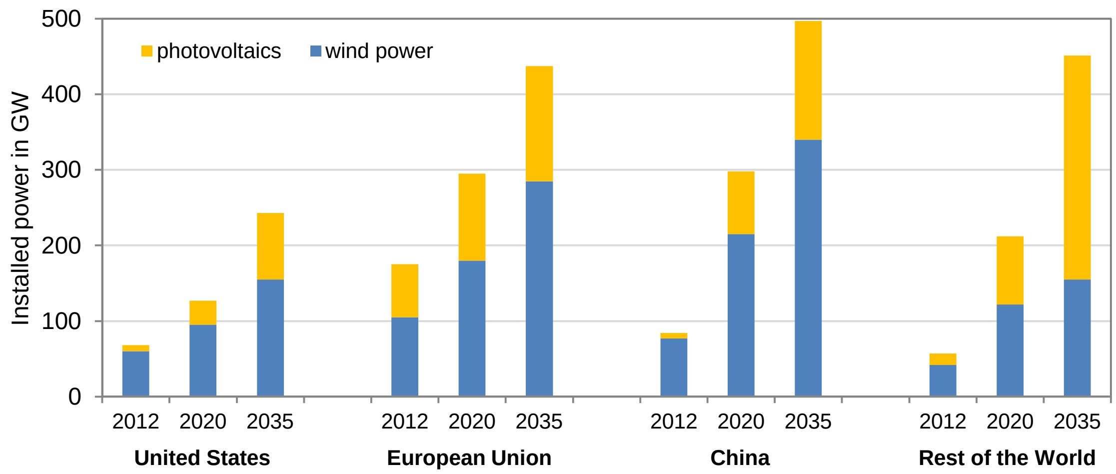

Figure 5. Prognosis of future installed power of fluctuating renewable power sources, based on data from IEA (2013) [9]

This strong growth of fluctuating renewable power sources (photovoltaics and wind power) will also lead to an increased demand for energy balancing and storage options. Detailed information on energy system flexibility measures can be for instance gathered from Lund et al. [10]. Available storage technologies are illustrated in Figure 6. Whereas technologies such as flywheels or batteries are better suited for short-term energy storage, energy storage via H_2 or synthetic CH_4 (power-to-gas) is more a long-term energy storage technology. In contrast to the other storage technologies in Figure 6 the output product of power-to-gas needs not to be electricity. The produced H_2 or CH_4 can also be utilized as transport fuels, for heating purposes or as raw materials in industry. Power-to-gas technology could therefore lead to a hybridization of the energy system, where surplus[2] from electricity generation is utilized to provide renewable products. The potential for renewable products in other energy sectors is huge, as for instance in the transport sector no real alternatives are given.

[2] Surplus electricity could be specified as the electricity that cannot be fed into the public electricity grid or be utilized otherwise. Reasons for that could be a lower electricity demand than the actual generation or that in local grids the electricity network may be too weak to transport peak production from renewables.

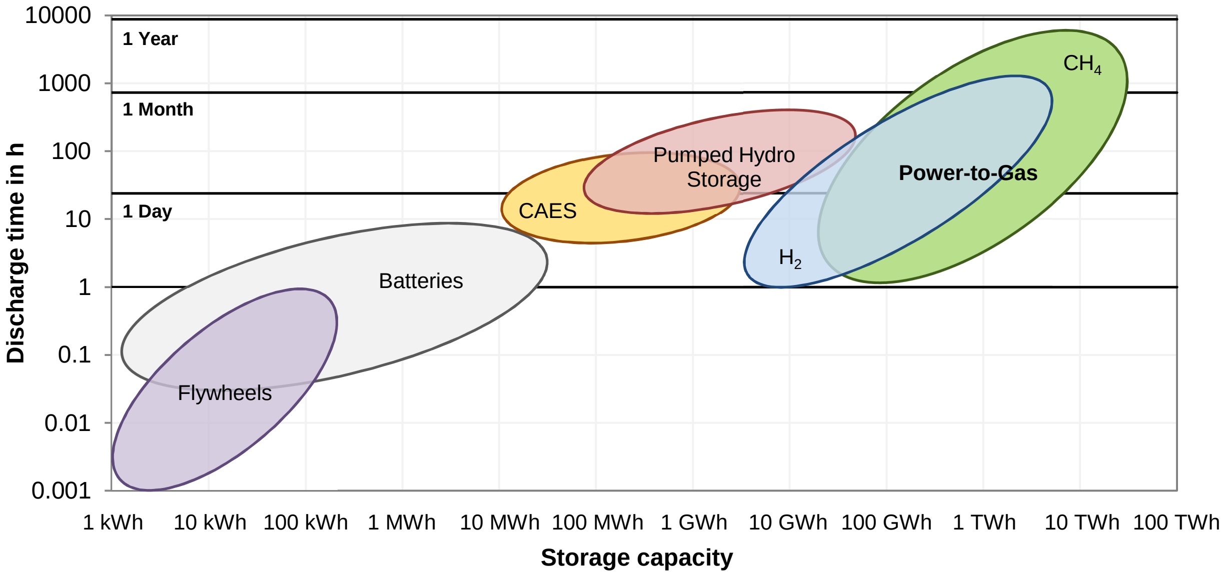

Figure 6. Comparison of different storage technologies by capacity and storage time, based on [11]

However, if power-to-gas is utilized to produce renewable fuels out of surplus electricity, the energy carriers are not available for reconversion into electricity in times of low demand. Power-to-gas is thus not necessarily a typical electricity storage technology and could provide renewable fuels for transportation or heating purposes with an overall higher efficiency. Electricity for times with low power generation but high demand would then have to be provided in other ways – either by typical electricity storage technologies, back-up capacities or an increased installation of renewable power sources. Increased installation of renewable power sources could on the one hand offer more electricity in times of high demand and would produce more “surplus” for production of renewable fuels via power-to-gas.

4.1 Energy storage demand in Austria

The future energy storage demand for the integration of fluctuating renewable power sources in Austria is analysed by Boxleitner et al. [12] in the project “Super-4-Micro-Grid” and by Zach et al. [13] within the EU-project “Store”.

Assuming a full supply with renewable electricity in 2050, Boxleitner et al. [12] predict an energy storage demand of between 17 and 23 TWh, depending on the development of the future electricity demand – 69 or 86 TWh respectively. That would require pumped hydro power plants with an installed power of between 10 and 21 GW. However, the potential for pumped hydro storage in Austria is with 4.8 GW far too low. Boxleitner et al. thus recommend [12] the expansion of flexible renewable power generation as well as the implementation of long-term storage technologies such as power-to-gas. Further analysis of the installation of power-to-gas plants based on Boxleitner et al. in Steinmüller et al. [5] showed that power-to-gas plants complement pumped hydro storage plants. With an installed capacity of 4 GW of power-to-gas plants, a regenerative supply of up to 90% would be possible in Austria.

Zach et al. [13] state a similar storage demand of 21 TWh for an electricity demand of 83 TWh. The required installed pumped hydro capacity therefore would be 21 GW. Since they, in contrast to Boxleitner et al. [12], assume a higher potential for pumped hydro (9.2 GW), the remaining storage demand is 7.7 TWh or 12 GW.

Table 1 shows the H_2 or CH_4 that could be produced via power-to-gas with the electricity that could not be stored by pumped hydro storage plants. With the produced amount of H_2, between 13% and 29% of future demand for transport fuels in Austria could be covered (see section 4.3 for more information on the future demand for transport fuels.)

Table 1. Potential for H_2 or CH_4 production from electricity that could not be stored by pumped hydro storage plants in Austria in 2050, based on data from Boxleitner et al. [12] and Zach et al. [13]

		Super-4-Micro-Grid	**STORE**
Electricity PtG	GWh/a	23 300	10 300
H_2 production	Mio. m³/a	4 660	2 060
CH_4 production	Mio. m³/a	1 099	486

It has to be mentioned here, that the remaining storage demand is based on the efficiency of a pumped hydro power plant (80%). A power-to-gas plant with reconversion into electricity has a much lower overall efficiency of between 30% and 45%.[3] The overall efficiency of power-to-gas is higher if the produced H_2 or CH_4 are directly applied, e.g. as transport fuels. However, as the assessed storage demand assumes that electricity is provided by the storage technology, this demand would have to be met in another way if power-to-gas is applied. One possible solution could be the increased installation of renewable power generation. This is also proposed by Budischak et al. [14], who found out that the cost-optimized way for an energy system supplied by renewable energy is to install excessive generation capacity. The surplus electricity is then utilized for example to replace fossil energy carriers such as natural gas by H_2.

4.2 Self-sufficient energy systems

As power-to-gas is able to store energy from renewable power sources and provide a fuel for heating purposes, transport applications or electricity generation, it would also be suited for self-sufficient energy systems (see Reiter et al. [4] for more information). Remote regions often have no access to a public electricity grid and thus rely on diesel generators. This type of electricity generation is very cost-intensive and is related with high emissions [14]. According to the REN21 Global Status Report [16], about 15% of the global population is without access to electricity - most of them in rural areas of Sub-Saharan Africa and South Asia. Remote regions often have a high potential for renewable power generation (e.g. high wind potential on remote islands), but due to

[3] Electrolyser efficiency of between 60% and 70%, efficiency of reconversion (e.g. gas power plant) of between 50% and 60%

the fluctuating nature of wind and solar power, a storage possibility such as power-to-gas would be required.

Apart from the lack of access to the public electricity grid, other factors could also lead to a demand for self-sufficient energy systems. These systems could be interesting for companies or households which want to be self-sufficient and are willing to pay for that.

4.3 H_2 integration into the Austrian natural gas grid

The potential of H_2 injection into the natural gas grid depends on various parameters. In Austria, the ÖVGW guideline G31 is of essential importance as it determines the maximum allowed volumetric fraction of H_2 (4 vol.-%) in natural gas as well as the combustion characteristics Wobbe-Index, calorific value and relative density. The currently existing limits are shown in Figure 7, which also provides information about the change of combustion characteristics at higher H_2-fractions. These limits for the gas quality and allowed volumetric fraction of H_2 in natural gas are different in each country, but will probably be adapted in the European gas quality harmonization.

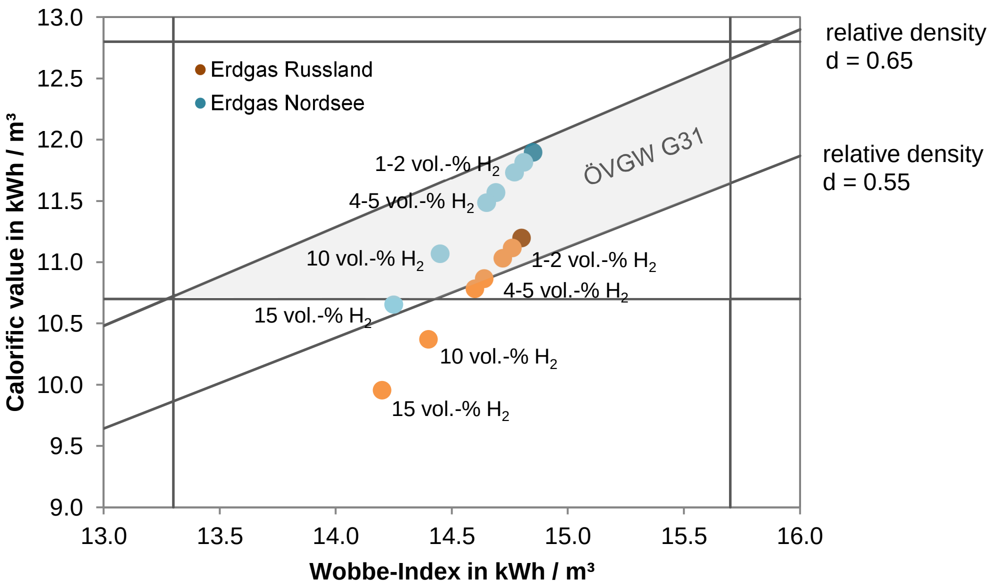

Figure 7. Combustion characteristics of natural gas with different H_2 fractions, based on Müller-Syring [16]

From a technical point of view, the H_2-tolerance of the various components in the gas infrastructure is decisive. Details on the tolerance of components and materials against H_2 were analyzed by the German DVGW and are summarized by Müller-Syring et al. [17]. Demand for adaptations is especially given for gas turbines, compressors, CNG vehicles and process gas chromatographs. A significant research demand has been identified for subsurface pore storage. Higher H_2-contents in natural gas cause a higher flame temperature and thus could cause material problems in gas turbines. Several manufacturers state that higher H_2-contents would be possible, but adaptations are necessary. Manufacturer guarantees for existing gas turbines are usually given for H_2-concentrations up to 1 vol.-%. Material problems also occur in CNG vehicles or more precisely in

CNG tanks of CNG vehicles. Utilization of CNG tanks with higher quality steel would enable higher H_2-contents. Process gas gaschromatographs that are currently installed in the natural gas infrastructure are not able to detect H_2. However, the detection of H_2 would be feasible with new or adapted devices. More details on the tolerance of H_2 in the gas infrastructure are presented in [18].

The integration capacity for H_2 into the Austrian natural gas grid is also depending on seasonal and daytime fluctuations in natural gas flow as well as on local grid and consumer structures. The gas flow in transit gas pipelines is huge and thus offers a large potential for H_2 injection, although it has to be mentioned that the gas quality strongly depends on the country of origin and could already have certain H_2 content. Transit pipelines have thus not been considered for the estimation of H_2-injection potential. The gas flow in large transport pipelines is often determined by existing contracts and therefore could not be reliably forecasted. In the distribution network, gas flows are determined by pressure levels and consumption. Figure 8 shows the gas consumption in Austria for each hour in the year 2013. As natural gas is to a large extent utilized for heating purposes, the gas consumption is much lower in summer (from April to August).

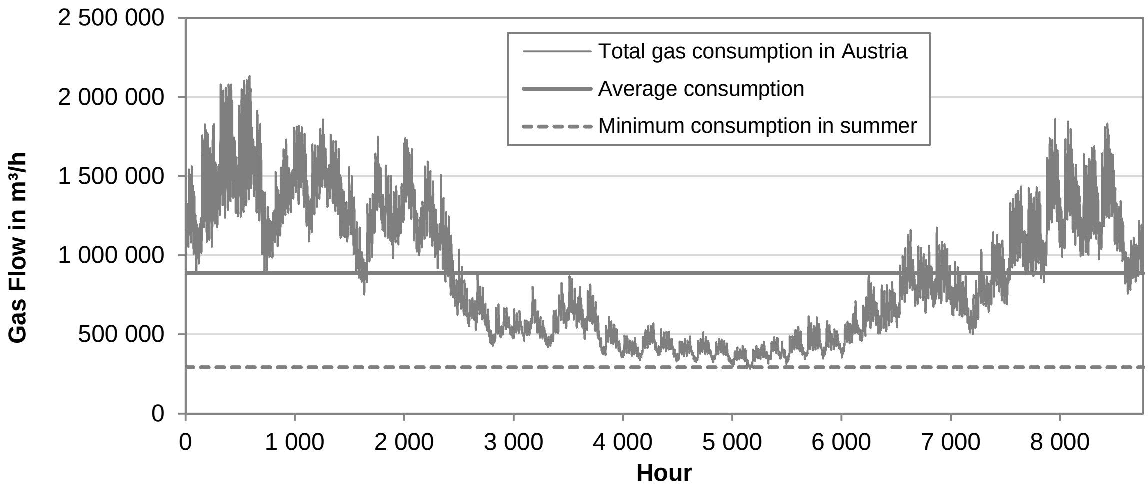

Figure 8. Natural gas consumption in Austria, data for 2013 from [19]

In addition to seasonal and daily fluctuations in general, there are also huge differences in gas consumption depending on the consumer profiles in the specific grid segments. Grid segements with predominantly households as consumers have very low consumption in summer and high consumption in winter. Grid segments with high proportion of industrial consumers have tentatively a more continuous gas flow and thus offer a higher potential for H_2 integration. However, the investigation of data from various exemplary grid segements indicates that there can be huge differences even between the consumption profiles of industrial consumers. Figure 9 shows load duration curves[4] of exemplary grid segments. Whereas consumption profile Industry I is continuously high, consumption profile Industry II shows a steep decrease in gas flow with increasing hours per year. Even though both consumption profiles Region I and Region II have a

[4] A load duration curve illustrates the variation of a certain load in a downward form such that the greatest load is plotted in the left and the smallest one in the right.

predominant supply of households, these profiles also differ quite significantly. The potential H_2 injection is thus strongly depending on local consumption profiles and has to be assessed for each grid segment separately.

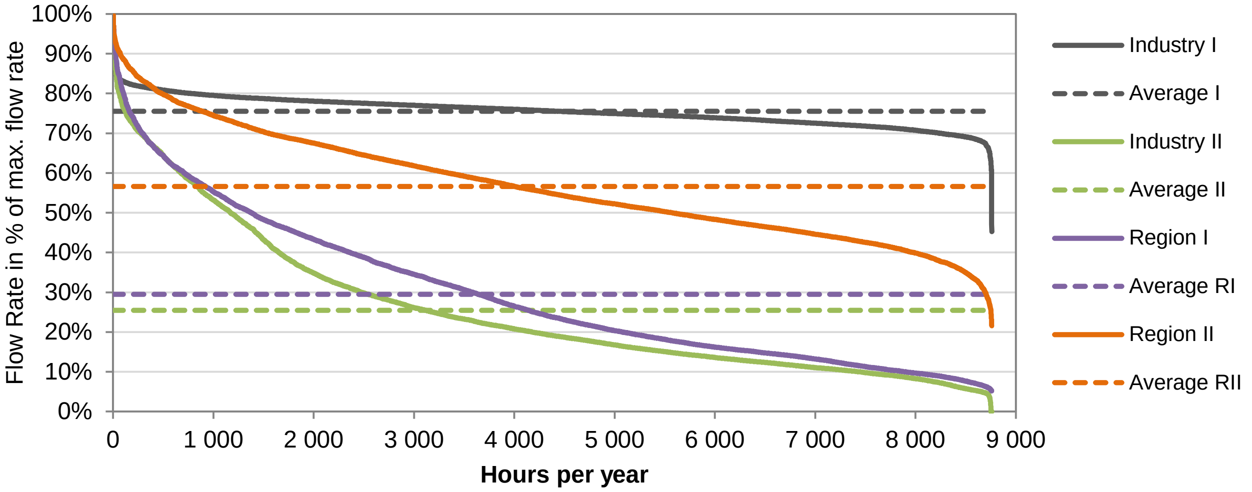

Figure 9. Load duration curves of grid segments with predominant supply of households or industry, anonymized data

Nevertheless, a rough estimation of the H_2 injection potential into the Austrian natural gas grid is conducted here for several scenarios and assumptions. The theoretical potential is derived from the annual gas consumption, assuming either that the produced H_2 can be buffered in storage tanks or that the electrolyser is only operated in part load most time of the year. Another scenario is to design the electrolyser for the capacity that is reached in 4 300 hours per year or for the minimum capacity in summer. Considering local constraints in the Austrian natural gas grid, Hofmann et al. [20] assessed the potential for biomethane integration into the gas distribution grid, which is 40 700 m³ gas per hour[5] in summer load case (summer load II). Each scenario is leading to different potentials for H_2-integration into the gas distribution grid and results are given in Table 2. In addition to the potential H_2 integration into the gas distribution grid, information about the related annual electricity demand for power-to-gas and the total nominal power of power-to-gas is provided. Therefore an average electricity demand of 5 kWh per m³ H_2 produced is determined.

Table 2. Potential for H_2 integration into the Austrian natural gas grid for different scenarios, allowed volumetric fraction of 4 vol.-% H_2 in natural gas.

		Theoretical potential	Full Capacity in 4300 h/a	Full capacity in Summer load	Full capacity in Summer load II
Electricity	GWh/a	1545	1152	532	71
Nominal Power PtG	MW	176	161	61	8
H_2 production	Mio m³/a	309	230	106	14

[5] scaled for the gas consumption in 2013

The regional differences in the potential for H_2-integration are illustrated in Figure 10 for the nine Austrian states. Comparing the storable energy via H_2-integration with the electricity produced from wind power in these states, the importance of a regional assessment gets clear. While the electricity production from wind power is very high in Burgenland and Lower Austria, the potential of H_2-integration in these federal states is low. Even if the whole theoretical potential for H_2-integration could be realized, only 9% of electricity from wind power could be stored in this way. However, due to the proximity of the wind parks to the state of Vienna, the potential of H_2-integration might increase. In Upper Austria, the situation is the other way round as the gas consumption is very high but only little electricity is produced from wind power.

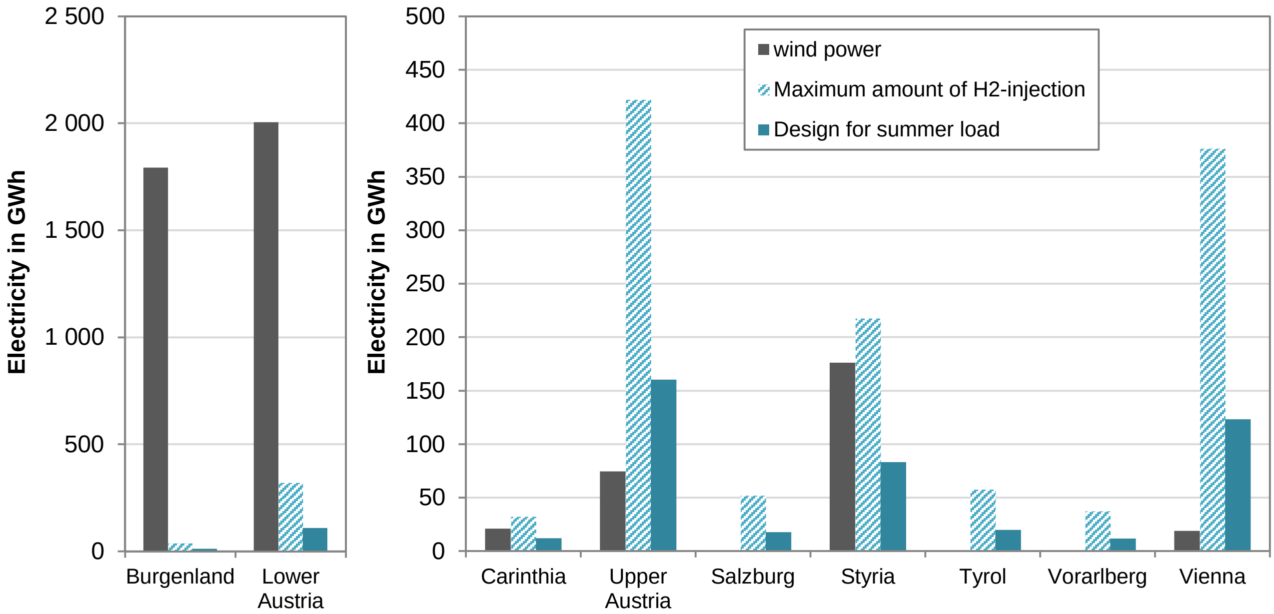

Figure 10. Storable energy via H_2-integration into gas grid for the nine states of Austria in comparison to the electricity produced from wind power, with data from E-Control Austria [21].

In addition to the instantaneous gas flow in the gas grid, the purpose and operational mode of the power-to-gas plant has great influence on the realizable H_2-integration. If full load hours of power-to-gas plants are high and H_2 should be integrated over the whole year, the capacity in the summer load case will be decisive. If there are other options for H_2 utilization or the power-to-gas plant only operates in certain time periods (especially in winter), the potential capacity for H_2 integration could be much higher.

In conclusion, the implementation of power-to-gas plants with H_2 feed-in is limited in Austria and strongly depends on local conditions and consumption profiles in the grid segments. The time of the year is also decisive, as the H_2 injection potential is much larger in winter, than in summer. Nevertheless, apart from H_2 injection, there are other options for power-to-gas plants such as direct utilization at the production site, transport in pressurized storage tanks or methanation. If the produced H_2 is converted into synthetic CH_4, the injection potential into the gas distribution grid would be much larger, as synthetic CH_4 can directly substitute natural gas.

4.4 Availability of CO_2 sources for methanation in the power-to-gas process

Synthetic CH_4 production has a lower total efficiency compared to H_2 production as further process steps are involved in the power-to-gas system. However, the infrastructure for CH_4 (or natural gas) is better developed than for H_2 as the gas distribution grid represents an existing transport and storage infrastructure. It has been shown that H_2 could be integrated in the natural gas infrastructure, but the capacity is limited depending on the allowed volumetric fraction of H_2 in the gas infrastructure. Synthetic CH_4 could be easily integrated in the existing gas infrastructure, but requires a CO_2 source for the methanation process. Potential CO_2 sources and their availability in Austria were examined in [8]. Regarded parameter for evaluation of potential CO_2 sources are the capture costs, the CO_2 penalty[6] for separation, total amount of annual production and the distance to renewable power sources in Austria. The regional distribution of CO_2 sources in Austria and the installed wind power is illustrated in Figure 11.

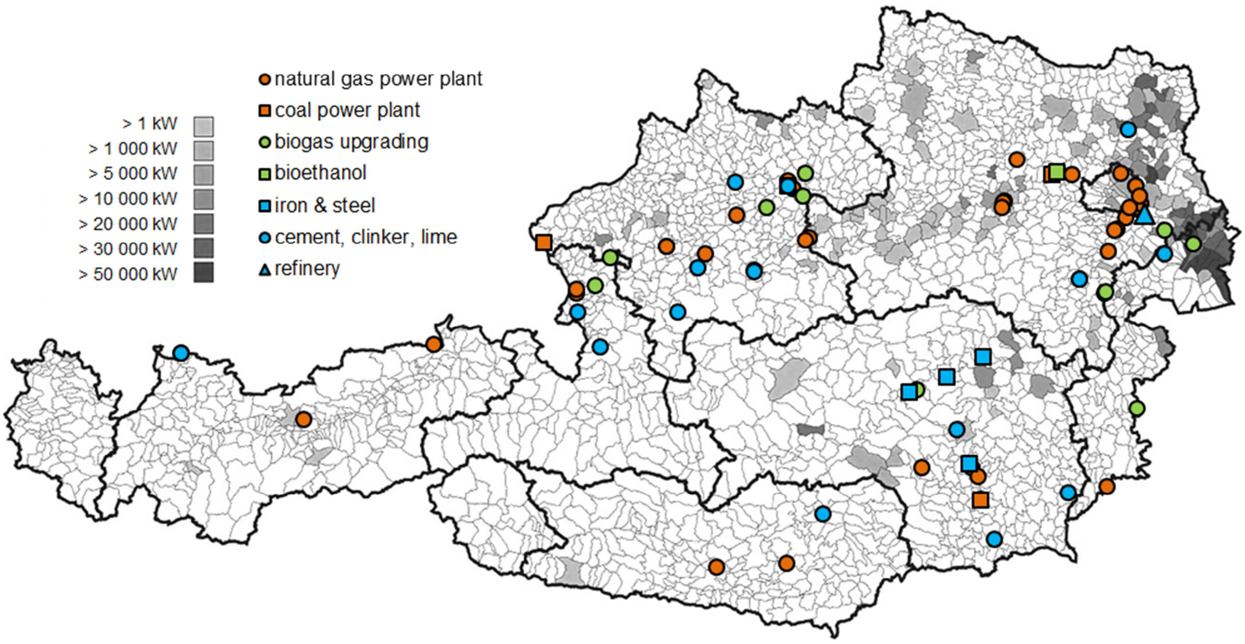

Figure 11. CO_2 sources and installed wind power in Austria, from [8]

In [8] it is concluded that processes such as bioethanol production and biogas upgrading are best suited for application in power-to-gas as the capture costs are low (CO_2 is separated in these processes anyhow), there is no CO_2 penalty and the production sites are near existing wind power plants in Austria. However, the total amount of produced CO_2 from these biogenic sources is low. Much more CO_2 is produced in natural gas and coal power plants and could be separated with medium capture costs. However, these are no biogenic sources and the CO_2 penalty for coal is

[6] Analogous to the term energy penalty, the additional CO_2 emission incurred by CO_2 capture is termed the **CO_2 penalty** in [8]. CO_2 capture technologies mostly require primary energy input, which lowers the total efficiency of the power plant. Thus, for production of the same amount of electricity, more primary energy input is required. This additional primary energy input causes additional greenhouse gas emissions. These additional greenhouse gas emissions related to the captured CO_2 are called the **CO_2 penalty**.

quite high. Huge amounts of CO_2 are also produced in other industrial processes (e.g., iron and steel production, refineries, cement, lime and clinker production). They have medium CO_2 capture costs but a relatively high CO_2 penalty and should therefore not be the primary source for power-to-gas. Especially sites for cement, lime and clinker production are far from installed wind power plants in Austria. The annual amounts of CO_2 produced and the derived potential for synthetic CH_4 production from [8] is summarized in Table 3.

Table 3. Annual CO_2 production from various sources and derived potential for utilization in CH_4 production via power-to-gas

		CO_2 from bioethanol production and biogas upgrading	CO_2 from power plants	CO_2 from industrial processes
Electricity	GWh/a	1127	47666	136947
CH_4 production	Mio m³/a	56	2384	6847
CO_2 demand	kt CO_2/a	113	4799	13695

With CH_4, synthesized from H_2 and CO_2 from bioethanol, biogas upgrading, power plants and industrial processes, the whole natural gas demand of Austria could be easily covered (8 050 Mio. m³ natural gas in 2013). With the amounts of CO_2 displayed in Table 3, 185 TWh of electricity could be converted into synthetic CH_4 via power-to-gas. This is about three times the current electricity demand of Austria (60 TWh in 2013). Although the amount of CO_2 from biogas upgrading and bioethanol production is comparably low, it would be enough to convert 30% of the electricity from wind power and photovoltaics (4 TWh in 2014) into synthetic CH_4.

4.5 Renewable fuels for mobility purposes in Austria

Both energy carriers H_2 and CH_4 produced via power-to-gas can be utilized as transport fuels for mobility purposes. The relevant technologies, issues on the supply infrastructure as well as economic and ecological aspects have already been presented by Reiter et al. in [7], [23] or [4]. In this section the potential demand for utilization in the transport sector is evaluated. The real future demand is strongly depending on the general demand for green products and on the emission goals set by politics.

As electricity is utilized as input for H_2 and CH_4 production, the question arises, why electricity is not directly utilized for mobility purposes. The direct utilization of electricity in electric vehicles has the advantage of a significantly higher overall efficiency: The production of H_2 has an efficiency of about 70% and the reconversion into electricity in a fuel cell has an effiency of about 50%, leading to an overall efficiency of 35% (see Reiter [3] for detailed information). However, electric vehicles need large batteries for storing the electricity and have a reduced range. The energy carriers H_2 or CH_4 are much easier to store and to transport (e.g. via the gas distribution grid) and thus could be produced in remote regions with high renewable energy potential (e.g. in the North Sea). If electricity has to be transported from remote regions to the consumers, power grids have to be built or at least expanded. Depending on the type of application (short or long distances), the local constraints (power grid availability) and the time horizon (short-term or long-term storage), both technologies have their advantages and could complement each other.

Hydrogen could be utilized in both, internal combustion engines and fuel cell vehicles. Fuel cell vehicles generate electricity out of H_2 and utilize it in an electric motor that drives the car. This technology could thus be a good additive technology for electric vehicles, as the range could be extended. The future potential of H_2 for mobility purposes is estimated, based on data from the Greenpeace-study “energie [r]evolution 2050” [24]. The energy demand for transport in 2013 and the future energy demand in 2020 and 2030 are illustrated in Figure 12. A significant reduction of energy demand for transportation is assumed for 2030 as well as an increase in the utilization of fossil gas and electric vehicles (see Bliem et al. [24] for more information). Nevertheless, a large part of energy for transportation will still be provided via fossil liquids.

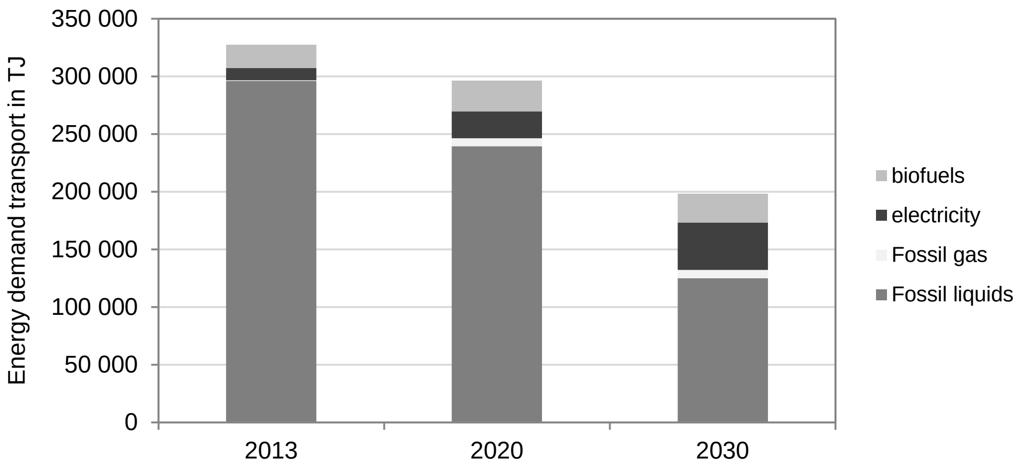

Figure 12. Energy demand for transport, based on data from Statistik Austria (2013) and Bliem et al. [24]

The theoretical potential in Table 2 assumes that the total energy demand for transport is provided via H_2 as transport fuel. The second scenario assumes that about 50% of the future e-mobility will be realized via H_2 as fuel in fuel cell vehicles. The third scenario is deteremined according to information from the European Hydrogen Roadmap HyWays [25], and assumes that in 2030, about 10% of energy for transportation will be provided via H_2. The results for H_2 production, required electricity and number of H_2 vehicles are shown in Table 4.

With renewable electricity generated in Austria in 2013 (46 TWh), 56% of the whole energy demand for transportation (theoretical potential) could be provided via H_2 vehicles. If 50% of e-mobility would be realized via H_2-vehicles, 40% of renewable electricity would be needed. The HyWays scenario could be realized with 18% of renewable electricity in Austria. However, as wind and photovoltaics together sum up to only 4 TWh of electricity per year, other renewable sources such as water power would be necessary in any of the presented scenarios.

Table 4. Future Potential for H_2 as transport fuel in Austria, 2030; caluclations based on the predicted energy demand for transport in Bliem et al. [24]

Hydrogen for mobility [1]		**Theoretical potential**	**50% of E-mobility**	**HyWays Scenario** [3]
H_2 production	Mio. m³/a	16 345	3 803	1 635
H_2 vehicles [2]	Mio.	8.2	1.9	0.8
Electricity PtG	GWh/a	81 727	19 014	8 173

[1] Different fuel consumption of drive concepts are considered (electric vehicles consume about 50% less than H_2-vehicles, vehicles with fossil liquids or gas consume about 40% more than H_2-vehicles)

[2] vehicles with an average driving distance of 15 000 km per year

[3] Assumption according to projections in the European Hydrogen Roadmap HyWays (high policy support and fast technological learning); 10% of transport fuels is covered by H_2. See Wurster et al. [25]

Synthetic CH_4 from power-to-gas could be utilized in CNG (compressed natural gas) vehicles, with the advantage that the transport, storage and refueling infrastructure already exist. The future potential for synthetic CH_4 from power-to-gas is also estimated on the basis of Bliem et al. [24]. The theoretical potential in Table 5 assumes that the total energy demand for transport is provided via CH_4 from power-to-gas. The second scenario assumes that about 50% of the future fossil gas demand will be substituted by synthetic CH_4.

Table 5. Future Potential for synthetic CH_4 as transport fuel in Austria, 2030; caluclations based on the predicted energy demand for transport in Bliem et al. [24]

SNG[1] for mobility		**Theoretical potential**	**50% of natural gas**
SNG production	Mio m³/a	6 770	98
SNG vehicles	Mio.	8.2	0.12
Electricity PtG	GWh/a	143 022	2 067
CO_2 demand	Mio t/a	137	2

[1] SNG (synthetic natural gas)

With renewable electricity generated in Austria in 2013 (46 TWh), only 33% of the whole energy demand for transportation (theoretical potential) could be provided via synthetic CH_4. The percentage is considerably lower than for H_2, as H_2 vehicles have higher conversion efficiency and additionally the production of CH_4 from power-to-gas needs more electricity.

However, as the predicted future fossil gas demand (according to Bliem et al. [24]) is comparably low, the required synthetic CH_4 in the second scenario could be produced via electricity from wind power in Austria.

H_2 or CH_4 for mobility purposes could also be produced via electricity from the public grid, without the requirement that it is generated from a renewable power source. However, the current electricity mix of the EU-countries leads to a very high global warming potential of the produced transport fuels, which is far worse than that of fossil fuels such as diesel or gasoline. The life cycle assessment of power-to-gas by Reiter et al. in [7] shows, that fuel production via power-to-gas only has a reduction potential in greenhouse gas emissions if the applied electricity originates mainly from renewable power sources. Another aspect that has to be considered: If not only surplus electricity is utilized, H_2 or CH_4 production from renewable electricity leads to an additional electricity demand in the energy system. From an ecological perspective, the power source which produces this additional electricity has great influence on the overall ecological performance. Considerations on ecological aspects of power-to-gas are presented in more detail in section 5.1.

4.6 Demand for renewable products in industry

H_2 produced via power-to-gas can be utilized in numerous industrial processes (e.g., materials processing, chemical manufacturing), but is currently mainly produced from fossil resources such as crude oil or natural gas [3]. According to Abbasi [26], less than 5% of H_2 is produced via water electrolysis, due to the significantly higher costs. However, H_2 production via power-to-gas would bring several positive aspects such as a reduced carbon footprint, substitution of fossil resources and the possibility of creating green products.

Data on H_2 production or demand are hardly available, as there is no obligation for reporting. Thus there are only estimations of the H_2 demand, which unfortunately were not available for Austria. Stiller [27] presents some data on H_2 demand in larger regions of the world, the EU-27 and some selected European countries such as Germany, the Netherlands or France. It is stated there, that from 2003 to 2011, the H_2 demand for industrial processes in the EU-27 countries increased from 11 billion m³ per year to 18.5 billion m³ per year. For the next years an annual increase of H_2 demand of about 4% is expected. The theoretical potential for renewable H_2 production in Europe (Table 6) is related to the H_2 demand in 2011, given by Stiller in [27]. For production of the whole H_2 demanded for industrial processes in Europe, about 12% of electricity from renewables or 45% of electricity from wind power in the EU-27 countries would be required.[7]

Table 6. Potential for renewable H_2 production for industry applications in Europe.

		Theoretical potential
Electricity PtG	GWh/a	92 500
H_2 production	Mio m³/a	18 500

In conclusion, the theoretical potential for H_2 production via power-to-gas is huge. However, as costs are higher than for conventional production from fossil resources, the real demand for green H_2 will strongly depend on the demand for green products in general and on the costs of CO_2 certificates that have to be paid for utilizing fossil resources such as natural gas. If not only surplus electricity is utilized, H_2 production from renewable electricity leads to an additional electricity demand in the energy system. From an ecological perspective, the power source which produces this additional electricity has great influence on the overall ecological performance. This is further considered in section 5.1.

[7] 757 TWh electricity produced from renewable energy sources in 2012 in the EU-27 countries; 205 TWh electricity produced from wind energy; data from the EIA [28]

5 Environmental performance and economic viability of power-to-gas

The environmental performance and the economic viability of power-to-gas are influencing each other, as evaluated by Reiter et al. in [29]. Since on the one hand, high full load hours are required for reaching economic viability of power-to-gas, electricity has to be gathered for instance from the public electricity grid in addition to surpluses from renewable power sources. On the other hand, the source of this additional electricity is decisive for the environmental performance. If for instance electricity with the typical EU-27 generation mix is utilized, the greenhouse gas emissions are significantly higher than that of other H_2 and CH_4 production technologies. The main influencing parameters on the environmental and economic performance are evaluated in this section.

5.1 Environmental performance

The life cycle assessment (LCA) of power-to-gas in Reiter et al. [7] showed that the electricity input is the most influencing parameter on the ecological performance of power-to-gas plants. If synthetic CH_4 is produced, the CO_2 source and the related effort for CO_2 separation are also decisive. These two parameters are discussed in the following sections.

5.1.1 Influence of electricity input on the global warming potential of H_2 and CH_4 production

The influence of the electricity input on the global warming potential (GWP) of H_2 produced from power-to-gas is evaluated in Reiter et al. [7] and the results are shown in Figure 13.

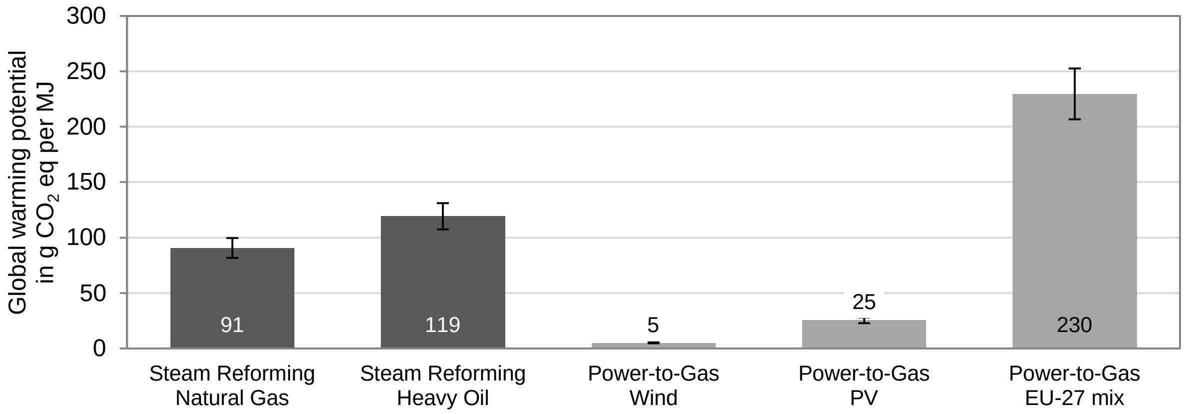

Figure 13. Global warming potential of H_2 produced via power-to-gas with different electricity inputs compared to the benchmark technology steam reforming, data from Reiter et al. [7]

If renewable electricity is utilized for H_2 production via power-to-gas, the GWP is significantly lower than for the fossil benchmark technology steam reforming. However, if the electricity mix of the EU-27 countries is utilized, the GWP is significantly higher. This means that H_2 production from power-to-gas leads to increased greenhouse gas (GHG) emissions in comparison with steam reforming of natural gas or crude oil.

Based on the GWP of steam reforming of natural gas, the environmental break-even point can be calculated. In other words, this is the maximum specific GWP that the utilized electricity may have so that the H_2 produced has a lower GWP than the fossil reference. The environmental break-even point has been calculated in Reiter et al. [7] and is 190 g CO_2 per kWh for H_2 production from power-to-gas. Table 7 shows typical GHG emissions of electricity generation technologies and electricity mixes. Comparing these values with the required GWP of electricity, it gets obvious that only renewable power sources or an electricity mix with a majority of renewable generation is suited for H_2 production via power-to-gas.

Table 7. Greenhouse gas emissions of various electricity generation technologies and electricity mixes, data from PE International [30] and Wagner et al. [31]

	GHG emissions in g CO_2 per kWh
Coal power plants	750 - 1 200
Electricity mix EU-27	565
Natural gas power plants	400 - 550
Electricity mix Austria	406
Photovoltaics	50 - 100
Wind power, water power	10 - 40

For reaching economic competitiveness, high full load hours of about 4 000 h/a will be required for power-to-gas plants. Thus, utilization of electricity from the public power grid or from renewable power sources will be necessary in addition to the utilization of surplus electricity. As long as the implementation of power-to-gas plants is low and thus no additional power capacity is needed in the energy system, the ecological performance depends on the direct electricity input (see Figure 13). However, if the implementation of power-to-gas plants is increasing, there will be an additional power demand in the energy system, especially if power-to-gas is utilized to produce renewable transport fuels or H_2 for the industry. For the ecological performance it is relevant, which generation technology provides the additional power that is needed by power-to-gas plants. This could be considered with a marginal electricity supply or a future electricity mix, as suggested by Del Duce et al. [32].

5.1.2 Influence of the CO_2 source on the global warming potential

For production of synthetic CH_4 via power-to-gas, CO_2 is required as input. CO_2 is produced in many combustion and production processes and is the main greenhouse gas causing global warming. Potential CO_2 sources and available separation technologies are described in more detail in Reiter et al. [8].

By utilization of CO_2 in the power-to-gas process, the energy carrier CH_4 is produced, which is able to directly substitute natural gas. Although the previously bound CO_2 is emitted again when CH_4 is utilized as transport fuel or for combustion processes, natural gas is substituted and thus the process could be deemed carbon-neutral. It is also important to mention, that the production or combustion process the CO_2 originates from (e.g. a power plant) is not automatically carbon-neutral too. The emitted CO_2 has to be considered as it is added to the atmosphere in the end. The allocation of the direct CO_2 emissions could be made in different ways, e.g. allocation according to weight, other physical parameter or the economic value. Von der Assen et al. [33] for example, suggest allocation according to the economic value of the products. However, it is recommended here, that the emissions usually caused by the production process or power plant are allocated to the original process. The additional emissions caused by the CO_2 separation process should be allocated to the power-to-gas process.

Additional GHG emissions into the atmosphere are caused by the additional energy input that is required for CO_2 separation. If CO_2 is for instance separated from a coal power plant, an additional primary energy input of 20% to 30% is required for generation of the same amount of electricity. This additional energy input is called "energy penalty" and leads to a significantly lower efficiency of the power plant. More information on the energy penalty of various CO_2 sources could be gathered from Reiter et al. [8].

The additional primary energy input for CO_2 separation and the related GHG emissions have to be considered in the ecological evaluation of power-to-gas or other CO_2 utilization processes. Thus the term "CO_2 penalty" has been defined in Reiter et al. [8] analogous to the term energy penalty. The CO_2 penalty accounts for the additional GHG emissions (mainly CO_2) incurred by CO_2 capture. CO_2 penalties for the main CO_2 sources considered for power-to-gas applications are shown in Table 8.

Table 8. CO_2 penalty of different CO_2 sources considered for utilization in power-to-gas plants, data from Reiter et al. [8].

	CO_2 penalty g CO_2 per kg CO_2 captured
Coal power plant	184 - 257
Natural gas power plant	160 - 200
Refinery	116 - 218
Steel & Iron	362 - 473
Cement	487

CO_2 sources with biogenic origin (e.g. CO_2 from biogas upgrading or bioethanol production) have no CO_2 penalty, as all the inputs are already carbon-neutral. Other processes have quite different CO_2 penalties that have to be considered in the ecological evaluation of synthetic CH_4 production via power-to-gas. Figure 14 shows the GWP of synthetic CH_4 with CO_2 from different sources. Direct CO_2 emissions from combustion of synthetic CH_4 are not regarded here as it is assumed that the original process (e.g. the power plant or industrial process) are accounted for these emissions.

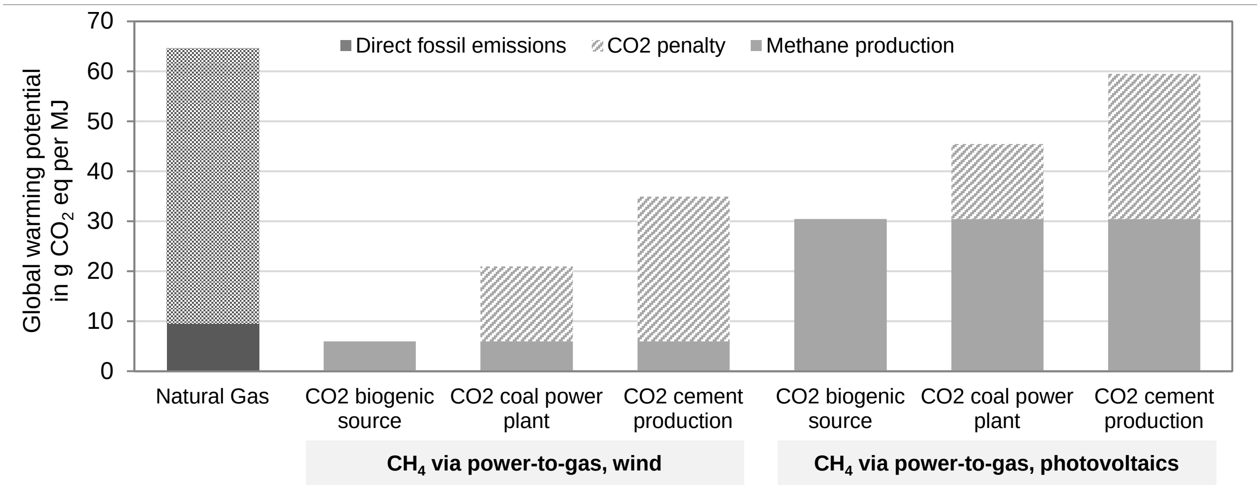

Figure 14. Global warming potential of CH_4 produced via power-to-gas with different CO_2 sources compared to the benchmark natural gas, data from Reiter et al. in [7] and [8].

Figure 14 indicates that, if the electricity input originates from a renewable power source such as wind power or photovoltaics, the GWP of synthetic CH_4 including different CO_2 penalties is always lower than that of natural gas. However, if electricity from photovoltaics is applied and the CO_2 is separated from cement production processes the resulting GWP is nearly the same as that of natural gas. If parts of the CO_2 emissions of the original process are allocated to power-to-gas, as for instance suggested by von der Assen et al. [33], the GWP will increase and be in some cases higher than that of natural gas. This has not been considered in Figure 14.

Based on natural gas as benchmark for the GWP, the environmental break-even point for synthetic CH_4 production via power-to-gas is 113 g CO_2 per kWh electricity input (see Reiter et al. [7]). This environmental break-even point is lower if the CO_2 does not originate from a biogenic source. For the utilization of CO_2 from cement production, electricity with 63 g CO_2 per kWh would be required. The input of electricity from renewable power sources is thus absolutely necessary.

5.2 Economic viability

Economic aspects of power-to-gas have been handled in various publications with the author's contribution. In Steinmüller et al. [5] the cost developments of electrolyser technologies, methanation reactors and CO_2 separation have been evaluated. Furthermore, the specific generation costs of H_2 and CH_4 from power-to-gas have been calculated for selected cases of application there. Gahleitner et al. [23] evaluate specific costs of H_2 and CH_4 for application as transport fuels in mobility. In Reiter et al. [29] economic evaluation is linked to ecological performance of power-to-gas. From an economic point of view, high full load hours are desirable to reach low specific generation costs of H_2 and CH_4. Since high full load hours could not be reached by sole utilization of surplus electricity from renewable power sources, additional electricity has to be utilized for instance from the public power grid. The source for this additional electricity has then again strong influence on the environmental performance of power-to-gas. If it is generated from fossil resources, the GHG emissions of H_2 and CH_4 are higher then the fossil reference technologies (for more information on the environmental performance see section 5.1).

For evaluation of the main influencing parameters of economic viability, the specific production costs of H_2 and CH_4 are calculated for an exemplary power-to-gas plant. Specific production costs are the annual costs of power-to-gas related to the annual production of H_2 or CH_4. The annual costs are calculated with the annuity method according to ÖNORM M7140 (see [34] for detailed information on the calculation method). The calculations in this section consider an interest rate of 6%. Cost information are mainly taken from the market and technology scouting in Steinmüller et al. [5], a techno-economic study by Reiter et al. [35] and another economic and ecological evaluation of power-to-gas in Reiter et al. [29].

Figure 15 shows the specific production costs of H_2 and CH_4 from a power-to-gas plant with an installed electrical power of 1 MW. The assumed PEM electrolyser has specific investment costs of € 1 940 per kW and an electricity demand of 5 kWh per m³ H_2 produced. Including the costs ofplant construction, piping, control equipment, building etc. the total initial investment sums up to € 323 000. With an additional methanation reactor, the total initial investment costs are considerably higher and sum up to € 469 000. The annual operation and maintenance costs are calculated on the basis of the initial investment costs, ranging vom 3% for the electrolyser to 10% for the methanation reactor (see Grond et al [36]). The full load hours of the power-to-gas plant has been determined to be 4 000 h/a. Electricity costs of € 30 per MWh have been assumed and the additional proceeds are 2 Cent per kWh heat and € 50 per ton oxygen. Additionally, current power grid and natural gas grid charges for Austria have been considered in the cost calculations. More details on grid charges are described in Steinmüller et al. [5].

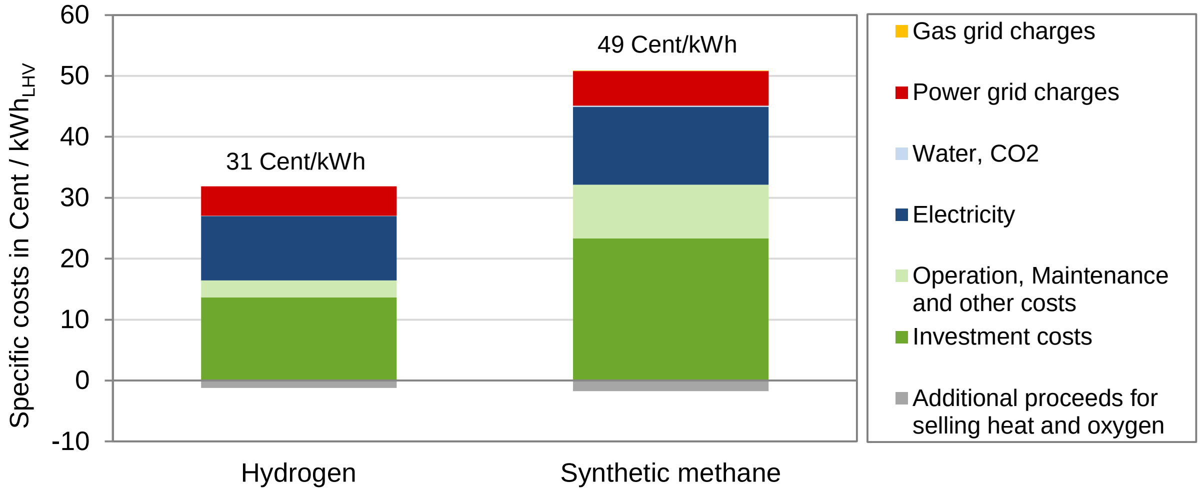

Figure 15. Specific production costs of H_2 and synthetic CH_4 in a power-to-gas plant with a 1 MW PEM electrolyser and 4 000 full load hours per year.

Figure 15 indicates that the main influencing parameter on specific investment costs are the investment and electricity costs. If the full load hours are lower than 4 000 h/a, the influence of investment costs is even higher, as can be seen in Figure 16. In general, the specific costs are decreasing with increasing full load hours. However, the influence of full load hours is especially strong for lower full load hours of up to about 4 000 hours per year.

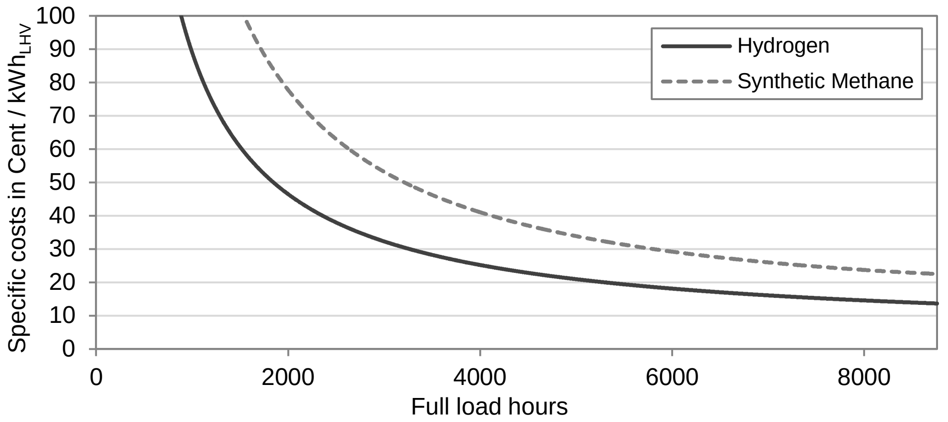

Figure 16. Influence of full load hours on the specific production costs of H_2 and synthetic CH_4.

The most influencing parameters on specific production costs and their potential for cost reduction are analyzed in more detail in this section. A sensitivity analysis is conducted and the specific costs of power-to-gas are compared to relevant benchmark technologies.

5.2.1 Influence of scaling and learning effects on the investment costs of power-to-gas

The main part of investment costs of a power-to-gas plant are the electrolyser and, if required, the methanation reactor. Since these two components additionally have the largest potential for technological improvement, the learning and scaling effects are described here.

Current costs depending on the scale of the electrolyser have been evaluated in a broad market and technology scouting by Steinmüller et al. [5] and are shown in Figure 17. The investment costs are based on data from manufacturers and literature. The investment costs are especially high for small systems with low H_2 production capacity. With increasing scale of the electrolyser, the specific investment costs per kW installed capacity are decreasing. From H_2 production capacities of about 200 m³/h or 1 000 kW installed power, the specific investments are hardly changing anymore.

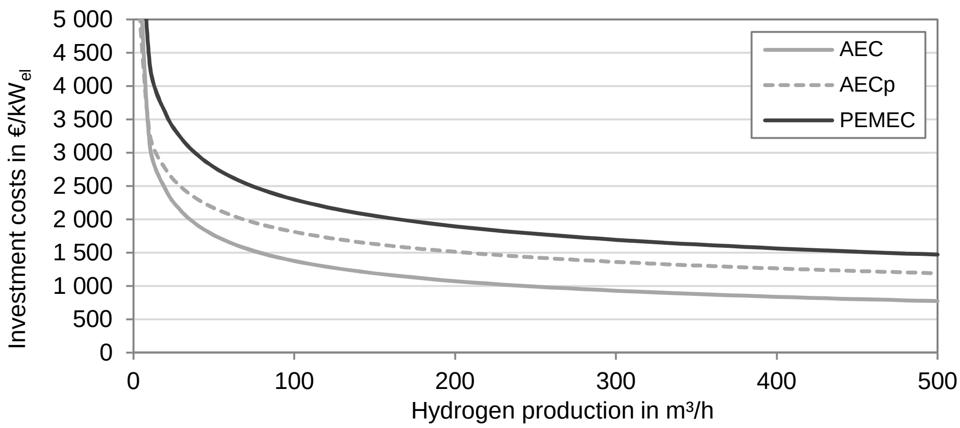

Figure 17. Investment costs of alkaline and PEM electrolysers, based on Steinmüller et al. [5]

Scaling effects are also expected for methanation reactors, but cost informations on methanation systems are rare and investment costs are only provided by Grond et al [36]. They are shown in Figure 18.

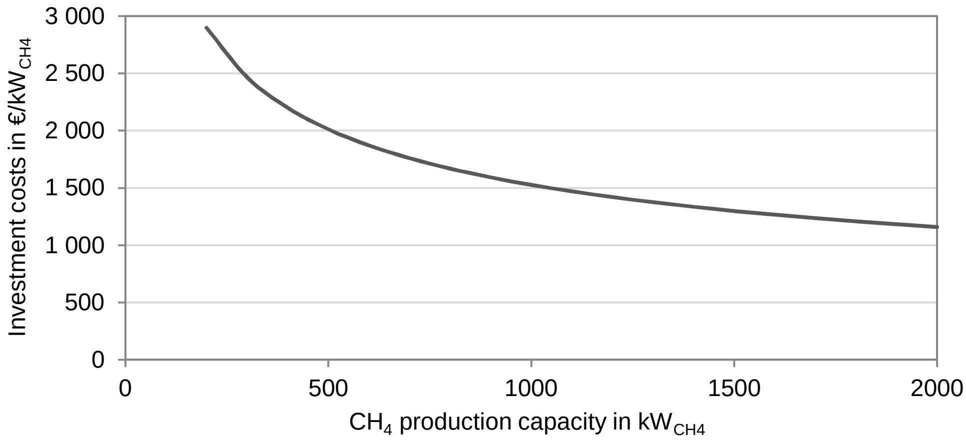

Figure 18. Investment costs of methanation reactors, based on Grond et al [36]

The future reduction potential of investment costs of electrolysers and methanation reactors is strongly influenced by the technological learning. It is distinguished between the cost reduction due to technological improvement and the cost reduction due to increase in produced units. Grond et al. [36] state an annual cost reduction of 0.4% and 2.2% for AEC and PEMEC respectively.

The cost reduction through increase in produced units or cumulative installed power is characterized by formula (1), taken from Schoots et al. [37]. The investment costs C_t at the moment t are depending on the investment costs C_0 at the moment t=0, the cumulative installed power P_t und P_0 and on the learning index α.

$$C_t = C_O \left(\frac{P_t}{P_0}\right)^{-\alpha} \qquad (1)$$

The relation of learning rate *lr* and learning index α is described by formula (2). The learning rate has to be assessed specifically for each technology, whereby a learning rate of 20% is typical for most components [37]. A learning rate of 20% implies a 20% reduction of the specific investment costs if the cumulated installed power is doubled.

$$lr = 1 - 2^{-\alpha} \qquad (2)$$

Schoots et al. [37] identified a learning rate of 18% for water electrolysers. This has also been confirmed by a broad assessment of manufacturer data in Steinmüller et al. [5]. For the evaluation of the future cost development on the basis of learning effects, assumptions on the future cumulative installed capacity have to be made. The globally installed wind power for instance increased from 48 GW in 2004 to 370 GW in 2014. This is a multiplication by a factor of 8 in ten years. The global installed capacity of photovoltaics has multiplied by a factor of 48 from 2004 to 2014, with an increase of 3.7 to 177 GW respectively.

Currently, the specific investment costs of a PEM electrolyser with 1 MW are on average € 1 940 per kW (according to information from cost assessments in Steinmüller et al. [5]). These investment costs could be significantly reduced by a higher installed overall capacity. If the installed capacity is increased tenfold, the specific investment costs could be reduced to € 1 000 per kW. Learning effects could cause a further cost reduction to € 630 per kW, if the cumulated installed capacity is increased by a higher multiplying factor of 50.

The reduced investment costs of electrolyser and methanation reactor would significantly improve the specific costs of H_2 and CH_4 production, which is shown in Figure 19. For the increase in installed capacity, it is assumed that half of the installed power-to-gas plants will have a methanation. The multiplying factor for the cumulative installed capacity of methanation reactors is thus half that of electrolysers.

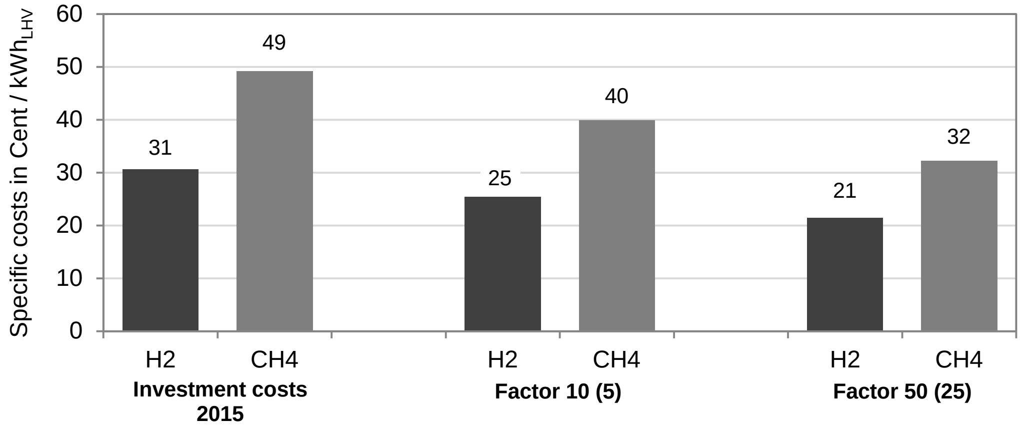

Figure 19. Influence of learning effects on the specific H_2 and CH_4 production costs.

If the installed capacity of power-to-gas plants grows as fast as that of wind power plants in the next 10 years, then a reduction of 20% in specific production costs of H_2 could be achieved. If higher growth rates are reached, as for example that of photovoltaics (approximately a factor of 50), then a reduction of 33% could be reached.

5.2.2 Electricity input and CO_2 costs

Apart from the investment costs, the electricity input is decisive for the economics of power-to-gas, especially at high full load hours. The type of application influences not only the full load hours but also the electricity costs and the fluctuations in electricity input. Fluctuations in electricity input may lead to an increased electricity demand for H_2 production, as overall system efficiency is lower in part load than in full load (see Steinmüller et al. [5] for more information). This is especially relevant for alkaline electrolysers and less important for PEM electrolysers. If the total efficiency of the electrolyser is for instance reduced from 70% to 50%[8], the specific H_2 production costs increase by 40%. The influence of the overall efficiency on the production costs is thus very high and efficiency issues should be considered in research and development of power-to-gas plants.

Electricity input to power-to-gas could come directly from **renewable power sources** such as wind power plants, photovoltaics or water power plants. If only the surplus from renewable power

[8] Electricity demand for H_2 production increases from 5 to 7 kWh per m³ H_2 produced.

generation is utilized for power-to-gas, the electricity is for free but the reached full load hours are low. For Schleswig-Holstein, a region in Germany, the wind curtailment has been approximately 185 hours in 2011 (information according to Reiter et al. [35] based on Bömer et al. [38]). With the planned expansion of wind power plants in Germany, wind curtailment is expected in 1 300 hours per year in 2020 (see Münch et al. [39]). For reaching higher full load hours for power-to-gas, the additional utilization of non-surplus electricity from renewable power plants is thus required. Guandalini et al. [40] found out, that the cost-optimum for power-to-gas is reached for installed electrolysis power of 6% of the nominal power of a wind park.

If not only surplus electricity from renewable power sources is utilized in power-to-gas plants, the specific power generation costs of the related technology are relevant for the H_2 or CH_4 production cost assessment. According to Kost et al. [41], photovoltaic plants in Germany have electricity generation costs of between 7.8 and 14.2 Cent per kWh. Onshore wind power plants have electricity generation costs of between 4.5 and 10.7 Cent per kWh [41]. Despite the higher full load hours of offshore wind power plants, the generation costs are higher with 12.9 to 19.4 Cent per kWh due to the increased investment costs [41].

Electricity could also be obtained from the public power grid, where the fluctuations are lower and the reached full load hours could be much higher. If there is no need to create a renewable product, the electricity could be obtained at **spot market prices**. The average spot market price in Austria was € 31.8 per MWh in the last year (July 2014 to June 2015, data from http://www.exaa.at/de). However, it has to be mentioned that this leads to a product with a very high GWP, as then the electricity mix has to be considered in the life cycle assessment (see section 5.1). Obtaining electricity at spot market prices may be interesting from an economical point of view, but is not recommended from an ecological point of view, as it leads to much higher GHG emissions as if the H_2 and CH_4 would be obtained from fossil resources. Green electricity could also be obtained from the public electricity grid, with slightly higher costs that have to be paid for the guarantee of origin of the electricity. According to Reichmuth et al. [42], the costs of the guarantee of origin vary significantly between € 0.2 per MWh for Scandinavian water power and € 3.0 to € 4.0 per MWh for water power from Austria.

Power-to-gas plants could also provide balancing power to the public power grid. From an economic point of view, the most interesting way is to provide **negative secondary balancing power**[9] as the power-to-gas plant is paid for the utilization of surplus electricity. The remuneration for providing these system services is determined via a weekly auction and is paid for the provision of control power (€/MW) and for the called demanded energy (€/MWh). For gaining access to the tenders for control energy, the so-called prequalification criteria have to be fulfilled, one of them being a minimum power of 5 MW. More information can be gained from Austrian Power Grid (see http://www.apg.at/en/market/balancing/conditions-for-participation). Whereas the price paid for provision of negative balancing power is relatively low (€ 4 to € 5 per MWh in 2015), the payment

[9] Negative balancing power is required, when more power is generated in the control area than required at this moment. It could be provided by additional consumers such as power-to-gas plants or pumped hydro storage or by switching off power generation units.

for called negative secondary control energy is significantly higher. The weighted average price of activated negative secondary control energy[10] has been between -186 €/MWh and -203 €/MWh in 2015 (up to calendar week 31). This means that on average the power-to-gas plant would have been paid about 20 Cent per kWh of electricity consumed. The tendered price is strongly influencing the probability of being called and if high full load hours should be reached with the power-to-gas plants, the offered prices should be low. Figure 20 shows the development of weighted average price of activated negative secondary control energy in the last years.

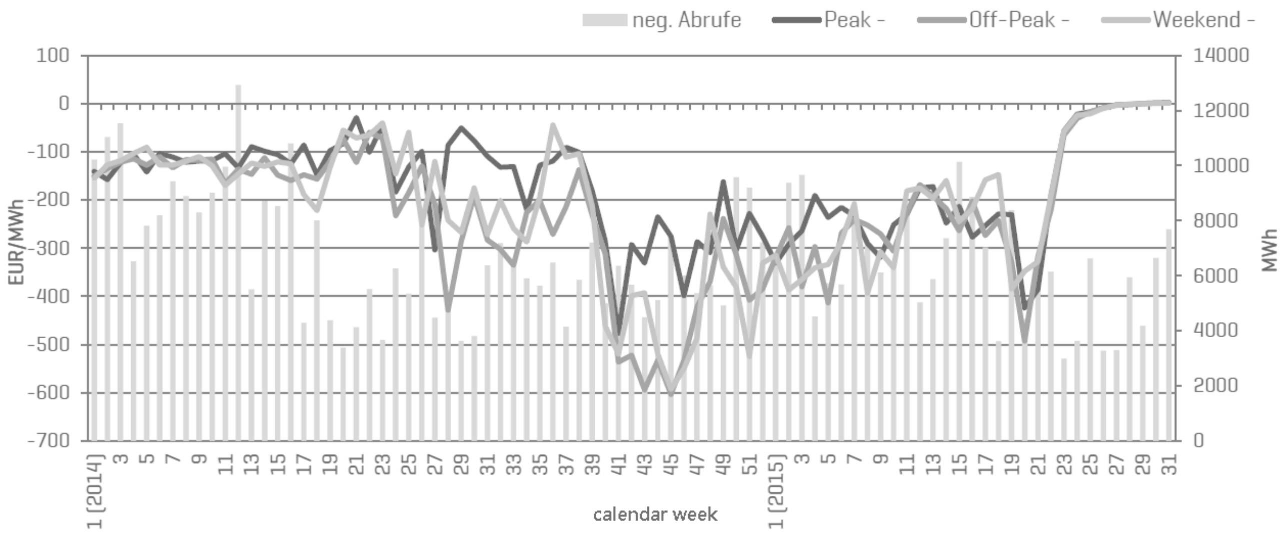

Figure 20. Weighted average prices of activated negative secondary control energy per calendar week, http://www.apg.at/de/markt/netzregelung/marktforum

The average prices for activated negative secondary control energy vary quite significantly and have been especially low from calendar week 41 in 2014 to 19 in 2015. However, since then the average prices for activated negative secondary control energy have increased and at the moment, average prices of approximately € 0 per MWh. The influences on the price formation are very hard to describe and to quantify as at the moment only 5 to 7 players are participating at the tenders for control energy (see Muggenhumer [43] for more information). At the beginning of 2015, the provision of negative control energy seemed to be a very attractive application for power-to-gas. However, since prices in calendar weeks 21 tro 31 showed that the development of the average prices is not foreseeable at all, the participation of power-to-gas plants at the balancing energy market is connected with a considerable risk.

Based on the different types of application and related costs of electricity, the influence of the electricity price on the specific H_2 production costs has been evaluated and is shown in Figure 21. Due to the large uncertainties, negative electricity prices that could be achieved by providing negative secondary balancing power have not been considered.

[10] The weighted average price of activated negative secondary control energy always depends on the prices offered by the participants of the tenders. Those which offer lower prices, have a higher probability to be called. Those which offer higher prices on the other hand get more for the control energy if they are called.

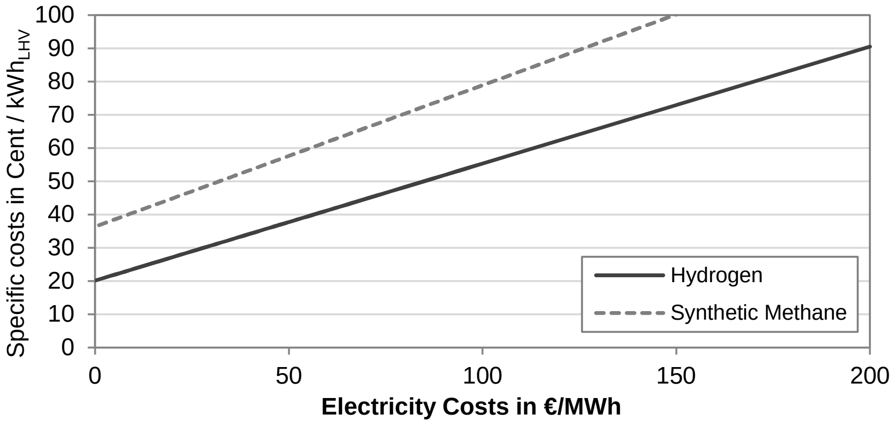

Figure 21. Influence of electricity price on the production costs of H_2 and CH_4 from power-to-gas

Figure 21 indicates that the electricity costs have a great influence on the specific production costs of H_2 and synthetic CH_4. Full load hours have been maintained constant at 4 000 h/a in the calculations for Figure 21. However, it has to be considered that full load hours and achievable electricity price is closely linked together. Low electricity prices could for instance be achieved if surplus from renewable power sources is utilized, but then 4 000 full load hours are not realistic.

The specific **costs of CO_2** are depending on the CO_2 source and the related costs of separation. Typical capture costs have been evaluated by Reiter et al. in [7] with the lowest costs of CO_2 from bioethanol production or biogas upgrading (€ 7 per ton CO_2), as CO_2 is separated there anyhow and just has to be dried for the application in methanation. The by far highest costs of € 235 per ton CO_2 are related to CO_2 capture from ambient air. The results presented in Figure 15 include the lowest CO_2 costs from biogas upgrading. If CO_2 is taken from combustion processes in power plants or from other industrial processes such as the cement production, the specific production costs of synthetic CH_4 only increase by 2%. If the highest possible costs of CO_2 separation from air are assumed, the specific production costs increase by 10%. Thus, the influence of CO_2 input on the production costs of synthetic CH_4 is relatively low and there is no need to focus on cost reduction of CO_2 separation.

5.2.3 Sensitivity analysis

For evaluation of the main influencing parameter on the economic viability of power-to-gas plants, a sensitivity analysis is conducted. Several parameters are varied and the influence on the specific production costs of H_2 and CH_4 are shown in Figure 22 and Figure 23, respectively. The presented power-to-gas plant at the beginning of section 5.2 is the reference case for the sensitivity analysis.

The most influencing parameters on H_2 production costs are the reached full load hours and the efficiency of the power-to-gas plants. 4 000 h/a has been determined for the reference case and it gets clear in Figure 22, that lower full load hours lead to a sharp increase in H_2 production costs. The decrease of production costs is much lower for higher full load hours, but compared to other parameter it is still the most influencing one. Efficiency of the power-to-gas plant has already been determined to be comparatively high in the reference case (70%). If the total efficiency is reduced due to high fluctuations in power input or components with a high electricity demand, the H_2 production costs increase in nearly the same way as when full load hours are decreasing.

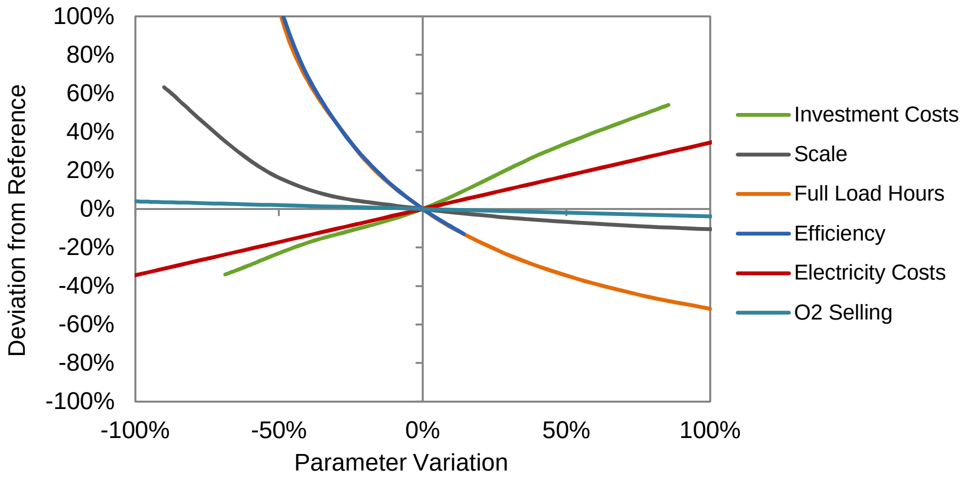

Figure 22. Influence of parameter variation on the H_2 production costs.

Investment costs of power-to-gas plants also have a great influence on the H_2 production costs (green line in Figure 22). Lower costs due to learning effects would reduce the H_2 production costs significantly, as already shown in Figure 19. The case of increasing costs of power-to-gas plants is also considered in the sensitivity analysis. However, due to the development state of the power-to-gas technology and a high potential for technological improvements, an increase in costs is not expected. The scale of the power-to-gas plant is also influencing the investment costs and leads to a strong increase in production costs if it is reduced. As already mentioned in section 5.2.1, the investment costs are hardly changing anymore for power-to-gas plants with an installed power of more than 1 MW. This can also be seen in Figure 22 where the grey line is hardly changing with increased installed power (1 MW is the reference case).

Electricity costs also have a significant influence on the H_2 production costs. The reference case assumes average electricity costs of € 30 per MWh. A doubling of these costs leads to an increase in production costs of about 35%. However, electricity costs of power-to-gas plants could even be higher than € 60 per MWh, as described in section 5.2.2. Lower electricity costs of € 0 per MWh on the other hand lead to a production cost reduction of 35%. Negative electricity costs in terms of providing negative balancing power would further reduce the H_2 production costs.

According to Figure 22, the price for the by-product oxygen would not influence the H_2 production costs significantly.

Figure 23 shows the results for CH_4 production via power-to-gas in the same way as for H_2 production. Compared to the influencing parameter on H_2 production, the results are similar for CH_4 production. Reached full load hours and efficiency of the power-to-gas process have the greatest influence on the specific production costs. However, the influence of investment costs and scale of the plant are slightly higher than for H_2 production, as the total investment is higher for the additional methanation reactor. The influence of electricity costs on the other hand is slightly lower than for H_2 production.

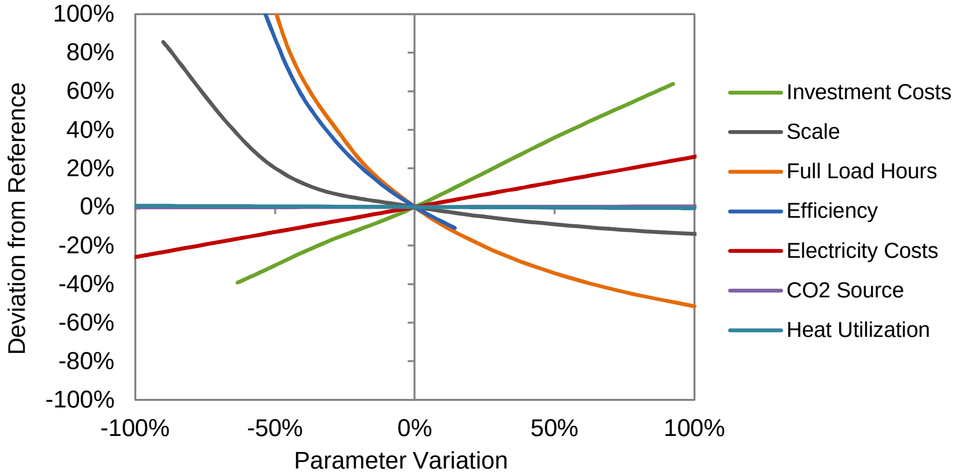

Figure 23. Influence of parameter variation on the CH_4 production costs.

When synthetic CH_4 is produced via power-to-gas, CO_2 is required and the heat from methanation could be utilized. The CO_2 source in the reference case is biogas upgrading, which is related to very low CO_2 costs of € 7 per ton. However a change of these costs is hardly influencing the CH_4 production costs. Even CO_2 separation from natural gas power plants, which is related to costs of € 80 per ton (+1043%), only results in a 2.9% increase of CH_4 production costs. The proceeds for heat utilization have been determined to be 2 Cent per kWh in the reference case. Figure 23 indicates that it hardly influences the CH_4 production costs, if 4 Cent per kWh could be achieved or if the heat is not utilized (0 Cent per kWh).

5.2.4 Comparison to economic benchmarks

Due to several potential applications of power-to-gas, there is a great variety of possible benchmark technologies that differ for each use case. If power-to-gas is utilized to store electricity, other electricity storage technologies could be the benchmark technologies. If power-to-gas is utilized for energy transport and thus substitutes power lines, the expansion or building of these power lines is the benchmark. For utilization of H_2 or CH_4 as transport fuels, diesel, gasoline, natural gas, bioethanol or biodiesel are the relevant benchmarks. For the utilization of H_2 in industrial processes, the benchmark technology is steam reforming of natural gas. Other potential benchmarks and comparison to power-to-gas could be found in Steinmüller et al. [5], Gahleitner et al. [23] or Reiter et al. in [7], in [29] and in [35].

The exemplary reference case for power-to-gas and some future costs are compared here to the direct benchmarks natural gas, biomethane and H_2 from natural gas or biomass gasification. The informations on specific costs have been taken from Abbasi et al. [26], Raine et al. [44] and Schiffers et al. [45]. Figure 24 and Figure 25 show the specific production costs of H_2 and CH_4 respectively. The specific production costs of H_2 and CH_4 from power-to-gas are given for the above reference case with a 1 MW PEM electrolyser, full load hours of 4 000 h/a and electricity costs of € 30 per MWh. Additionally, investment cost reduction through learning effects (factor 50) have been regarded and one version with higher full load hours of 7 000 h/a and electricity costs of € 40 per MWh has been added.

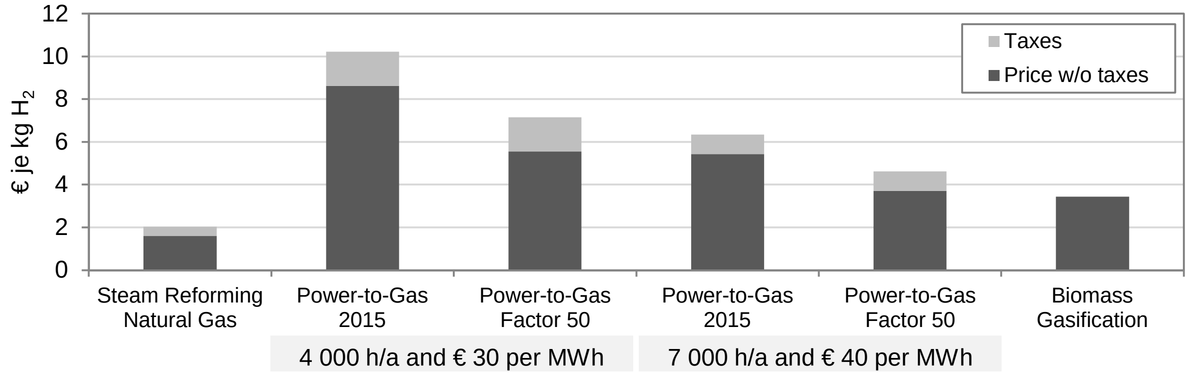

Figure 24. H_2 production costs from power-to-gas in comparison to benchmarks.

The comparison with benchmark technologies for H_2 production shows, that the specific production costs of H_2 from power-to-gas are higher in any of the presented cases. It is also shown that taxes contribute significantly to specific production costs. In the case of H_2 production, these are the taxes that have to be paid for utilization of electricity. The presented values are specific production costs and the real market prices of H_2 could be much higher in many cases. At Austrian fueling stations for instance, H_2 currently costs € 9 per kg. Steam reforming of natural gas is a large-scale industrial technology. If industrial processes have no on-site production of H_2 due to smaller required amounts, their H_2 costs could easily reach € 30 per kg. Smaller power-to-gas plants for H_2 production could thus be an interesting alternative. If renewable electricity is utilized for H_2 production via power-to-gas, the GHG emissions of the process are lower than that of steam reforming of natural gas (see section 5.1). This has also to be considered when comparing specific H_2 production costs.

The comparison of CH_4 from power-to-gas in Figure 25 shows, that the specific costs are significantly higher than the costs of the benchmarks natural gas and biomethane. Even with assumed cost reduction through learning effects and higher full load hours, the production costs of CH_4 are still twice as high as that of biomethane production from biogas. However, biogas production is confronted with issues of resource availability and competition with food production (see Ajanovic [46] or Söderberg et al. [47]).

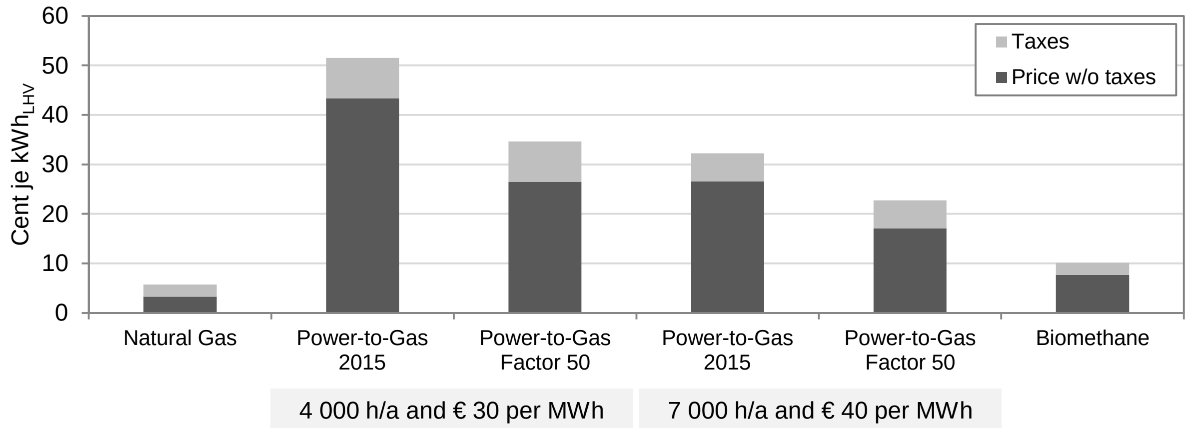

Figure 25. CH_4 production costs from power-to-gas in comparison to benchmarks.

6 Conclusions

The long-term energy storage technology power-to-gas has the potential to fulfill several functions in the energy system. By converting electricity into H_2 or CH_4 and feeding these energy carriers into the gas distribution grid, energy infrastructures are coupled. The existing gas distribution grid could thereby be applied for transporting energy over large distances and for seasonal storage of considerable amounts of energy. Furthermore, the coupling of the power grid and the natural gas grid via the technology power-to-gas enables a hybridization of the energy system and provides more flexibility to enable higher integration of renewable power sources. H_2 and CH_4 produced via power-to-gas could be applied for mobility purposes or industrial processes. If electricity from renewable power sources is utilized and the CO_2 for methanation originates from biogenic sources, the H_2 and CH_4 produced are renewable energy carriers. Power-to-gas technology thus enables higher percentages of renewables not only in power generation, but also in the transport and industry sector. Furthermore, the technology system could contribute to maintain the high level of energy supply security for instance in Europe or North America and could provide energy supply to remote regions. As H_2 and CH_4 may be applied for heating and transport purposes or be reconverted into electricity, power-to-gas is suited to provide self-sufficient energy supply in combination with renewable power sources. However, the production of H_2 or CH_4 out of electricity via power-to-gas technology is also associated with significant energy losses along the process chain. In general, the production of H_2 is more efficient than the further synthesis of CH_4, but the integration of H_2 into the existing natural gas network is limited. As CH_4 from power-to-gas is very similar to natural gas, it could directly replace it without the need for further adaptations in the gas infrastructure. Numerous power-to-gas pilot plants have been built in the last decade and are evaluated in detail by Gahleitner et al. in [2].

The sustainable implementation of the technology system power-to-gas has the goal of improving the viability of the energy system and should bring benefits to both, the environment and the society. One main research question of this dissertation is the determination of influencing parameter on the potential for implementation of power-to-gas and the identification of limitations and barriers. The superordinate influencing parameters are the economic viability, the environmental performance, the demand for products (H_2 and CH_4), and the demand for energy storage and energy transport.

The **demand for energy storage** via power-to-gas depends on the development of renewable power generation from fluctuating energy sources such as wind or solar power. A strong increase in installed power of wind power plants and photovoltaics is expected in the next years, as growth rates of these technologies are high and many countries (especially in the EU) have ambitious goals for high percentage of renewables in power generation. However, the increased implementation of fluctuating power sources also requires adequate balancing options such as energy storage via power-to-gas. The future storage demand for Austria (2050) is projected to be approximately 23 TWh per year with a required installed storage capacity of 21 GW, assuming a fully renewable power generation. Part of this storage demand could be covered by pumped hydro power plants in Austria, leading to a remaining storage demand of about 10 TWh.

This storage demand is based on a conversion efficiency of 80%. However, the efficiency of reconversion of produced H_2 from power-to-gas into electricity is between 30% and 45%. As the overall efficiency is higher if the produced H_2 or CH_4 are directly applied, e.g. as transport fuels, it is recommended not to convert them back into electricity. By converting the surplus of 10 TWh electricity into H_2, about 13% of the future demand for transport fuels in Austria could be covered. However, the times with low renewable power supply then must be balanced by other options (such as demand side management) or by an increased installation of renewable power generation, as for instance suggested by Budischak et al. in [14]. Increased installation of renewable power sources could on the one hand offer more electricity in times of high demand and would produce more “surplus” for production of renewable fuels via power-to-gas.

By injection of H_2 or CH_4 from power-to-gas into the gas distribution system, the energy transport and storage could be shifted from the power grid to the natural gas grid. Whereas the injection of synthetic CH_4 is not limited, only 4 vol.-% of H_2 are allowed in natural gas. However, the production of H_2 via power-to-gas has a higher efficiency as the methanation step is omitted. The potential of **H_2 injection into the Austrian natural gas grid** is strongly influenced by consumption profiles in the regional grid segments with strong daily, weekly and seasonal fluctuations. Generally spoken, the natural gas consumption and thus the potential for H_2 injection are comparably high in winter. However, if H_2 should be injected over the whole year, the potential capacity decreases significantly. Wind power plants in Austria are predominantly situated in Lower Austria and Burgenland. The natural gas consumption is comparably low there and thus only a maximum of 9% of electricity generated by wind power could be injected into the gas grid. The potential amount of H_2 injection into the natural gas grid is thus a limiting factor for the implementation of power-to-gas in Austria. Nevertheless, there are other options for power-to-gas plants such as direct utilization at the production site, transport in pressurized storage tanks or methanation. In general, a higher volumetric percentage of H_2 is also possible, but would require several adaptations in the natural gas infrastructure (e.g., gas turbines, CNG vehicles, process gas chromatographs).

Carbon dioxide is required for the production of synthetic CH_4 via power-to-gas and thus the different **CO_2 sources**, separation technologies and related economic and ecological aspects have been evaluated in Reiter et al. [8]. With CO_2 from bioethanol production, biogas upgrading, power plants and industrial processes in Austria, the whole natural gas demand of Austria could be easily covered by synthetic methane from power-to-gas. However, this would require enormous amounts of electricity (185 TWh) - about three times the current electricity demand of Austria. Only with CO_2 from biogas upgrading and bioethanol production about 30% of the electricity produced from wind power and photovoltaics in Austria could be synthesized to methane. The availability of CO_2 is thus not a limiting parameter for the implementation of power-to-gas technology, although it has to be considered that some CO_2 sources are not located near wind generation in Austria and CO_2 transport could be neccessary.

H_2 and CH_4 from power-to-gas could be applied as **transport fuels** and if produced with electricity from renewable power sources, would contribute to a reduction of GHG emissions. With the whole electricity generated from renewable power sources in Austria, theoretically only 56% of the energy required for transportation in 2030 could be provided via H_2. The available amount of electricity from renewable power sources is thus a limiting parameter. However, the actual implementation of H_2 as transport fuel strongly depends on the future availability of fueling stations and vehicles. If only about 10% of the future energy demand for transport in Austria could be covered by H_2 (as projected in scenarios of the European Hydrogen Roadmap in [25]), 18% of the electricity from renewable power sources in Austria would be required for H_2 production. Electricity from wind power and photovoltaics would thus be not sufficient. Due to the lower efficiency of CH_4 production via power-to-gas and the lower efficiency of CNG engines compared to H_2 vehicles, even more electricity is required for synthetic CH_4 as transport fuel.

H_2 is also required in several **industrial processes** and is currently mainly produced from fossil resources such as natural gas or crude oil. For production of the whole H_2 demanded for industrial processes in Europe, about 12% of electricity from renewables or 45% of electricity from wind power generated in the EU-27 countries would be required.

In conclusion, the theoretical potential for **H_2 and CH_4 as renewable products** for mobility or industrial purposes is huge. However, as production costs are higher than for conventional production from fossil resources, the real future demand for green H_2 and CH_4 will strongly depend on the demand for green products in general and on the costs of CO_2 certificates that have to be paid for utilizing fossil resources. Political targets for share of renewables in all energy sectors will also influence the demand significantly. If not only surplus electricity is utilized, H_2 or CH_4 production from renewable electricity leads to an additional electricity demand in the energy system. This could increase the burden on the power grid and the additionally required power generation technologies may increase overall GHG emissions.

The **environmental performance** of H_2 or CH_4 production via power-to-gas is strongly depending on the electricity input. Reiter et al. [7] analyzed the global warming potential and primary energy demand of power-to-gas in a life cycle assessment and concluded that the electricity input for H_2 production should have a GWP of less than 190 g CO_2 per kWh. This means that compared to the fossil reference technology steam reforming of natural gas, a reduction of GHG emissions is only achieved if the electricity is produced mainly from renewable power sources. If the increased implementation of power-to-gas plants reults in an additional power demand in the energy system, it has to be considered which technology provides this additional power.

For synthesis of CH_4, a carbon dioxide source is required. CO_2 is produced in many industrial processes and is usually emitted to the atmosphere, where it contributes to global warming. Utilizing it in the power-to-gas process would thus be beneficial, although it has to be mentioned that CO_2 separation is always accompanied by a certain additional energy demand. It is recommended, that the emissions caused by this additional energy demand (CO_2 penalty) are allocated to the power-to-gas process. If the utilized electricity is generated by photovoltaics or wind power plants, the GWP of synthetic CH_4 is never higher than natural gas, although the CO_2 penalty is accounted for. Without any CO_2 penalty (biogenic CO_2 sources) the environmental break-even is 113 g CO_2 per kWh of utilized electricity. When CO_2 is separated for instance from cement production, the additional energy demand is comparably high and the environmental break-even decreases to 63 g per kWh electricity input.

A sensitivity analysis indicates that full load hours and efficiency are the most influencing parameter on the **economic performance** of power-to-gas. Due to the high investment demand, the specific production costs of H_2 and CH_4 are especially high for low full load hours. From full load hours of about 4 000 h/a the influence decreases. The power-to-gas technology is in an early stage of development and thus learning effects could bring significant investment cost reductions in the next years. Specific cost reductions could also be achieved for larger installed capacities with the strongest effect beneath 1 MW of installed electrical power. Another important influence on the economics of power-to-gas is the price that has to be paid for electricity. The sensitivity analysis showed that at 4 000 full load hours, a doubling of electricity costs leads to an increase in specific production costs of 35%. These costs are strongly depending on the type of application which is again influencing the achievable full load hours. If surplus from renewable power sources is utilized, electricity costs are very low and so are full load hours. If higher electricity prices are paid, for instance for green electricity from the public power grid, higher full load hours can be achieved. However, high full load hours could on the other hand lead to a higher power demand in the energy system that has to be provided by additional power generation technologies. These technologies again influence the ecological performance of power-to-gas.

The sensitivity analyses indicated similar results for H_2 and CH_4 production in general. As the investment demand is higher for the production of synthetic CH_4, the influence of the investment costs (learning and scaling effects) is slightly higher and the influence of electricity costs is lower. The additional proceeds for oxygen and heat utilization as well as costs of CO_2 have hardly any influence on the specific production costs.

A significant decrease in specific production costs of H_2 and CH_4 from power-to-gas could be achieved when providing negative control energy. The remuneration for providing these system service is determined via a weekly auction and is paid for the provision of control power (€/MW) and for the called control energy (€/MWh). The tendered price is strongly influencing the probability of being called and if high full load hours should be reached with the power-to-gas plants, the offered prices should be tentatively low. Whereas at the beginning of 2015 the average prices for called control energy seemed to be very interesting from an economic point of view (on average 20 Cent were paid per kWh of electricity consumed), the paid prices dropped to € 0 per MWh in June and July. Thus the participation of power-to-gas plants at the balancing energy market could be very beneficial, but is connected with a considerable risk.

The relevant economic benchmarks are strongly depending on the type of application, which could be energy storage, energy transport, production of renewable transport fuels or chemicals for industry as well as a combination of these applications. For the presented exemplary power-to-gas plant, specific production costs of H_2 and CH_4 are higher than the direct benchmarks natural gas, biomethane and H_2 from natural gas or biomass gasification. However, H_2 production from natural gas is a large-scale technology and the real H_2 costs are significantly higher for industrial processes without on-site generation. Power-to-gas could thus be an alternative for small scale solutions. A significant reduction of specific costs could be achieved by reduction of investment costs through scaling and learning effects, higher full load hours, a reduction of taxes or with additional proceeds for provision of system services (such as providing negative balancing power).

In addition to the economic aspects, other additional benefits of power-to-gas such as the possibility of long-term energy storage or the hybridization of the energy system leading to a higher flexibility have to be considered too. Furthermore, with utilization of renewable electricity, H_2 and CH_4 from power-to-gas contribute to a reduction in GHG emissions compared to fossil reference technologies.

In conclusion, power-to-gas technology could bring several benefits to the energy system and could enable both, higher percentages of renewable power generation by fluctuating energy sources and higher percentages of renewables in transport and industry sector by provision of renewable H_2 or CH_4. Due to its versatile applications, several parameters are influencing the potential for the implementation of this technology system. Limiting parameters could be the potential for H_2 injection into the natural gas grid, the available amount of electricity from renewable power sources and the real demand for renewable products in the transport and industry sector. The real demand for H_2 and CH_4 from power-to-gas as green products is strongly depending on the development of the relevant benchmarks as well as on national and regional targets for renewable energy supply.

Apart from synthesis of CH_4, liquid hydrocarbons could also be produced from H_2 (also called power-to-liquids). Liquid energy carriers have advantages in terms of higher energy density and potential storage time but would require an own infrastructure as now realized for fossil liquid energy carriers such as diesel or gasoline. A comprehensive comparison of advantages and disadvantages of the technologies power-to-gas and power-to-liquids together with an economic and ecological assessment is one of the future research demands.

The surplus from renewable power generation is strongly influenced by the power grid quality and other storage technologies for balancing the strong fluctuations in wind and solar energy supply. As long as times with surplus from renewable power sources are comparatively low, the power-to-gas technology would not be cost-competitive due to its high investment costs. To reach higher full load hours and an increase in H_2 or CH_4 production, additional electricity has to be utilized from the public electricity grid or renewable power sources. This leads to an additional power demand in the energy system that could increase the burden on the power grid and has to be provided by additional power generation technologies. The type of these additional generation technologies influences the ecological performance of power-to-gas and should be quantified in further research. Suggestions on how to treat the additional electricity demand have been made for instance by Del Duce et al. [32] for life cycle assessments of electric vehicles.

For improvement of the economic viability of power-to-gas systems, future research should focus on the improvement of the applied technologies and systems in terms of lower costs and higher system efficiency (especially in part load and dynamic operation). As power-to-gas could fulfill system services such as energy storage, energy transport, energy supply for remote regions or provision of balancing power, potential remuneration systems have to be developed.

References

[1] M. Sterner (2009) *Bioenergy and renewable power methane in integrated 100% renewable energy systems. Limiting global warming by transforming energy systems.* Dissertation, University of Kassel.

[2] G. Gahleitner (2013) *Hydrogen from renewable electricity: An international review of power-to-gas pilot plants for stationary applications*. International Journal of Hydrogen Energy 38 (5): 2039-2061. DOI:10.1016/j.ijhydene.2012.12.010

[3] G. Reiter (2015) *Power-to-Gas*. In: D. Stolten (Ed.) Data, Facts and Figures on Fuel Cells. Wiley-Verlag, Forthcoming.

[4] G. Reiter, J. Lindorfer (2013) *Möglichkeiten der Integration von Power-to-Gas in das bestehende Energiesystem.* Jahrbuch Energiewirtschaft 2013, NWV-Verlag.

[5] H. Steinmüller, R. Tichler, G. Reiter, et al. (2014) *Power to Gas – Eine Systemanalyse. Markt- und Technologiescouting und -analyse*. Final report on behalf of the Austrian BMWFJ.

[6] R. Tichler, J. Lindorfer, G. Reiter, C. Friedl, H. Steinmüller (2014) *FTI-Roadmap Power-to-Gas Österreich*. Final report on behalf of the Austrian bmvit. http://www.energiesystemederzukunft.at/nw_pdf/1450_fti_roadmap_power_to_gas.pdf, accessed 13.04.2015.

[7] G. Reiter, J. Lindorfer (2015) *Global warming potential of hydrogen and methane production from renewable electricity via power-to-gas technology.* International Journal of Life Cycle Assessment 20 (4): 477-489. DOI:10.1007/s11367-015-0848-0

[8] G. Reiter, J. Lindorfer (2015) *Evaluating carbon dioxide sources for power-to-gas applications – A case study for Austria.* Journal of CO_2 Utilization 10: 40-49. DOI:10.1016/j.jcou.2015.03.003.

[9] IEA (2013) *World Energy Outlook 2013 – Renewable Energy Outlook.* http://www.worldenergyoutlook.org/media/weowebsite/2013/WEO2013_Ch06_Renewables.pdf, accessed at 13.08.2015

[10] P.D. Lund, J. Lindgren, J. Mikkola, J. Salpakari (2015) *Review of energy system flexibility measures to enable high levels of variable renewable electricity.* Renewable and Sustainable Energy Reviews 45: 785-807.

[11] M. Specht, J. Brellochs, V. Frick, B. Stürmer, U. Zuberbühler, M. Sterner, G. Waldstein (2010) *Storage of Renewable Energy in the Natural Gas Grid.* Erdöl Erdgas Kohle 126: 342-346.

[12] M. Boxleitner, C. Groiß, M. Chochole et al. (2011) *Super-4-Micro-Grid. Nachhaltige Energieversorgung im Klimawandel.* Final Report, Vienna. http://www.ea.tuwien.ac.at/fileadmin/t/ea/projekte/super-4-micro-grid/Super-4-Micro-Grid_-_FFG-Nr._818954_-_Approbierter_Endbericht.pdf, accessed at 25.08.2015.

[13] K. Zach, H. Auer, G. Lettner, T. Weiß (2013) *Abschätzung des zukünftigen Energiespeicherbedarfs in Österreich zur Integration variable erneuerbarer Stromerzeugung.*

http://www.store-project.eu/en_GB/current-situation-in-the-target-countries-austria, accessed at 25.08.2015.

[14] C. Budischak, A. Sewell, H. Thomson, L. Mach, D.E. Veron, W. Kempton (2013) *Cost-minimized combinations of wind power, solar power and electrochemical storage, powering the grid up to 99.9% of the time.* Journal of Power Sources 225:60-74. DOI: 10.1016/j.jpowsour.2012.09.054

[15] S. Miles, M. Gillie. *Benefits and Barriers of the Development of Renewable Hydrogen Systems in Remote and Island Communities.* International Energy Agency, Hydrogen Implementing Agreement Task 18. http://ieahia.org/pdfs/RemoteIslandBenefits.pdf, accessed at 17.12.2012.

[16] G. Müller-Syring, J. Hüttenrauch, S. Zöllner (2012) *Erarbeitung von Basisinformationen zur Positionierung des Energieträgers Erdgas im zukünftigen Energiemix in Österreich – Gasverwendungstechnologien.* Final Report on behalf of the Austrian ÖVGW. http://initiative-gas.at/fileadmin/content/Downloads/OEVGW_IO-AP3-Gasverwendungstechnologien_2013-01-25_final.pdf, accessed at 19.08.2015.

[17] G. Müller-Syring, M. Henel, H. Krause, H. Rasmusson, H. Mlaker, W. Köppel, T. Höcher, M. Sterner, T. Trost (2011) *Power-to-Gas: Entwicklung von Anlagenkonzepten im Rahmen der DVGW-Innovationsoffensive.* http://www.dvgw-innovation.de/fileadmin/dvgw/angebote/forschung/innovation/pdf/powertogas2011gwf.pdf, accessed at 25.08.2015.

[18] G. Müller-Syring, M. Henel (2014) *Wasserstofftoleranz der Erdgasinfrastruktur inklusive aller assoziierten Anlagen.* DVGW Deutscher Verein des Gas- und Wasserfaches e.V., Bonn. http://www.dvgw-innovation.de/fileadmin/dvgw/angebote/forschung/innovation/pdf/g1_02_12.pdf, accessed at 25.08.2015.

[19] E-Control, *Daten zur Erdgasstatistik in Österreich*, http://www.e-control.at/de/statistik/gas, accessed at 03.03.2015.

[20] F. Hofmann, A. Plättner, F. Scholwin (2005) *Möglichkeiten der Einspeisung von Biogas in das österreichische Gasnetz.* Institut für Energetik und Umwelt. http://www.e-control.at/portal/page/portal/medienbibliothek/gas/dokumente/pdfs/studie-biogaseinspeisung-ife-2005.pdf, accessed at 03.03.2015.

[21] E-Control (2013) *Ökostrombericht 2013.* http://www.e-control.at/portal/page/portal/medienbibliothek/oeko-energie/dokumente/pdfs/EC_Oekobericht_final.pdf, accessed at 03.03.2015.

[22] REN21 (2015) *Renewables 2015. Global Status Report.* http://www.ren21.net/wp-content/uploads/2015/07/GSR2015_KeyFindings_lowres.pdf, accessed at 18.08.2015.

[23] G. Gahleitner, J. Lindorfer (2013) *Alternative fuels for mobility and transport: Harnessing excess electricity from renewable power sources with power-to-gas.* eceee 2013 Summer Study, France.

[24] M. Bliem, B. Friedl, T. Balabanov, I. Zielinska (2011) *Energie [R]evolution Österreich 2050.* http://www.greenpeace.org/austria/Global/austria/dokumente/Studien/klima_EnergieRevolutionOesterreich2050.pdf, accessed at 12.08.2015.

[25] R. Wurster (2008) *The European Hydrogen Energy Roadmap.* HyWays, http://www.hyways.de/docs/Brochures_and_Flyers/HyWays_Roadmap_FINAL_22FEB2008.pdf, accessed at 19.08.2015.

[26] T. Abbasi, S.A. Abbasi (2011) *Renewable hydrogen: prospects and challenges.* Renewable and Sustainable Energy Reviews 15 (6): 3034-3040. DOI: 10.1016/j.rser.2011.02.026

[27] C. Stiller (2014) *Nutzung von konventionellem und grünem Wasserstoff in der chemischen Industrie.* In J. Töpler, J. Lehmann (Hrsg.) Wasserstoff und Brennstoffzelle, Springer-Verlag Berlin Heidelberg. DOI: 10.1007/978-3-642-37415-9_10

[28] U.S. Energy Information Administration. *International Energy Statistics 2012*. http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=2&pid=29&aid=12&cid=CG1,&syid=2008&eyid=2012&unit=BKWH, accessed on 12.08.2015.

[29] G. Reiter, J. Lindorfer (2014) *Ökonomische und ökologische Prozessbewertung des Technologiekonzeptes Power-to-Gas.* Minisymposium Verfahrenstechnik, Wien.

[30] PE International (2013) GaBi Software with built-in Database (DB) Version 5. Available from http://www.gabi-software.com

[31] H.J. Wagner, M.K. Koch, J. Burkhardt, T. Große Böckmann, N. Feck, P. Kruse (2007) *CO2-Emissionen der Stromerzeugung.* BWK Bd. 59 Nr. 10. https://www.vdi.de/fileadmin/vdi_de/redakteur_dateien/geu_dateien/FB4-Internetseiten/CO2-Emissionen%20der%20Stromerzeugung_01.pdf, accessed at 14.08.2015.

[32] A. Del Duce, P. Egede, G. Öhlschläger, T. Dettmer, H.J. Althaus, T. Bütler, E. Szczechowicz (2013) *Guidelines for the LCA of electric vehicles.* http://www.elcar-project.eu/fileadmin/dokumente/Guideline_versions/eLCAr_guidelines.pdf, accessed on 18.08.2015.

[33] N. von der Assen, J. Jung, A. Bardow (2013) *Life-cycle assessment of carbon dioxide capture and utilization: avoiding the pitfalls.* Energy & Environmental Science 6: 2721–2734. DOI: 10.1039/c3ee41151f

[34] Österreichisches Normungsinstitut (2004) *Guideline ÖNORM M7140: Economic comparison calculation of energy systems based on the extended annuity method.* Österreichisches Normungsinstitut.

[35] G. Reiter, R. Tichler, H. Steinmüller, M. Furtlehner, S. Goers, J. Lindorfer, S. Schmidinger, M. Schwarz (2014) *Technoökonomische Studie von Power-to-Gas Konzepten. TP D „Wirtschaftlichkeit und Systemanalyse von Power-to-Gas Konzepten“.* Final Report on behalf of the DVGW.

[36] L. Grond, P. Schulze, J. Holstein (2013) *Systems analyses Power to Gas: A technology review.* http://www.dnv.com/binaries/dnv%20kema%20(2013)%20-

%20systems%20analyses%20power%20to%20gas%20-%20technology%20review_tcm4-567461.pdf, accessed at 30.01.2014.

[37] K. Schoots, F. Ferioli, G.J. Kramer, B.C.C. van der Zwaana (2008) *Learning curves for hydrogen production technology: An assessment of observed cost reductions.* International Journal of Hydrogen Energy 33, 2630-2645. DOI:10.1016/j.ijhydene.2008.03.011

[38] J. Bömer, M. Doering, K. Burges (2012) *Einspeisemanagement in Schleswig-Holstein.* Final Report, Ecofys Germany GmbH, Berlin. http://www.schleswigholstein.de/Energie/DE/Energiewende/Kosten_Energiewende/einspeisemanag ement_endbericht_pdf__blob=publicationFile.pdf, accessed at 30.7.2013.

[39] W. Münch, M. Robra, L. Volkmann, P. Riegebauer, D. Oesterwind (2012) *Hybride Wärmeerzeuger als Beitrag zur Systemintegration erneuerbarer Energien.* In: Energiewirtschaftliche Tagesfragen 62 (5): 44-48.

[40] G. Guandalini, S. Campanari, M.C. Romano (2015) *Power-to-gas plants and gas turbines for improved wind energy dispathcability: Energy and economic assessment.* Applied Energy 147: 117-130. DOI: 10.1016/j.apenergy.2015.02.055

[41] C. Kost, J.N. Mayer, J. Thomsen, N. Hartmann, C. Senkpiel, S. Philipps, S. Nold, S. Lude, T. Schlegl (2013) *Stromgestehungskosten Erneuerbare Energien.* http://ise.fraunhofer.de/de/veroeffentlichungen/veroeffentlichungen-pdf-dateien/studien-und-konzeptpapiere/studie-stromgestehungskosten-erneuerbare-energien.pdf, accessed at 20.08.2015.

[42] M. Reichmuth, C. Lorenz, C. Beestermöller, C. Nabe, C. Markgraf, J. Schließer, J. Gerstenberg, A. Kramer et al. (2014) *Marktanalyse Ökostrom*. Final Report. http://www.umweltbundesamt.de/sites/default/files/medien/376/publikationen/texte_04_2014_marktanalyse_oekostrom_0.pdf, accessed at 20.08.2015.

[43] G. Muggenhumer (2015) *Der österreichische Sekundärregelenergiemarkt - Eine ökonomische und ökonometrische Analyse.* Master Thesis, JKU Linz. http://epub.jku.at/obvulihs/download/pdf/496323?originalFilename=true, accessed 21.08.2015.

[44] D. Raine, H. Strom, G. Maisonnier, S. Vinot, J. Linnemann, S. Trümper (2009) *Analysis of the Current Hydrogen Structure.* Roads2HyCom.

[45] J. Schiffers, A. Vogel, B. Meyer-Prescher (2009) *Beseitigung technischer, rechtliche rund ökonomischer Hemnisse bei der Einspeisung biogener Gase in das Erdgasnetz zur Reduzierung klimarelevanter Emissionen durch Aufbau und Anwendung einer georeferenzierten Datenbank.* Final Report for the BMBF project „Biogaseinspeisung", Vol. 5. http://www.biogaseinspeisung.de/download/Abschlussbericht_Biogaseinspeis ung_Band_5_Gasnetz_AP3_4.pdf, accessed at 14.01.2014.

[46] A. Ajanovic (2011) *Biofuels versus food production: does biofuels production increase food prices?* Energy 36: 2070–2076. DOI 10.1016/j.energy.2010.05.019.

[47] C. Söderberg, K. Eckerberg (2012) *Rising policy conflicts in Europe over bioenergy and forestry*. Forest Policy and Economics. DOI 10.1016/j.forpol.2012.09.015.

Abbreviations

AEC	alkaline electrolysis cell
CAES	compressed air energy storage
CCS	carbon capture and storage
CNG	compressed natural gas
GHG	greenhouse gas
GWP	global warming potential
LCA	life cycle assessment
LHV	lower heating value
O&M	operation and maintenance
PEMEC	proton exchange membrane electrolysis cell
PtG	power-to-gas
PV	photovoltaics
SNG	synthetic natural gas
SOEC	solid oxide electrolysis cell

Appendix

a) G. Gahleitner (2013) *Hydrogen from renewable electricity: An international review of power-to-gas pilot plants for stationary applications*. International Journal of Hydrogen Energy 38 (5): 2039-2061. DOI:10.1016/j.ijhydene.2012.12.010

b) G. Reiter, J. Lindorfer (2015) *Global warming potential of hydrogen and methane production from renewable electricity via power-to-gas technology.* International Journal of Life Cycle Assessment 20 (4): 477-489. DOI:10.1007/s11367-015-0848-0

c) G. Reiter, J. Lindorfer (2015) *Evaluating carbon dioxide sources for power-to-gas applications – A case study for Austria.* Journal of CO_2 Utilization 10: 40-49., DOI:10.1016/j.jcou.2015.03.003

d) G. Gahleitner, J. Lindorfer (2013) *Alternative fuels for mobility and transport: Harnessing excess electricity from renewable power sources with power-to-gas.* eceee 2013 Summer Study, France.

e) G. Reiter, J. Lindorfer (2014) *Ökonomische und ökologische Prozessbewertung des Technologiekonzeptes Power-to-Gas.* Minisymposium Verfahrenstechnik, Wien.

INTERNATIONAL JOURNAL OF HYDROGEN ENERGY 38 (2013) 2039–2061

Available online at www.sciencedirect.com

SciVerse ScienceDirect

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

Review

Hydrogen from renewable electricity: An international review of power-to-gas pilot plants for stationary applications

*Gerda Gahleitner**

Energy Institute at the Johannes Kepler University Linz, Department of Energy Technologies, Altenberger Straße 69, 4040 Linz, Austria

ARTICLE INFO

Article history:
Received 19 September 2012
Received in revised form
28 November 2012
Accepted 3 December 2012
Available online 31 December 2012

Keywords:
Power-to-gas
Renewable hydrogen
Pilot plant
Energy storage
Electrolyzer
Fuel cell

ABSTRACT

An increasingly large percentage of power is being generated from renewable energy sources with intermittent and fluctuating outputs. Therefore there is a growing need for energy storage. With power-to-gas, excess electricity is converted into hydrogen by water electrolysis, which can be stored and, when needed, can be reconverted into electricity with fuel cells. Besides the energy vector for electricity, mobility and heat, hydrogen can be utilized as a raw material for the chemical industry or further be used for the synthesis of various hydrocarbon fuels such as methane.

This article is an international review of numerous power-to-gas pilot plants that have either already been realized or are being planned. It provides information about their installed components and capacities as well as about operating experience that has been had with them. In many of the projects it was concluded that the design and sizing, control strategy and system integration of the power-to-gas plants have a great influence on their overall efficiency, reliability and economics.

Topics for further research are the improvement of the efficiency, reliability, lifetime and costs of electrolyzers and fuel cells and better ways of dealing with power sources. In order to improve the overall performance, the reduction of auxiliary equipment and the continuous long-term operation of power-to-gas pilot plants will be necessary. The further development of codes and standards for permits to operate, as well as of hydrogen components and control strategies, would bring additional benefits for power-to-gas systems. It is also recommended that optimum system configurations and components be determined with regard to the available infrastructure and the type of application involved.

* Tel.: +43 732 2468 5657; fax: +43 732 2468 5651.
E-mail addresses: gahleitner@energieinstitut-linz.at, gerda.gahleitner@gmx.at.

0360-3199/$ – see front matter Copyright © 2012, Hydrogen Energy Publications, LLC. Published by Elsevier Ltd. All rights reserved.
http://dx.doi.org/10.1016/j.ijhydene.2012.12.010

Nomenclature

AFC	alkaline fuel cell
CHG	compressed hydrogen gas
CHP	combined heat and power
CNG	compressed natural gas
CO, CO_2	carbon monoxide, carbon dioxide
DC, AC	direct current, alternating current
FC	fuel cell
H_2	hydrogen
ICE	internal combustion engine
KOH	potassium hydroxide
LHV, HHV	lower heating value, higher heating value, MJ/Nm^3
MH	metal hydride
MPPT	maximum power point tracker
n/a	information not available
P_{el}	installed power of electrolyzer, kW
PAFC	phosphoric acid fuel cell
PEM	polymer electrolyte membrane, proton exchange membrane
PEMFC	PEM fuel cell
RFC	reversible/regenerative fuel cell
SOC	state of charge
SOEC	solid oxide electrolysis cell
$\dot{V}_{H_2}$	nominal hydrogen capacity of electrolyzer, Nm^3/h
$\eta_{Electrolyzer}$	electrolyzer energy efficiency

1. Introduction

Because of the increasing levels of greenhouse gas emissions and the rising global energy demand new technologies for the generation of environmentally friendly power are needed. Renewable energy sources like solar and wind energy have a great potential, but their utilization is difficult due to their fluctuating and intermittent nature. In large electricity networks, renewable power sources with a low output can be balanced by conventional power generation, but a higher percentage of renewables would necessitate improved energy storage. Whereas batteries, compressed air, flywheels or capacitors are suited for the short-term storage of electricity, long-term storage could be realized with hydrogen as an energy vector.

Up to now, problems with fluctuating and intermittent electricity from renewable power sources have only occurred in local power grids with a high percentage of renewables. In the future, high percentages of renewable electricity are expected to be fed into larger power grids too, since for example Germany has the goal of generating 80% of its electricity from renewable energy sources by the year 2050 [1]. This will lead to an increased need for balancing power, which is why Germany is currently emphasizing the so-called power-to-gas technology.

With power-to-gas, electricity is converted into hydrogen by water electrolysis. The hydrogen that is thereby produced can be stored in pressure tanks and when needed can be reconverted into electricity with fuel cells or hydrogen combustion engines. Besides its use as an energy vector for electricity, mobility and heat, hydrogen can be utilized as a raw material for the chemical industry or for the synthesis of various hydrocarbon fuels such as methane. Additionally, a certain percentage of hydrogen could be fed into the gas distribution system. Fig. 1 shows the main components of a power-to-gas system and the various types of applications for it.

This article presents a review of power-to-gas pilot plants that have been realized or are being planned worldwide and focuses on the main components that are presented in Fig. 1. The information about the different systems that are evaluated was taken from scientific peer-reviewed articles to the extent that such articles were available. Some projects are very well documented and various articles about their modeling and experimental results from them have been published. Other projects, however, only provide information about their systems via homepage, news releases or in presentations. Additional information about the power-to-gas pilot plants that were evaluated was gathered by contacting the responsible researchers directly.

The evaluation includes projects realized between 1990 and 2012 and several power-to-gas plants that were in the planning stage at that time. Power-to-gas systems which only

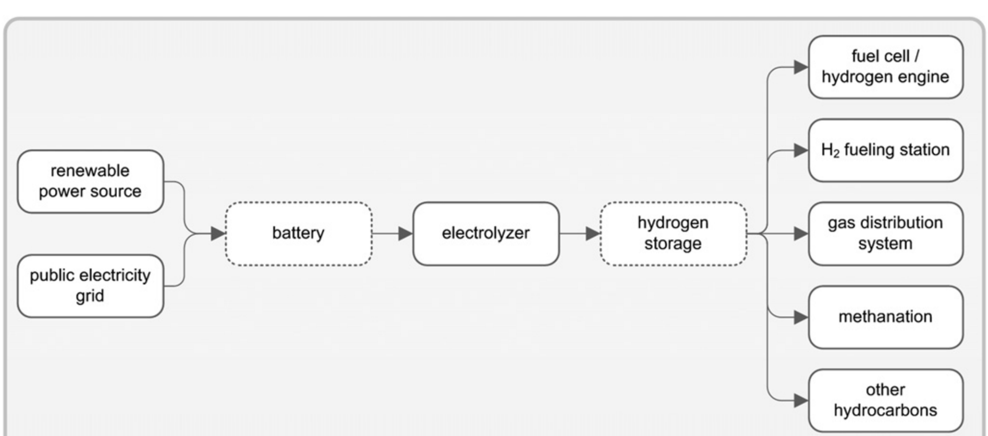

Fig. 1 – Main components of a power-to-gas system.

use hydrogen in fueling stations for vehicles are not included in the evaluation, since they can be regarded as state-of-the-art technology. Renewable hydrogen fueling stations consist of a renewable electricity source, an electrolyzer, a hydrogen compressor and a filling device. Over a hundred of them have already been realized or are in the planning stage and have been very well documented in Ref. [2].

Detailed analyses of stack efficiencies, control strategies and safety aspects of the power-to-gas projects will not be undertaken here since information concerning these aspects was scarce. Therefore the main focus is on the evaluation of complete systems. Most of the pilot plants are prototypes, and so economic considerations such as costs are also not included in the evaluation, since information about them is hardly ever given.

Lymberopoulos documents several case studies of renewable hydrogen installations that already have been realized in Ref. [3] and some hydrogen demonstration projects were evaluated and simulated in the course of the IEA Hydrogen Implementing Agreement in Refs. [4,5]. A review article by Yilanci et al. [6] focuses on solar-hydrogen/fuel cell hybrid energy systems and provides information about various projects.

This review article presents general information on realized and planned power-to-gas plants like the year of start-up, the location and the total installed capacity. The main components of the hydrogen production process and the utilization of the hydrogen are evaluated and operating experience is summarized. The main lessons that have been learned in the evaluated power-to-gas projects are presented and conclusions and recommendations are drawn.

2. Power-to-gas pilot plants that have been evaluated

The power-to-gas pilot plants that were considered for evaluation in this article are presented in Table 1, in the order of the countries they are located in and the year of their start-up. The analysis covers 41 realized and seven planned projects. Table 1 also provides information about the data sources for each project.

In respect to the geographical distribution of power-to-gas pilot plants, most of the projects that have been realized are situated in Germany (7), the USA (6), Canada (5), Spain (4) and the United Kingdom (4). Therefore the largest number of projects (95%) is located in Europe and North America.

Germany has placed a great emphasis on developing power-to-gas systems that will go into operation in the future; five of the seven currently planned projects will be realized there. Most of the evaluated projects that are currently in the planning stage will be installed by the year 2013.

Some additional power-to-gas pilot plants are listed in Table 2. They were not included in the evaluation for various reasons. For most of these systems, the most important information about components or system design could not be gathered. Systems with an installed capacity of less than 1 kW were also not included in the evaluation.

Fig. 2 shows the size of the realized pilot plants in respect to the installed power in kW and in dependence on the year they went (or will go) into operation. The plants are classified according to their operational state, which is determined as follows:

- In operation: plant is in continuous operation
- Laboratory plant: no continuous operation, different analyses and tests are being performed, different system configurations are possible in some of these plants
- Demonstration purpose: no continuous operation, plant is only operated for demonstration purposes
- Out of operation: plant is not operating any more, components have been decommissioned or even removed
- n/a: no or contradictory information is available
- Planning stage: plant has not yet been installed or commissioned.

One power-to-gas pilot plant could not be considered in the diagram, since the year of its start-up could not be ascertained.

The first power-to-gas system for storing renewable electricity by means of electrolysis and subsequent hydrogen storage was realized in 1991. The number of installations per year increased in the 21st century, as can be seen in Fig. 2. There is a trend to higher installed capacities and the power-to-gas plant with the highest installed power that is currently in operation was commissioned in 2009, in the course of the Hychico project in Argentina.

14 of the realized power-to-gas pilot plants are in operation and another 12 projects are at least being used for demonstration purposes or for various tests in laboratory plants. Information about the operating time of laboratory plants is difficult to obtain, since the configurations and components of these systems are frequently altered.

Regarding the overall capacity of the power-to-gas pilot plants in Fig. 2, a trend toward increased installed power seems to be becoming increasingly apparent. Whereas all of the realized systems have power levels of 1 MW or less, three of the planned projects have a higher capacity. The largest planned system has a total installed power of 6.3 MW and will be realized in Germany.

Fig. 3 provides information about the operating period of the power-to-gas pilot plants that have been evaluated. The month of commissioning was not taken into consideration as in most projects only the year of initial operation was reported. As mentioned above, some power-to-gas pilot plants are only put into operation for demonstration purposes or are not being continuously operated. Accordingly, the varying state of operation in these projects is not considered in Fig. 3.

32% of the power-to-gas systems have already been decommissioned and most of them only were in operation for a short period of between a few months and 4 years. Exceptions are the SWB Project in Germany that was in operation for 8 years, the PHOEBUS project in Germany that operated for 10 years, the system on Utsira Island that operated for 6 years and the recently decommissioned Schatz Solar Hydrogen Project that was in operation for 21 years. Some reasons for decommissioning or only operating power-to-gas pilot plants for demonstration purposes are that a research project has ended and no funding is available for further operation. This was the case for the Hawaii Hydrogen Power Park [89].

Table 1 – Power-to-gas pilot plants that have been evaluated.

Country	Project name	State	Start-up	End	Data sources
Argentina	Hychico, Comodoro Rivadavia	In operation	2009	–	[7], Perez RA (personal communication, 21 May 2012)
	Laboratory Plant HRI Quebec	Laboratory plant	2001	–	[8,9]
	IRENE System	Out of operation	2007	2009	[10], Rowe A (personal communication, 14 May 2012)
Canada	Wind-Hydrogen Village Prince Edward Island	Out of operation	2009	2011	[11,12], Victor M (personal communication, 08 May 2012)
	HARP System, Bella Coola	*In operation*	2010	–	[13–15]
	Ramea Wind-Hydrogen-Diesel Project	In operation	2011	–	[16,17], Lacroix A (personal communication, 07 May 2012)
Cook Islands	Hydrogen Island Aitutaki	Planning stage	n/a	–	[18,19]
Denmark	Nakskov Industrial & Energy Park Lolland	*Demonstration purpose*	2007	–	[5,20]
France	PVFCSYS Sophia Antipolis	Out of operation	2000	2004	[3,21], Metkemeijer R (personal communication, 14 May 2012)
	MYRTE, Corsica	In operation	2012	–	[22,23], Poggi P (personal communication, 08 May 2012)
Germany	SWB Project, Neunburg vorm Wald	Out of operation	1991	1999	[3,24]
	Freiburg Solar House	Out of operation	1992	1995	[25], Smolinka T (personal communication, 14 May 2012)
	PHOEBUS, Jülich	Out of operation	1993	2003	[3,26–28]
	Laboratory Plant Stralsund	Laboratory plant	1998	–	[3,29,30]
	HyWindBalance – laboratory plant Oldenburg	Laboratory plant	2006	–	[31,32]
	Solar Fuel Alpha-Plant, mobile device	Demonstration purpose	2009	–	[33–35]
	Hybrid Power Plant Enertrag, Prenzlau	In operation	2011	–	[36,37]
	Solar Fuel Plant, ZSW Stuttgart	Planning stage	2012	–	[33,34]
	H2Herten	Planning stage	2012	–	[38], Klug K (personal communication, 18 June 2012)
	RH2 WKA	Planning stage	2012	–	[38–42]
	Demonstration Plant EON, Falkenhagen	Planning stage	2013	–	[43,44]
	Solar Fuel Beta-Plant Audi, Werlte	Planning stage	2013	–	[33,34]
Greece	Stand-alone power system, Neo Olvio of Xanthi	In operation	2008	–	[45–47], Ipsakis D (personal communication, 04 April 2012)
Greenland	H2KT – Hydrogen Energy Storage in Nuuk	In operation	2010	–	[7,48,49]
Italy	SAPHYS	Laboratory plant	1997	–	[3,6,50]
	PVFCSYS Agrate	Out of operation	2004	2004	[3,21], Metkemeijer R (personal communication, 14 May 2012)
	H_2 from the Sun, Brunate	n/a	2008	–	[51]
Japan	Hydrogen Energy Storage System, Takasago Thermal Engineering	n/a	2005	–	[4]
Norway	Grimstad Renewable Energy park	Out of operation	2000	n/a	[52], Nielsen HK (personal communication, 01 June 2012)
	Laboratory Plant IFE Kjeller	Laboratory plant	2003	–	[53–55]
	Utsira Island	Out of operation	2004	2010	[55,56]

Table 1 – (continued)

Country	Project name	State	Start-up	End	Data sources
Spain	FIRST – Showcase II	Out of operation	2003	2004	[4,57,58]
	RES2H2 Gran Canaria	*In operation*	2007	–	[5]
	Hydrogen Wind Farm Sotavento	Demonstration purpose	2008	–	[59,60]
	Hidrolica, Tahivilla	Out of operation	2008	2009	[61], Rodriguez Golan M (personal communication, 05 June 2012)
Turkey	Hydepark	*Laboratory plant*	2008	–	[62], Cubukcu M (personal communication, 27 April 2012)
	Hydrogen Island Bozcaada	In operation	2011	–	[18,19,63], Tabakoglu G (personal communication, 03 April 2012)
United Kingdom	HARI project, West Beacon Farm	In operation	2004	–	[14,64,65], Marmont T (personal communication, 03 April 2012)
	PURE project, Unst	In operation	2005	–	[3,66,67], Johnson E (personal communication, 03 April 2012)
	Baglan Energy Park, Wales	In operation	2008	–	[7,68,69]
	The Hydrogen Office	In operation	2010	–	[70–72], Hogg D (personal communication, 04 April 2012)
	Hydrogen Mini Grid System Yorkshire	Planning stage	2012	–	[73–75]
USA	Schatz Solar Hydrogen Project, California	Out of operation	1991	2012	[6,76–79]
	DTE Energy Hydrogen Technology Park, Southfield Michigan	In operation	2004	–	[80–83]
	Small Scale Renewable Power System DRI	Laboratory plant	2004	–	[3,84]
	Wind2H2 Project	Laboratory plant	2007	–	[85–88]
	Hawaii Hydrogen Power Park	Out of operation	2007	2007	[89,90], Busquet S (personal communication, 15 May 2012)
	Hybrid energy storage system at NFRC, California	Laboratory plant	2010	–	[91]

n/a – information not available, contradictory or not confirmed information in italics.

3. Hydrogen production process

The global hydrogen production is estimated to be around 50 million tons per year [109]. Nearly all of it is produced from fossil feedstock like natural gas, oil and coal. As costs and energy consumption are high, only a small fraction is being produced by water electrolysis at the moment [110]. Pathways for renewable hydrogen production include thermal processes such as biomass gasification, photolytic processes such as photoelectrochemical or photobiological water splitting and electrolytic processes that use electricity from renewable power sources like solar or wind energy [111].

In the power-to-gas pilot plants that were evaluated, hydrogen is produced via electrolytic conversion. The evaluated process steps of the various evaluated systems include renewable electricity generation, storage of fluctuating electricity in batteries, splitting of water into hydrogen and oxygen via electrolysis and storage of the produced hydrogen in pressure tanks (CHG – compressed hydrogen gas) or metal hydrides (MH).

Table 3 provides the main characteristics of each of the components in the hydrogen production process of these power-to-gas pilot plants. To enhance the clarity of the presentation, the data sources have been omitted from this table, as they were already presented in Table 1. The projects are ranked by the year of start-up and the power-to-gas pilot plants that are in the planning stage are specified at the end of the table.

3.1. *Renewable electricity as a source of input for hydrogen production*

The most frequently applied renewable energy sources for power-to-gas systems are wind and solar energy, both of which fluctuate strongly. Other renewable technologies that utilize water power, biomass or geothermal energy are suited for base load, and there is no need to balance their power sources [112].

Table 3 shows that in 24% of the realized power-to-gas pilot plants electricity is obtained from the public grid. The rest of the projects are directly coupled to renewable power generators or to programmable devices that simulate fluctuating renewable power sources. Electricity from the public grid in connection with programmable power sources is employed in the laboratory plants which are described in Refs. [10,53]. These systems can simulate different electricity profiles and sources of renewable power.

Table 2 – Power-to-gas pilot plants that are not considered in the evaluation.

Project name	Start-up	Remark	Source
Helsinki Hydrogen Energy Test Bed, Finland	1989-1992	Alkaline electrolyzer with 0.8 kW	[78]
HySolar - Test Bed Stuttgart, Germany	1989	Alkaline electrolyzer with 10 kW, no utilization of produced hydrogen	[3]
HySolar - Test Bed at Riyadh, Saudi Arabia	1993	Alkaline electrolyzer with 500 kW, no utilization of produced hydrogen	[3,92]
Demo Plant Agricultural University Athens, Greece	2006	PEM electrolyzer with 0.17 kW	[93]
Demonstration Plant Kuala Terengganu, Malaysia	2006	PEM electrolyzer with 1 kW, no utilization of produced hydrogen	[94]
The Hydrogen House, USA	2006	No information about capacity of PEM electrolyzer	[95,96]
HYLINK - Totara Valley, New Zealand	2008	PEM electrolyzer with 0.5 kW	[88,97]
BTU Cottbus, Germany	2012	Alkaline electrolyzer, insufficient information about components/design	[98]
Commercial Plant Svartsengi by Carbon Recycling Int. Iceland	2012	Methanol production of 2 million liters per year, insufficient information about components/design	[99,100]
Pilot plant Air Fuel Synthesis, United Kingdom	2012	Hydrocarbon fuels from syngas, insufficient information about components/design	[101]
Akershus Energy Park, Norway	2013	SOFC, biomethane reforming, hydrogen dispenser, insufficient information about components/design	[102]
Sunfire Demonstration Plant, Germany	2016	High temperature steam electrolysis, liquid hydrocarbons made from synthetic gas, insufficient information about components/design	[103]
Carbazol pilot plant, University of Erlangen-Nürnberg, Germany	2020	Ethylcarbazole as a liquid organic hydrogen carrier, insufficient information about components/design	[104,105]
Fronius Energy Cell, Austria	n/a	Self-sufficient home, insufficient information about components/design	[106]
RABH2, United Kingdom	n/a	Alkaline electrolyzer with 5 kW, insufficient information about components/design	[107]
Sir Samuel Griffith Center in Brisbane, Australia	n/a	Insufficient information about components/design	[108]

n/a – information not available, contradictory or not confirmed information in italics.

Five pilot plants obtain electricity from the public grid, although renewable power generating devices are being operated at their sites, in order to avoid the need for smoothing out the renewable power output [29].

Problems with the grid quality occur especially in local grids with a high percentage of renewable electricity. Grid stability can be provided there by operating a flywheel for frequency control and a synchronous machine for voltage control and short circuit power [56].

Table 3 provides additional information about the installed power of the renewable electricity generators. A comparison with the installed capacity of power-to-gas pilot plants is not

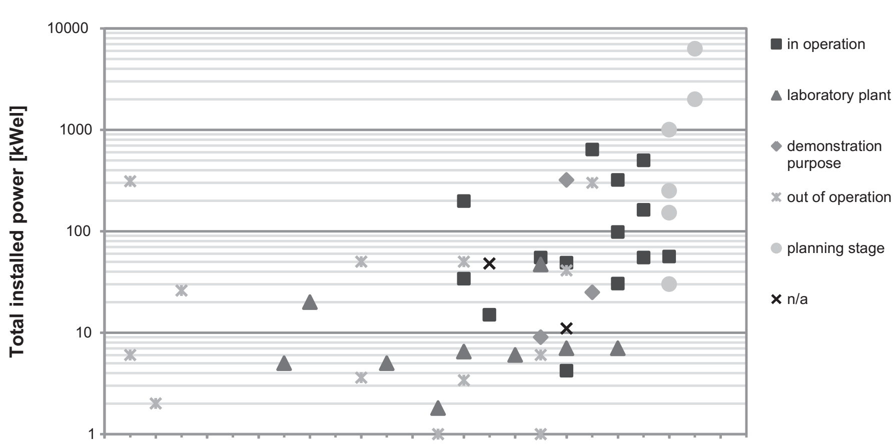

Fig. 2 – Total installed power [kW] in realized power-to-gas pilot plants.

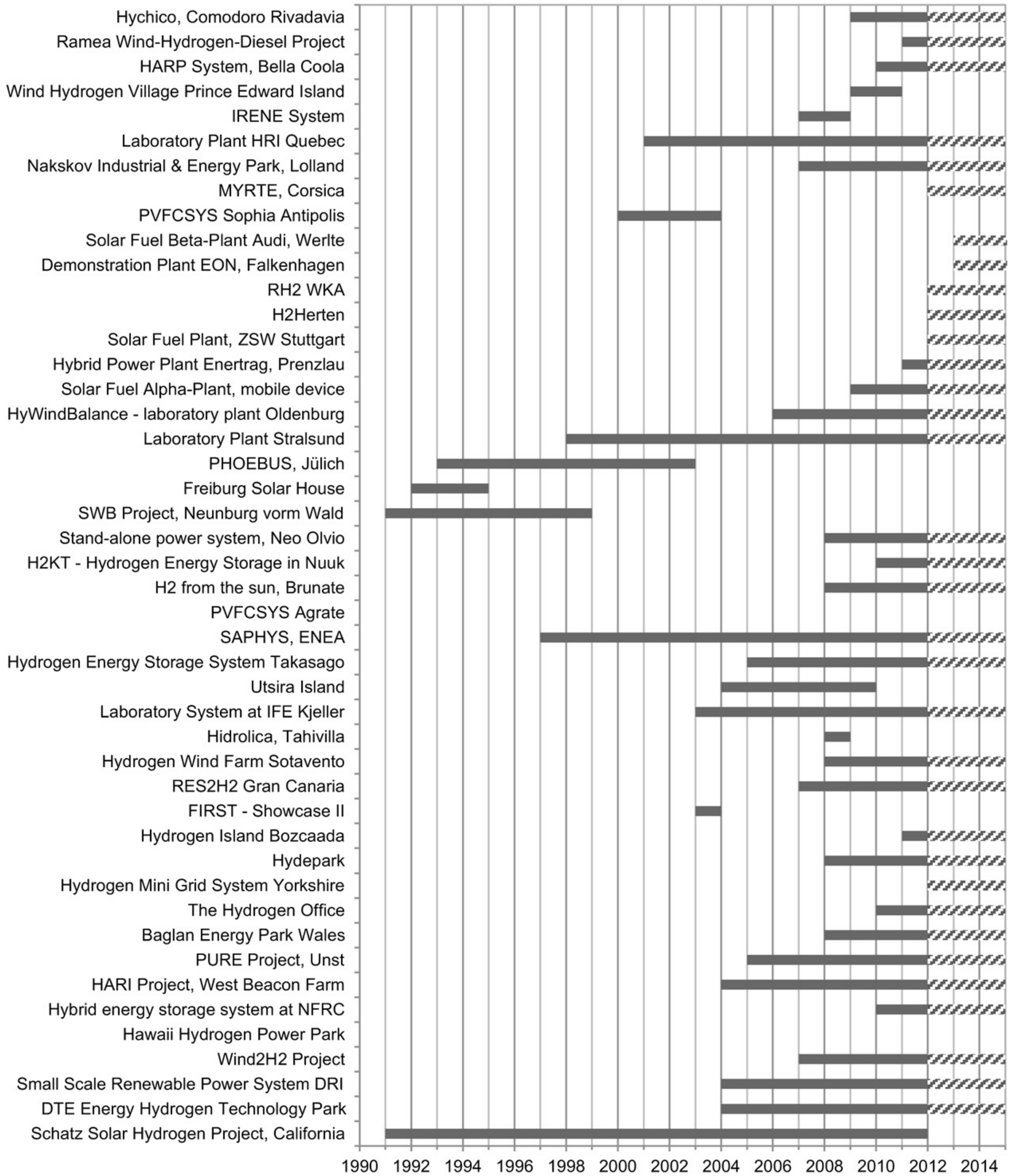

Fig. 3 – Period of operation of the power-to-gas pilot plants that have been evaluated.

made here, since the energy yield strongly depends on the location and on the configuration of each system.

Solar energy is the sole renewable power source in 12 realized projects. In five systems photovoltaics is applied together with electricity from the public grid and in seven projects photovoltaic arrays are combined with other renewable energy sources such as wind or water. Altogether, solar energy is utilized in 59% of the realized projects, whereby different photovoltaic module types are utilized, such as polycrystalline, monocrystalline and amorphous silicon or thin film CIS (copper indium selenide) ones. Some power-to-gas pilot plants even operate various module types in parallel, as reported in Refs. [24,30,52,62].

Problems with photovoltaic arrays have been most frequently documented in older systems; they result from degradation and low efficiency. The photovoltaic modules have undergone 16% degradation after 15 years of operation in Ref. [76] and a low efficiency of photovoltaics is also reported

Table 3 – Hydrogen production in the evaluated power-to-gas pilot plants (based on information from data sources presented in Table 1).

Project name	Energy source		Battery			Electrolyzer					Hydrogen storage		
	Type	Power [kW]	yes/no	Type	Capacity [kWh]	Type	Capacity [Nm^3/h]	Power [kW]	Eff. HHV [–]	Press. [bar]	Type	Volume [Nm^3]	Press. [bar]
Schatz Solar Hydrogen Project	Solar	7.5	y	Lead-acid	5	Alkaline	1.2	6	71%	7.9	CHG	5.7	30
SWB Project, Neunburg vorm Wald	Solar	370	n	–	–	Alkaline	22.3	100	79%	atm.	CHG	5000	30
						Alkaline	24.7	111	79%	atm.			
						Alkaline	20	100	71%	32			
Freiburg Solar House	Solar	4.2	y	Lead-acid	20	PEM	0.4	2	63%	30	CHG	15	30
PHOEBUS, Jülich	Solar	43	y	Lead-acid	303	Alkaline	5.1	26	70%	7	CHG	2100	120
SAPHYS	Solar	5.6	y	Lead-acid	51	Alkaline	1	5	70%	20	CHG	300	20
Laboratory Plant Stralsund	Wind–solar, public grid	100–10	n	–	–	Alkaline	4	20	71%	25	CHG	200	25
PVFCSYS Sophia Antipolis	Solar	3.6	y	n/a	1.9	Alkaline	0.7	3.6	70%	10	CHG	0.4	10
Grimstad Renewable Energy Park	Solar	20	n	–	–	Alkaline	10	50	71%	15	CHG	8	15
Laboratory Plant HRI Quebec	Wind–solar	10–1	y	Lead-acid	42	Alkaline	1	5	71%	7	CHG	35	10
FIRST – Showcase II	Solar	1.5	y	Lead-acid	20	PEM	0.2	1	63%	30	MH	70	30
Laboratory Plant IFE Kjeller	Wind–solar, public grid[a]	5.8–4.0	y	Lead-acid	14.4	PEM	0.3	1.5	63%	16	MH	14	16
						PEM	0.4	1.8	79%	n/a			
PVFCSYS Agrate	Solar	3.6	n	–	–	Alkaline	0.7	3.4	70%	30	CHG	4	10
HARI Project, West Beacon Farm	Wind–solar–water	50–13–3	y	$Na–NiCl_2$	20	Alkaline	8	34	83%	25	CHG	2856	137
Utsira Island	Wind	300	y	NiCd	50	Alkaline	10	50	71%	12	CHG	2400	200
DTE Energy Hydrogen Technology Park, Southfield Michigan	Solar, public grid	27	n	–	–	Alkaline	15	99	54%	n/a	CHG	1491	393
						Alkaline	15	99	54%	n/a			
Small Scale Renewable Power System DRI	Wind–solar	3–2	y	Lead-acid	8.4	Alkaline	1.1	5	78%	6	CHG	2.2	13.8
						PEM	0.33	1.5	78%	13.8			
PURE Project, Unst	Wind	30	n	–	–	Alkaline	3.55	15	84%	30	CHG	44	30
Hydrogen Energy Storage System, Takasago Thermal Engineering	Public grid	–	n	–	–	PEM	5	28	63%	10	MH	100	10
						PEM	3	20	53%	10			
HyWindBalance – laboratory plant Oldenburg	Public grid	–	n	–	–	Alkaline	1	6	59%	30	CHG	36	30
RES2H2 Gran Canaria	Wind, public grid	225	y	n/a	n/a	Alkaline	11	55	71%	25	CHG	500	25
Nakskov Industrial & Energy Park, Lolland	*Public grid*	–	n	–	–	PEM	0.84	4.5	66%	6.9	CHG	150	6
						PEM	0.84	4.5	66%	6.9			
Wind2H2 Project	Wind–solar, public grid	110–10	n	–	–	Alkaline	5.6	33	60%	11	CHG	945	241
						PEM	1.1	7	56%	13.8			
						PEM	1.1	7	56%	13.8			
Hawaii Hydrogen Power Park	Wind–solar	7.5–4.9	y	Lead-acid	343	PEM	0.2	1	71%	12	CHG	50	12
IRENE System	Public grid[a]	–	y	Lead-acid	272 A h	Alkaline	1.2	6	70%	n/a	CHG	111	200
											MH	8.9	17
Hydepark	Wind–solar	5–12	y	Lead-acid	*1500 A h*	PEM	1.05	7	53%	13.8	CHG	n/a	103
H_2 from the sun, Brunate	Solar	11	y	Lead-acid	3000 A h	Alkaline	1.9	11	61%	10	CHG	120	200
											MH	30	15
Hydrogen Wind Farm Sotavento	Wind	17,560	n	–	–	Alkaline	60	320	66%	10	CHG	1725	200
Stand-alone power system, Neo Olvio	Wind–solar	3–5	y	Lead-acid	144	PEM	0.7	4.2	63%	n/a	CHG	54	30
Hidrolica, Tahivilla	Wind	800	n	–	–	PEM	6	41	52%	18	CHG	5.5	200
Baglan Energy Park Wales	Solar	20	n/a	n/a	n/a	Alkaline	10	49	72%	10	CHG	n/a	350

Wind Hydrogen Village Prince Edward Island	Wind	250	n	–	–	Alkaline	66	300	78%	atm.	CHG	5560	17
Hychico, Comodoro Rivadavia	Wind	6300	n/a	n/a	n/a	Alkaline	60	320	66%	10	CHG	90	10
						Alkaline	60	320	66%	10			
Solar Fuel Alpha-Plant, mobile device	Public grid	–	n	–	–	Alkaline	4.9	25	70%	atm.	CHG	n/a	n/a
HARP System, Bella Coola	Water	2000	y	ZnBr	50	Alkaline	60	320	66%	10	CHG	1100	200
H2KT – Hydrogen Energy Storage in Nuuk	Wind–water	n/a	n/a	n/a	n/a	Alkaline	19.4	98	70%	12	CHG	185	12
The Hydrogen Office	Wind	750	n	–	–	Alkaline	5.3	30.5	62%	12	CHG	133	12
Hybrid energy storage system at NFRC, California	Solar, public grid	5	y	n/a	n/a	PEM	1.1	7	53%	13.8	CHG	0.5	13.8
Hybrid Power Plant Enertrag, Prenzlau	Wind	6000	n	–	–	Alkaline	120	500	85%	atm.	CHG	15,017	31
Hydrogen Island Bozcaada	Wind–solar	30–20	n	–	–	Alkaline	11	55	71%	30	CHG	667	n/a
Ramea Wind-Hydrogen-Diesel Project	Wind	300	n	–	–	Alkaline	27	162	59%	10	CHG	1000	16.2
MYRTE, Corsica	Solar	560	n	–	–	PEM	10	56	63%	35	CHG	494	35
Hydrogen Mini Grid System Yorkshire	Wind	225	y	n/a	n/a	Alkaline	5.9	30	70%	30	CHG	2225	420
Solar Fuel Plant, ZSW Stuttgart	Public grid	–	n	–	–	Alkaline	49	250	70%	n/a	CHG	n/a	n/a
H2Herten	Public grid[a]	–	y	n/a	n/a	Alkaline	30	152	70%	n/a	CHG	n/a	n/a
RH2 WKA	Wind	140,000	n	–	–	Alkaline	200	1000	71%	n/a	CHG	9500	300
Demonstration Plant EON, Falkenhagen	Public grid	–	n	–	–	Alkaline	360	2000[b]	64%	n/a	None	–	–
Solar Fuel Beta-Plant Audi, Werlte	Public grid	–	n	–	–	Alkaline	1245	6300[b]	70%	n/a	CHG	n/a	n/a
Hydrogen Island Aitutaki	Wind–solar	174–20	n	–	–	Alkaline	11	55	71%	30	CHG	n/a	n/a

n/a – information not available; efficiency (eff.); pressure (press.); contradictory information, author's assumptions and calculations in italics.

a Programmable power source.

b Total installed capacity.

in Ref. [50], where 20-year old modules are being utilized. For a better distribution of the power output over the day, the photovoltaic modules were installed in four different orientations in Ref. [113].

Wind energy is the sole renewable power source in nine realized power-to-gas pilot plants. In four projects wind turbines are applied in combination with the public grid and in eight projects they provide power in combination with other renewable energy sources. Altogether, wind turbines generate electricity in 51% of the realized power-to-gas systems.

Problems resulting from turbulent and gusty winds occur particularly often with wind turbines mounted on islands that have a large wind energy potential [67]. A market gap was detected in Ref. [66] for wind turbines between 6 kW and 300 kW, that are suitable for high wind classes, and so prototypes have been put into operation. That usually entailed technical problems. In Ref. [88] it was recommended that power-limiting settings for wind turbines be applied when strong winds occur instead of a total power-shutdown. Further challenges are caused by the high moisture and salt content in the air in power-to-gas systems located on remote islands. Therefore, efforts should be made to optimize wind turbines for higher wind speeds and to attain high standards for the materials they are made of, as is recommended in Ref. [67].

Water power is only utilized in three realized power-to-gas pilot plants, in two of them together with other renewable power sources. Water power in combination with hydrogen storage is better suited for stand-alone applications such as the ones realized in Refs. [13,49,65], since there the need for balancing power in grid-connection mode is negligible.

34% of the realized power-to-gas pilot plants obtain their renewable electricity from more than one renewable power source, leading to flattened power output, since especially solar and wind energy complement each other to a certain extent [56].

In contrast to the realized power-to-gas pilot plants, systems that are in the planning stage obtain electricity from the public power grid in 43% of cases. Two of the planned projects are going to obtain electricity from wind turbines as their sole power source and one system utilizes wind and solar energy to generate renewable electricity.

The main focus is shifting from autonomous energy supply and stand-alone operation to grid-connected systems. Grid-connected power-to-gas plants may balance power fluctuations that result from a higher percentage of renewables in the overall electricity generation. Especially in Germany, a strong focus is being placed on the power-to-gas technology, since five out of the seven planned pilot plants are going to be realized there.

3.2. *Application of batteries in power-to-gas systems*

In the power-to-gas pilot plants that have been realized, 46% of the systems operate an additional battery bank for storing electricity. In systems that obtain electricity from the public grid, only two out of ten plants utilize a battery. On the contrary, in projects in which the renewable energy generator is directly connected to the electrolyzer 53% make use of a battery bank.

Batteries are suitable for short-term energy storage and minimize the cycling of the electrolyzer [65]. Besides, they can manage load transients and intermittent power peaks, provide bus stability and smooth out the power output of renewables [8,10,65].

Hardly any problems were reported in the course of the various power-to-gas pilot plants in connection with batteries, possibly due to the application of state-of-the-art battery technology such as lead-acid in most of the systems (see Table 3). Only one project reports problems; there a significant loss in the capacity of the lead–acid battery occurred after three years of operation [25].

Batteries can play an important role in control strategies of power-to-gas systems, since the state of charge (SOC) of the battery is used as the main control variable in many pilot plants. That has been documented in Refs. [10,27,50,58,65]. The determination of the SOC-levels that start or stop the operation of the electrolyzer and the fuel cell has a strong influence on the operational performance of those plants.

Employing the SOC as main control variable enables a high-current operation of the electrolyzer and therefore a high purity of the hydrogen that is obtained. Furthermore, a smooth operation of the electrolyzer and the fuel cell can be realized [50].

Table 3 provides additional information about the capacity of the batteries for some power-to-gas pilot plants. There are considerable differences in the sizes of the batteries in relation to the installed system size, but no overall evaluation is made, since the design always depends on the system configuration of the pilot plant.

3.3. *Electrolyzer operation*

Electrolyzer technologies can be divided into alkaline, proton exchange membrane (PEM) and solid oxide electrolysis cells (SOEC), according to the electrolyte that is applied.

Alkaline electrolyzers have an aqueous alkaline electrolyte, operate between 70 °C and 140 °C at pressures between 1 bar and 200 bars [114] and typically achieve efficiencies of between 60% and 71% (HHV) [115]. The commercially available modules have capacities of up to 760 Nm^3/h [112]. The alkaline technology is the most highly developed and cheapest one [115].

PEM electrolyzers have the advantage of simple design. They typically reach high efficiencies of between 65% and 83% (HHV) [115] and are ideal for fast load changes [114]. They do however give rise to problems because of the limited lifetime of their membrane, their small available capacities of up to 30 Nm^3/h [112], their higher costs due to the noble metal catalysts like Pt which they contain and their expensive membranes [116]. Other electrolyzer technologies are not described here, as they were not applied in the evaluated power-to-gas pilot plants.

Table 3 shows the main specifications of the electrolyzers that were employed in the evaluated power-to-gas systems. 67% of the realized projects make use of alkaline electrolyzers and in the other systems PEM technology is utilized. In two of the evaluated systems, both electrolyzer types are operated, but a comparison of the two technologies is only documented in Ref. [85]. Altogether, 52 realized electrolyzers are evaluated, as in some projects more than one device is used.

Further information on the nominal capacity and the installed power of the electrolyzer is given in Table 3. The energy efficiency of the electrolyzer is defined as $\eta_{electrolyzer} = \dot{V}_{H_2} * HHV/P_{el}$ where $\dot{V}_{H_2}$ is the nominal capacity, P_{el} is the installed power of the electrolyzer and HHV is the higher heating value of hydrogen with 12.75 MJ/Nm^3 [6]. As for many projects only the capacity or the installed power has been reported, the missing value is calculated on the basis of the average efficiency of all the projects that stated both their nominal capacity and their power; a distinction was thereby made between PEM and alkaline electrolyzers. The average nominal efficiency of applied alkaline electrolyzers based on the higher heating value is 70%. For applied PEM electrolyzers the average nominal efficiency is 63% (HHV). While stated efficiency values for alkaline electrolyzers range from 54% up to 85%, PEM nominal energy efficiency ranges from 52% to 79% in the evaluated power-to-gas systems. It should be possible to achieve higher efficiencies with PEM technology, as stated previously, but it was not possible to demonstrate this for the devices in the evaluated power-to-gas pilot plants.

For the performance of power-to-gas pilot plants, the achieved operational efficiency is more crucial than the nominal efficiency. The real performance depends on various parameters like operating pressure, temperature and operating power range. It is also influenced by the age of the electrolyzer, as the degradation of stacks lowers the efficiency. Measured efficiencies in the evaluated power-to-gas systems strongly depend on the whole system configuration, the operating conditions and in many cases they are related to different system boundaries. The efficiency calculation is often not sufficiently documented and is therefore excluded in the article, since the comparison of operating efficiencies cannot be substantiated.

Fig. 4 shows the installed capacity of alkaline and PEM electrolyzers during the initial years of their operation. As can be seen in Fig. 4, alkaline type electrolyzers have been utilized in power-to-gas pilot plants from the very beginning of this technology in 1991, and they are still being used today.

The nominal powers of the alkaline electrolyzers tend to increase and the largest electrolyzer that is currently in operation has an installed power of 500 kW and is operated at the hybrid power plant of Enertrag in Germany [36]. The average power of all installed alkaline electrolyzers is 98 kW.

PEM electrolyzers have been increasingly often installed since the year 2003. The average installed PEM unit has a capacity of 8.6 kW and the largest PEM electrolyzer that is currently in operation has a nominal power of 41 kW. This clearly indicates that PEM electrolyzers are applied in a lower power range compared to alkaline units and that they are not yet suitable for large plants.

In the power-to-gas systems that are now being planned only alkaline electrolyzers are going to be employed. Information about the size of the individual devices could not be obtained for all of the planned projects and so the total installed power of electrolyzers is only stated for two systems in Table 3.

3.3.1. *Coupling renewable power sources with the electrolyzer*

Difficulties in matching the characteristics of electrolyzer and renewable power sources, such as the ones reported in Ref. [76], can in most systems be solved by using DC-to-DC converters. This enables each device to operate at its optimum power range [65]. The application of DC-to-DC converters or MPPT (maximum power point trackers) enables quicker load changes, a high current operation of the electrolyzer and protects the device from fast voltage fluctuations [50]. The disadvantage that thereby arises is that the installation of DC-to-DC converters leads to efficiency losses. The stated efficiency of the converters utilized in realized power-to-gas pilot plants considerably varies, namely from a maximum of 98% in Ref. [26] to an efficiency of 77% in Ref. [50].

Experience with MPPT that has given rise to controversy is reported in Refs. [27,85]. In the course of the Wind2H2 project it was reported that despite the losses resulting from the installation of DC-to-DC converters, the overall energy delivered by the photovoltaics increased by 10%–20%. Operating the wind turbine in connection with an AC-to-DC converter leads to an optimal result and eliminates the need for a battery link and several power electronics conversions [85].

On the contrary, it is reported in Ref. [27] that the photovoltaic MPPT was eliminated after 4 years of operation in the

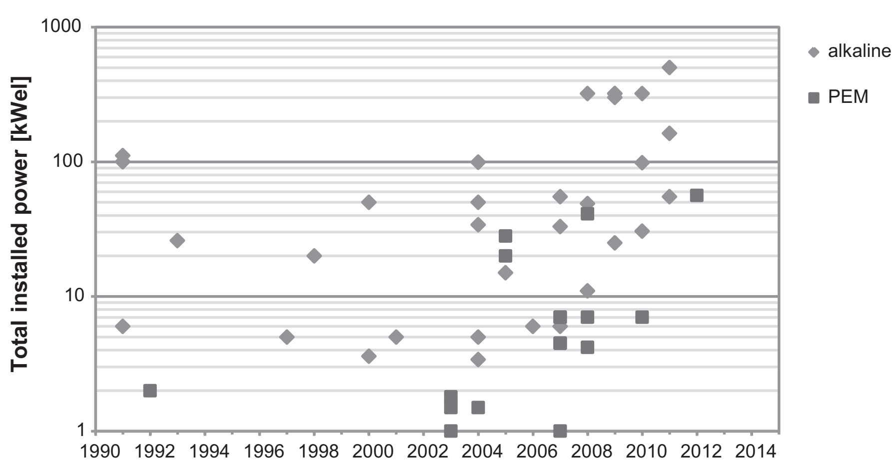

Fig. 4 – Installed power of electrolyzers.

Phoebus project and the photovoltaic array was directly coupled to the battery. This resulted in 3% less solar energy conversion but a 10% greater efficiency due to the elimination of the MPPT. Problems with power electronics were reported in the first projects in 1991 [24], in which only prototypes were available, and harmonic interferences occurred between DC-to-DC converters and batteries in 1997 [50].

3.3.2. *Operating experience with alkaline electrolyzers*

In many power-to-gas pilot plants the alkaline electrolyzer operates reliably, as was reported in Refs. [29,66,77,113]. However, a number of problems occurred in connection with alkaline electrolyzers:

- Low purity of the hydrogen that was produced [24].
- Stack degradation, membrane deterioration and decreased efficiency after 5 years of operation in Ref. [24] and after 2 years in Ref. [65].
- Safety problems with the KOH electrolyte solution. The operating personnel experienced severe headaches and tiredness [64].
- Problems with intermittent and fluctuating power sources [66], such as delayed reaction [31] and difficulties in starting the system after a shut-down [56]. That is why continuous electrolyzer operation is suggested in Ref. [56].
- Measured efficiency 20% lower than what the manufacturer claimed was possible in Ref. [88].
- Extensive maintenance in Ref. [6].

In order to operate electrolyzers with fluctuating renewable power sources, a wide operational range is required. Typical operational power ranges of the evaluated alkaline electrolyzers lie between 20% and 100% of their nominal power, as was reported in Refs. [65,113]. Compared to PEM electrolyzers, the operational range of alkaline electrolyzers is smaller and therefore they are less suitable for operation with intermittent and fluctuating power sources.

Alkaline electrolyzers are being utilized in most power-to-gas pilot plants, even though that has led to several problems. At the moment that is the only technology available for higher capacities.

3.3.3. *Operating experience with PEM electrolyzers*

Compared to alkaline systems, PEM type electrolyzers display better starting behavior [89] and a wider operational range between 5% and 100% of nominal power [56]. The dynamic operation with intermittent and fluctuating power sources is satisfying [66], and brief transients are tolerated by the PEM electrolyzer, as is reported in Ref. [91].

The hydrogen purity is greater with PEM technology, and so the gas purification unit after the electrolyzer can be omitted [66]. For the evaluated power-to-gas projects with PEM electrolyzers a hydrogen purity of 99,999% and 99.9995% has been reported in Refs. [62,91]. Further auxiliary equipment is not necessary, since PEM electrolyzers have no need to circulate a liquid electrolyte. Since they can withstand high pressures, hydrogen compression can also be avoided [66]. However, PEM electrolyzers have problems in respect to their lifetimes, as was stated for example in Ref. [66]. Alkaline technology was employed in that project, since the PEM manufacturers could only give 6–12 month warranties with an expected lifetime of 5 years.

Other technical problems that occurred are freezing of the membrane in winter [57] and very rapid stack degradation, such as was reported in Ref. [89]. There, a new stack was needed only three months after the initial installation.

Measurements in Ref. [85] showed that the measured efficiency of the PEM electrolyzer was higher than that of the alkaline electrolyzer. Despite the better performance of PEM technology with intermittent and fluctuating power sources, mainly alkaline electrolyzers are now being purchased due to the limited lifetime and the lack of high capacities of PEM electrolyzers.

3.4. *Hydrogen storage*

Table 3 presents the most important information about the hydrogen storage systems of the power-to-gas pilot plants that were evaluated. A vast majority (88%) of the realized projects utilizes pressure tanks (CHG) for hydrogen storage and only in five systems are metal hydride (MH) tanks being tested. Two of the realized plants are testing both technologies, as was reported in Refs. [10,51]. In planned projects only pressure tanks will be utilized. This is primarily due to the various advantages of this state-of-the-art technology such as commercial availability, low costs and high capacities.

The size of the long-term hydrogen storage device that is needed depends on the availability and the seasonal variation of the renewable power sources and can be reduced by using more renewable power generators [26]. Table 3 provides information about the hydrogen storage capacity, but since there are various system configurations which utilize hydrogen differently, that value is not directly related to the overall plant capacity.

The pressure needed for hydrogen storage varies between 4 bars and 400 bars and depends on the type of application. In fueling stations, for example, high pressures with around 300 bars are required for dispensing devices. High-pressure storage has the advantage of saving space [27], but it necessitates the operation of a hydrogen compressor, which lowers the efficiency of the whole system. In order to save compression energy, a buffer tank can be installed after the electrolyzer and compression can be started when the tank is at full charge, as described in Refs. [8,47]. Hydrogen compression can be avoided by applying a pressure electrolyzer, such as the ones realized in various evaluated projects. These power-to-gas pilot plants, described in Refs. [10,24,29,31,52,53,89], store hydrogen at the electrolyzer operating pressure that ranges from 12 to 30 bars. That has the advantages of reducing the investment that is needed and avoiding downtimes. In Ref. [56] it is stated that high-pressure electrolysis without hydrogen compression is more efficient (approx. 5%), but since it results in increased costs for material, safety and control systems, it is advisable to use low-pressure electrolysis with adjacent hydrogen compression.

Since metal hydrides for hydrogen storage are still in the developmental phase, various problems have been reported in the power-to-gas pilot plants that have been realized. Since the metal hydride has to be cooled in summer for safety reasons and heated to enable hydrogen to be released in winter, an air conditioning system had to be installed in Ref. [57]. In Ref. [53] it is reported that heat from the fuel cell had to be provided to maintain the internal pressure in the metal hydride during discharge.

Alternatively, hydrogen can be stored with liquid organic hydrogen carriers (LOHC) like ethylcarbazole $C_{14}H_{13}N$. This chemical substance exists in low- and high-energy states, can be charged with hydrogen and is not consumed in the dehydrogenation process. The charged liquid substance can be utilized in gas turbines, fuel cells or transport applications, and since ethylcarbazole has a high chemical stability and storage density, it is well suited for long-term storage. Due to the fact that the discharging process operates at ambient pressure, the compound could prove interesting for transport applications [117]. This technology is at the stage of basic research and a pilot plant has not yet been realized, as was stated in chapter 2.

4. Hydrogen application pathways

Currently, hydrogen is mostly utilized as a raw material for chemicals in industrial processes [110], but the application of hydrogen as an energy vector is promising for the future. Hydrogen as an energy vector has the clear advantage that it does not contain any C-atoms and therefore makes no contribution to the greenhouse effect by emitting carbon dioxide or other greenhouse gases. Hydrogen is the lightest of all the elements and has a high diffusivity in many materials. Thus, storage requires high pressure, low temperatures and special materials to limit diffusion and leakages [118]. Hydrogen gas leakage could give rise to explosion hazards and significant amounts of that gas in the atmosphere could lead to the formation of radicals that enhance ozone depletion [110]. Another challenge to the utilization of hydrogen as an energy vector is the fact that hardly any infrastructure for it exists, except for the facilities of the chemical industry [117].

The hydrogen produced in power-to-gas plants can be utilized in different pathways:

- Electricity generation with fuel cells, internal combustion engines or cogeneration plants.
- Fueling stations for hydrogen vehicles or the utilization of hydrogen in industry.
- Gas distribution system feed-in of hydrogen.
- Further synthesis to methane (or other hydrocarbon fuels).

As was already established in chapter 2, hydrogen fueling stations with on-site electrolytic hydrogen production will not be dealt with in this evaluation.

Hydrocarbon fuels such as methane, methanol or synthetic gas can be synthesized out of hydrogen and some pilot plants that perform methane synthesis are included in the evaluation. There are also pilot plants which produce synthetic gas [119] and methanol [99,100], but as information about these projects was scarce, they are not evaluated in this article.

The main information about the modes of hydrogen utilization in the various power-to-gas pilot plants is summarized in Table 4. Detailed information is provided about the nominal power of the electricity generating devices that are used.

With the exception of one pilot plant that utilizes hydrogen to produce methane, all of the other realized projects use the hydrogen that is produced for the generation of electricity. In one third of these systems, the hydrogen is additionally utilized for heat generation or as fuel in fueling stations. Two of the realized power-to-gas pilot plants additionally apply other devices like catalytic heaters in Refs. [24,29] or a catalytically heated absorption-type refrigeration unit in Ref. [24].

Planned power-to-gas plants display a broad range of applications; for example, 4 projects generate electricity out of hydrogen, 2 systems synthesize methane and 1 project is going to feed hydrogen into the gas distribution system.

4.1. *Electricity generation out of hydrogen*

Depending on the choice of fuel and the electrolyte, fuel cell technologies can be divided into alkaline (AFC), phosphoric acid (PAFC), solid oxide (SOFC), molten carbonate (MCFC), proton exchange membrane (PEMFC) and direct methanol (DMFC) fuel cells [120]. AFCs utilize an alkaline electrolyte in a water based solution, operate at temperatures between 60 and 90 °C, have an electrical efficiency of 60% and are available up to 20 kW. They have simple structures and utilize low-cost catalysts, but as they easily are contaminated by carbon dioxide, purified air or pure oxygen has to be applied [120]. PAFCs have a liquid phosphoric acid electrolyte, operate between 150 and 220 °C, achieve electrical efficiencies ranging between 40 and 50% and are commercially available up to 200 kW. They can be operated with air and have the advantage of long-term stability, but their initial costs are high, since a Pt catalyst has to be used. PEMFCs operate at low temperatures between 60 and 100 °C, achieve electrical efficiencies of between 40 and 50% and are available up to 250 kW. The systems are compact, their start-up process is rapid and the sealing is easier due to the solid electrolyte. PEMFC have a longer lifetime and are cheaper to manufacture than other technologies [120]. Other fuel cell technologies are not described here, as they have not been utilized in the power-to-gas pilot plants that are evaluated.

Table 4 provides the main information about the electricity generating devices like the type of fuel cell or the nominal power. In the realized power-to-gas pilot plants, electricity is generated with fuel cells in 83% of the systems and 5 of these projects also utilize an internal combustion engine or a cogeneration plant. Two of the projects are trying out different fuel cell technologies in parallel, as was reported in Refs. [24,113]. In eight projects, rejected heat from fuel cells is applied for heating purposes.

Systems that do not operate a fuel cell generate electricity with an internal combustion engine in (five projects) or with a cogeneration plant (one project). The cogeneration unit documented in Ref. [30] operates with a mixture of natural gas and hydrogen (up to 60%). The hydrogen engine in Ref. [56] is a modified diesel genset that has low efficiency of maximum 20% and developed technical problems after 3 years of reliable operation. Operating experience with hydrogen engines or cogeneration plants has hardly been subjected to documentation in the various power-to-gas projects.

Table 4 – Utilization of hydrogen in power-to-gas pilot plants (based on information from data sources presented in Table 1).

Project name	Final energy	Infrastructure	Devices				Electricity generation		
			FC	ICE	CHP	H_2 fueling station	Type	Power [kWel]	Heat [kWth]
Schatz Solar Hydrogen Project, California	Electricity	Local grid	x	–	–	–	PEMFC	1.5	–
SWB Project, Neunburg vorm Wald	Electricity, heat, fuel	Public grid	x	–	–	x	AFC PAFC	6.5 79.3	– 42.2
Freiburg Solar House	Electricity, heat	Local grid	x	–	–	–	PEMFC	3.5	n/a
PHOEBUS, Jülich	Electricity	Local grid	x	–	–	–	AFC PEMFC	6.5 5.6	– –
SAPHYS	Electricity	Local grid	x	–	–	–	PEMFC	2.75	–
Laboratory Plant Stralsund	Electricity, heat, fuel	Public grid	x	–	x	x	PEMFC CHP	1.2 30	– 60
PVFCSYS Sophia Antipolis	Electricity	Local grid	x	–	–	–	PEMFC	4	–
Grimstad Renewable Energy Park	Electricity	Local grid	x	–	–	–	AFC	2.5	–
Laboratory Plant HRI Quebec	Electricity	Local grid	x	–	–	–	PEMFC	5	–
FIRST – Showcase II	Electricity	Local grid	x	–	–	–	PEMFC	0.4	–
Laboratory Plant IFE Kjeller	Electricity	Local grid	x	–	–	–	PEMFC PEMFC	0.5 1.2	– –
PVFCSYS Agrate	Electricity	Local grid	x	–	–	–	PEMFC	2	–
HARI Project, West Beacon Farm	Electricity, heat	Local grid	x	–	x	–	PEMFC PEMFC CHP	2 5 15	2 – 38
Utsira Island	Electricity	Local grid	x	x	–	–	PEMFC ICE	10 55	– –
DTE Energy Hydrogen Technology Park, Southfield Michigan	Electricity, fuel	Public grid	x	–	–	x	PEMFC	10 × 4	–
Small Scale Renewable Power System DRI	Electricity	Local grid	–	x	–	–	ICE	n/a	n/a
PURE Project, Unst	Electricity, heat, fuel	Local grid	x	–	–	x	PEMFC	5	n/a
Hydrogen Energy Storage System, Takasago Thermal Engineering	Electricity	Local grid	x	–	–	–	PEMFC	5	–
HyWindBalance – laboratory plant Oldenburg	Electricity	Local grid	x	–	–	–	PEMFC	1.2	–
RES2H2 Gran Canaria	Electricity	Local grid	x	–	–	–	PEMFC	6 × 5	–
Nakskov Industrial & Energy Park, Lolland	Electricity, heat	*Public grid*	x	–	–	–	PEMFC PEMFC	7.5 2	n/a n/a
Wind2H2 Project	Electricity, fuel	Public grid	x	x	–	x	PEMFC ICE	5 60	– –
Hawaii Hydrogen Power Park	Electricity	Local grid	x	–	–	–	PEMFC	5	–
IRENE System	Electricity	Local grid	x	–	–	–	PEMFC	1.2	–
Hydepark	Electricity	Local grid	x	–	–	–	PEMFC	2 × 1.2	–
H_2 from the sun, Brunate	Electricity	Local grid	x	–	–	–	PEMFC	5	–
Hydrogen Wind Farm Sotavento	Electricity	Public grid	–	x	–	–	ICE	55	–
Stand-alone power system, Neo Olvio of Xanthi	Electricity	Local grid	x	–	–	–	PEMFC	4	–
Hidrolica, Tahivilla	Electricity	Public grid	x	–	–	–	PEMFC	12	–
Baglan Energy Park Wales	Electricity, fuel	Local grid	x	–	–	x	PEMFC	12	–
Wind Hydrogen Village Prince Edward Island	Electricity	Local grid	–	x	–	–	ICE	130	–
Hychico, Comodoro Rivadavia	Electricity	Local grid	–	x	–	–	ICE	14,000	–
Solar Fuel Alpha-Plant, mobile device	Methane	None	–	–	–	–	None	–	–
HARP System, Bella Coola	Electricity, fuel	Local grid	x	–	–	x	PEMFC	10 × 10	
H2KT – Hydrogen Energy Storage in Nuuk	Electricity, heat, fuel	Local grid	x	–	–	x	PEMFC	2 × 10	n/a
The Hydrogen Office	Electricity	Public grid	x	–	–	–	PEMFC	10	n/a
Hybrid energy storage system at NFRC, California	Electricity	Local grid	x	–	–	–	PEMFC	1	–
Hybrid Power Plant Enertrag, Prenzlau	Electricity, heat, fuel	Public grid	–	–	x	x	CHP	700	680

Table 4 – (continued)

Project name	Final energy	Infrastructure	Devices				Electricity generation		
			FC	ICE	CHP	H_2 fueling station	Type	Power [kWel]	Heat [kWth]
Hydrogen Island Bozcaada	Electricity	Local grid	x	x	–	–	PEMFC ICE	21 35	– –
Ramea Wind-Hydrogen-Diesel Project	Electricity	Local grid	–	x	–	–	ICE	250	–
MYRTE, Corsica	Electricity	Public grid	x	–	–	–	PEMFC	100	–
Hydrogen Mini Grid System Yorkshire	Electricity, fuel	Local grid	x	–	–	x	PEMFC	3 × 12	–
Solar Fuel Plant, ZSW Stuttgart	Methane	None	–	–	–	–	None	–	–
H2Herten	Electricity, heat, fuel	Local grid	x	x	–	x	PEMFC ICE	50 n/a	n/a –
RH2 WKA	Electricity, heat	Public grid	–	–	x	–	CHP	250	400
Demonstration Plant EON, Falkenhagen	Hydrogen feed-in	Gas distribution system	–	–	–	–	None	–	–
Solar Fuel Beta-Plant Audi, Werlte	Methane	Gas distribution system	–	–	–	–	None	–	–
Hydrogen Island Aitutaki	Electricity, fuel	Local grid	x	–	–	x	PEMFC	15	–

n/a – information not available, contradictory or not confirmed information in italics.

Electricity will be generated out of hydrogen in 4 of the 7 planned projects with the help of fuel cells, combustion engines and cogeneration plants.

Fig. 5 shows the installed capacity of PEM, alkaline and phosphoric acid fuel cells during the initial years.

As shown in Fig. 5, only 1 phosphoric acid and 3 alkaline fuel cells have been installed in realized systems and therefore PEM is clearly the dominant technology for fuel cells. Alkaline fuel cells and PAFCs were however installed in earlier power-to-gas pilot plants. Since the year 2000 only PEM fuel cells have been installed. Three of the planned systems are also going to utilize PEM fuel cells and therefore it appears that this is the only relevant technology at the moment.

The average power of the operating PEM fuel cells is 7.2 kW and the maximum capacity of one single unit is 100 kW. As illustrated in Fig. 5, PEM fuel cells with a nominal power capacity greater than 10 kW are only in operation in four pilot plants. For large scale power-to-gas plants it is a disadvantage that only PEM fuel cells with low capacities are available, since numerous fuel cell units are required to provide the power that is needed, and it is expensive to install all of them.

4.1.1. *Operating experience with PEM fuel cells*

PEM fuel cells can incur damage during long stand-by periods under freezing temperatures [3,6]. When in operation they are easy to maintain and reach high efficiencies at part load, as was reported in Ref. [89]. PEM technology is therefore very well suited for fast load changes [121] and one device in the evaluated projects is even capable of black starting [56]. Although PEM is definitely the most commonly applied fuel cell type, many problems occur in the power-to-gas pilot plants that have been evaluated:

- Internal leakage in Refs. [56,57].
- Short operation times of less than 100 h due to rapid stack degradation in Refs. [56,122].

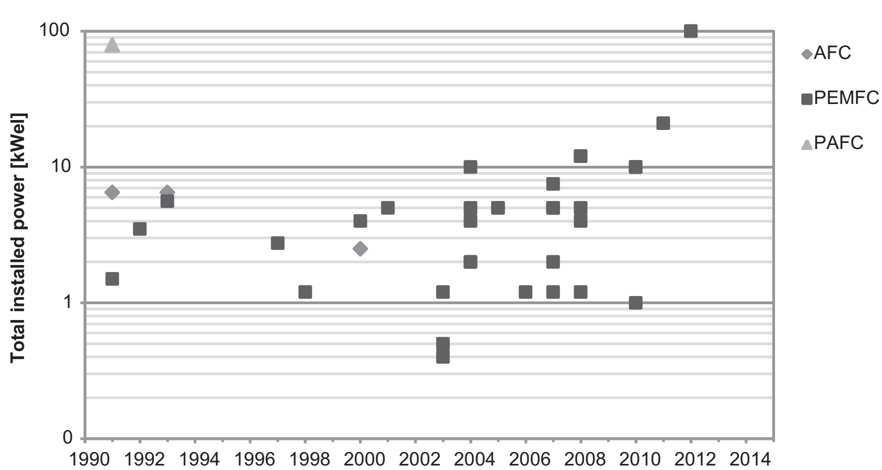

Fig. 5 – Installed power of fuel cells.

- Problems with drastic changes in load. Voltage drop has a negative effect on stack lifetime [31].
- Defective purging system (pipeline and valves) in Ref. [52].

4.1.2. *Operating experience with alkaline and phosphoric acid fuel cells*

Alkaline fuel cells require very pure input gases (oxygen and hydrogen) and are highly complex and sensitive. All of the three alkaline fuel cells that were installed have already been decommissioned. The stacks of the alkaline fuel cells in the SWB project [24] were replaced several times and after only 100 operating hours the fuel cell was decommissioned, because the manufacturer abandoned this area of activity. A problem with leakage is reported in Ref. [27] and since the fuel cell was not appropriate for unmanned operation due to the complex design and high sensitivity, it was replaced by a PEM fuel cell [28].

Although several problems occurred during the commissioning of the PAFC in Ref. [24] which entailed extensive repairs in the peripheral systems, it was possible to operate it over a long term, although with over 500 starts and stops [123]. The device operates with natural gas, hydrogen or a mixture of these fuels and provides electricity and heat.

4.2. *Hydrogen fueling stations*

Utilizing hydrogen in fueling stations for mobile devices can be seen as a state-of-the-art technology, as was mentioned in chapter 2. The hydrogen from fueling stations can be utilized in transport vehicles like cars, trucks or forklifts and in the chemical industry. Table 4 shows that in addition to electricity generation, ten of the realized power-to-gas pilot plants have a hydrogen fueling station. Most of these projects also have mobile devices such as forklifts in Ref. [24] or hydrogen fuel cell vehicles in Ref. [66]. The typical dispensing pressure of hydrogen fueling stations lies between 300 bars and 700 bars.

4.3. *Feeding hydrogen into the gas distribution system*

Feeding hydrogen or methane from power-to-gas plants into the gas distribution system would have several advantages, since it would link the power grid with the gas distribution system. Storage of excess electricity in the form of hydrogen or methane would become possible, since the gas infrastructure has a very large energy storage capacity [124].

Whereas the feeding-in of synthetic methane is unproblematic, hydrogen feed-in involves several uncertainties. It is not clear to what extent hydrogen can be fed into the gas distribution system and the information about the impacts and risks of doing so is very contradictory.

Besides the impact of hydrogen on the gas infrastructure such as the pipelines and the storage facilities, the tolerances of the various hydrogen equipment and devices is crucial for the determination of a limit for hydrogen content. Hydrogen influences the gas characteristics like higher heating value and density and is critical for gas turbines and combined-cycle plants, since the power is reduced and an adaptation of the gas burners is necessary at higher hydrogen content [125]. Little research has been carried out on the hydrogen tolerance of gas storage infrastructure facilities and CNG vehicles, where the storage tank actually has a limit of max. 2 vol% hydrogen [126]. The hydrogen tolerance of pipeline material, gas pressure controlling plants and new gas burners and devices in households is reported to be greater [126].

Table 4 shows that no project has yet been realized that feeds hydrogen or methane out of electrolysis into the gas distribution system. However, plans exist to install two power-to-gas pilot plants in Germany into which hydrogen and synthetic methane will be fed in the near future.

4.4. *Synthesizing methane*

Hydrogen produced by electrolysis can be further synthesized to various types of hydrocarbon fuels. The great advantage of synthesizing methane out of hydrogen is that it can be fed into the gas distribution system without any restrictions. Methane is highly flexible in application and can be utilized for heating, transportation, long distance traffic, electricity generation or as a feedstock for the chemical industry and substitute for fossil hydrocarbons in the material cycle [114].

Synthetic methane is produced out of hydrogen and carbon monoxide or carbon dioxide in the so-called Sabatier process [117]. The chemical reactions are strongly exothermic and require catalysts such as Ni or Ru. Ni is thereby optimal in respect to its activity, selectivity and costs, but requires input gases that are very pure [112].

CO methanation is the state-of-the-art in coal gasification and is being applied on an industrial scale with efficiencies of between 75% and 85% at operating temperatures between 250 °C and 500 °C [125].

The CO_2 methanation process is currently being tested on a laboratory scale and although efficiencies similar to those with CO have been attained, some technical challenges do remain: heat dissipation, providing an optimal reaction temperature and storing hydrogen in a manner that precludes fluctuations [125].

Carbon dioxide may be obtained from fossil sources by carbon capture in coal-fired power plants or as a by-product in industrial processes like cement or lime production. Regenerative carbon dioxide is delivered as a by-product in the fermentation process of biogas plants and in biomass gasification and it can also be extracted from the ambient air [127]. Some problems in respect to carbon dioxide sources are the low efficiency of the absorption process from air, the limited capacity of biogas plants and the higher energy demand of power plants that capture fossil carbon dioxide [117]. The overall efficiency of CO_2 methanation is largely dependent on the purity of the carbon dioxide [128].

Table 4 shows that methane is the only hydrocarbon fuel that has already been synthesized in power-to-gas pilot plants. With regard to fluctuating and intermittent renewable power sources, the methanation process is more critical than the electrolysis process, since its operating temperatures are higher. To be able to operate the methanation reactor continuously and thus be able to maintain the reaction temperature at a constant level, hydrogen storage has to be installed as a buffer. The optimum capacity of the hydrogen storage facilities in relation to the power of the methanation device has not yet been determined [34].

Two more power-to-gas plants with methane synthesis are going to be realized in Germany in the near future. One 250 kW plant delivers methane at a fueling station and the other 6.3 MW plant is going to feed methane into the gas distribution system.

5. Lessons learned

In this chapter, the problems and conclusions of the various power-to-gas pilot plants that have been evaluated are summarized. As mentioned in chapter 2, the extent of documentation of the systems differs significantly and whereas some projects provide detailed information about their design and operational experiences, other projects do not report having learned any particular lessons.

The main experience from the evaluated power-to-gas pilot plants and the consequent recommendations are divided into design aspects, problems with various components, efficiency, the lifetime of the systems and system integration with respect to the available infrastructure.

5.1. *Design and sizing of power-to-gas systems*

The design of a power-to-gas plant depends to a large extent on its location, power requirements and load profile and greatly influences the overall system efficiency, as reported in Refs. [4,46,56].

In the course of many projects, some components were found to be oversized. In Ref. [64] some simulations of the whole system show that the renewable power source and the fuel cell are of the correct size, but the electrolyzer and the hydrogen storage up to 40% larger than necessary. In Ref. [113] it was also reported that a smaller electrolyzer capacity would have been sufficient for the system. It is very important to have a battery that is optimal for the given electrolyzer capacity, as is reported in Ref. [64]. Due to the oversizing of the photovoltaic array in Ref. [57], the running time of the fuel cell was very low.

Other considerations that often are problematical are the sizes of the auxiliary units and the high complexity of the systems. They gave rise to parasitic energy consumption and decreased reliability in Refs. [50,58,61]. The complexity of the auxiliary systems is often underestimated, as reported in Ref. [24], and communication problems in the control systems that result from their complexity occur in Ref. [61]. In almost all of the project reports it is recommended that a great deal of attention be devoted to the design and sizing of the power-to-gas system, since that has great influence on their efficiency, reliability and economics. Additionally, attention should be paid to attendance, service and safety aspects [3]. In Ref. [123] centralized hydrogen production and large scale plants are recommended, since the sizes of the auxiliaries are large and safety aspects and maintenance show little dependence on system size. Placing system installations outdoors reduces the complexity of the auxiliary equipment, as stated in Ref. [24]. In highly complex systems improvements could also be brought about by utilizing very flexible control systems [57] or taking a modular approach [14].

System integration is another important consideration for improving the overall efficiency and reducing complexity and costs. Open-architecture approaches would enable various components from a wide range of manufacturers to work together, which is why standard communication protocols are demanded in Refs. [10,85].

One of the main impediments to the installation of power-to-gas pilot plants is the lack of permission codes and standards, as was reported in Refs. [10,20,59,66,85]. Due to the lack of such codes, it was sometimes difficult and time-consuming to obtain licenses for the pilot plants [61]. In Ref. [20] it is recommended that all of the relevant authorities be involved in the permission process at the earliest possible stage to avoid loss of time.

Codes and standards for control and communication profiles, safety issues, fuel cells and hydrogen as an energy vector are also scarce, as stated in Refs. [66,85,89]. Clear and consistent codes and standards for all these considerations could bring improvements in planning efforts and overall costs [85].

5.2. *Experiences with the main components*

In the first hydrogen systems such as that reported in Ref. [24], nearly all components were prototypes and an individual design was necessary for each project. A more recent project which is documented in Ref. [31] exclusively made use of components that were available on the market. Nevertheless, many project evaluations state that components of the right size were hardly available on the market. A lack of reliable mass produced components, technology solutions and small-scale systems has been reported in various projects. Since the initial capital and installation costs were therefore high, some pilot plants had to operate with components of inappropriate sizes [5]. In one of the first projects [24], which was launched in 1991, procurement of spare parts was reported to have been difficult, since some manufacturers stopped producing items necessary for the plant subsystems.

In the course of the PURE project [66] that went into operation in 2005, only one manufacturer could be found that guaranteed continued electrolyzer efficiency for plants operating with intermittent renewable power sources. In the Schatz Solar Hydrogen Project, which was initiated in 1991, it was difficult to get a fuel cell, since the one that had been ordered could not be provided by the manufacturer for over two years [77]. Although the HARI project started operating 13 years later, finding a manufacturer that could provide a PEM fuel cell was still difficult as reported in Ref. [64]. A slight improvement in the fuel cell market could be observed at the time when the second fuel cell was purchased for this project.

In Ref. [10] it is stated that all of the major components except the batteries had manufacturing defects, several repairs were required before they could be implemented and their performance was poor. A great deal of technical support for the components was required in Ref. [25]. Leakage problems with hydrogen and KOH electrolyte were reported to have resulted from untight valves and fittings in Refs. [28,65].

For all components improvements will be needed in respect to efficiency [31], reliability [28], robustness [56], better operational behavior with fluctuations [31], lifetime and maintenance [89]. The costs of hydrogen components have to be reduced and the range of commercial electrolyzers and fuel cells should be increased, as is demanded by many projects [3]. In the course of the RES2H2 project [88] it was suggested that components should have a higher tolerance for hydrogen impurities such as small amounts of oxygen and humidity, since purification would then not be necessary. More research and development is also necessary in the field of power electronics in order to achieve an integration of renewable power generators, electrolyzers and fuel cells [85,88].

The complexity of power-to-gas systems could be reduced by utilizing a regenerative or reversible fuel cell (RFC), as is recommended in Refs. [3,4,129]. Unitized regenerative fuel cells utilize a bi-functional electrode pair that enables operation in both electrolysis and fuel cell mode [130]. In addition to reducing the complexity of the whole system, RFC have the advantage of lower material size and weight. However, in Ref. [91] it is stated that RFCs are far from being cost competitive with batteries and are not yet commercially available [130].

5.3. *Operating efficiency and lifetime*

One of the factors that has a major impact on system efficiency is the high auxiliary energy demand for fans, air compressors and the control system which was reported for various projects in Ref. [28] or [58]. Additionally, the operating efficiency and the system lifetime are strongly influenced by the main control system and the power management strategy, as was stated in Refs. [46,58,88]. The system described in Ref. [24] worked reliably for several years, after some system failures at the beginning of the project. Nevertheless, problems with plant components did crop up as a result of repeated starts and stops. These were necessary because the plant had to shutdown whenever it was unmanned. In Ref. [50] poor operating reliability of the auxiliary systems is documented.

It proved possible to offset power fluctuations from photovoltaics in Ref. [26], and adequate operation with the fluctuating power output of a wind farm is reported in Ref. [61]. In Ref. [91], load dynamics were successfully maintained by operating a battery in parallel and a reliable operation of the electrolyzer with fluctuating solar energy was guaranteed. To maintain the operating temperature of the fuel cell the battery was charged at a reduced load.

Although some projects report successful operation with fluctuating power sources, other systems had problems, especially ones involving the operation of the electrolyzer, as was already mentioned in chapter 3.3. It is therefore recommended to devote effort to the adaptation of electrolyzers to intermittent and fluctuating power sources.

As the energy demands and efficiency losses that result from auxiliary systems are not proportional to the overall system size, large scale power-to-gas plants are recommended in Ref. [28]. Efficiency improvements could also be achieved by improving the water management [65,113], optimizing the heat management [4,12] and matching the input and output requirements of all of the components [12].

5.4. *Integration of power-to-gas pilot plants into available infrastructure*

Since electricity is converted into hydrogen or methane in power-to-gas plants, there are different possibilities for integrating these facilities into the power grid or the gas distribution system.

A connection to the public power grid was available in 37% of the projects that were realized, either for feeding in electricity or for obtaining electricity from the grid. Three more projects utilized programmable power sources to simulate a renewable electricity input, although they were connected to the public power grid [10,38,55].

Different system configurations like grid-connection or stand-alone operation are possible, especially in laboratory plants such as the ones documented in Refs. [55,85]. Problems in connection with the public grid were reported in Ref. [61], as no price for the electricity produced by the hydrogen engine had been fixed by the public authorities.

Power-to-gas pilot plants have not yet been connected to the gas distribution system, but two systems for feeding in hydrogen and methane are being planned in Germany.

24 of the evaluated projects are stand-alone systems, and therefore operate in isolation from the public grid and the gas distribution system. Since the power-to-gas systems that were described are pilot plants, some of them have a grid-connection as a back-up in case of emergencies, as in Refs. [56,65,113]. Due to increased local electricity demand and low efficiency in Ref. [56], additional electricity had to be obtained from the grid to generate extra hydrogen in order to maintain the hydrogen storage pressure. Stand-alone power-to-gas systems are especially suitable for islands and remote communities, since there is often a great potential in renewable energy sources there [56], energy prices are high due to the lack of a public grid and fuel transportation is difficult [66]. The size of renewable electricity generators and batteries in remote communities can be reduced by using long-term storage of fluctuating electricity in power-to-gas plants [57]. Challenges arose in Ref. [15] as the transportation of the heavy equipment was difficult and the procurement of spare parts proved to be time-consuming in that remote location. It is emphasized in Ref. [15] that the support of the local people is very important, as they have to run the systems. A very effective way to introduce them to the hydrogen technology is by operating hydrogen vehicles such as the ones utilized in Refs. [15,20]. Power-to-gas systems in remote communities can have a positive effect on tourism [66], and they can enhance the competitiveness of the local economy. Besides, the skills acquired with the new technology can be passed on in training centers there, as has been done in Refs. [66,67].

6. Conclusions

The number of power-to-gas pilot plants that produce hydrogen from fluctuating renewable power sources and either apply it to electricity generation or feed it into the gas distribution system is increasing all over the world. A strong focus on this technology is becoming apparent in Germany, where several projects have been realized and numerous further systems are being planned. One critical aspect of the power-to-gas pilot plants that have been evaluated is that most of them have only been operated for a short time and it has only been possible to gather long-term experience from a small number of projects.

In most power-to-gas pilot plants, wind or solar energy is used to generate electricity. These energy sources can fluctuate strongly, and therefore there is a great need for energy storage. In the realized projects, hardly any problems were reported in this respect, since these technologies are state-of-the-art. Nevertheless, there is a need for the further development of wind turbines for remote locations with high wind speeds. Batteries are primarily employed in stand-alone power-to-gas pilot plants, where they are used for short-term storage, serve to minimize the cycling of the electrolyzer and to compensate for transients and power peaks. The SOC of the battery bank is the main control variable in most systems and guarantees the smooth operation of all of the components.

Alkaline electrolyzers are mainly used for hydrogen production, since they are commercially available. Although their reliable operation has been reported in several projects, problems with low hydrogen purity and stack degradation do occur. PEM electrolyzers have been utilized increasingly often since 2003, since they are better suited for fluctuating power sources, achieve higher degrees of hydrogen purity and have a simpler design. Nevertheless, serious problems arise in respect to their lifetimes and rapid stack degradation, and the available capacities of PEM electrolyzers are considerably smaller than those of alkaline ones. Higher conversion efficiencies can be reached by applying pressure electrolyzers, since with them compression is not necessary, but their costs are then higher. It is difficult to find the optimum between efficiency and economics.

In most projects, DC-to-DC converters connect the components via a DC bus and thus enable the optimal operation of each component. Since energy is lost when converters are employed, it is important to utilize highly efficient ones. Hydrogen storage is mainly done with pressure tanks, since these are commercially available and high capacities can be realized with them. Metal hydride tanks are still under development and using them gives rise to various problems, especially ones concerning the heat management. The level of storage pressure is strongly dependent on the type of application.

Hydrogen can be used to generate electricity, in fueling stations or for the synthesis of hydrocarbon fuels like methane. Whereas fueling stations and electricity generation in fuel cells have been realized in several projects, feeding hydrogen or synthesized methane into the gas distribution system has not yet been accomplished. PEM is clearly the dominant technology for fuel cells and is very well suited for fast load changes, as high efficiencies are reached under conditions of partial loading. The main problems with them are their short lifetime due to rapid stack degradation and the small available capacities. Alkaline fuel cells were rarely utilized as they are highly complex and sensitive and are not suited for operation with fluctuating power sources.

The design and sizing of the components of power-to-gas plants considerably influences their efficiency, reliability and economics. Which ones are optimal depends to a great extent on the location, the system configuration and the available infrastructure. As the auxiliary equipment of power-to-gas systems is often highly complex, necessitates an increased energy demand and is responsible for unreliable operation, it is recommended to take a modular approach and produce centrally. The overall efficiency of power-to-gas plants strongly depends on the control strategy and can be improved by higher efficient components, improved heat management and optimal system integration. There is currently a lack of mass-produced, reliable hydrogen components of the proper size. Hardly any manufacturer could guarantee reliable electrolyzer operation with intermittent power sources, and various projects reported problems in purchasing fuel cells.

Power-to-gas systems can be operated in various combinations with the public grid and/or the gas distribution system. Each combination has different requirements for system design and type of components and is suited for different applications. Several pilot plants have already been realized that obtain electricity from the public grid or feed it into it. These systems can provide balancing power and are especially interesting for electricity grids with high percentages of renewable electricity. Feeding in hydrogen or synthesized methane would bring several advantages, since the gas distribution grid has a large storage capacity. Whereas methane could be fed in without any restrictions, the hydrogen tolerance of the gas infrastructure und components is not clear and further research on it is needed. No power-to-gas plant with feeding-in hydrogen or methane has yet been realized, but several projects are being planned in Germany. Most of the realized and evaluated power-to-gas pilot plants are stand-alone systems. They are often realized in remote communities or islands as there are often large potentials for renewable power generation in such places and the energy prices are high there. It is recommended that different renewable power generators be operated in stand-alone systems, since they complement each other to a certain extent and this leads to a more balanced power output.

The most important topics for further research are summarized as follows:

- Continuous long-term operation of power-to-gas pilot plants in order to improve their system configurations and overall performance.
- Improvement of efficiency, reliability, lifetime, maintenance, costs of hydrogen components (electrolyzer and fuel cell) and better ways of dealing with fluctuating power sources.
- System integration of components and reduction in the extent of auxiliaries.
- Codes and standards for operating permission, hydrogen components, control strategy, hydrogen safety etc.
- Determination of optimum system configurations and components with respect to the available infrastructure and type of application.

Acknowledgments

The support of this work by the Austrian Center of Competence in Mechatronics (ACCM) and the association Energy Institute at the Johannes Kepler University is gratefully acknowledged.

REFERENCES

[1] Bundesregierung. Fragen und Antworten zum Energiekonzept, <http://www.bundesregierung.de/Content/DE/Artikel/2011/06/2011-06-06-faq-energie.html>; 06. 06. 2011 [accessed 20.08.12].

[2] Ludwig Bölkow Systemtechnik. Hydrogen filling stations worldwide. <http://www.h2stations.org/> [accessed 30.08.12].

[3] Lymberopoulos N. Hydrogen production from renewables. CRES Greece, http://ec.europa.eu/energy/efficiency/studies/doc/industry/res_hydrogen.pdf; 2005 [accessed 27.08.12].

[4] Ulleberg O, Ito H, Maack MH, Ridell B, Miles S, Kelly N, et al. Hydrogen demonstration project evaluations. IEA Task 18 Subtask B, ISBN 978-0-9815041-0-0; 2007, http://ieahia.org/pdfs/finalreports/18subtaskB/Task18_SubtaskB_Final_ISBN.pdf; 2007 [accessed 27.08.12].

[5] del Pilar Argumosa M, Simonsen B, Schoenung S. Evaluations of hydrog. demonstration projects. Final report for IEA, HIA Task 18 Subtask B. Madrid; 2010. <http://ieahia.org/pdfs/Task_18_Final_Report.pdf> [accessed 27.08.12].

[6] Yilanci A, Dincer I, Ozturk HK. A review on solar-hydrogen/fuel cell hybrid energy systems for stationary applications. Prog Energy Combust 2009;35:231–44.

[7] Presentation hydrogenics. http://www.newenergy.is/newenergy/upload/files/naha/presentations/hydrogenics_-_hydrogen_energy_storage_in_remote_communities.pdf [accessed 17.07.12].

[8] Bose TK, Agbossou K, Kolhe M, Hamelin J. Stand-alone renewable energy system based on hydrogen production – IEA report. Canada, http://ieahia.org/pdfs/res_uquebec.pdf; 2004 [accessed 27.08.12].

[9] Kelouwani S, Agbossou K, Chahine R. Model for energy conversion in renewable energy system with hydrogen storage. J Power Sources 2004;140:392–9. http://dx.doi.org/10.1016/j.jpowsour.2004.08.019.

[10] Bergen A, Schmeister T, Pitt L, Rowe A, Djilali N, Wild P. Development of a dynamic regenerative fuel cell system. J Power Sources 2007;164:624–30. http://dx.doi.org/10.1016/j.jpowsour.2006.10.067.

[11] PEI Energy Corporation. Project description. http://www.windh2.ca/projectdesc.php [accessed 27.08.12].

[12] Harrison KW, Remick R, Martin GD, Hoskin A. Hydrogen production: fundamentals and case study summaries. Conference Paper, http://www.nrel.gov/hydrogen/pdfs/47302.pdf; 2010 [accessed 27.08.12].

[13] HARP data sheet. Canada, http://www.powertechlabs.com/temp/20112439066/HARP_DataSheet_Feb_4_2011web.pdf; 2011 [accessed 17.07.12].

[14] Miles S, Gillie M. Benefits and barriers of the development of renewable hydrogen systems in remote and island communities. International Energy Agency, Hydrogen Implementing Agreement Task 18. http://ieahia.org/pdfs/RemoteIslandBenefits.pdf [accessed 27.08.12].

[15] Grant A. Hydrogen Assisted Renewable Power (HARP) Project in British Columbia. <http://der.lbl.gov/sites/der.lbl.gov/files/vancouver_grant-sagoo.pdf> [accessed 18.07.12].

[16] Hydrogenics. News alert. Hydrogenics delivers hydrogen station in Stuttgart, Germany for vehicle refueling. <http://www.hydrogenics.com/news/news_alerts/2011/2011_Refueler%20in%20Stuttgart%20germany%20and%20Island%20Fuel%20winds%20of%20change.asp> [accessed 17.07.12].

[17] Ramea Report. Nalcor energy 2010. <http://www.nalcorenergy.com/uploads/file/nalcorenergyrameareport_january2010.pdf> [accessed 17.07.12].

[18] UNIDO-ICHET. Hydrogen energy in action, Turkey, <http://www.unido.org/fileadmin/user_media/Services/Energy_and_Climate_Change/Energy_Efficiency/Background_Papers/ICHET_7years_book_second_edition_eversion.pdf>; 2011 [accessed 17.07.12].

[19] Hydrogen Island. http://www.unido-ichet.org/index.php/en/demonstration-projects/256-hydrogen-islands [accessed 04.07.12].

[20] Iskov H. IEAHIA task 18 – Lolland case study, <http://ieahia.org/pdfs/Task18_Lolland_MicroCHP_(Denmark).pdf>; 2009 [accessed 27.08.12].

[21] PVFCSYS Project summary, <http://www.scep.ensmp.fr/Public/contrats__projets_e/title_proj/pvfcsys_project/view>; 2004 [accessed 05.07.12].

[22] Plateforme Myrte. Universitá di Corsica. <http://myrte.univ-corse.fr/downloads/> [accessed 17.07.12].

[23] Hoguet JC. Hydrogen & renewable energy. Derbi 2009 Conference, Perpignan. <http://www.pole-derbi.com/photo_derbi/HELION-DERBI-2009-JCH-110609.pdf> [accessed 21.08.12].

[24] Szyszka A. Ten years of solar hydrogen demonstration project at Neunburg vorm Wald, Germany. Int J Hydrogen Energy 1998;23(10):849–60.

[25] Voss K, Goetzberger A, Bopp G, Häberle A, Heinzel A, Lehmberg A. The self-sufficient solar house in Freiburg – results of 3 years of operation. Sol Energy 1996;58(1–3):17–23.

[26] Emonts B, Janßen H, Stolten D. 10 Jahre Phoebus-Projekt System zur autarken Versorgung mit regenerativer Energie, http://www.now-gmbh.de/uploads/media/14__Emonts__FZ_Juelich__10_Jahre_Phoebus-Projekt.pdf; 2008 [accessed 23.07.12].

[27] Meurer C, Barthels H, Brocke WA, Emonts B, Groehn HG. Phoebus – an autonomous supply system with renewable energy: six years of operational experience and advanced concepts. Sol Energy 1999;67(1–3):131–8.

[28] Barthels H, Brocke WA, Bonhoff K, Groehn HG, Heuts G, Lennartz M, et al. Phoebus-Jülich: an autonomous energy supply system comprising photovoltaics, electrolytic hydrogen, fuel cell. Int J Hydrogen Energy 1998;23(4):295–301.

[29] Menzl F. Windmill-electrolyser system for hydrogen production at Stralsund. IEA-report. Germany, <http://ieahia.org/pdfs/stralsund.pdf>; 2004 [accessed 27.08.12].

[30] Laboratory for integrated energy systems, Stralsund; 2006. <http://www.fh-stralsund.de/dokumentenverwaltung/dokumanagement/psfile/file/82/test_beds_45f9399739119.pdf> [accessed 05.07.12].

[31] Stolzenburg K, Linnemann J, Steinberger-Wilckens R, Tudel LV, Waldl HP, Lange M, et al. HyWindBalance Ergebnisse des Oldenburger Wind-Wasserstoff-Projekts, <http://www.hywindbalance.de/index11.html>; 2008 [accessed 16.07.12].

[32] http://www.hywindbalance.de/index8.html [accessed 16.07.12].

[33] Specht M, Jentsch M, Rieke S. Power-to-Gas Technologie. Erneuerbares Methan aus Ökostrom. ZSW Baden-Württemberg, Fraunhofer IWES, Solar Fuel GmbH, <http://www.solar-fuel.net/fileadmin/user_upload/Publikationen/1204PowerToGas_Broschuere_WEB.pdf>; 2012 [accessed 17.07.12].

[34] Grimm N, Zoch I, Weiß U. Deutsche Energie-Agentur GmbH; 2012. <http://www.powertogas.info/fileadmin/user_upload/downloads/Broschuere/Fachbroschuere_Power_to_Gas.pdf> [accessed 05.09.12].

[35] Solar Fuel GmbH. Alpha-Anlage läuft, erfolgreicher Probebetrieb seit November, <http://www.solar-fuel.net/loesung/alpha-anlage-laeuft/>; 2009 [accessed 17.07.12].

[36] Enertrag – Hybridkraftwerk. Dauerthal; 2009. <https://www.enertrag.com/download/prospekt/hybridkraftwerk_kurzinfo_090417.pdf> [accessed 17.07.12].

[37] Enertrag Hybridkraftwerk. <https://www.enertrag.com/download/praesent/grafik_funktionsprinzip-hybridkraftwerk.pdf> [accessed 17.07.12].
[38] Klug H. Grüner Wasserstoff auf Windkraft – Herten baut Windstromelektrolyse-System. http://www.wasserstoffstadt-herten.de/uploads/media/Windstromelektrolyse_01.pdf [accessed 17.07.12].
[39] WIND-projekt. Das Innovationsprojekt RH2-Werder/Kessin/Altentreptow, <http://www.wind-projekt.de/deu/hydrogen/index>; 2011 [accessed 17.07.12].
[40] Energie. de. WIND-projekt Gruppe plant Deutschlands leistungsstärkstes Wind-Wasserstoff-System. http://www.energie.de/news/energie/wasserstoff-und-brennstoffzelle/wind-projekt-gruppe-plant-deutschlands-leistungsstaerkstes-wind-wasserstoff-system_5113.html [accessed 17.07.12].
[41] Weiße M. RH2 WKA – Making Wind Energy a Steady PowerSource. <http://juwel.fz-juelich.de:8080/dspace/bitstream/2128/3978/1/HP3a_pp_Wei_Weisse.pdf> [accessed 27.08.12].
[42] Hydrogenics to provide a one MegaWatt electrolyzer for renewable energy project. <http://www.hydrogenics.com/invest/news_Details.asp?RELEASEID=616085> [accessed 21.08.12].
[43] Steiner K. Power2Gas – Praxistest Windstromspeicherung im Erdgasnetz. <http://www.eon.com/content/dam/eon-com/download/dwn-news/10737_694/Factsheet_Power2Gas.pdf> [accessed 17.07.12].
[44] klimaretter.info. Eon baut Waserstoffspeicher in Falkenhagen. <http://www.klimaretter.info/energie/nachricht/11265-eon-baut-wasserstoffspeicher-in-falkenhagen> [accessed 17.07.12].
[45] Ipsakis D, Stergiopoulos F, Ziogou C, Voutetakis S, Seferlis P, Papadopoulou S, et al. Analysis of a stand-alone power system based on solar and windenergy with hydrogen long-term storage: operational experience and control studies. In: CPERI, CERTH – conference in Greece, <http://www.systems-sunlight.com/dgm/17-03-11-11-26-24-Paper4.PDF>; 2008 [accessed 27.08.12].
[46] Ipsakis D, Voutetakis S, Seferlis P, Stergiopoulos F, Elmasides C. Power management strategies for a stand-alone power system using renewable energy sources and hydrogen storage. Int J Hydrogen Energy 2009;34:7081–95.
[47] Ziogou C, Ipsakis D, Elmasides C, stergiopoulos F, Papadopoulou S, Seferlis P, et al. Automation infrastructure and operation control strategy in a stand-alone power system based on renewable energy sources. Int J Hydrogen Energy 2011;196:9488–99.
[48] Johansson L, Boisen J. Greenland's first hydrogen plant – information sheet. <http://www.h2logic.com/com/news/H2KT_info-sheet-ENG.pdf> [accessed 17.07.12].
[49] Islandic New Energy. NAHA/Nalcor Energy Work-shop. <http://www.newenergy.is/newenergy/upload/files/naha/presentations/neilson_newfoundland.pdf> [accessed 17.07.12].
[50] Galli S. The solar-hydrogen SAPHYS project: operating results. Italy: ENEA, <http://gasunie.eldoc.ub.rug.nl/FILES/root/1998/2044920/2044920.pdf>; 2003 [accessed 27.08.12].
[51] Stewart EM, Lutz AE, Schoenung S, Chiesa M, Keller JO, Fletcher J, et al. Modeling, analysis and control system development for the Italian hydrogen house. Int J Hydrogen Energy 2009;34:1638–46.
[52] Valand T, Bartholdsen W, Ottestad M, Vage M. Agder University College, Norway, IEA Task. <http://ieahia.org/pdfs/grimstad.pdf> [accessed 27.08.12].
[53] Miland H, Ulleberg O. Testing of a small-scale stand-alone power system based on solar energy and hydrogen. Sol Energy 2012;86:666–80.
[54] Institute for Energy Technology. Renewable energy system. <http://www.ife.no/main_subjects_new/energy_environment/reh2systems> [accessed 17.07.12].
[55] Ulleberg O, Vie PJS, Tesfahunegn S. Distributed power generation with renewable energy, hydrogen and fuel cell technology. Technoreport 2012 RERC Research, Trondheim. Personal communication Oystein Ulleberg, Oystein.Ulleberg@ife.no; 21.08.2012.
[56] Ulleberg O, Nakken T, Ete A. The wind/hydrogen demonstration system at Utsira in Norway: evaluation of system performance using operational data and updated hydrogen energy system modeling tools. Int J Hydrogen Energy 2010;35:1841–52.
[57] del Pilar Argumosa M, Schucan TH. Fuel cell innovative remote energy system for telecom. Mazagon, <http://ieahia.org/pdfs/FIRST.pdf>; 2004 [accessed 27.08.12].
[58] Chaparro AM, Soler J, Escudero MJ, de Ceballos EML, Wittstadt U, Daza L. Data results and operational experience with a solar hydrogen system. J Power Sources 2005;144:165–9.
[59] Porto MR, Carratero T, Aguado M, Garde R. H_2 production in Sotavento Wind Farm. Jülich: WHEC, <http://juwel.fz-juelich.de:8080/dspace/bitstream/2128/3977/1/HP3a_pp_Por_Rey-Porto_rev0426.pdf>; 2010 [accessed 27.08.12].
[60] Sotavento project: system to produce hydrogen, <http://www.sotaventogalicia.com/area_tecnica/english/py_produccion_hidrogeno.php>; 2012 [accessed 16.07.10].
[61] Correas L, Aso I. Task 24: wind energy and hydrogen integration, <http://juwel.fz-juelich.de:8080/dspace/bitstream/2128/4130/1/IP1b_4_Aso.pdf>; 2010 [accessed 27.08.12].
[62] Ilhan N, Ersöz A, Cubukcu M. FZ Jülich; 2010. <http://juwel.fz-juelich.de:8080/dspace/bitstream/2128/3975/1/HP3a_pp_Ilh_Ilhan_rev0426.pdf> [accessed 27.08.12].
[63] International Centre for Hydrogen Energy Technologies. First hydrogen energy production on a Turkish Island has started on Bozcaada. <http://www.unido-ichet.org/index.php/en/component/content/article/456-bozcaada-hidrojen-adas-tuerkiyenin-lk-hidrojen-adasnda-enerji-ueretimi-balad> [accessed 04.07.12].
[64] Gammon R, Roy A, Barton J, Little M. Hydrogen and renewables integration (HARI) IEA task, <http://ieahia.org/pdfs/HARI.pdf>; 2006 [accessed 27.08.12].
[65] Little M, Thomson M, Infield D. Electrical integration of renewable energy into stand-alone power supplies incorporating hydrogen storage. Int J Hydrogen Energy 2007;32:1582–8.
[66] Gazey R, Slamn SK, Aklil-D'Halluin DD. A field application experience of integrating hydrogen technology with wind power in a remote island location. J Power Sources 2006;157:841–7.
[67] Sovacool BK, Hirsh RF. Island wind-hydrogen energy: a significant potential US resource. Renew Energy 2008;33:1928–35.
[68] H2Wales. http://www.h2wales.org.uk/directions.html [accessed 17.07.12].
[69] The Hydrogen Centre, The University of Glamorgan Renewable HydrogenResearch and Demonstration Centre. <http://www.h2wales.org.uk/Assets/Images/hydrogen_brochure.pdf> [accessed 17.07.12].
[70] The Hydrogen Office. <http://www.hydrogenoffice.com/files/HOLinfoPDF.pdf> [accessed 17.07.12].
[71] Pure Energy Centre 5Nm3h hydrogen electrolyzer production. <http://www.pureenergycentre.com/pureenergycentre/Hydrogen/Hydrogen_Electrolyzer/Pure%

20Energy%20Centre%205Nm3h%20hydrogen%20electrolyzer%20production.pdf> [accessed 17.07.12].
[72] FPS engine — FPS series. <http://www.altergy.com/pdf/FPS_Engine_4_16_09.pdf> [accessed 17.07.12].
[73] Fuel cell installation for the hybrid hydrogen mini-grid at the EETC, Rotherham. <http://www.upssystems.co.uk/case-studies/fuel-cell-installation-for-the-hybrid-hydrogen-mini-grid-at-the-eetc-rotherham/> [accessed 17.07.12].
[74] Hydrogen generation. <http://www.hydrogen-yorkshire.co.uk/documents/Hydrogen_Generation_HMGS_fact_sheet.pdf> [accessed 17.07.12].
[75] Hydrogen mini grid system. <http://www.hydrogen-yorkshire.co.uk/documents/HMGS_Flyer.pdf> [accessed 17.07.12].
[76] Rommel S. Refurbishing the Schatz solar hydrogen project, <http://www.schatzlab.org/docs/v1n4_dig_sm.pdf>; 2006 [accessed 27.08.12].
[77] Lehman PA, Chamerlin CE, Pauletto G, Rocheleau MA. Operating experience with a photovoltaic-hydrogen energy system. Int J Hydrogen Energy 1997;22(5):465–70.
[78] Bergen AP. Integration and dynamics of a renewable regenerative hydrogen fuel cell system. Dissertation at the University of Victoria; 2008. <http://www.iesvic.uvic.ca/pdfs/Dissertation-Bergen.pdf> [accessed 27.08.12].
[79] Schatz Energy Research Center (SERC). Schatz solar hydrogen project. <http://www.schatzlab.org/projects/archive/schatz_solar.html> [accessed 05.07.12].
[80] Bacyinski R, Whitney B, Gronich S, Garbak J, Bednarz M. DTE Energy Hydrogen Technology Park. Detroit; 2006. <http://www.hydrogen.energy.gov/pdfs/progress06/vi_c_1_bacyinski.pdf> [accessed 16.07.12].
[81] Regan R. 2005 DOE program review. DTE Energy Hydrogen Technology Park, <http://www.hydrogen.energy.gov/pdfs/review05/tv2_regan.pdf>; 2005 [accessed 17.06.12].
[82] Chao EM, Chase M, Jadd K. An economic analysis of the DTE Energy Hydrogen Technology Park. Center for Sustainable Systems, University of Michigan, <http://css.snre.umich.edu/css_doc/CSS06-10.pdf>; 2006 [accessed 27.08.12].
[83] Fuel cells 2000. U.S. Hydrogen Fueling Stations, <http://www.fuelcells.org/wp-content/uploads/2012/02/h2fuelingstations-US2.pdf>; 2012 [accessed 16.07.12].
[84] Robbins C, Purcell R, Sheetz L, Jacobson R, Gertler A. Small scale renewable energy power system with hydrogen combustion. In: NHA hydrogen conference, <http://www.dri.edu/images/publications/2008_robbinsc_purcellr_etal_ssrepshc.pdf>; 2008 [accessed 16.07.12].
[85] Harrison KW, Martin GD, Ramsden TG, Kramer WE, Novachek FJ. The wind-to-hydrogen project: operational experience, performance testing and systems integration, <http://www.nrel.gov/hydrogen/pdfs/44082.pdf>; 2009 [accessed 27.08.12].
[86] Harrison K, Ainscough C. Wind-to-hydrogen project, http://www.nrel.gov/hydrogen/proj_wind_hydrogen.html; 2012 [accessed 16.07.12].
[87] National Renewable Energy Laboratory (NREL). Wind-to-hydrogen project animation. <http://www.nrel.gov/hydrogen/proj_wind_hydrogen_animation.html> [accessed 16.07.12].
[88] IPHE renewable hydrogen report. IPHE, <http://www.iphe.net/renewablereport.html>; 2011 [accessed 27.08.12].
[89] Lutz A, Stewart E, Busquet S, Ewan M, Rocheleau R. Case study: the Hawaii Hydrogen Power Park demonstration, <http://ieahia.org/pdfs/Task18_Kahua_Ranch_Case_Study(USA).pdf>; 2010 [accessed 27.08.12].
[90] Rocheleau R, Ewan M. Hawaii Hydrogen Power Park. Hawaii Natural Energy Institute, <http://www.hnei.hawaii.edu/research/hawaii-hydrogen-power-park>; 2011 [accessed 16.07.12].
[91] Maclay JD, Brouwer J, Samuelsen GS. Experimental results for hybrid energy storage systems coupled to photovoltaic generation in residential applications. Int J Hydrogen Energy 2011;36:12130–40.
[92] Abaoud H, Steeb H. The German-Saudi HYSOLAR program. Int J Hydrogen Energy 1998;23(6):445–9.
[93] Kyriakarakos G, Dounis AI, Rozakis S, Arvanitis KG, Papadakis G. Polygeneration microgrids: a viable solution in remote areas for supplying power, potable water and hydrogen as transportation fuel. Appl Energy 2011;88:4517–26.
[94] Sopian K, Ibrahim MZ, Wan Daud WR, Othman MY, Yatim B, Amin N. Performance of a PV-wind hybrid system for hydrogen production. Renew Energy 2009;34(8):1973–8.
[95] Hydrogen house project. The hydrogen house. <http://hydrogenhouseproject.org/the-hydrogen-house.html> [accessed 18.07.12].
[96] Biello D. Inside the solar-hydrogen house: no more power bills—ever. East Amwell, <http://www.scientificamerican.com/article.cfm?id=hydrogen-house>; 2008 [accessed 18.07.12].
[97] Sudol P. Modelling and analysis of hydrogen-based wind energy transmission and storage systems: HyLink system at Totara Valley. New Zealand: Massey University, <http://mro.massey.ac.nz/bitstream/handle/10179/786/02whole.pdf>; 2009 [accessed 27.08.12].
[98] Tillmann C. Presseinformation: 4. Juni 2012: Eröffnung des ersten brandenburgischen Wasserstoff-Forschungszentrums an der BTU Cottbus, <http://www.tu-cottbus.de/btu/de/universitaet/presse/presseinformationen/details/4-juni-2012-eroeffnung-des-ersten-brandenburgischen-wasserstoff-forschungszentrums-an-der-btu-cott.html>; 2012 [accessed 20.08.12].
[99] Carbon Recycling International. www.carbonrecycling.is/ [accessed 25.04.12].
[100] Olah GA, Goerppert A, Prakash GKS. Chemical recycling of carbon dioxide to methanol and dimethyl ether: from greenhouse gas to renewable, environmentally carbon neutral fuels and synthetic hydrocarbons. J Org Chem 2009;74(2):487–98.
[101] Air fuel synthesis. www.airfuelsynthesis.com [accessed 26.04.12].
[102] Ulleberg O. From R&D to technology demonstration. Institute for Energy Technology; 2012. Personal Communication Oystein Ulleberg, Oystein.Ulleberg@ife.no, 21.08.2012.
[103] www.sunfire.de [accessed 26.04.12].
[104] http://www.uni-erlangen.de/infocenter/meldungen/forschung/2011/7/11/66.shtml [accessed 27.08.12].
[105] Teichmann D, Arlt W, Wasserscheid P, Freymann R. A future energy supply based on liquid organic hydrogen carries (LOHC). Energy Environ Sci 2011;4:2767–73.
[106] Fronius International GmbH. Energy self-sufficient family home.<http://www.fronius.com/cps/rde/xbcr/SID-8EB34451-DAA87086/fronius_international/Energy_self_sufficient_family_home_235153_snapshot.pdf> [accessed 20.08.12].
[107] RE Hydrogen, Arcola Energy & BOC. http://www.rabh2.co.uk/ [accessed 20.08.12].
[108] Ariizumi R. Renewable hydrogen: key to a new civilization, <http://ourworld.unu.edu/en/renewable-hydrogen-key-to-a-new-civilization/>; 2010 [accessed 20.08.12].
[109] Raman V. Hydrogen production and supply infrastructure for transportation – discussion paper, <http://www.c2es.org/docUploads/10-50_Raman.pdf>; 2004 [accessed 07.08.12].

[110] Abbasi T, Abbasi SA. Renewable hydrogen: prospects and challenges. Renew Sust Energy Rev 2011;15(6):3034–40.
[111] FreedomCAR & Fuel Partnership. Hydrogen production overview of technology options, <http://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/h2_tech_roadmap.pdf>; 2009 [accessed 29.08.12].
[112] Bajohr S, Götz M, Graf F, Ortloff F. Speicherung von regenerativ erzeugter elektrischer Energie in der Erdgasinfrastruktur. Artikel in gwf-Gas Erdgas, <http://www.dvgw-innovation.de/fileadmin/dvgw/angebote/forschung/innovation/pdf/speicherung.pdf>; April 2011. S. 200–10. [accessed 27.08.12].
[113] Ghosh PC, Emonts B, Janßen H, Mergel J, Stolten D. Ten years of operational experience with a hydrogen-based renewable energy supply system. Sol Energy 2003;75: 469–78.
[114] Sterner M. Bioenergy and renewable power methane in integrated 100% renewable energy systems. Limiting global warming by transforming energy systems. Dissertation; 2009. <http://www.uni-kassel.de/upress/online/frei/978-3-89958-798-2.volltext.frei.pdf> [accessed 27.08.12].
[115] Hollady JD, Hu J, King DL, Wang Y. An overview of hydrogen production technologies. Catal Today 2009;139:244–60.
[116] Graves C, Ebbesen SD, Mogensen M, Lackner KS. Sustainable hydrocarbon fuels by recycling CO_2 and H_2O with renewable or nuclear energy. Renew Sust Energy Rev 2011;15:1–23.
[117] Müller B, Müller K, Teichmann D, Arlt W. Energiespeicherung mittels Methan und energietragenden Stoffen – ein thermodynamischer Vergleich. Chemie Ingenieur Technik 2011;83(II):2002–13. http://dx.doi.org/10.1002/cite.201100113.
[118] Olah GA. Beyond oil and gas: the methanol economy. Wiley-VCH Verlag – Angewandte Chem. Int. Ed., http://desertec-uk.org.uk/articles/methanol_synthesis.pdf; 2005 [accessed 27.08.12].
[119] Beck J, Johnson R, Naya T. Electrochemical conversion of CO_2 to hydrocarbon fuels – EME 580, <http://www.ems.psu.edu/~elsworth/courses/egee580/2010/Final%20Reports/co2_electrochem.pdf>; 2010 [accessed 27.08.12].
[120] Mekhilef S, Saidur R, Safari A. Comparative study of different fuel cell technologies. Renew Sust Energy Rev 2012;16:981–9.
[121] Agbossou K, Chahine R, Hamelin J, Laurencelle F, Anouar A, St-Arnaud JM, et al. Renewable energy systems based on hydrogen for remote applications. J Power Sources 2011;96: 168–72.
[122] Goetzberger A, Bopp G, Griesshaber W, Stahl W. The PV/hydrogen/oxygen-system of the self-sufficient solar house Freiburg. In: Proceedings of 23rd IEEE photovoltaic specialists conference; 1993. p. 1152–8. Louisville.
[123] Szyszka A. Ziele und wichtige Ergebnisse des Solar-Wasserstoff-Projekts der SWB in Neunburg vorm Wald, http://www.solarhydrogen.com/pdfs/veroeffentlichungen_d_01.pdf; 1999 [accessed 23.07.12].
[124] Specht M, Zuberbühler U, Baumgart F, Feigl B, Frick V, Stürmer B, et al. Storing renewable energy in the natural gas grid. Methane via power-to-gas (P2G): a renewable fuel for mobility, <http://www.solar-fuel.net/fileadmin/user_upload/Paper_111027_P2G_CNG_ZSW_IWES_SolarFuel_final.pdf>; 2011 [accessed 27.08.12].
[125] Müller-Syring G, Henel M, Krause H, Rasmusson H, Mlaker H, Köppel W, et al. Power-to-gas: Entwicklung von Anlagenkonzepten im Rahmen der DVGW-Innovationsoffensive. Artikel aus gwf-Gas/Erdgas:770–7, <http://www.dvgw-innovation.de/fileadmin/dvgw/angebote/forschung/innovation/pdf/powertogas2011gwf.pdf>; 2011 [accessed 27.08.12].
[126] Krause H, Müller-Syring G. Wasserstoff aus Windstrom als chemischer Energiespeicher im Erdgasnetz und die Rolle der Brennstoffzellen zur Rückverstromung. Präsentation DBI GUT, <http://www.dbi-gut.de/fileadmin/downloads/3_Veroeffentlichungen/Vortraege/2011/111201_Koop.forum_H2ausWindstoff_GUT_Krause.pdf>; 2011 [accessed 27.08.12].
[127] Breyer CH, Rieke S, Sterner M, Schmid J. Hybrid PV-wind-renewable methane power plants. In: European photovoltaic solar energy conference, Hamburg, Germany, <http://www.q-cells.com/uploads/tx_abdownloads/files/6CV.1.31_Breyer2011_HybPV-Wind-RPM-Plants_paper_PVSEC_preprint.pdf>; 2011 [accessed 27.08.12].
[128] Kuhnhenne E, Ecke J. Power-to-gas: Stromspeicher, Gasproduktion, Biomethan oder flexible Last?. In: Energie wasser-praxis. p. 8–11, <http://www.gat-dvgw.de/fileadmin/gat/newsletter/pdf/pdf_2011_02/ewp_ 070811_08-11_Ecke.pdf>; 2011 [accessed 27.08.12].
[129] Maclay JD, Brouwer J, Samuelsen GS. Dynamic modeling of hybrid energy storage systems coupled to photovoltaic generation in residential applications. J Power Sources 2007; 163:916–25.
[130] Maclay JD, Brouwer J, Samuelsen GS. Dynamic analyzes of regenerative fuel cell power for potential use in renewable residential applications. Int J Hydrogen Energy 2006;31: 994–1009.

Int J Life Cycle Assess (2015) 20:477–489
DOI 10.1007/s11367-015-0848-0

Global warming potential of hydrogen and methane production from renewable electricity via power-to-gas technology

Gerda Reiter · Johannes Lindorfer

Received: 24 April 2014 / Accepted: 5 January 2015 / Published online: 20 January 2015

Abstract

Purpose Power-to-gas technology enables storage of surplus electricity from fluctuating renewable sources such as wind power or photovoltaics, by generating hydrogen (H_2) via water electrolysis, with optional methane (CH_4) synthesis from carbon dioxide (CO_2) and H_2; the advantage of the latter is that CH_4 can be fed into existing gas infrastructure. This paper presents a life cycle assessment (LCA) of this technological concept, evaluating the main parameters influencing global warming potential (GWP) and primary energy demand.

Methods The conducted LCA of power-to-gas systems includes the production of H_2 or CH_4 from cradle to gate. Product utilization was not evaluated but considered qualitatively during interpretation. Material and energy balances were modeled using the LCA software GaBi 5 (PE International). The assessed impacts of H_2 and CH_4 from power-to-gas were compared to those of reference processes, such as steam reforming of natural gas and crude oil as well as natural gas extraction. Sensitivity analysis was used to evaluate the influence of the type of electricity source, the efficiency of the electrolyzer, and the type of CO_2 source used for methanation.

Results and discussion The ecological performance of both H_2 and CH_4 produced via power-to-gas strongly depends on the electricity generation source. The assessed impacts of H_2 production are only improved if GWP of the utilized electricity does not exceed 190 g CO_2 per kWh. Due to reduced efficiency, the assessed impacts of CH_4 are higher than that of H_2. Thus, the environmental break-even point for CH_4 production is 113 g CO_2 per kWh if utilized CO_2 is treated as a waste product, and 73 g CO_2 per kWh if the CO_2 separation effort is included. Electricity mix of EU-27 countries is therefore not at all suitable as an input. Utilization of renewable H_2 and CH_4 in the industry or the transport sector offers substantial reduction potential in GWP and primary energy demand.

Conclusions H_2 and CH_4 production through power-to-gas with electricity from renewable sources, such as wind power or photovoltaics, offers substantial potential to reduce GWP and primary energy demand. However, the input of electricity predominately generated from fossil resources leads to a higher environmental impact of H_2 and CH_4 compared to fossil reference processes and is not recommended. As previously bound CO_2 is re-emitted when CH_4 is utilized for instance in vehicles, the type of CO_2 source and the allocation method have a significant influence on overall ecological performance.

Keywords Alternative fuels · Carbon dioxide utilization · Energy storage · Life cycle assessment (LCA) · Methane · Power-to-gas · Hydrogen

Responsible editor: Christian Bauer

Electronic supplementary material The online version of this article (doi:10.1007/s11367-015-0848-0) contains supplementary material, which is available to authorized users.

G. Reiter (✉) · J. Lindorfer
Energy Institute at the Johannes Kepler University Linz, Altenberger Straße 69, 4040 Linz, Austria
e-mail: reiter@energieinstitut-linz.at

G. Reiter
e-mail: gerda_reiter@gmx.at

1 Introduction

Renewable energy sources such as wind power or photovoltaics (PV) have a significant potential to reduce greenhouse gas emissions in electricity generation. However, due to their intermittent and fluctuating characteristics, their increased implementation is accompanied by major challenges within energy systems. Currently, photovoltaics and wind power play only a minor role in global electricity generation; however, a significant increase in installed power has been forecasted, for example, by Pieper and Rubel (2010). Nevertheless, some regions with a high percentage of renewables already face problems related to the strongly fluctuating nature of electricity generation. Power-to-gas technology could balance these fluctuations by storing electricity at times of surplus production and is being extensively discussed and supported at present. In contrast to battery systems, power-to-gas is a long-term energy storage option and is especially suited for balancing seasonal fluctuations. Whereas pumped hydropower plants are depending on sites with appropriate geography and, therefore, have a limited potential, power-to-gas could be installed in various regions and, in combination with the existing gas infrastructure, offers a huge potential (Breyer et al. 2011). A number of power-to-gas pilot and demonstration plants have been recently built, with others planned, especially in Europe and North America (Gahleitner 2013).

The power-to-gas system utilizes (surplus) electricity to split water into hydrogen (H_2) and oxygen (O_2) in an electrolyzer. Surplus electricity can be defined as electricity that cannot be fed into the public electricity grid or be otherwise utilized. A further optional step in power-to-gas technology is the synthesis of H_2 and carbon dioxide (CO_2) to methane (CH_4) through methanation via the Sabatier reaction. The production of CH_4 results in lower total efficiency but could be advantageous in terms of feeding the produced energy carrier into the gas distribution grid; in contrast to the case of H_2, the injection of CH_4 is not limited in amount. The allowed volumetric fraction of H_2 in the gas distribution grid is different in each country (e.g., 5 vol% in Germany). A harmonized transnational standardization of gas quality is under way (see http://ec.europa.eu/energy/gas_electricity/gas/gas_quality_harmonisation_en.htm). Another possibility is the transportation of compressed H_2 or CH_4 in pressurized tanks via ship, train, or truck. H_2 can also be transported via a hydrogen pipeline. However, only a few H_2 pipelines exist in industrial regions and the built-up of an area-wide H_2 network would be necessary.

The various pathways of the power-to-gas system are illustrated in Fig. 1. By storing surplus electricity from fluctuating renewable sources, such as wind power plants or photovoltaics, power-to-gas enables higher percentages and further expansion of renewables in the electricity sector. Notwithstanding some related restrictions, both energy carriers (H_2 and CH_4) could be fed into the existing gas distribution infrastructure. This enables coupling of electricity and natural gas networks and allows exchange in both directions (Dickinson et al. 2010; Breyer et al. 2011; Anderson and Leach 2004). Besides the storage of electricity, power-to-gas could thus be applied for energy transport via the gas distribution grid, production of renewable fuels for heating and transport purposes, and production of renewable raw materials for the chemical industry. At the moment, hydrogen is primarily utilized as a raw material in industrial processes such as materials processing, chemical manufacturing, and many other applications. If methanation is included, power-to-gas also serves for utilization of CO_2 manifoldly emitted from industrial processes and power plants.

Several life cycle assessments of (renewable) H_2 production have already been conducted by Dufour et al. (2009), Smitkova et al. (2011), Cetinkaya et al. (2012), and Acar and Dincer (2014). Wietschel et al. (2006) analyzed the CO_2 reduction potential of H_2 infrastructure development in Europe. Numerous articles deal with the ecological evaluation of H_2 as fuel for transport applications, e.g., Briguglio et al. (2010), Lee et al. (2010), Lee et al. (2011), Wulf and Kaltschmitt (2012), Edwards et al. (2011), and Bartolozzi et al. (2013). The ecological aspects of H_2 as an energy carrier are thus already very well addressed in the literature. However, synthesis of CH_4 out of H_2 and CO_2, which also forms part of the power-to-gas process, is a rather novel topic from the life cycle perspective. Jentsch et al. (2011) deal with some ecological aspects of power-to-gas and with the influence of electricity and CO_2 source. Even in the case of carbon capture and utilization (including synthesis of CH_4 in power-to-gas), few articles dealing with ecological evaluation via life cycle assessment (LCA) could be identified (see, for example, von der Assen et al. 2013).

The LCA presented here thus has the goals of identifying the ecological performance of the total power-to-gas system (with H_2 and CH_4 as products) and of evaluating the main system parameter influencing global warming potential (GWP) and primary energy demand. Influencing parameters, such as type of electricity source, efficiency of the electrolyzer, or type of CO_2 source, were evaluated using sensitivity analysis. As power-to-gas can be applied for multiple purposes, various reference processes exist. The LCA is therefore limited to the production of H_2 and CH_4 in a power-to-gas plant and does not address transportation and conversion into final energy in detail. In addition to the ecological assessment for H_2 and CH_4 from power-to-gas, examples are provided for possible application pathways. These include the utilization of H_2 in the chemical industry, as well as the provision of H_2 and CH_4 as fuels for transport purposes.

2 Methods

The environmental impacts of the power-to-gas system were evaluated using a comprehensive LCA, according to ISO 14040 (2006) standards. As a first step, the goal and scope of the LCA were determined by defining the process steps and system boundaries, selecting the functional unit, and providing information about evaluated impact categories and geographical and time references. The second step in LCA

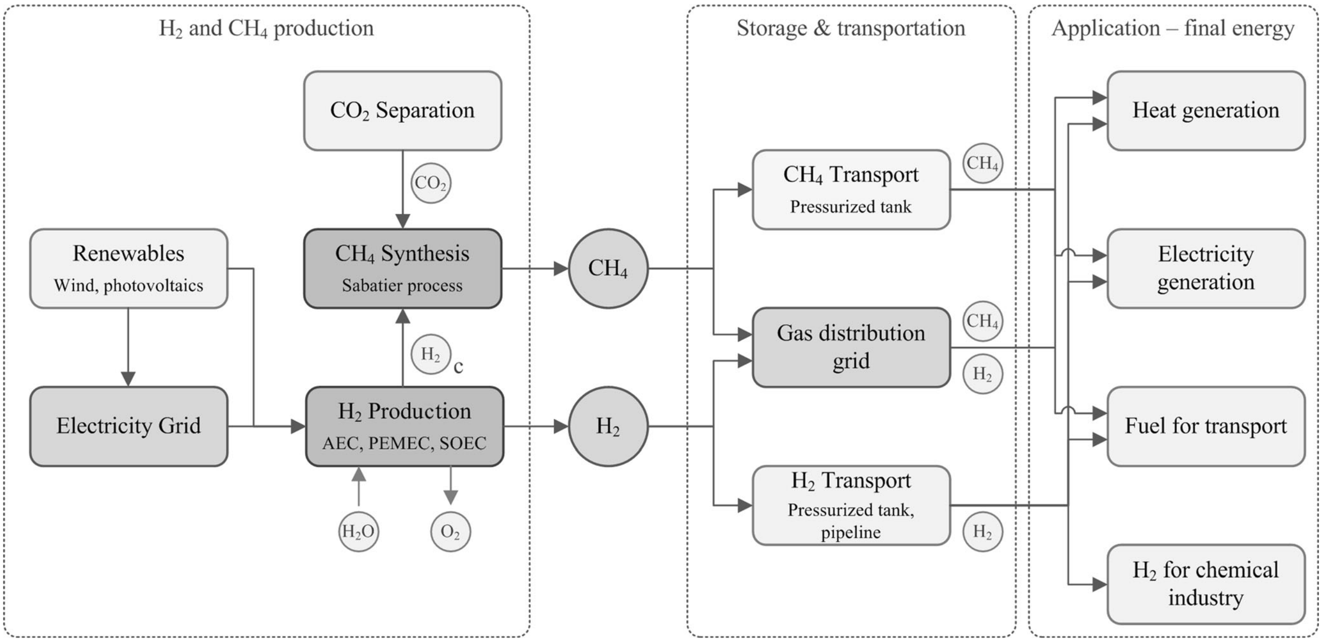

Fig. 1 Power-to-gas system and its numerous application pathways

comprises inventory analysis, dealing with the collection and validation of data. The gathered data must be allocated to specific process steps, with quantification of inputs (resources) and outputs (recyclable or waste material as well as correlated emissions) of these. If specific process data concerning energy or material flows is not available, databases such as ecoinvent (Swiss Centre for Life Cycle Inventories; see http://www.ecoinvent.ch/), GaBi (PE International; see http://www.gabi-software.com), or GEMIS (IINAS; see http://www.iinas.org/gemis-de.html) are used. Impact assessment analyzes the potential environmental impacts of the systems considered within selected impact categories and represents the third step of LCA. Interpretation, the fourth LCA step, includes the results of the inventory analysis and impact assessment. It is essential to sum up the results of an LCA and to display these in a comprehensive manner so that conclusions can be drawn about the environmental impacts of the systems considered (Margni and Curran 2012).

2.1 Goal and scope definition

The goal of this LCA was to identify the ecological performance of power-to-gas technology and the main parameter influencing GWP and primary energy demand. The results for H_2 and CH_4 derived from power-to-gas were compared to those of reference processes, such as steam reforming of natural gas and crude oil as well as natural gas extraction. Although ISO 14040 standards on LCA only cover assessments of environmental impacts of a product, the methodology can also be applied to processes. The software GaBi 5 (PE International, GaBi Version 5, 2013) was utilized for modeling power-to-gas pathways and calculating environmental impacts. The GaBi-LCA software offers all major impact assessment methodologies such as TRACI, CML, Ecoindicator, EDIP, etc. (see http://www.gabi-software.com).

2.1.1 Functional unit

The function of power-to-gas technology is, on the one hand, storing electricity, and on the other hand, the production of an energy carrier that can be applied for heat generation, electricity generation, or as fuel for transport applications. Power-to-gas technology covers H_2 as well as CH_4 production, and a functional unit, therefore, has to be determined to render the two energy carriers comparable. The energy content of H_2 and CH_4 was selected as a functional unit, due to the primary application of these for final energy provision. All results of the LCA are therefore related to 1 MJ of H_2 or CH_4, based on lower heating value (LHV). The LHV of H_2 is 119.9 MJ per kg and the LHV of CH_4 is 50.0 MJ per kg.

2.1.2 System boundaries

The definition of system boundaries determines input and output flows considered, as well as the process steps of the evaluated system. The life cycle usually begins with extraction of raw materials and energy carriers and ends with waste generation, energy recovery, or disposal. According to ISO 14044 (2006) regulations on system boundaries, it is not permissible to cut short process models if this results in fundamental limitations for LCA conclusions. Since the present LCA excludes the process step of product utilization, it can be specified to be a cradle-to-gate LCA. Nevertheless, examples relating to product utilization are provided in Section 3.2.

Figure 2 shows the system boundaries of the LCA conducted, with a focus on the production of H_2 or CH_4 in a power-to-gas plant. The transportation and storage of the products and their application were not evaluated but were considered qualitatively during interpretation.

The production of H_2 or CH_4 in a power-to-gas plant includes process steps such as water electrolysis, methanation, CO_2 separation, and electricity production. Depending on the applied electrolyte, water electrolyzers can be divided into alkaline (AEC), polymer electrolyte membrane (PEMEC), and solid oxide (SOEC) types. Whereas alkaline and PEM electrolyzers are commercially available, SOEC are predominantly at the development stage. In addition to water, electricity is the main input to the electrolyzer. This LCA includes electricity inputs from wind power, photovoltaics, and the electricity mix of EU-27 countries.

An optional process step of the power-to-gas system is the synthesis of CH_4 out of H_2 and CO_2, which takes place in the methanation reactor. In addition to H_2 taken from the electrolyzer, CO_2 is required for the synthesis of CH_4. CO_2 can be separated from various point sources, such as flue gas from power plants, industrial process in lime and cement production, or various fermentation processes. CO_2 could even be separated from ambient air, but the energy demand for absorption is very high (Breyer et al. 2011). The option of CO_2 separation from flue gas of a coal-fired power plant via amine scrubbing was selected within this assessment. The reference processes for H_2 and CH_4 derived from power-to-gas technology were steam methane reforming (H_2), reforming of crude oil (H_2), and natural gas extraction (CH_4).

2.1.3 Time and geographical references

Preference was given to the collection of up-to-date information relating to process steps as well as inputs and outputs, and the year 2014 was thus determined as the temporal reference framework. The geographical reference framework, which in this case especially influences the mix of electricity generation, was determined to comprise EU-27 countries.

2.1.4 Impact categories

This LCA evaluates the environmental impacts of power-to-gas in the impact categories climate change and (nonrenewable) primary energy demand. The impact category climate change with the indicator *GWP in kg CO_2 equivalents* was calculated using the CML 2001 (Guinee et al. 2001) method developed by the Institute of Environmental Sciences at the University of Leiden in the Netherlands (De Bruijn et al. 2002), which implements the ISO 14040 standard. For calculation of CO_2 equivalents of different air emissions, characterization factors were applied as per the Intergovernmental Panel on Climate Change (IPCC), considering a time horizon of 100 years (IPCC 2007). Primary energy demand in *MJ equivalents* was calculated according to the cumulative energy demand (CED) method, which includes the entire demand connected with production, use, and disposal of an economic

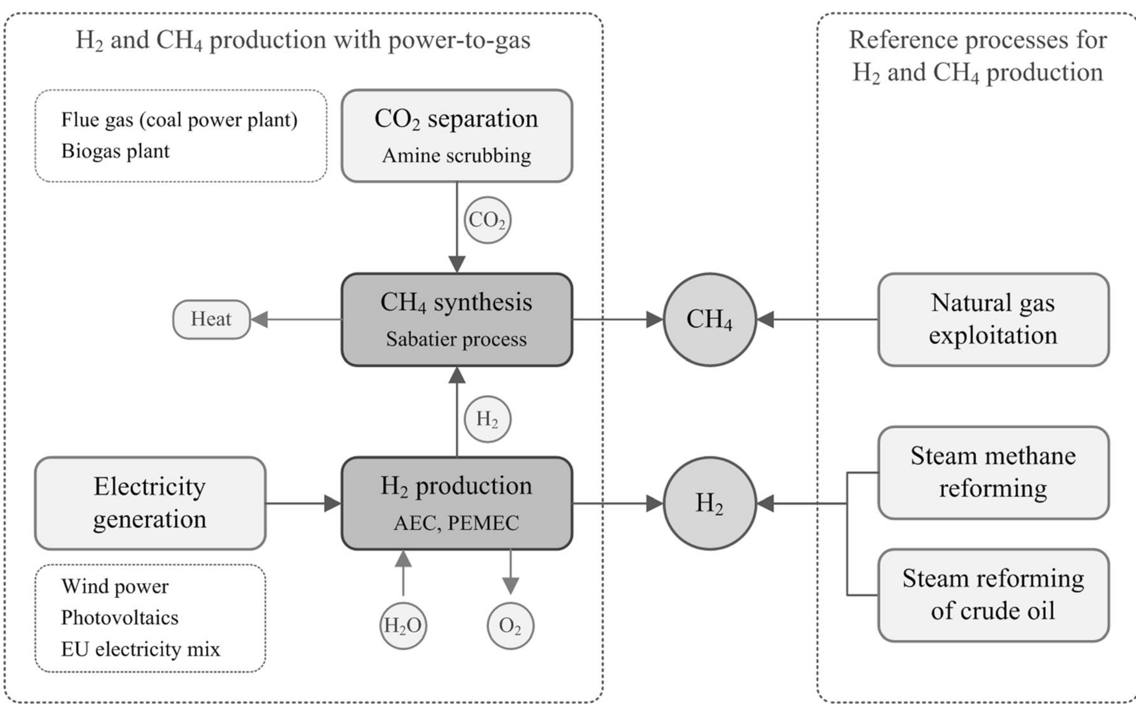

Fig. 2 System boundaries and reference processes for the conducted LCA

good or demand that may be attributed to it (VDI 2012; Klöpffer and Grahl 2011).

2.1.5 Sensitivity

Although power-to-gas is a relatively new technology system, the main components applied are proven technologies, and therefore, the uncertainties (e.g., about the efficiency of methanation or the water demand of the electrolyzer) are low. Nevertheless, there are three key parameters that could influence the results significantly. These are the origin of electricity input, the effort for CO_2 separation, and the efficiency of the electrolyzer. The following scenarios were developed to account for these uncertainties in the sensitivity analysis:

(a) Electricity generation from wind power, photovoltaics, or electricity mix of the EU-27 countries;
(b) CO_2 as waste product (e.g., from a biogas upgrading plant) or specific separation from the flue gas of a coal-fired power plant via amine scrubbing; and
(c) Impact of operation mode on the efficiency of the electrolyzer, such that electricity demand increases when the electrolyzer is operated in part load (see, for example, Ulleberg et al. 2010) and electricity demand therefore varies in the range of 5.2–10.4 kWh per m^3 H_2.

2.2 Inventory analysis

The inputs and outputs of different power-to-gas process steps, as well as of reference processes, were described with data from literature and manufacturers. The material and energy balance is required as an input for modeling using the LCA software GaBi. This LCA considered the resources required for H_2 or CH_4 production and the related supply chain. The production and maintenance of buildings, plants, and other infrastructure (e.g., streets) were beyond the scope of the inventory analysis. Reference processes, as well as electricity generation data, were taken from the GaBi Software database (PE International).

2.2.1 H_2 production in a water electrolyzer

In an electrolyzer, water is split with electrical energy into hydrogen and oxygen, as per the reaction equation 2 $H_2O \rightarrow$ 2 H_2+O_2. The related material and energy inputs and outputs of H_2 production via water electrolysis are illustrated in Fig. 3. Although there are some major differences between AEC and PEMEC, the LCA-relevant inputs and outputs are valid for both technologies. Table 1 describes additional characteristics of AEC and PEMEC that are relevant for power-to-gas systems.

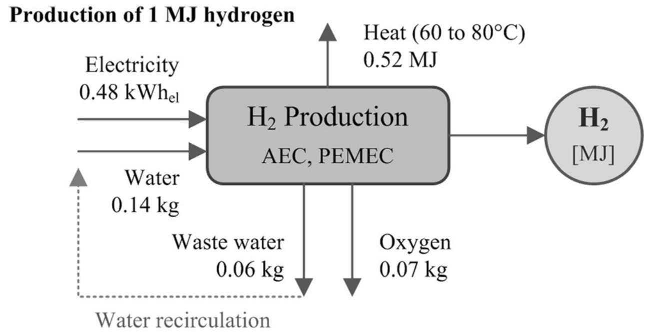

Fig. 3 H_2 production via water electrolysis—inputs and outputs—based on Ursua et al. (2012), Smolinka et al. (2011), and Maclay (2011)

AEC employ an aqueous alkaline electrolyte, representing the most highly developed and cheapest electrolyzer technology (Ursua et al. 2012). Alkaline electrolyzers are available at high capacities and exhibit good performance if operated continuously. Challenges arise in dynamic operation as the auxiliary equipment limits the flexibility of an AEC and start-up behavior is slow due to the high thermal capacity of the system. The power range of alkaline electrolyzers is smaller than that of PEM electrolyzers, and the gas quality is very low in part load (Smolinka et al. 2011). PEMEC have a simpler design, utilize a polymer electrolyte membrane, and therefore, can tolerate load transients and exhibit faster start-up behavior (Smolinka et al. 2011). Disadvantages are the limited lifetime of the membrane, the small available capacities, and the high costs due to the use of noble metal catalysts such as platinum (Ursua et al. 2012). At the moment, PEMEC are only available in smaller capacities and have a lower efficiency and lifetime than AEC; however, in the long term, their efficiency is expected to exceed that of AEC, and comparable lifetimes are forecasted. Current challenges for both types of electrolyzers, especially when utilized in power-to-gas systems, are low efficiency and reliability with fluctuating power input from renewables, decreased durability, and high initial investment costs.

Three different types of electricity generation were considered in this LCA, namely wind power, photovoltaics, and the

Table 1 Characteristics of alkaline and PEM water electrolyzers, based on Ursua et al. (2012), Smolinka et al. (2011), and Maclay et al. (2011)

Parameter	AEC	PEMEC
Nominal power	Several MW$_{el}$	Up to 1 MW$_{el}$
Power range	20–100 % of nominal power	0–100 % of nominal power
Operational pressure	1 to 30 bar	Up to 100 bar
Operational temperature	~80 °C	~80 °C
Life time	10 to 20 years	6 to 15 years
	(Strongly depending on the operational mode)	
Space requirement	PEMEC are a factor 5 to 10 smaller than AEC	

electricity mix of the EU-27 countries. The input and output data of all three processes were derived from the GaBi Professional database. As noted above, water, as well as electricity, is required for the production of H_2 via electrolysis. The LCA considers deionized water conditioned via reverse osmosis. The process data were also taken from the GaBi database.

2.2.2 *CH_4 synthesis via Sabatier reaction*

Hydrogen and carbon dioxide are synthesized to methane via heterogenous catalysis through the Sabatier reaction ($4\ H_2 + CO_2 \rightarrow CH_4 + 2\ H_2O$) with the aid of predominantly nickel-based catalysts (Müller et al. 2011; Sterner et al. 2011). The related material and energy inputs and outputs of the methanation process are illustrated in Fig. 4.

CH_4 can be synthesized not only out of H_2 and CO_2 but also out of H_2 and carbon monoxide (CO); the latter is indeed the more advanced technology and is applied, among other examples, in coal-to-gas processes or for other product gas cleaning (e.g., Mills and Steffgen 1974; Rönsch and Ortwein 2011; Sehested et al. 2005). Nevertheless, CO methanation is not within the scope of this LCA, the main focus of which is the utilization of CO_2 in power-to-gas systems. Information about the two processes is provided in Table 2.

In addition to H_2 produced in the water electrolyzer, CO_2 is utilized for CH_4 synthesis in the power-to-gas process. CO_2 is produced through various processes, such as the burning of coal in coal-fired power plants, industrial processes such as cement or lime production, fermentation processes in biogas plants, or biomass gasification. Theoretically, CO_2 can even be extracted from ambient air; however, the efficiency of these absorption processes is very low (Breyer et al. 2011).

2.2.3 *CO_2 separation from the flue gas of a coal-fired power plant via amine scrubbing*

One possible source of CO_2 for methanation is its separation from the flue gas of a coal-fired power plant. A state-of-the-art technology for CO_2 separation from flue gas is amine scrubbing, also considered in this LCA. The material and energy inputs and outputs of CO_2 separation are illustrated in Fig. 5.

Production of 1 MJ synthetic methane

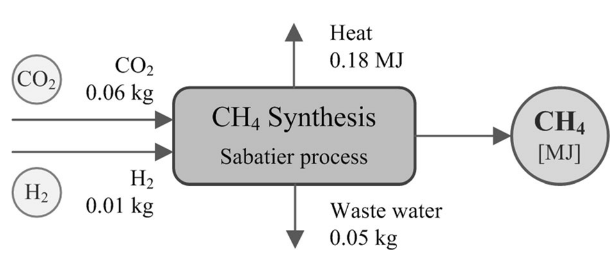

Fig. 4 CH_4 synthesis via Sabatier process—inputs and outputs—based on the stoichiometric reaction and information from Haldor Topsoe (2009)

Table 2 Characteristics of CO and CO_2 methanation, based on Cover et al. (1985), Sterner (2009), and Breyer et al. (2011)

Parameter	CO methanation	CO_2 methanation
Process design	Fixed bed, fluidized bed, bubble column with 1 to 4 stages	
Power range	80 to 110 % of nominal power	
Operational pressure	13 to 60 bar	6 to 7 bar
Operational temperature	300 to 700 °C	180 to 350 °C
Space requirement	Depending on process type and capacity (doubling of capacity does not mean doubling of space requirement)	

Table 3 presents selected information relating to the characteristics of amine scrubbing technology.

Amine scrubbing is a post-combustion process and is applied for separation of CO_2 from a gas flow by chemical reaction with an organic solvent, e.g., monoethanolamine (MEA). The solvent loaded with CO_2 has to be regenerated with heat that could be taken from the power plant (Rubin et al. 2012). As this heat would otherwise be applied for electricity generation, the overall efficiency of the power plant decreases when CO_2 is captured and the primary energy demand per kilowatt-hour increases. In the CH_4 synthesis process of a power-to-gas system, heat is produced as by-product; this could also be utilized for regeneration in amine scrubbing.

2.2.4 *Reference processes*

Currently, H_2 is predominantly utilized as a raw material in the chemical industry and is mainly produced out of fossil raw materials, such as natural gas, oil, or coal. Due to high costs, only a very small proportion of the H_2 produced globally is obtained through water electrolysis (Abbasi and Abbasi

Separation of 1 ton carbon dioxide

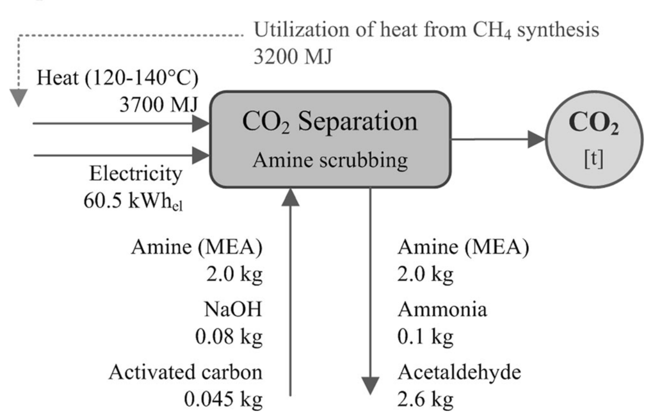

Fig. 5 CO_2 separation from flue gas of coal-fired power plants via amine scrubbing—inputs and outputs—based on Desideri and Paolucci (1999), Kothandaraman et al. (2009), Metz et al. (2006), De Koeijer et al. (2011), and Mangalapally and Hasse (2011)

Table 3 Characteristics of CO_2 separation via amine scrubbing, based on Chapel and Mariz (1999), De Koeijer et al. (2011), Mangalapally and Hasse (2011), and Linßen et al. (2006)

Parameter	Amine scrubbing
Typical size	2100 to 350,000 t_{CO2}/a
Operational pressure	~1 bar
Operational temperature	25 to 50 °C
Life time	15 to 20 years
CO_2 separation efficiency	85 to 90 %

2011). The selected reference processes for H_2 production were steam reforming of natural gas and crude oil. The related material and energy input and output data were taken from the GaBi database.

The reference process for CH_4 synthesis is the extraction of natural gas and considers extraction, conditioning, and transportation of natural gas. As the geographical reference framework was determined to be Europe, the mix for EU-27 countries was selected from the GaBi database.

3 Results and discussion

This section presents the impact assessment results for H_2 and CH_4 production from power-to-gas in the impact categories climate change and primary energy demand. The sensitivity analysis shows the influence of electricity production, type of CO_2 source, and electrolyzer efficiency. Section 3.2 presents additional aspects relating to provision of final energy from H_2 or CH_4.

3.1 Impact assessment results for production of H_2 and CH_4 from power-to-gas

3.1.1 Climate change

Figure 6 shows GWP for H_2 and CH_4 produced via power-to-gas in comparison to reference processes. As per the established scenarios for sensitivity analysis, three different types of electricity generation and different CO_2 sources were considered for the power-to-gas process. Cetinkaya et al. (2012) have documented comparable results for the global warming impact of H_2 derived from wind, photovoltaics, or steam methane reforming.

The results of the impact assessment indicate that the global warming impact of both H_2 and CH_4 produced via power-to-gas strongly depends on the type of electricity generation. In comparison to reference processes, global warming impact can be reduced with renewable electricity from wind power or photovoltaics; conversely, the electricity mix of EU-27 countries leads to much higher GWP than conventional production. When comparing, for example, H_2 produced from photovoltaics or wind power in a power-to-gas plant to that produced through steam methane reforming, GWP could be reduced by 73 to 95 %, respectively. If the EU-27 electricity mix is considered as the input to the power-to-gas process, GWP is +147 % higher than in the case of steam methane reforming. The electricity source for H_2 and later CH_4 production in power-to-gas plants is thus essential for the parameter GWP.

The reference process for CH_4 production is the extraction of natural gas. CH_4 synthesis in power-to-gas plants causes a higher global warming impact in most of the considered pathways, even with renewable electricity input. In part, this is due to the reduced total efficiency caused by the additional process step of methanation; an additional cause is the energy demand for CO_2 separation. This energy demand can be reduced by utilizing waste heat from methanation. If CO_2 is taken from, for example, a biogas upgrading plant, it would be considered as a waste product and would therefore make no significant contribution to global warming impact. This results in significantly lower GWP of CH_4 from power-to-gas. However, when considering only electricity produced from wind energy, a reduction in greenhouse gas emissions (of approximately 44 % compared to natural gas) for CH_4 production can be achieved. It also has to be noted that bound CO_2 is emitted again when CH_4 is converted into final energy. Whereas the CO_2 emitted by natural gas is of fossil origin, the CO_2 emitted by CH_4 from power-to-gas has been recycled before, and thus, the allocation procedure has to be discussed with reference to CO_2 origin.

3.1.2 Primary energy demand

Figure 7 illustrates the primary energy demand of H_2 and CH_4 produced via power-to-gas in comparison to reference processes. As in the case of GWP, primary energy demand strongly depends on the type of electricity source. When renewable electricity from wind power or photovoltaics is utilized, the nonrenewable primary energy demand is lower than for fossil reference processes. However, if the electricity mix from the EU-27 countries is considered, the primary energy demand is many times higher. Comparing H_2 derived from power-to-gas to steam methane reforming, primary energy demand could be reduced by 77 to 97 % when utilizing photovoltaics and wind power, respectively. If the EU-27 electricity mix is taken as the input for the power-to-gas process, the primary energy demand would be +148 % higher than for steam methane reforming. The electricity source for H_2 and subsequent CH_4 production in power-to-gas plants is thus a strong determinant of primary energy demand.

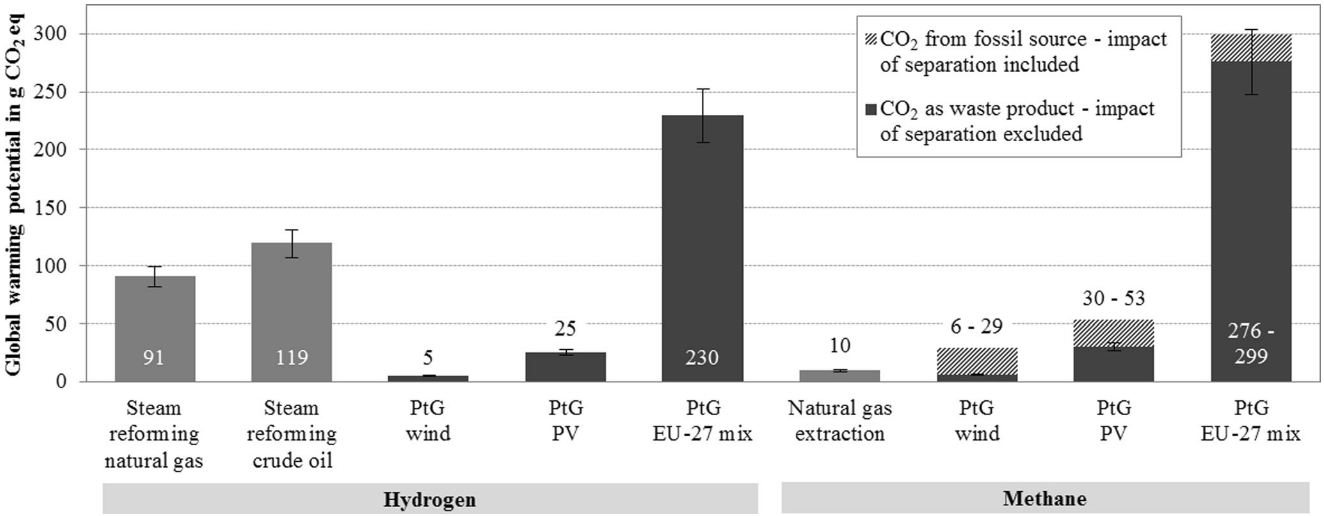

Fig. 6 Global warming potential of 1 MJ H_2 or CH_4 from power-to-gas (PtG) in comparison to the reference processes

In contrast to the global warming impact, the primary energy demand of CH_4 from power-to-gas with renewable electricity utilization is significantly lower than for natural gas extraction. Even when including the energy demand for CO_2 separation (hatched part of bar chart in Fig. 7), there is still potential for reducing nonrenewable primary energy demand. This is due to CO_2 separation from coal-fired power plants, which requires additional coal as primary energy that is accompanied by high specific greenhouse gas emissions. If the CO_2 is taken from, for example, a biogas upgrading plant, it is considered to be a waste product and, therefore, has no additional primary energy demand.

As in the case of global warming impact, primary energy demand is influenced more by the electricity source than by the type of CO_2 and by whether separation is accounted for. It can therefore be concluded that the utilization of renewable electricity for production of H_2 and CH_4 from power-to-gas is essential to have positive ecological performance.

3.1.3 Sensitivity analysis

For the sensitivity analysis, some variation in parameters was defined in Section 2.1. The results of the impact assessment already include variations in electricity input and CO_2 source. Nevertheless, the influencing parameters and the sensitivity of the results are mentioned here for the sake of completeness.

The type of electricity generation strongly influences the ecological performance of power-to-gas systems. Whereas the application of electricity from renewable sources, such as wind power or photovoltaics, offers potential to reduce GWP and primary energy demand, H_2 and CH_4 derived from the electricity mix of EU-27 countries have a significantly

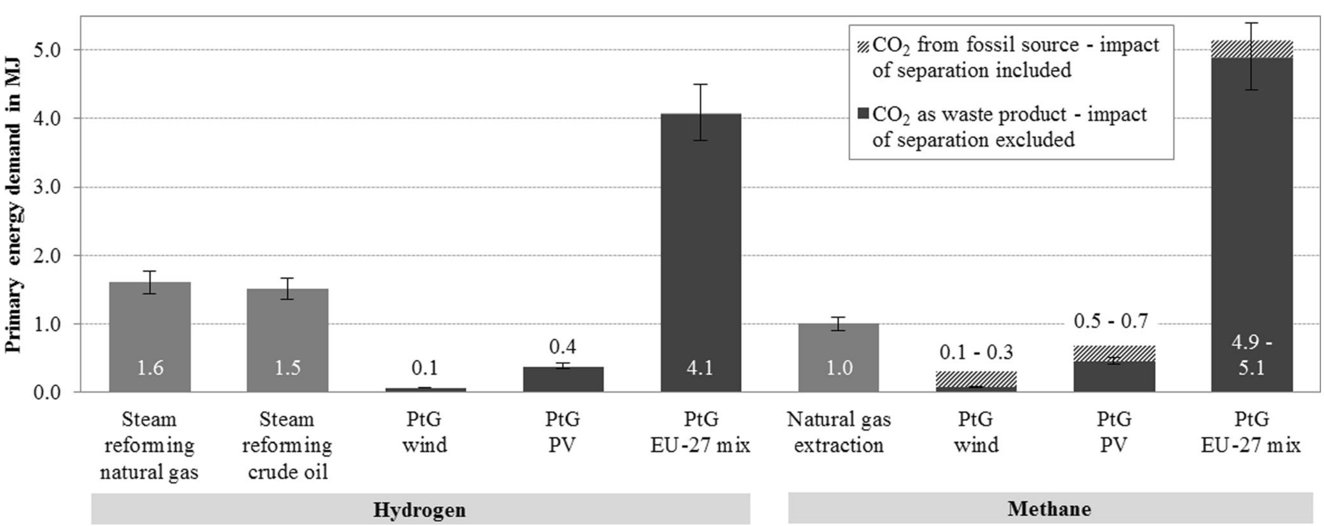

Fig. 7 Primary energy demand of 1 MJ H_2 or CH_4 from power-to-gas (PtG) in comparison to the reference processes

higher impact than reference processes. As an example, GWP of H_2 and CH_4 production in a power-to-gas plant is 9 to 55 times higher when using EU-27 electricity mix than in the case of photovoltaics and wind power, respectively.

The type of CO_2 source is only relevant for the production of CH_4 in a power-to-gas plant. If CO_2 is separated from flue gas of a coal-fired power plant via amine scrubbing, GWP is 23 kg CO_2 eq per MJ higher than if CO_2 is a waste product and does not account for GWP of CH_4. With reference to the results illustrated in Figs. 6 and 7, the type of CO_2 source has a low influence on overall ecological performance of power-to-gas if the electricity mix is utilized, as GWP is very high anyway. However, if H_2 is produced out of electricity derived from wind power, the CO_2 source has a larger influence, as GWP may be 5.6 times higher when utilizing CO_2 from coal-fired power plant. If electricity from renewable sources is utilized, the type of CO_2 source therefore has quite a significant impact on ecological performance, even though in general the electricity source is the main influencing parameter.

The mode of operation of the water electrolyzer mainly influences the specific electricity demand for H_2 production. The stated electricity demand of 5.2 kWh per m^3 H_2 is only valid for continuous operation at nominal power. If the electrolyzer is operated in part load, the specific electricity demand increases. This problem occurs especially with alkaline electrolyzers and is accounted for in the sensitivity analysis by varying the electricity demand between 5.2 and 10.4 kWh per m^3 H_2. This relates quite well to the simulation results of Ulleberg et al. (2010), which show that electricity demand doubles at 50 % part load. The strong influence of the electrolyzer efficiency on the GWP of H_2 is illustrated in Table 4. Doubling of the electricity demand of H_2 production leads to an increase in GWP between 87 and nearly 100 %. Nevertheless, H_2 from power-to-gas (wind power and photovoltaics) still exhibits better ecological performance than fossil-dominated alternatives.

Table 4 Influence of the electrolyzer efficiency (electricity demand between 5.2 and 10.4 kWh per m^3 H_2) on the GWP of 1 MJ H_2

H_2 production process	GWP at 5.2 kWh per m^3 (g CO_2 eq)	GWP at 10.4 kWh per m^3 (g CO_2 eq)	Increase in GWP (%)
Power-to-gas wind	5.0	9.3	+86.6
Power-to-gas photovoltaics	25.4	50.1	+97.4
Power-to-gas EU-27 mix	229.6	458.6	+99.7
Steam reforming of natural gas	90.6		
Steam reforming of crude oil	119.3		

3.2 Interpretation of results for production of H_2 and CH_4 from power-to-gas

In addition to the ecological assessment for H_2 and CH_4 from power-to-gas, the impact of converting them into final energy is shown on the basis of two examples. These are the utilization of H_2 in chemical industry and the provision of H_2 and CH_4 as fuels for transport purposes. Whereas the conversion of H_2 into final energy does not cause any greenhouse gas emissions, the conversion of CH_4 is associated with the emission of CO_2 that was previously bound in the power-to-gas process. The duration of binding CO_2 is hence limited and the emission of greenhouse gases into the atmosphere, with related effects on GWP, is merely postponed. Nevertheless, an additional benefit can be generated by CH_4 from power-to-gas, as it is applied for provision of final energy and, thus, replaces fossil fuels. For the ecological performance of CH_4 from power-to-gas, the type of CO_2 source and allocation are essential considerations. Three potential ways for considering the utilization of CO_2 were defined as follows:

- CO_2 has a biogenic origin or is a waste product and would (if not utilized for methanation) be emitted to the atmosphere nearly in the appropriate physical condition required for methanation; CO_2 emissions from the conversion of CH_4 into final energy are not relevant for GWP, as the application is considered to be CO_2 neutral.
- CO_2 is a waste product or has a biogenic origin (as in point 1) but has an additional energy demand for separation and processing; CO_2 emissions related to the separation process have to be taken into account.
- CO_2 has a fossil origin and would otherwise be stored (CCS), utilized in other processes, or companies would have to pay for emission allowances; allocation of CO_2 emissions is necessary.

Von der Assen (2013) deals with LCA of CO_2 utilization and recommends allocating the CO_2 burden according to the financial value of products. However, this is beyond the scope of this LCA and so only extreme values are illustrated for application of CH_4 from power-to-gas (i.e., no additional global warming impact for CO_2 separation, or full impact of separation as well as direct emissions).

3.2.1 Provision of H_2 as raw material for chemical industries

H_2 is an important raw material in the chemical industry, utilized, for example, for the production of aldehydes, ketones, high-strength polyethylenes and polypropylenes, alcohols from aldehydes and ketones, and chlorinated hydrocarbons. H_2 is also applied for methanol synthesis, hydrogenation of oil and fat, or as auxiliary material in the electronics and semiconductor industries. Global production is estimated to be 43 million tons per year (Freedonia Group 2010) and is mainly based on fossil raw materials. According to the results presented in Figs. 6 and 7, GWP and primary energy demand (nonrenewable) are reduced by 75 to 95 % when H_2 is produced through electricity from photovoltaics or wind power in a power-to-gas plant (electrolyzer). Assuming that all 43 million tons of H_2 are produced from PV/wind electricity instead of from fossil resources in steam reforming, this leads to a substantial theoretical reduction potential of 400 to 500 million tons CO_2 eq per year.

3.2.2 H_2 and CH_4 from power-to-gas as fuels for transport purposes

Both H_2 and CH_4 can be utilized as fuels for transport purposes and, thus, could replace conventional fossil fuels. CH_4 from power-to-gas is comparable to compressed natural gas (CNG), and if it fulfills the quality criteria (e.g., ISO 13686:1998), it could be utilized in the existing infrastructure of CNG vehicles and refueling stations. H_2 as a fuel for transport purposes is less common than CNG, and although numerous refueling stations have been built in recent years (see Ludwig Bölkow Systemtechnik, www.h2stations.org), an area-wide network is not yet available. However, the emission-free operation of H_2 vehicles would be one of the main advantages.

In addition to emissions related to the production of fuels (results of LCA in Section 3.1), direct emissions during the operation of the vehicle have to be considered when evaluating different fuels for transport. Whereas H_2 does not cause direct emissions at all, 1 kg CH_4 emits 2.75 kg CO_2 eq, 1 l diesel emits 2.64 kg CO_2 eq, and 1 l gasoline emits 2.33 kg CO_2 eq. When comparing H_2 and CH_4 from power-to-gas to conventional fuels, it has to be borne in mind that the different drive concepts all have specific fuel consumptions. The vehicle "Opel Zafira" has been chosen for the comparison of various fuels, as this vehicle type can be fueled with H_2, CNG, diesel, or gasoline. Specific consumption per 100 km is 1.2 kg of H_2 or 4.7 kg of CNG or 5.2 l of diesel or 7.0 l of gasoline (see data sheets for Opel Zafira at http://www.opel-rabl.at/media/pdf/zafira.pdf and http://auto.pege.org/2004-opel-zafira/verbrauch.htm). The production of the vehicle is not included in well-to-wheel (WTW) emissions. A comparison with battery-operated electric vehicles is omitted here but can be found, for example, in Bartolozzi et al. (2013).

The comparison of different drive concepts and fuels for the transport sector in Fig. 8 shows that H_2 and CH_4 produced from power-to-gas with renewable electricity input (wind and PV) have significantly lower GWP than conventional fossil fuels. However, when H_2 or CH_4 is produced out of the electricity mix (EU-27 countries), GWP is much higher than in the case of compared fuels. Figure 8 shows that, besides the type of electricity, the type of CO_2 utilized also has major impacts on the ecological performance of power-to-gas. The hatched part of the bar chart includes both emissions related to the energy demand for CO_2 separation and direct emissions during operation of the vehicle. It is certain that this is a boundary value, as all CO_2 emissions are allocated to CH_4 from power-to-gas. However, this shows very well that the type of CO_2 source and the allocation method for CO_2 emitted during vehicle operation have a significant influence on overall ecological performance. If all CO_2 emissions are allocated to CH_4 from power-to-gas, GWP is even higher than that of natural gas, even if renewable electricity is utilized (+30 to +68 % when using wind and PV, respectively).

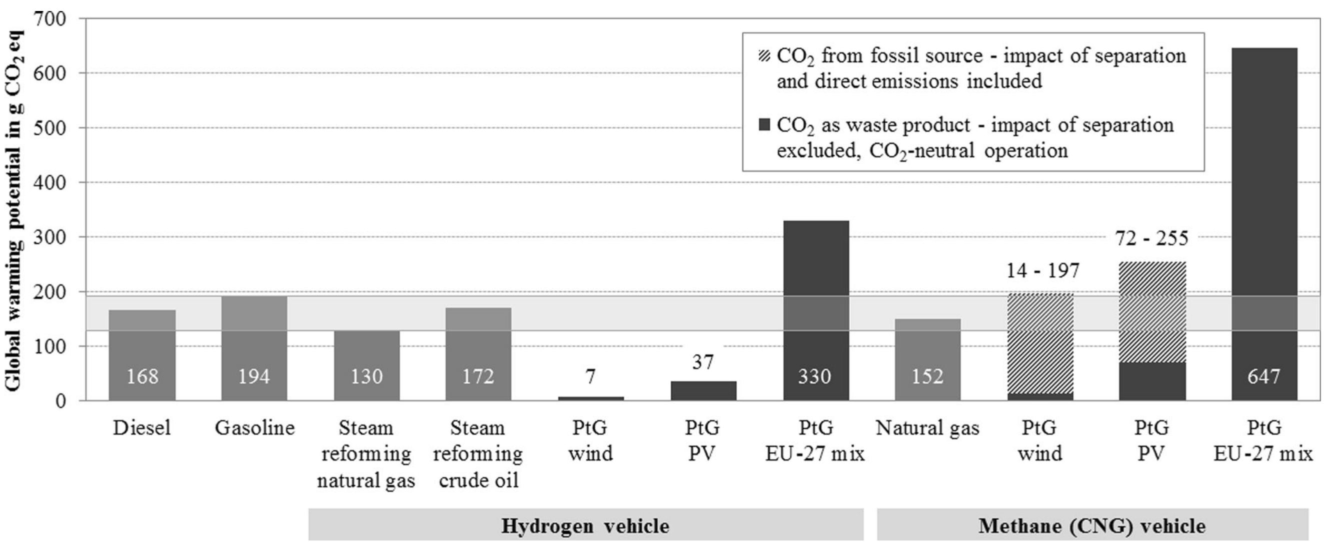

Fig. 8 Global warming potential of the utilization of H_2 or CH_4 from power-to-gas (PtG) as fuel for transport in comparison to conventional fossil fuels; GWP in grams CO_2 equivalent per kilometer of the whole process chain from fuel production to its consumption in the vehicle (well-to-wheel, WTW), production of vehicle is not included

4 Conclusions

H_2 and CH_4 production through power-to-gas with electricity from renewable sources, such as wind power or photovoltaics, offers substantial potential to reduce GWP and primary energy demand, compared to fossil reference processes. The ecological evaluation conducted based on a LCA indicated that the type of electricity production mainly influences the ecological performance of power-to-gas. If the electricity mix from EU-27 countries is considered as an input, GWP and primary energy demand for H_2 and CH_4 are significantly higher compared to reference processes. Utilizing electricity from renewables is therefore essential to improve the ecological performance of H_2 and CH_4 production.

On the basis of the results of the conducted LCA, GWP of electricity utilized for H_2 production via power-to-gas must not exceed 190 g CO_2 per kWh, as otherwise the produced H_2 would have higher GWP than the fossil benchmark of steam methane reforming. For the production of CH_4, this environmental break-even point is 113 g CO_2 per kWh if the utilized CO_2 is treated as a waste product, and 73 g CO_2 per kWh if the CO_2 separation effort is included. The regarded reference process for CH_4 production is natural gas extraction, including direct emissions related to CH_4. Full allocation of the separation effort and direct emissions to CH_4 from power-to-gas gives a negative environmental break-even point. These results show that electricity from fossil resources is not at all suitable as an input for power-to-gas technology. Furthermore, as long as electricity is predominately generated from fossil primary energy resources, electricity from renewables should only be utilized for H_2 and CH_4 production via power-to-gas if it cannot be utilized in the electricity sector (surplus electricity).

Fluctuating input from renewable power sources strongly influences the efficiency of the electrolyzer, as the specific electricity demand for H_2 production can significantly increase in part load. When electricity demand doubles, GWP and primary energy demand of renewable H_2 from power-to-gas increase between +84 and +97 %. Nevertheless, H_2 from power-to-gas (wind power and photovoltaics) still shows better ecological performance than the fossil-dominated alternatives.

The total efficiency of power-to-gas is reduced for CH_4 production, as another process step with certain conversion efficiency is involved. Thus, additional electricity is required and consequently both GWP and primary energy demand are higher for CH_4 than for H_2 from power-to-gas. Furthermore, the input of CO_2 is required for CH_4 synthesis. CO_2 can be obtained from different fossil or biogenic sources and is always accompanied by a certain energy demand for separation, which has a negative influence on overall environmental performance. If, for instance, CO_2 is separated from the flue gas of a coal-fired power plant via amine scrubbing, GWP is 23 kg CO_2 eq per MJ higher than if CO_2 is a waste product and does not account for GWP of CH_4.

H_2 is an important raw material in the chemical industry and is mainly produced out of fossil raw materials such as natural gas or crude oil. Power-to-gas technology for production of H_2 out of electricity from photovoltaics or wind power provides 75–95 % reduction of GWP and (nonrenewable) primary energy demand.

The use of H_2 and CH_4 produced from power-to-gas with renewable electricity input (wind and PV) as fuels for transport also offers a significant GWP and primary energy demand reduction potential compared to conventional fossil fuels (diesel, gasoline, natural gas). While the conversion of H_2 to final energy does not cause any direct CO_2 emissions, prebound CO_2 is emitted when utilizing CH_4 and so the type of CO_2 source has to be considered for calculation of GWP. If CO_2 is separated from a coal-fired power plant and emissions are fully allocated to CH_4 from power-to-gas, GWP is higher than that of other fossil fuels, although renewable electricity is utilized (+33 to +72 % for wind and PV, respectively). This example certainly represents a boundary value but indicates that the type of CO_2 source and allocation method for emitted CO_2 during vehicle operation have a significant influence on overall ecological performance.

A reconversion of H_2 or CH_4 from power-to-gas into electricity would be related to a very high primary energy demand. As the efficiency of direct utilization of H_2 and CH_4 in the industry or for mobility purposes is much higher, it is recommended to first tap this significant potential.

Future work in the field has to address the consequences of the technology concept power-to-gas in other environmental impact categories, such as water depletion, emission of toxic pollutants, ecological diversity, or depletion of resources. As the investment costs of power-to-gas systems are relatively high, economic aspects of H_2 and CH_4 production also have to be considered in combined ecological and economic performance assessments.

Acknowledgments The support of this work by the association Energy Institute at the Johannes Kepler University and the Austrian Federal Ministry of Economy, Family and Youth is gratefully acknowledged.

References

Abbasi T, Abbasi SA (2011) Renewable hydrogen: prospects and challenges. Renew Sust Energ Rev 15(6):3034–3040

Acar C, Dincer I (2014) Comparative assessment of hydrogen production methods from renewable and non-renewable sources. Int J Hydrogen Energy 39:1–12

Anderson D, Leach M (2004) Harvesting and redistributing renewable energy: on the role of gas and electricity grids to overcome intermittency through the generation and storage of hydrogen. Energ Policy 32:1603–1614

Bartolozzi I, Rizzi F, Frey M (2013) Comparison between hydrogen and electric vehicles by life cycle assessment: a case study in Tuscany, Italy. Appl Energy 101:103–111

Breyer CH, Rieke S, Sterner M, Schmid J (2011) Hybrid PV-wind-renewable methane power plants. European Photovoltaic Solar Energy Conference, Germany, 2011. http://www.q-cells.com/uploads/tx_abdownloads/files/6CV.1.31_Breyer2011_HybPV-Wind-RPM-Plants_paper_PVSEC_preprint.pdf. Accessed 04 Mar 2014

Briguglio N, Andaloro L, Ferraro M, Di Blasi A, Dispenza G, Matteucci F, Breedveld L, Antonucci V (2010) Renewable energy for hydrogen production and sustainable urban mobility. Int J Hydrogen Energy 35:9996–10003

Cetinkaya E, Dincer I, Naterer GF (2012) Life cycle assessment of various hydrogen production methods. Int J Hydrogen Energy 37: 2071–2080

Chapel DG, Mariz CL, Ernest J (1999) Recovery of CO_2 from flue gases: commercial trends. Annual Meeting of the Canadian Society of Chemical Engineers, Canada

Cover AE, Hubbard DA, Jain SK, Shah KV, Koneru PB, Wong EW (1985) Review of selected shift and methanation processes for SNG production. Kellogg Rust Synfuels Inc., Texas

De Bruijn H, van Duin R, Huijbregts MAJ (2002) Handbook on life cycle assessment: operational guide to the ISO standards. Series: eco-efficiency in industry and science. Kluwer Academic, Dordrecht

De Koeijer G, Enge Y, Sanden K, Graff OF, Falk-Pedersen O, Amundsen T, Overa S (2011) CO2 Technology Centre Mongstad—design, functionality and emissions of the amine plant. Energy Procedia 4: 1207–1213

Desideri U, Paolucci A (1999) Performance modelling of a carbon dioxide removal system for power plants. Energy Convers Manag 40: 1899–1915

Dickinson RR, Battye DL, Linton VM, Ashman PJ, Nathan GJ (2010) Alternative carriers for remote renewable energy sources using existing CNG infrastructure. Int J Hydrogen Energy 35:1321–1329

Dufour J, Serrano DP, Galvez JL, Moreno J, Garcia C (2009) Life cycle assessment of processes for hydrogen production. Environmental feasibility and reduction of greenhouse gases emissions. Int J Hydrogen Energy 34:1370–1376

Edwards R, Larivé JF, Beziat JC (2011) Well-to-wheel analysis of future automotive fuels and power trains in the European context. Report version 3c. European Commission, Joint Research Center, Institute for Energy and Transport, Luxembourg. doi:10.2788/79018.

Freedonia Group (2010) Brochure world hydrogen—industry study with forecasts for 2013 & 2018. Cleveland, Ohio 2010. http//www.freedoniagroup.com/brochure/26xx/2605smwe.pdf. Accessed 26 Mar 2014

Gahleitner G (2013) Hydrogen from renewable electricity: an international review of power to gas pilot plants for stationary applications. Int J Hydrogen Energy 38(5):2039–2061

Guinee JB, Gorree M, Heijungs R, Huppes G, Kleijn R, de Koning A (2001) Handbook on life cycle assessment. Operational guide to the ISO standards. Kluwer Academic, Dordrecht

Haldor Topsoe (2009) From solid fuels to substitute natural gas (SNG) using TREMP™. http://www.topsoe.com/business_areas/gasification_based/~/media/PDF%20files/SNG/Topsoe_TREMP.ashx. Accessed 05 Mar 2014

IPCC, Intergovernmental Panel on Climate Change (2007) Climate change: synthesis report. IPCC, Geneva, p 104

ISO 13686:1998 Natural gas—quality designation. International Organization for Standardization, Geneva, Switzerland

ISO 14040:2006 Environmental management—life cycle assessment—principles & framework. International Organization for Standardization, Geneva, Switzerland

ISO 14044:2006 Environmental management—life cycle assessment—requirements and guidelines. International Organization for Standardization, Geneva, Switzerland

Jentsch M, Trost T, Sterner M (2011) Evaluation of power-to-gas as long-term storage concept regarding electricity and CO2 sources. 6th International Renewable Energy Storage Conference – IRES 2011. http://www.iwes.fraunhofer.de/en/publications/list_of_publication/2011/evaluation-of-power-to-gas-as-long-term-storage-concept-regardin/_jcr_content/pressrelease/linklistPar/download/file.res/2011-053_Evaluation_of_power-to-gas.pdf. Accessed 04 Mar 2014

Klöpffer W, Grahl B (2011) Ökobilanz (LCA): Ein Leitfaden für Ausbildung und Beruf. (Life cycle assessment: a guide for education and profession). Wiley-VCH Verlag GmbH & Co. KGaA, Weinheim. ISBN 978-3-527-32043-1

Kothandaraman A, Nord L, Bolland O, Herzog HJ, McRae GJ (2009) Comparison of solvents for post-combustion capture of CO2 by chemical absorption. Energy Procedia 1:1373–1380

Lee JY, An S, Cha K, Hur T (2010) Life cycle environmental and economic analyses of a hydrogen station with wind energy. Int J Hydrogen Energy 35:2213–2225

Lee JY, Cha KH, Lim TW, Hur T (2011) Eco-efficiency of H2 and fuel cell buses. Int J Hydrogen Energy 36:1754–1765

Linßen J, Markewitz P, Martinsen D, Walbeck M (2006) The future of energy supply considering large-scale CCS (Zukünftige Energieversorgung unter den Randbedingungen einer großtechnischen CO2-Abscheidung und Speicherung), Forschungszentrum Jülich. https://www.cooretec.de/lw_resource/datapool/Neuigkeiten/Abschlussbericht.pdf. Accessed 05 Mar 2014

Ludwig Bölkow Systemtechnik. Hydrogen filling stations worldwide. http://www.h2stations.org. Accessed 17 Dec 2012

Maclay JD, Brouwer J, Samuelsen GS (2011) Experimental results for hybrid energy storage systems coupled to photovoltaic generation in residential applications. Int J Hydrogen Energy 36(19):12130–12140

Mangalapally HP, Hasse H (2011) Pilot plant experiments for post combustion carbon dioxide capture by reactive absorption with novel solvents. Energy Procedia 4:1–8

Margni M, Curran MA (2012) Life cycle impact assessment. In: Curran MA (ed) Life cycle assessment handbook. A guide for environmentally sustainable products. Wiley

Metz B, Davidson O, de Coninck H, Loos M, Meyer L (2006) IPCC special report on carbon dioxide capture and storage. Cambridge University Press

Mills GA, Steffgen FW (1974) Catalytic methanation. Catal Rev 8(1): 159–210

Müller B, Müller K, Teichmann D, Arlt W (2011) Energiespeicherung mittels Methan und energietragenden Stoffen – ein thermodynamischer Vergleich. Chem-Ing-Tech 83(II):2002–2013

PE International GaBi Software with built-in Database (DB) Version 5, 2013. Available from: http://www.gabi-software.com

Pieper C, Rubel H (2010) Electricity storage—making large-scale adoption of wind and solar energies a reality. The Boston Consulting Group. http://www.abve.org.br/downloads/BCG_-_Electricity_Storage.pdf. Accessed 04 Mar 2014

Rönsch S, Ortwein A (2011) Methanisierung von Synthesegasen - Grundlagen und Verfahrensentwicklungen. (Methanation of synthetic gas—fundamentals and process development). Chem-Ing-Tech 83(8):1200–1208

Rubin ES, Mantripragada H, Marks A, Versteeg P, Kitchin J (2012) The outlook for improved carbon capture technology. Prog Energy Combust 38:630–671

Sehested J, Dahl S, Jacobsen J, Rostrup-Nielsen JR (2005) Methanation of CO over nickel: mechanism and kinetics at high H2/CO ratios. J Phys Chem B 109:2432–2438

Smitkova M, Janicek F, Riccardi J (2011) Life cycle analysis of processes for hydrogen production. Int J Hydrogen Energy 36:7844–7851

Smolinka T, Günther M, Garche J (2011) Stand und Entwicklungspotenzial der Wasserelektrolyse zur Herstellung von Wasserstoff aus regenerativen Energien. Kurzfassung NOW-Studie. Fraunhofer ISE, FCBAT. http://www.now-gmbh.de/fileadmin/user_upload/RE-Mediathek/RE_Publikationen_NOW/NOW-Studie-Wasserelektrolyse-2011.pdf. Accessed 17 Dec 2012

Sterner M (2009) Bioenergy and renewable power methane in integrated 100 % renewable energy systems. Dissertation, Kassel University

Sterner M, Jentsch M, Holzhammer U (2011) Energiewirtschaftliche und ökologische Bewertung eines Windgas-Angebotes. Fraunhofer IWES. http://michaelwenzl.de/wiki/_media/ee:greenpeace_energy_gutachten_windgas_fraunhofer_sterner.pdf. Accessed 18 Dec 2012

Ulleberg O, Nakken T, Ete A (2010) The wind/hydrogen demonstration system at Utsira in Norway: evaluation of system performance using operational data and updated hydrogen energy system modeling tools. Int J Hydrogen Energy 35:1841–1852

Ursua A, Gandia LM, Sanchis P (2012) Hydrogen production from water electrolysis: current status and future trends. Proc IEEE 100(2): 410–426

Verein Deutscher Ingenieure e.V. (2012) VDI-Richtline 4600: cumulative energy demand (KEA)—terms, conditions, methods of calculation. VDI, Düsseldorf

Von der Assen N, Jung J, Bardow A (2013) Life-cycle assessment of carbon dioxide capture and utilization: avoiding the pitfalls. Energy Environ Sci 6:2721–2734

Wietschel M, Hasenauer U, de Groot A (2006) Development of European hydrogen infrastructure scenarios—CO2 reduction potential and infrastructure investment. Energ Policy 34: 1284–1298

Wulf C, Kaltschmitt M (2012) Life cycle assessment of hydrogen supply chain with special attention on hydrogen refueling stations. Int J Hydrogen Energy 37:16711–16721

Journal of CO_2 Utilization 10 (2015) 40–49

Contents lists available at ScienceDirect

Journal of CO_2 Utilization

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

Evaluating CO_2 sources for power-to-gas applications – A case study for Austria

Gerda Reiter *, Johannes Lindorfer

Energy Institute at the Johannes Kepler University Linz, Altenberger Straße 69, 4040 Linz, Austria

ARTICLE INFO

Article history:
Received 29 January 2015
Received in revised form 10 March 2015
Accepted 11 March 2015

Keywords:
Power-to-gas
Carbon dioxide utilization
Carbon capture
Energy penalty
Capture costs

ABSTRACT

The intermittent nature of wind and solar power requires long-term energy storage options such as power-to-gas. This technology utilizes (surplus) electricity from renewable power sources to produce hydrogen in an electrolyzer. The produced hydrogen can be either directly utilized as an energy carrier or combined with CO_2 and further converted to methane. This article evaluates different CO_2 sources concerning their potential utilization within the power-to-gas energy storage technology with regard to capture costs, specific energy requirement and CO_2 penalties. The results of a case study for Austria indicate that there is enough CO_2 available from point sources to store all of the electricity produced from fluctuating renewable power sources (wind power plants and photovoltaics) via power-to-gas. Due to low capture costs, low CO_2 penalties, biogenic origins, and short distances to wind power plants, biogas upgrading facilities and a bioethanol plant were determined to be the CO_2 sources best suited for utilization in novel power-to-gas plants. However, as the total amount of CO_2 produced from these facilities is relatively low in Austria, other CO_2 sources would also be required. With moderate capture costs and CO_2 penalties, power plants and an existing refinery could also provide CO_2 for power-to-gas. Although large amounts of CO_2 are available from iron, steel, and cement production facilities, these sources are not recommended for CO_2 utilization in power-to-gas, as the CO_2 penalty is relatively high and the facilities are rarely located near wind power plants in Austria.

1. Introduction

The sustainable transformation of the energy system requires increased energy efficiency as well as renewable resources such as biomass, water, wind, and solar power. Electricity generation from wind and solar power has high global potential, but the increased integration of these strongly fluctuating renewable sources represents a major challenge for local and transnational energy systems. The intermittent nature of wind and solar power requires compensating measures such as power grid expansion, the development of load management options, and short-term as well as long-term energy storage technologies. The power-to-gas system represents a long-term energy storage option that is potentially able to fulfill other functions in the energy system, such as fuel provision for mobility. Fig. 1 shows the main process steps in the power-to-gas system. By utilizing (surplus) electricity from renewable power sources, water is split into hydrogen (H_2) and oxygen (O_2) in an electrolyzer. The produced H_2 can be either directly utilized as an energy carrier or further synthesized to methane (CH_4). In methanation, CH_4 is produced from H_2 and carbon dioxide (CO_2) via the Sabatier reaction ($4H_2 + CO_2 \rightarrow CH_4 + 2H_2O$, [1]). The produced energy carrier CH_4, which is the main component of natural gas, can be easily integrated into the existing gas distribution grid.

CO_2 is a by-product of many industrial processes and is emitted in large amounts during fuel combustion in power plants. To limit global warming, the reduction of CO_2 emissions is required, which can be realized in the hierarchy of prevention, storage, and recycling. However, as current CO_2 mitigation measures are not sufficient to effectively limit the increase of CO_2 in the atmosphere, another approach is to capture it from point sources. Once captured, CO_2 can be stored in underground reservoirs such as saline aquifers, exploited oil and gas fields or deposits under the seabed. However, so-called carbon capture and storage faces problems including leakage, risks to the environment, and considerable costs and energy requirement (see [3–6] or [7] for more information).

Abbreviations: CCU, carbon capture and utilization; η_{withCC}, power plant efficiency with carbon capture; η_{ref}, power plant efficiency without carbon capture; MEA, monoethanol amine; IGCC, integrated gasification combined cycle; n.s., not specified.

* Corresponding author. Tel.: +43 732 2468 5657; fax: +43 732 2468 5651.
E-mail address: reiter@energieinstitut-linz.at (G. Reiter).

http://dx.doi.org/10.1016/j.jcou.2015.03.003
2212-9820/

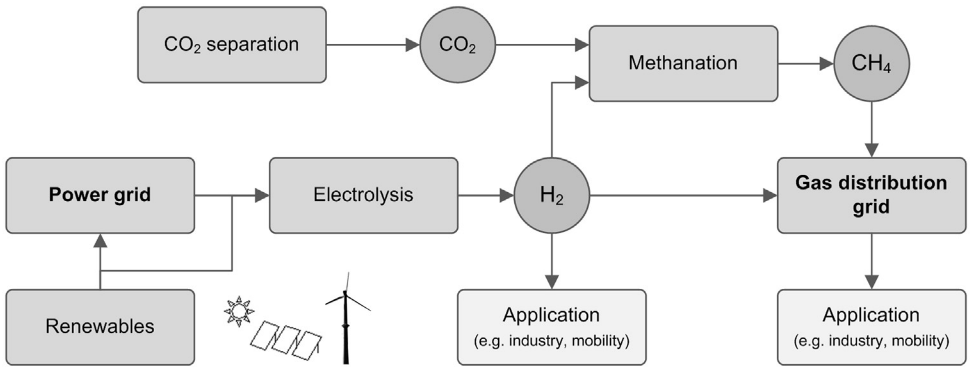

Fig. 1. Power-to-gas technology utilizing carbon dioxide.
Source: Adapted from Reiter [2].

Another possibility is to utilize the captured CO_2 for the synthesis of polymers, fuels and chemicals (see [1] or [8] for more information). The methanation process in the power-to-gas system is an example of a carbon capture and utilization (CCU) technology. The CH_4 produced by methanation can serve as a substitute for natural gas, which is a fossil resource, and thus is able to reduce greenhouse gas emissions, especially in the energy sector.

The concept of power-to-gas, including the CO_2 methanation process step, was first proposed by Sterner in 2009 [9]. An evaluation of potential CO_2 sources for Germany was published by Trost et al. [10] but is only available in German. They identify a large potential of biogenic CO_2 sources in Germany for utilization in power-to-gas processes, including sources such as biogas upgrading, bioethanol plants and sewage treatment plants. Utilizing CO_2 from these biogenic sources for the synthesis of methane in the power-to-gas process offers an electricity storage potential of 20 TWh per year. Industrial processes such as metal processing or cement production also offer quite a large electricity storage potential of over 200 TWh. Trost et al. [10] additionally present a case study for Germany, which focuses on CO_2 from biogas upgrading.

This article deals with the utilization of captured CO_2 within the power-to-gas energy storage technology. In a case study for Austria, the annual amounts of CO_2 emissions from various industrial point sources as well as power plants are quantified. These potential CO_2 sources are evaluated with regard to specific capture costs, energy requirement, CO_2 penalty, and their general suitability for utilization in the methanation process.

2. Method

Potential CO_2 sources for utilization in power-to-gas systems were identified via emission data analysis and literature research concerning the evaluated criteria. The evaluation of the suitability of different CO_2 sources considered the CO_2 quality requirements for methanation, the specific costs of CO_2 capture, the additional energy requirement and CO_2 emissions for CO_2 capture, and whether the source is fossil or biogenic.

Methanation using CO_2 requires standards for the characteristics of the input CO_2 gas. The utilized CO_2 may contain no catalyst poisons and only small amounts of inert gases, water vapor, and oxygen. Furthermore, a continuous minimum flow rate of CO_2 has to be available to handle the maximum turnover rate of the methanation process [11]. The requirements for CO_2 utilized in power-to-gas plants are summarized in Table 1. The most critical components for methanation are H_2S, N_2, particles, tar, and NH_3 [12].

The energy requirement of capturing CO_2 from different point sources depends on the separation technology applied and is often reported as the energy penalty (especially in terms of additional fuel combustion in power plants). However, the energy penalty is defined differently in literature. According to [13], the energy requirement of CO_2 capture in power plants can be defined as the reduced net energy output per unit of energy input ($1-\eta_{withCC}/\eta_{ref}$), the additional energy input per unit of energy output ($\eta_{ref}/\eta_{withCC}-1$) or the efficiency reduction in %points (η_{ref}–η_{withCC}). As CO_2 is seen as an input resource for the power-to-gas process, the specific energy requirement per kg CO_2 captured is relevant for this evaluation. This is calculated from the relationship between the additional energy input and the amount of CO_2 captured. Knowing the type of primary energy input, additional CO_2 emissions per kg CO_2 captured can also be calculated based on the additional primary energy demand. Analogous to the term energy penalty, the additional CO_2 emission incurred by CO_2 capture is termed the CO_2 penalty in the presented evaluation. The main fossil input resources are coal, with 96 g CO_2 per MJ, and natural gas, with 56 g CO_2 per MJ, according to IPCC [14]. Treating CO_2 as a resource in the evaluation of CO_2 utilization processes has been recommended by von der Assen et al. [15].

The costs of carbon capture are given as per ton avoided CO_2 emissions. This method accounts for the additional CO_2 emissions that are produced by the CO_2 separation process. However, because CO_2 is seen as a resource and not as an emission in CO_2 utilization processes, the costs are related to the actually captured CO_2 for this evaluation. The difference between CO_2 captured and avoided is illustrated schematically in Fig. 2.

In the case study for Austria, potential CO_2 point sources from industrial processes as well as power plants are identified. The data were gathered from the Austrian Emissions Trading Registry

Table 1
Requirements for CO_2 utilized in the methanation process, from Lehner et al. [12].

Component	Unit	Methanation input	CO_2 stream
H_2	vol.%	35–80	–
CO_2	vol.%	0–30	0–100
CO	vol.%	0–25	0–100
CH_4	vol.%	0–10	0–50
N_2	vol.%	<3	<15
O_2	vol.%	n.s.	n.s.
H_2O	vol.%	0–10	0–50
Particles	mg/m^3	<0.5	<2.5
Tar	mg/m^3	<0.1	<0.5
Na, K	mg/m^3	<1	<5
NH_3, HCN	mg/m^3	<0.8	<4
H_2S	mg/m^3	<0.4	<2
NO_x	mg/m^3	n.s.	n.s.
SO_x	mg/m^3	n.s.	n.s.
Halogens	mg/m^3	<0.06	<0.3

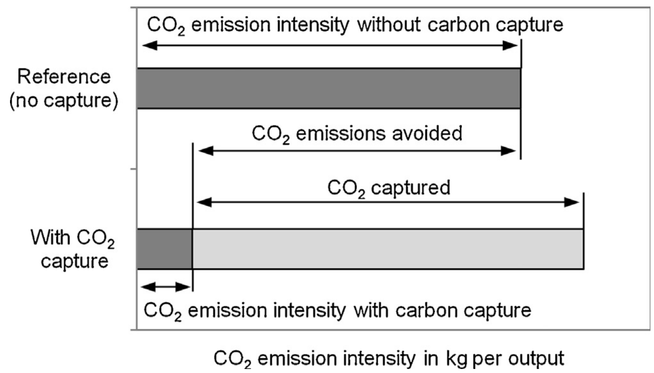

Fig. 2. Schematic illustration of CO_2 emission intensity with and without carbon capture.
Adapted from [16].

(http://www.emissionshandelsregister.at/ehr_en/), which provides information on the amount of verified fossil CO_2 emissions of installations in Austria. Additionally, information on the amount of CO_2 produced from biogenic sources such as bioethanol production and biogas upgrading is gathered for Austrian facilities.

3. CO_2 sources for power-to-gas applications

The required CO_2 can basically originate from either fossil or renewable point sources. Fossil CO_2 sources include off-gases from power plants or industrial processes such as lime or cement production [17]. Renewable sources comprise biotechnological anaerobic digestion and other fermentation processes that release CO_2. Furthermore, CO_2 can be absorbed from ambient air [18].

Fig. 3 provides an overview of potential CO_2 sources and the related CO_2 concentrations. The majority of CO_2 sources have concentrations less than 15 vol.%. However, some sources also indicate possible CO_2 concentrations above 95 vol.% and are therefore promising for the early implementation of capture techniques. The concentration and purity of CO_2 in the exhaust gas significantly influences the efficiency of the subsequent separation processes. In general, the technical implementation of CO_2 capture becomes easier and more economical as the CO_2 partial pressure in the exhaust gas increases [19]. A qualitative overview of different CO_2 separation technologies is provided in Fig. 4.

Chemical and physical absorption are well-established methods for CO_2 separation in industrial processes and power plants and can be relatively easily integrated [20]. Chemical absorption typically employs amine-based solvents such as monoethanolamine (MEA), and physical absorption employs organic solvents like selexol or rectisol. However, the regeneration of the solvents requires a relatively high thermal energy input. Adsorption processes exhibit very high selectivity but have not yet been utilized in commercial applications. The specific energy requirement demand of adsorption processes is also significant, but the further development of the adsorbents promises a huge potential for energy savings [20]. Cryogenic condensation is a well-known

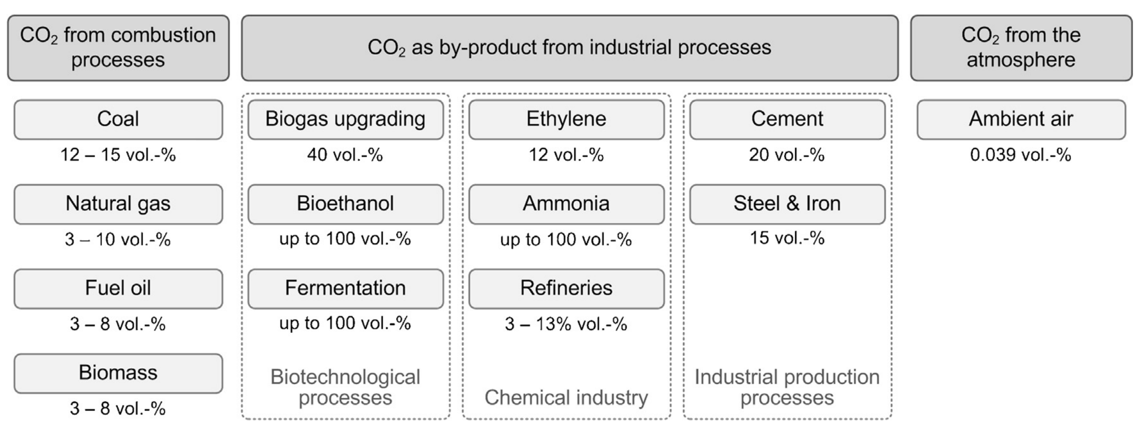

Fig. 3. Overview of potential CO_2 sources and related CO_2 concentrations, based on data from Metz et al. [19].

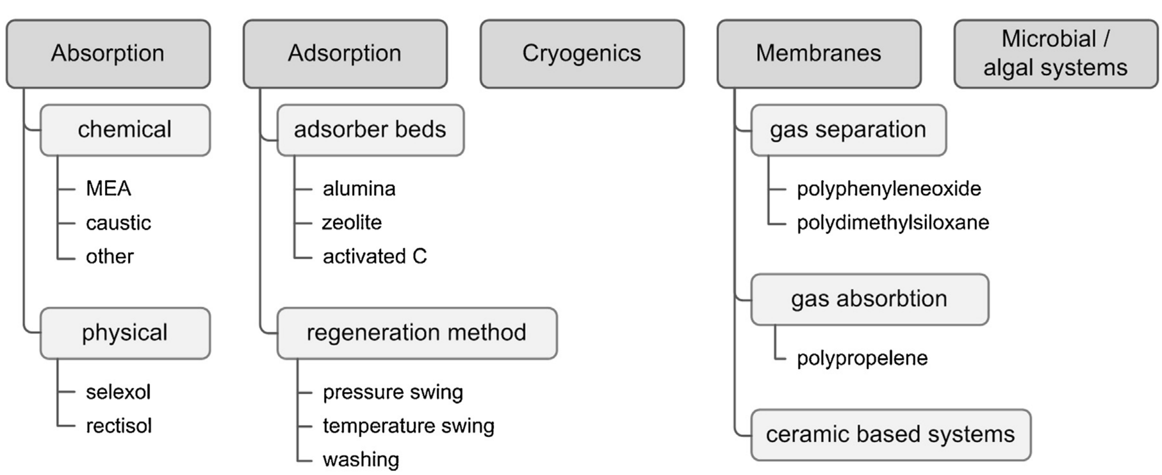

Fig. 4. Schematic overview of CO_2 separation technologies, based on Rubin et al. [21].

and state-of-the-art process in breweries and bioethanol production. The process operates at high pressure and low temperature and has a lower energy requirement than existing absorption and adsorption processes [20]. In streams with high CO_2 content, the separation efficiency is high and the remaining CO_2 has a high purity. However, cryogenic technologies for CO_2 separation are sensitive to moisture and have very high specific costs [20]. Membrane technology is especially suited for post-combustion processes and air separation units but is still in the development stage. Due to the modular design of the technology, CO_2 separation with membranes can be utilized for smaller applications. The energy requirement is low, but the membranes used are sensitive to several gas components. Critical parameters for the various membranes are selectivity and permeability [20].

In addition to the CO_2 separation technologies presented in Fig. 4, there are two more processes for CO_2 capture from combustion processes that do not require a further separation step. In the first, the oxyfuel process, the fuel is not burned in air, as in conventional combustion, but in pure oxygen and thus without the presence of nitrogen. The oxygen is generated using the energy-intensive cryogenic air separation method, which is a state-of-the-art technology. In the second, the chemical looping process, an absorbent (e.g. metal oxide) reacts with CO_2 produced in situ during oxidation in a fluidized bed reactor to form carbonate. The metal oxide is then regenerated from the carbonate in a second reactor by elimination of the pure CO_2 with air [22]. By avoiding direct contact between the fuel and air, the resulting combustion flue gas consists primarily of CO_2 and water.

3.1. CO_2 from combustion processes in power plants

Combustion processes in power plants emit huge amounts of CO_2 and represent a potential source for CO_2 that could be utilized in power-to-gas plants. Apart from fossil fuels such as coal, natural gas, and fuel oil, biomass combustion also causes CO_2 emissions. Because the volume percentage of CO_2 in the flue gas of combustion processes is relatively low compared to other sources, CO_2 separation is required. Basically, there are three possible methods of CO_2 capture from combustion processes [19]:

- post-combustion (CO_2 separation from the flue gas of a power plant),
- pre-combustion (CO_2 separation before fuel combustion), or
- the oxyfuel process.

All of the technologies described in Fig. 2 are suitable for post-combustion CO_2 separation. The most frequently employed methods are chemical absorption (with MEA), physical absorption, or pressure swing adsorption. Post-combustion processes typically have a CO_2 capture efficiency of 85–90% [21]. In pre-combustion processes, the fuel initially reacts with water vapor to form H_2 and carbon monoxide (CO) in a first gasification step. The CO_2 is then separated from the exhaust gas using one of the technologies listed in Fig. 2. The high CO_2 content in the shifted syngas (40 vol.% CO_2 [23]) enables a comparatively efficient CO_2 capture via physical absorption, reaching capture efficiencies of up to 95% [21]. The remaining H_2 is utilized as fuel for combustion and electricity generation. In the oxyfuel process, the fuel is burned with pure oxygen to avoid interference from nitrogen in the exhaust gas. The recycled flue gas is dosed to the CO_2 stream to prevent the combustion temperature from becoming too high. The flue gas consists primarily of CO_2 and water vapor, which can be removed with little effort by condensation after cooling. The major disadvantage of the oxyfuel process is that large quantities of pure oxygen have to be provided by extraction from air, which significantly reduces the overall efficiency (see [24] or [25]). Oxyfuel combustion enables CO_2 capture efficiencies of approximately 90% [21]. Carbonate looping is another method for CO_2 separation from combustion processes, but as it is in an early stage of development, it is not regarded here.

The described technologies for CO_2 capture from combustion processes are still under development and are currently being tested in pilot plants (for more information see [21,26]). The main issues for improvement are the CO_2 capture efficiency and the significant energy requirement of the capture technologies, which increases the fuel consumption of power plants. The additional fuel required for CO_2 capture is characterized by the energy penalty and is shown in Table 2 for different capture technologies and power plants. The various methods of calculating the energy penalty were described in Section 2.

Table 2 shows that in general, the efficiency of natural gas power plants is higher than that of coal power plants. Regardless of the CO_2 separation technology, the additional fuel requirement for CO_2 capture, which lies between 15% and 30% for fossil power plants, is very high. This additional primary energy demand has to be considered when utilizing CO_2 for power-to-gas processes. The stated efficiencies in Table 2 are valid for new power plants. It has to be considered that for existing power plants, the integration of CO_2 capture technologies may be more complex. Post-combustion capture technologies can be more easily added to a power plant, whereas the whole process design changes when pre-combustion or oxyfuel combustion is applied.

The CO_2 penalty takes into account the specific CO_2 emissions of different primary energy inputs related to captured CO_2 emissions.

Table 2
Energy and CO_2 penalties of various carbon capture technologies in power plants. Calculations according to efficiency information from Rubin et al. [21] and Damen et al. [27].

Fuel and capture technology	Net efficiency		Energy penalty			CO_2 penalty
	W/o carbon capture	With carbon capture	Efficiency reduction in %points	Additional energy input	Additional primary energy in MJ per kg CO_2 captured	g CO_2 per kg CO_2 captured
Pulverized coal power plant						
Post-combustion (chemical absorption)	40%	31%	9.0%	29.0%	2.7	257
Pre-combustion (IGCC, physical absorption)	40%	33%	7.0%	21.2%	1.9	184
Oxyfuel (with air separation unit)	40%	32%	8.0%	25.0%	2.3	222
Natural gas (NGCC) power plant						
Post-combustion (chemical absorption)	50%	43%	7.0%	16.3%	2.9	160
Pre-combustion (IGCC, physical absorption)	50%	42%	8.0%	19.0%	3.0	168
Oxyfuel (with air separation unit)	50%	41%	9.0%	22.0%	3.6	200
Biomass power plant						
Post-combustion (IGCC, chemical absorption)	47%	44%	3.0%	6.8%	1.3	142
Pre-combustion (IGCC)	47%	34%	13.0%	38.2%	5.5	615

Table 3
Typical impurities of flue gases, based on information from IEA [29] and Seevam et al. [30].

Capture technology	Component	Unit	Composition for coal-fired appliances	Composition for natural gas-fired appliances
Post-combustion	SO_2	vol.%	<0.01	<0.01
	NOx	vol.%	<0.01	<0.01
	$N_2/Ar/O_2$	vol.%	0.01	0.01
Pre-combustion	H_2S	vol.%	0.01–0.6	<0.01
	H_2	vol.%	0.8–2.0	1
	CO	vol.%	0.03–0.4	0.04
	CH_4	vol.%	0.01	2
Oxyfuel	SO_2	vol.%	0.5	<0.01
	NOx	vol.%	0.01	<0.01
	$N_2/Ar/O_2$	vol.%	3.7	4.1

Although the additional energy input per kg CO_2 captured is higher for natural gas power plants than for coal power plants, the CO_2 penalty is considerably lower for natural gas power plants. This is due to the lower specific CO_2 emissions of natural gas combustion.

In general, CO_2 can also be captured from biomass combustion with the same separation technologies employed for other power plants. CO_2 emitted from biomass combustion is of biogenic origin, and the process is therefore deemed carbon-neutral. The additional energy required for CO_2 capture would have a negative effect on the performance of the biomass plant identical to that of the fossil-based technologies. Consequently, until now, not much research effort has focused on carbon capture from biomass combustion. Jana et al. [28] modeled a biomass IGCC with CO_2 capture and found that a capture efficiency of more than 45% leads to a significant decrease in plant efficiency. This capture efficiency is much lower than reported for fossil power plants, but the CO_2 emissions from biomass combustion are biogenic.

The capture costs of CO_2 capture from fuel combustion in power plants are illustrated in Fig. 5. The capture costs consider the additional costs of the power plant with carbon capture compared to a reference plant without carbon capture. They also include the additional fuel input per unit of energy output.

Fig. 5 shows that the specific costs per ton CO_2 captured are lower for coal power plants than for natural gas power plants. This is due to the significantly higher absolute amount of CO_2 emissions in coal-combusting power plants. Post-combustion technology indicates high specific costs, but this is the only technology that can be easily retrofitted in existing power plants. The additional costs of the pre-combustion and oxyfuel processes are related to the reference costs of IGCC or oxyfuel plants and are therefore only valid for newly built power plants.

For the evaluation of the suitability of CO_2 from combustion for utilization in power-to-gas, the impurities of flue gases from coal- and natural gas-fired appliances in Table 3 are compared to the requirements of the methanation process in Table 1. A critical component in the CO_2 stream captured from power plants is H_2S, as the sulfur tolerances of metal catalysts are very low. Based on poisoning studies, the H_2S concentration must be kept as low as possible, i.e. below 0.1–5 ppm, to avoid a rapid and irreversible decrease in methanation catalyst activity [31]. Other limitations for components such as NOx or SO_2 have not yet been fully specified for CO_2 methanation.

3.2. CO_2 as a by-product in production processes

Production processes that yield CO_2 as a by-product can be differentiated into processes with biogenic and non-biogenic input materials. Depending on the volume percentage of CO_2 in the exhaust gas of the various production processes, CO_2 separation using one of the technologies described in Fig. 2 is required.

Biogenic CO_2 sources include biogas production and upgrading, bioethanol production and other fermentation processes in alcohol, vinegar, or acetone production. In bioethanol plants, CO_2 is produced in the fermentation process, and the exhaust stream already has a very high concentration of CO_2 [32]. Further purification of the CO_2 is not necessary, and thus the specific costs are low and no additional energy is required. Biogas from anaerobic digestion contains a large proportion of CH_4, approximately 40 vol.% of CO_2 and some other trace components. After a cleaning step for removal of trace components, the CO_2 is separated from the biogas to obtain biomethane of appropriate quality for injection into the gas distribution grid. Applied separation technologies for this step are physical or chemical absorption, pressure swing adsorption and membrane separation [33]. The remaining CO_2 stream has a high CO_2 content and does not require further purification. The specific costs per ton CO_2 are

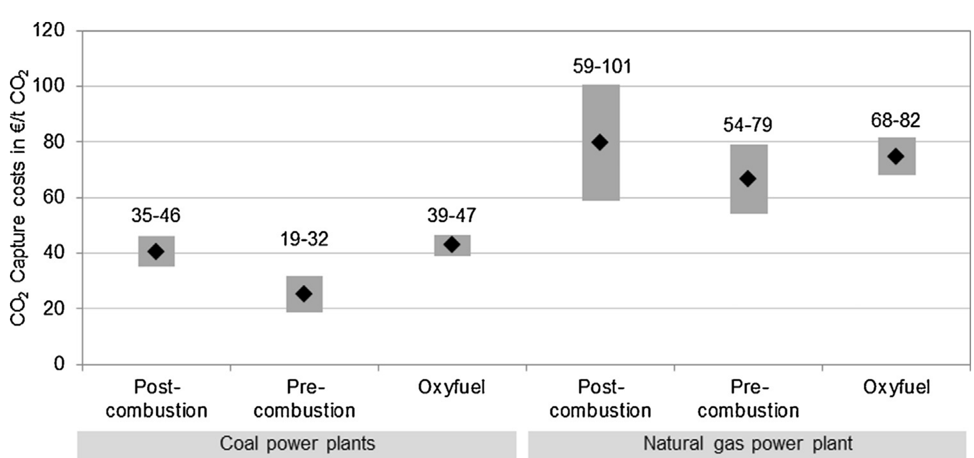

Fig. 5. Costs of CO_2 capture from fuel combustion in power plants, with information from Rubin et al. [21] and Damen et al. [27].

approx. €90 [10]. However, as CO_2 must already be separated in the process of biogas upgrading, it could be declared a waste product and thus would be available at no cost.

CO_2 from fossil resources is emitted in large amounts as a result of numerous processes in the chemical industry. In ammonia production plants, CO_2 is produced in the steam reforming of natural gas, a process for H_2 production [19]. As ammonia plants require the input of H_2 and H_2 is also a product of the power-to-gas process, the direct utilization of renewable H_2 should be preferred. It is not reasonable to produce H_2 from fossil natural gas in the chemical industry and then utilize the formed CO_2 for methanation in the power-to-gas process. The direct utilization of renewable H_2 from water electrolysis in the chemical industry would be much more effective.

CO_2 could also be captured from various processes in refineries, such as steam cracking, fuel combustion in process heaters, or H_2 or ethylene production. Suitable capture technologies include the post-combustion process with chemical absorption or the oxyfuel process, leading to CO_2 capture efficiencies of 59–77% and 77–84%, respectively [34]. Where H_2 is required, it is recommended to utilize the H_2 produced by the power-to-gas process instead of producing it from fossil resources, as already mentioned for ammonia production.

The production and processing of metals is another large source of CO_2, with iron and steel production as the main emitters. Two main ironmaking processes are considered here, namely the blast furnace and smelting reduction processes. These ironmaking processes are described in more detail in Kuramochi et al. [34]. CO_2 is captured via chemical or physical absorption in the blast furnace process, reaching a capture efficiency of approx. 65% [34]. Due to the higher CO_2 concentration of 25–35 vol.% in the gas from the smelting reduction process, CO_2 capture from this ironmaking process is more cost-effective [34]. With chemical or physical absorption, capture efficiencies up to 90% can be reached.

The production of mineral products such as cement, clinker and lime also causes a huge amount of CO_2 emissions. This is due to the large energy requirements of those production processes and CO_2 emissions from the chemical calcination process (approx. 60%) [34]. The heat required for cement production is primarily generated from coal. Kuramochi et al. [34] state that post-combustion is the most suitable technology for carbon capture in cement production because it can be retrofitted easily. With chemical absorption, a capture efficiency of 85% can be reached. Oxyfuel combustion for cement production is in the development stage and could be interesting for new plants in the long-term [34].

Table 4 shows the amounts of CO_2 avoided and captured per unit of output as well as the additional energy requirement and the CO_2 penalty per kg CO_2 captured. Carbon capture from refinery processes requires the least additional primary energy, and when related to natural gas, the CO_2 penalty is considerably lower than for cement or iron & steel production. Cement production has the highest additional energy input per CO_2 captured, and as primarily coal is utilized, the CO_2 penalty is considerably higher than for the other evaluated processes.

The costs of CO_2 capture from industrial processes are illustrated in Fig. 6. CO_2 from bioethanol production and biogas treatment already has a very high purity, and for further utilization only a drying step may be required, which results in the very low capture costs of €5–€9 per ton CO_2. These costs are stated in [32] for bioethanol plants and are assumed to be the same for CO_2 from biogas treatment. The lowest capture costs of the other industrial processes can be reached in iron and steel production.

3.3. CO_2 from the atmosphere

Apart from the separation of CO_2 from point sources such as combustion or production processes, it is also possible to separate CO_2 from the atmosphere [32]. Due to the low concentration of 0.039 vol.%, or about 370 ppm [35] in the atmosphere, this type of CO_2 recovery is complex and has a high-energy intensity that is approx. 3.4 times higher than for point sources with a CO_2 concentration of 10% [36].

Due to the low partial pressure of CO_2 in the ambient air, chemical absorption is suited for CO_2 capture (see [37]). Notwithstanding the great advantages of unlimited potential and the reduction of CO_2 content in the atmosphere, the energy requirement of 5.4–9.0 MJ per kg CO_2 [10] and specific costs of €150–€320 per t CO_2 [10] are far too high to be competitive with other CO_2 sources and separation technologies.

3.4. Transport of captured CO_2

If the captured CO_2 cannot be stored or applied directly, it has to be transported to the utilization site, e.g. a power-to-gas facility. Compressed or liquefied CO_2 can be transported by truck or in larger quantities via a CO_2 pipeline. Pipelines similar to the natural gas distribution system are applicable at distances up to several hundred kilometers. Average CO_2 pipeline transport costs are between €1 and €10 per ton of CO_2 for a 100-km pipeline, as reported in [38]. However, transport via CO_2 pipeline would require a large amount of additional infrastructure, and the literature values are related to American grid examples that carry relatively large amounts of CO_2. In principle, it is also possible to transport CO_2 in liquefied form (temperatures between −57 and

Table 4
Energy and CO_2 penalties of various technologies for CO_2 capture from industrial processes. Calculations according to information from Kuramochi et al. [34].

Industrial process and capture technology	Specific amount of CO_2 captured	Specific amount of CO_2 avoided	Additional energy in MJ per kg CO_2 captured	CO_2 penalty in g CO_2/kg CO_2 captured
Refinery (combined stacks, catalytic cracker)[a]				
Post-combustion	0.91 kg/kg$_{CO2ref}$	0.80 kg/kg$_{CO2ref}$	2.07	116
Oxyfuel	0.90 kg/kg$_{CO2ref}$	0.70 kg/kg$_{CO2ref}$	3.88	218
Steel & Iron production[b]				
Integrated steelmaking – blast furnace	0.54 kg/kg$_{output}$	0.35 kg/kg$_{output}$	3.76	362
Integrated steelmaking – top gas recycling	1.48 kg/kg$_{output}$	0.78 kg/kg$_{output}$	4.91	473
Smelting reduction (COREX)	1.22 kg/kg$_{output}$	0.77 kg/kg$_{output}$	3.87	373
Cement production[c]				
Post-combustion	1.17 kg/kg$_{output}$	0.60 kg/kg$_{output}$	5.06	487

[a] The primary energy input is natural gas (56.1 g CO_2/MJ); the amount of CO_2 captured and CO_2 avoided is related to the amount of CO_2 emitted in a reference plant without carbon capture (CO_2ref).
[b] The primary energy input is coal (96.3 g CO_2/MJ); the output is kg hot rolled coil.
[c] The primary energy input is coal (96.3 g CO_2/MJ); the output is kg clinker.

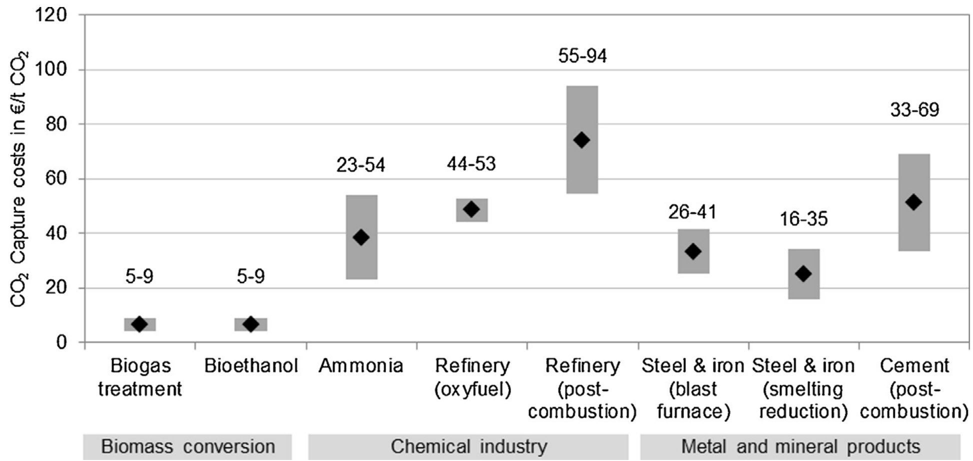

Fig. 6. Capture costs for CO_2 from industrial processes, with information from Kuramochi et al. [34].

31 °C; pressure >5.2 bar) by truck or ship. However, liquefaction has a significant energy requirement, and transportation by truck or ship is not suitable for large quantities of CO_2 [39,40]. Thus, utilization of CO_2 near its production site should be preferred.

4. Case study: evaluating CO_2 sources for power-to-gas applications in Austria

As a starting point, fossil CO_2 emission sources in Austria with an emission level of more than 1000 t CO_2/a were defined and further evaluated concerning their potential for CCU with a strong emphasis on power-to-gas applications. The information on these point sources regarding industry and annual amount of emitted CO_2 was taken from the Austrian emissions trading registry [41]. The 179 investigated sites are distributed across Austria but are denser in urban areas. Together, they emitted more than 30 million t CO_2 in the year 2013. A sectoral clustering is illustrated in Fig. 7.

With 38% of total fossil CO_2 emissions, iron and steel production accounts for the largest component of CO_2 emissions from point sources in Austria. A huge amount of CO_2 is also produced by fuel combustion for power and heat generation. The chemical industry and cement production are each responsible for approx. 12% of emissions. Another important sector in Austria is pulp and paper production, which accounts for 6% of fossil emissions. The energy industry, including gas storage and compression, emits approx. 3% of total CO_2 emissions in Austria. Some smaller installations with various processes such as brick production or magnesite production together account for 5% of total emissions, distributed among 48 sites (other installations in Fig. 7).

For the evaluation of their potential for utilization in power-to-gas, the CO_2 emitting installations were further classified. Some were omitted because separation is not feasible or because no information could be obtained about the applied processes. The CO_2 sources considered for the case study in Austria are listed in Table 5. In addition to the sources for fossil CO_2, producers of CO_2 with biogenic origins were also considered. Power and heat from fossil fuels was divided between coal and natural gas power plants, as these have quite different specific costs and energy requirements for CO_2 capture. Waste incineration was not considered as a potential source for power-to-gas due to the potential impurities in the flue gas. Of the chemical industry sector, the refinery was the focus as a potential CO_2 source, as ammonia production is not recommended for power-to-gas (see Section 3.2). Other processes such as pulp, paper and board production were omitted, as no information about the suitable CO_2 capture technology, the costs or

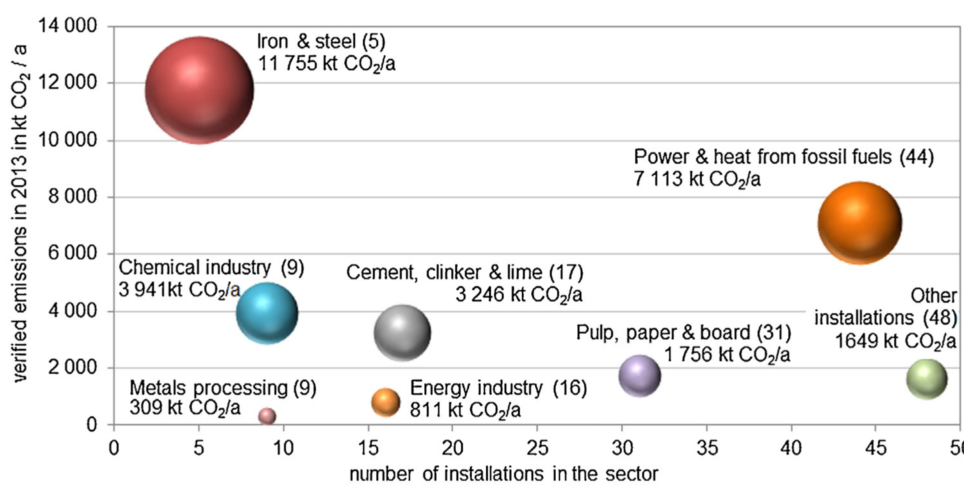

Fig. 7. CO_2 emissions for selected point sources in Austria. The size of the bubbles indicates the annual amount of CO_2 emissions in the respective sector and the number of installations is given in brackets.

Table 5
CO_2 sources in Austria for potential utilization in power-to-gas (reference year 2013) and potential amounts of methane produced via power-to-gas.

CO_2 source	No. of installations	Total amount kt CO_2/a	Capture efficiency	Amount for power-to-gas kt CO_2/a	Electricity GWh/a	Methane production Mio. m^3/a
Coal power plant	3	2319	90%	2087	20,872	1044
Natural gas power plant	39	2977	90%	2679	26,794	1340
Biogas upgrading	11	13	100%	13	127	6
Bioethanol production	1	100	100%	100	1000	50
Refinery	1	2827	75%	2120	21,200	1060
Iron and Steel	5	11,755	75%	8816	88,160	4408
Cement, lime, clinker	17	3246	85%	2759	27,587	1379

the efficiency were available. It is assumed that in many of these processes, CO_2 is produced from fuel combustion and thus could be captured from flue gas with the described separation technologies.

Table 5 also provides information on the amount of CO_2 that could be utilized for power-to-gas (total amount of CO_2 multiplied by the capture efficiency). Considering the efficiency of power-to-gas plants, the maximum amounts of electricity and synthetic CH_4 can be calculated for each CO_2 source. The calculations in Table 5 are based on a specific electricity demand of 5 kW h per m^3 H_2, a methanation efficiency of 80% and a stoichiometric CO_2 input of 2.75 kg per kg CH_4.

The results for relevant CO_2 sources in Austria summarized in Table 5 are now compared to the annual production of electricity from fluctuating renewables in Austria. In the year 2013, 7531 GWh were produced from wind power and 1800 GWh were produced from photovoltaics. Even if all the electricity from wind power and photovoltaics were utilized in power-to-gas plants for CH_4 synthesis, only a small percentage of the total CO_2 emissions in Austria would be required. With most of the CO_2 point sources evaluated in Table 5, the total amount of electricity generated in 2013 from fluctuating renewable power sources could be stored multiple times over as methane in the existing natural gas grid. However, due to the considerably smaller amount of CO_2 from biogas upgrading and bioethanol production, only 2% or 11% of the electricity from fluctuating renewable power sources could be converted into CH_4 via power-to-gas using those CO_2 sources, respectively.

Aside from the amount of CO_2, the distance between CO_2-producing facilities and fluctuating renewable power sources also influences the suitability of CO_2 point sources for utilization in power-to-gas plants. Whereas photovoltaic plants are distributed all over Austria, wind power plants are concentrated in certain regions, especially in Burgenland and Lower Austria. Fig. 8 shows the distribution of installed wind power infrastructure in Austria and the potential CO_2 sources for power-to-gas. Some of the CO_2 sources are located in regions with a high density of installed wind power, but there are also several CO_2-producing facilities large distances from renewable power sources. Transport of CO_2 would be required in these cases, which presents additional costs dependent on the transport distance (see Section 3.4). The bioethanol production facility as well as the refinery are located in Lower Austria, not far from large wind parks, and are therefore especially suitable as CO_2 sources for power-to-gas. Cement, lime or clinker production facilities are mostly not located in regions with a significant density of wind power plants.

The different criteria for evaluation of the suitability of potential CO_2 sources for utilization in power-to-gas are summed and classified in Table 6.

With over 11,000 kt CO_2 per year, the five iron and steel production facilities are by far the largest point emitters of CO_2 in Austria. However, only two of them are located near any wind parks, and none are located in the region with the highest density of installed wind power. Furthermore, the CO_2 emitted due to iron and steel production mostly originates from coal combustion, and

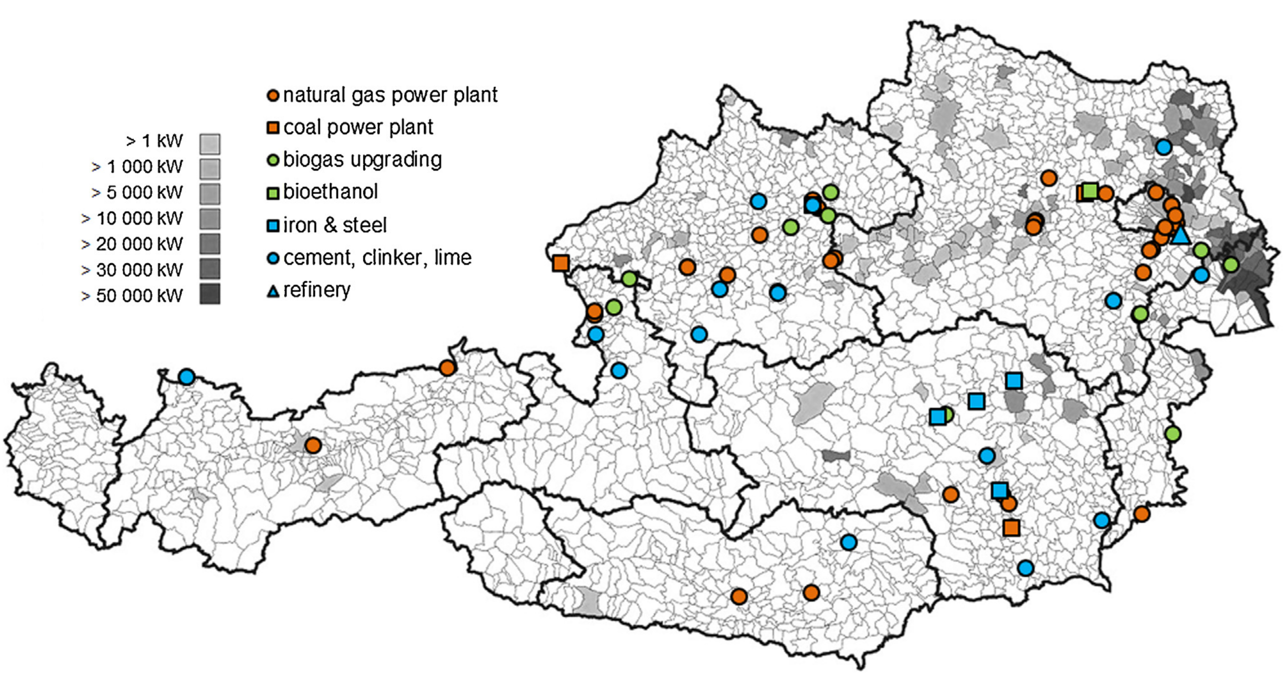

Fig. 8. Density of installed wind power and locations of potential CO_2 sources for power-to-gas in Austria. Map with installed wind power from e-control Austria [42].

Table 6
Qualitative evaluation of potential CO_2 sources for power-to-gas in Austria.

CO_2 source	Capture costs	CO_2 penalty	Biogenic source	Total amount	Site
Coal power plant	o	–	–	+	o
Natural gas power plant	o	o	–	+	o
Biogas upgrading	+	+	+	–	o
Bioethanol production	+	+	+	–	+
Refinery	o	o	–	+	+
Iron and steel	o	–	–	+	o
Cement, lime and clinker	o	–	–	+	–
Ambient air	–	–	+	+	+

its separation requires a significant energy input. CO_2 from cement, lime and clinker production does not appear to be well suited for power-to-gas applications, as the production facilities are not located near wind power plants, the costs and energy requirement are high and the CO_2 mostly originates from burning coal, resulting in a high CO_2 penalty. CO_2 separation from ambient air has the advantage that it could be applied at every site in Austria and that the amount is not limited. However, the costs as well as the energy needed for CO_2 separation from air are high.

5. Conclusions

In general, there are numerous different CO_2 sources available for utilization in power-to-gas processes. CO_2 is produced in the combustion process of power plants and in industrial processes such as iron and steel production, refineries, biogas upgrading, and bioethanol production. Depending on the CO_2 source and the CO_2 concentration in the gas stream, several capture technologies are available, some of them still under development. The methanation step in power-to-gas systems requires a certain purity of the CO_2 stream. Problems could arise if H_2S is present in the CO_2 stream, as this is a catalyst poison. H_2S is especially common in the CO_2 captured from coal power plants with pre-combustion technology.

There are significant differences in the specific capture costs and the CO_2 penalties of the examined CO_2 sources. The lowest costs and CO_2 penalty could be reached if CO_2 is produced as a by-product at a very high concentration, as is the case in biogas upgrading or bioethanol production. If the CO_2 concentration is low, for instance in the flue gas of natural gas combustion or especially in the atmosphere, the specific capture costs and energy requirement are significantly higher. The existing co-benefits in reduced PM, SOx, HCl and HF emissions for capture technologies cannot trade-off additional emissions and resource consumption (e.g. sorbent or water especially for post-combustion capture) and a relative increase in primary energy use at the actual development stage [39].

The case study for Austria shows that there is enough CO_2 available for power-to-gas processes in Austria. All of the electricity produced from fluctuating renewable power sources (wind power plants and photovoltaics) could easily be stored via power-to-gas technology. By far, the highest point emissions in Austria originate from iron and steel production and from fossil fuel combustion in power plants. The qualitative evaluation of CO_2 sources in Austria indicates that CO_2 from biogas upgrading facilities and the bioethanol plant is best suited for utilization in possible future power-to-gas plants. Reasons for those selections are the low capture costs, low CO_2 penalties, and biogenic origins of those sources and their relatively short distances to wind power plants in Austria. As the total amount of CO_2 produced from these facilities is relatively low, other CO_2 sources will also be required for a broader implementation of power-to-gas technology. Due to their moderate costs and CO_2 penalties, power plants and the refinery could also provide CO_2 for power-to-gas processes. Although large amounts of CO_2 would be available from iron, steel and cement production, these are not preferred sources for CO_2 utilization in power-to-gas because their CO_2 penalties are comparably high and the facilities are rarely located near wind power plants. In the absence of future electrical grid expansion, surplus electricity is expected particularly in regions with a dense investment portfolio on renewable generation facilities with fluctuating power output. CO_2 from the ambient air would be one option for application in power-to-gas systems in the long term, as it is available everywhere. However, there is still a lot of research required to significantly reduce the capture costs and energy requirement for use of atmospheric CO_2.

Further research should address the cost-effectiveness and environmental impacts of power-to-gas compared to other CCU technologies on a life cycle basis to ensure a positive economic and environmental balance [43]. Other CCU paths such as the production of methanol out of H_2 and CO_2 could offer advantages compared to power-to-gas technology. However, the opportunity of storing and transporting large amounts of renewable electricity via power-to-gas technology in the existing natural gas infrastructure is of considerable interest especially in North America and Europe [44]. An increasing number of power-to-gas demonstration plants have been built in recent years and the German Strategy Platform for instance expects market integration of power-to-gas in 2020 [45]. The presented capture costs, energy demand and developed CO_2 penalty are important parameter for integrated sustainability evaluations of power-to-gas and other CCU technologies.

Acknowledgements

The support of this work by the Energy Institute at the Johannes Kepler University and the Austrian Federal Ministry of Economy, Family and Youth within the Research Studios Austria 'OptFuel' and 'EE-Methan aus CO_2' is gratefully acknowledged.

References

[1] C. Graves, S.D. Ebbesen, M. Mogensen, K.S. Lackner, Renew. Sustain. Energy Rev. 15 (2011) 1–23.
[2] G. Reiter, in: N. Garland, R.C. Samsun, D. Stolten (Eds.), Wiley-VCH, 2015, (Forthcoming).
[3] R.S. Haszeldine, Science 25 (2009) 1647–1652.
[4] R. Shukla, P. Ranjith, A. Haque, X. Choi, Fuel 89 (2010) 2651–2664.
[5] N.E. Vaughan, T.M. Lenton, Clim. Change 109 (2011) 745–790.
[6] S. Bachu, D. Bonijoly, J. Bradshaw, R. Burruss, S. Holloway, N.P. Christensen, O.M. Mathiassen, Int. J. Greenh. Gas Control 1 (2007) 430–443.
[7] J. Lipponen, K. Burnard, B. Beck, J. Gale, B. Pegler, Energy Procedia 4 (2011) 5752–5761.
[8] M. Aresta (Ed.), Carbon Dioxide as a Chemical Feedstock,, Wiley-VCH, Weinheim, 2010, , ISBN 978-3-527-32475-0.
[9] M. Sterner, Bioenergy and renewable power methane in integrated 100% renewable energy systems. Limiting global warming by transforming energy systems, (dissertation), University of Kassel, 2009.
[10] T. Trost, S. Horn, M. Jentsch, M. Sterner, Z. Energiewirtschaft 36 (2012) 173–190.
[11] K. Müller, M. Fleige, F. Rachow, D. Schmeißer, Energy Procedia 40 (2013) 240–248.
[12] M. Lehner, R. Tichler, H. Steinmüller, M. Koppe, Power-to-Gas: Technology and Business Models Springer Briefs in Energy, 2014.
[13] K.E. Jenni, E.D. Baker, G.F. Nemet, Int. J. Greenh. Gas Control 12 (2013) 136–145.
[14] D.R. Gomez, J.D. Watterson, et al., IPCC Guidelines for National Greenhouse Gas Inventories. Vol. 2: Energy, 2006 http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf (accessed 19.12.14).
[15] N. von der Assen, J. Jung, A. Bardow, Energy Environ. Sci. 6 (2013) 2721–2734.
[16] Canadian Clean Power Coalition, http://www.canadiancleanpowercoalition.com/files/4713/0180/2978/Capture%20Costs%20Definitions%20Fact%20Sheet.pdf (accessed 19.12.14)
[17] K. Vatopoulos, E. Tzimas, J. Clean. Prod. 32 (2012) 251–261.
[18] K.S. Lackner, Eur. Phys. J. Spec. Top. 176 (2009) 93–106.
[19] B. Metz, O. Davidson, H. de Coninck, M. Loos, L. Meyer, Carbon Dioxide Capture and Storage, IPCC, Cambridge University Press, 2005 https://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf (accessed 14.04.14).
[20] B. Sreenivasulu, D.V. Gayatri, I. Sreedhar, K.V. Raghavan, Renew. Sustain. Energy Rev. 41 (2015) 1324–1350.

[21] E.S. Rubin, H. Mantripragada, A. Marks, P. Versteeg, J. Kitchin, Prog. Energy Combust. 38 (2012) 630–671.
[22] A. Lyngfelt, M. Johansson, T. Mattisson, 9th International Conference on Circulating Fluidized Beds, Hamburg, 2008.
[23] A.A. Olajire, Energy 35 (2010) 2610–2628.
[24] A. Kather, S. Kownatzki, Int. J. Greenh. Gas Control 5 (2011) 204–209.
[25] G. Scheffknecht, L. Al-Makhadmeh, U. Schnell, J. Maier, Int. J. Greenh. Gas Control 5 (2011) 16–35.
[26] E. Blomen, C. Hendriks, F. Neele, Energy Procedia 1 (2009) 1505–1512.
[27] K. Damen, M. van Troost, A. Faaij, W. Turkenburg, Prog. Energy Combust. 32 (2006) 215.
[28] K. Jana, S. De, Renew. Energy 72 (2014) 243–252.
[29] IEA, Impact of Impurities on CO_2 Capture, Transport and Storage, London, 2004 http://ieaghg.org/docs/General_Docs/Reports/Ph4-32%20Impurities.pdf (accessed 18.12.14).
[30] P. Seevam, J.M. Race, M.J. Downie, The Next Generation of CO_2 Pipelines, CCS Summer School, Vancouver Island, 2008.
[31] C.H. Bartholomew, Appl. Catal. A-Gen. 212 (2001) 17–60.
[32] A. Laude, O. Ricci, G. Bureau, J. Royer-Adnot, A. Fabbri, Int. J. Greenh. Gas Control 5 (2011) 1220–1231.
[33] E. Ryckebosch, M. Drouillon, H. Vervaeren, Biomass. Bioenergy 35 (2011) 1633–1645.
[34] T. Kuramochi, A. Ramírez, W. Turkenburg, A. Faaij, Prog. Energy Combust. 38 (2012) 87–112.
[35] R. Baciocchi, G. Storti, M. Mazzotti, Chem. Eng. Process 45 (2006) 1047–1058.
[36] D. Keith, M. Ha-Doung, J.K. Stolaroff, Clim. Change 74 (2006) 17–45.
[37] M. Specht, A. Bandi, M. Elser, et al., CO_2-Recycling zur Herstellung von Methanol (CO_2 Recycling for Production of Methanol), ZSW, 2000.
[38] K. Damen, M. van Troost, A. Faaij, W. Turkenburg, Prog. Energy Combust. 33 (2007) 580–609.
[39] J. Koornneef, A. Ramírez, W. Turkenburg, A. Faaij, Prog. Energy Combust. 38 (2012) 62–86.
[40] V. Vandeginste, K. Piessens, Int. J. Greenh. Gas Control 2 (2008) 571–581.
[41] Austrian Emissions Trading Registry, Status of Compliance, 2013 http://www.emissionshandelsregister.at/company/compliance_status/ (accessed 18.12.14).
[42] W. Boltz, M. Graf, Ökostrombericht 2014 (Green Electricity Report Austria), with information from the Stromnachweisdatenbank (database for electricity certificates) of the e-control Austria, 2014 http://www.e-control.at/portal/page/portal/medienbibliothek/publikationen/dokumente/pdfs/Oekostrombericht2014_final.pdf (accessed 19.12.14).
[43] R.M. Cuéllar-Franca, A. Azapagic, J. CO2 Util. (2014), http://dx.doi.org/10.1016/j.jcou.2014.12.001.
[44] G. Gahleitner, Int. J. Hydrogen Energy 38 (2013) 2039–2061.
[45] Homepage of the dena Power-to-Gas Strategy Platform, http://www.powertogas.info/plattform/information-in-english/roadmap-for-power-to-gas.html (accessed 10.03.15).

Gerda Reiter Gerda Reiter completed her Master's studies in Eco Energy Technologies at the University of Applied Sciences Upper Austria in 2011. Since November 2011, she has worked as a research associate at the Energy Institute at the Johannes Kepler University Linz. Gerda Reiter is currently completing her PhD in Process Engineering at the Technical University Graz. The focus of her work is on the technical, ecological, and economic evaluation of energy storage technologies such as power-to-gas.

Johannes Lindorfer Dipl.Ing. (FH) Johannes Lindorfer completed the Masters of Biotechnology and Environmental Engineering at the University of Applied Sciences in Upper Austria in 2005. Since September 2007, Mr. Lindorfer has worked as a Research Associate for the Energy Institute at the Johannes Kepler University in Linz, Austria managing research projects in the field of ecological and economic process analysis. Additionally, Mr. Lindorfer is currently completing a PhD in Chemical and Process Engineering at the Graz University of Technology. The issues addressed in his thesis include sustainable process development practices and life cycle assessment of the value chain of biomass conversion technologies.

Alternative fuels for mobility and transport: Harnessing excess electricity from renewable power sources with power-to-gas

Gerda Gahleitner
Energy Institute at the Johannes Kepler University Linz
Altenberger Straße 69
4040 Linz
Austria
gahleitner@energieinstitut-linz.at

Johannes Lindorfer
Energy Institute at the Johannes Kepler University Linz
Altenberger Straße 69
4040 Linz
Austria
lindorfer@energieinstitut-linz.at

Keywords
alternative fuels, power-to-gas, synthetic methane

Abstract
This article presents the analysis of economic, technical and ecological aspects of alternative gaseous fuel production from renewable excess electricity. Besides improvements in energy efficiency, renewable fuels will be required for the reduction of overall greenhouse gas emissions in the transport and mobility sector. The 'power-to-gas' technology provides hydrogen by splitting water with excess electricity from renewable power sources or further synthesizes methane by using carbon dioxide. Thereby both, the increasing demand for energy storage due to fluctuating renewable power sources and the demand of alternative fuels for mobility, are addressed.

The article provides a short review of realized power-to-gas demonstrations for transport applications and discusses occurring problems as well as topics for further development. In terms of ecological aspects it can be shown that if electricity and carbon dioxide origin from renewable sources, a substantial reduction in greenhouse gas emissions can be reached for synthetic methane compared to conventional diesel.

The presented case study for the supply of an Austrian public bus fleet with synthetic methane indicates that production costs are mainly influenced by the electricity price and the investment costs. They also strongly depend on the amount of full load hours per year of the power-to-gas facility. Currently, the synthetic methane production costs of 0.41 Euro/kWh are considerably higher than diesel prices. For the future utilization of expected excess electricity from renewable power sources and a possible adaptation of the legal framework in the electricity sector the costs of synthetic methane production can possibly be reduced to approximately 0.13 Euro/kWh. Future research should focus on improving the efficiency, reliability, costs and lifetime of the components, and optimum system configurations should be determined to improve the integration into the overall energy system.

Introduction
For mitigating climate change, the reduction of global greenhouse gas (GHG) emissions is essential and can be realized on the one hand with improvements in energy efficiency and on the other hand with the development of renewable technologies. Regarding the reduction of overall greenhouse gas emissions, not only the electricity but also the transportation, heating and industry sectors have to be addressed. In the year 2011, 20.3 % of global electricity has been produced from renewable power sources.[1] Wind and solar power actually account for a small fraction as the greatest amount (15.3 %) has been produced by hydropower, but these technologies show high potentials for the future. Nevertheless, wind and solar power show strongly fluctuating characteristics and require load levelling and energy storage.

Especially in the transportation sector, the development of renewable fuels is a big challenge as currently the vast majority is derived from fossil feedstock. Currently liquid biofuels account for only 3 % of global fuel production[2] and other renewable transport technologies play an insignificant role.

1. REN21, Renewables 2012 Global Status Report. Paris, 2012, REN21 Secretariat. http://www.map.ren21.net/GSR/GSR2012.pdf, accessed 17.12.2012.
2. REN21, 2012

Several problems are accompanied with biofuels as arable land is needed for growing feedstock, and competition with food production is an issue.[3,4] Direct utilization of renewable electricity in electric vehicles represents an efficient transport technology without emissions but faces challenges such as small driving range, heavy and expensive batteries with short lifetimes or extra burden of the public electricity grid. Power-to-gas technology for hydrogen or synthetic methane production out of renewable electricity represents another option for renewable fuel production. Additionally, it addresses the increasing demand for energy storage due to fluctuating renewable power sources when utilizing excess electricity. 'Excess electricity' could be specified as the electricity that cannot be fed into the public electricity grid or be utilized otherwise. Reasons for that could be a lower electricity demand than the actual generation or that in local grids the electricity network may be too weak to transport peak production from renewables.

With power-to-gas, electricity from renewable power sources splits water via an electrolyzer. The produced hydrogen can be either directly utilized or further synthesized to methane with carbon dioxide. Depending on the integration into the energy infrastructure, various applications can be realized. The produced hydrogen or methane can be directly utilized in refuelling stations for transportation purposes. Another possibility is to feed them into the gas distribution system and therefore provide energy for the electricity, heating and transportation sector. Further applications could be the utilization of hydrogen in industry or the reconversion into electricity via fuel cells. These applications are not considered in this article as only pathways for providing alternative fuels are evaluated.

The information for the review of realized power-to-gas pilot plants for transportation purposes is mainly gathered from www.h2stations.org[5] and Gahleitner, 2013[6]. The environmental impacts of various transportation fuels are evaluated with data from a well-to-wheel (WTW) analysis performed by Edwards et al., 2011[7]. The calculations for the Austrian case study are based on data from peer-reviewed literature and component manufacturers. Since power-to-gas is not a fully developed technology, well-defined cost values are not always available. The cost estimation of fuels from power-to-gas is therefore performed for the mid-term and the long-term perspective.

The article presents various applications of the power-to-gas technology for mobility purposes with information about the main components of the system. A short review of realized demonstration plants is provided, and occurring problems, future research demand and potential of the technology is discussed. Fuels produced via power-to-gas technology are compared to other transportation fuels in terms of environmental impacts such as greenhouse gas emissions. The presented case study for Austria deals with the system design for a bus fleet and economic evaluation of power-to-gas for sustainable mobility. SNG (synthetic natural gas) fuel production costs and total costs for the bus fleet are calculated for the mid-term and the long-term perspective and the required modification of regulations is discussed. Power-to-gas technology for alternative fuel production is evaluated with regard to economic and ecological aspects and future research demand is deduced.

Power-to-gas for transport applications

The power-to-gas technology utilizes electricity from fluctuating renewable power sources for splitting water into hydrogen and oxygen in an electrolyzer. The produced hydrogen can be utilized as fuel for transportation purposes, can be fed into the gas distribution system, utilized directly in the chemical industry or can be reconverted into electricity with a fuel cell. Another possibility is to further synthesize hydrogen to methane with carbon dioxide in the so-called Sabatier process.[8] Although this pathway has a lower efficiency, synthetically produced methane has the advantage that it can be utilized in the same way as natural gas and therefore no additional infrastructure is required. As this article focuses on alternative fuels for transportation purposes, only the pathways for fuel production via power-to-gas are illustrated in Figure 1.

Renewable electricity for operation of the water electrolyzer can be obtained directly from renewable power sources or indirectly over the public electricity grid. For every pathway there are different operating modes which determine the electricity costs as well as the operating hours. Grid-connected systems could obtain electricity with the conventional EU-mix or certified green electricity. Depending on the desired amount of full load hours excess electricity or base electricity has to be utilized.

There are several possible pathways to provide fuel from power-to-gas. The first option is to directly provide hydrogen as fuel for vehicles with a fuel cell or an internal combustion engine. The produced hydrogen can be distributed to the refuelling station with a hydrogen pipeline or in pressure vessels, depending on the distance and amount of hydrogen. If the refuelling station is on-site, there is no need for hydrogen distribution.

Hydrogen could also be directly fed into the gas infrastructure but the restrictions on the allowed volumetric fraction have to be considered.[9] In this option, the gas distribution system serves for energy transport and the fuel can be utilized in a CNG (compressed natural gas) refuelling station, independent from the site of production.

3. Ajanovic A, Biofuels versus food production: does biofuels production increase food prices?, Energy 2011, 36 pp. 2070–2076. DOI 10.1016/j.energy.2010.05.019.

4. Söderberg C, Eckerberg K, 2012, Rising policy conflicts in Europe over bioenergy and forestry, Forest Policy and Economics 2012. DOI 10.1016/j.forpol.2012.09.015.

5. http://www.h2stations.org, accessed January 04, 2013.

6. Gahleitner G, Hydrogen from renewable electricity: An international review of power-to-gas pilot plants for stationary applications, International Journal of Hydrogen Energy 2013, DOI 10.1016/j.ijhydene.2012.12.010.

7. Edwards R, Larivé J-F, Beziat J-C, Well-to-wheel analysis of future automotive fuels and power trains in the European context. Report Version 3c. European Commission, Joint Research Center, Institute for Energy and Transport, Luxembourg, 2011. doi:10.2788/79018.

8. Müller B, Müller K, Teichmann D, Arlt W, Energiespeicherung mittels Methan und energietragenden Stoffen – ein thermodynamischer Vergleich. Chemie Ingenieur Technik 2011, 83, No. II, 2002-2013. DOI 10.1002/cite.201100113.

9. Mueller-Syring G, Henel M, Power-to-Gas: Konzepte, Kosten, Potenziale. DBI Fachforum: Energiespeicherkonzepte und Wasserstoff, 2011. http://www.dbi-gti.de/fileadmin/downloads/5_Veroeffentlichungen/Tagungen_Workshops/2011/H2-FF/07_Mueller-Syring_DBI_GUT.pdf, accessed 17.12.2012.

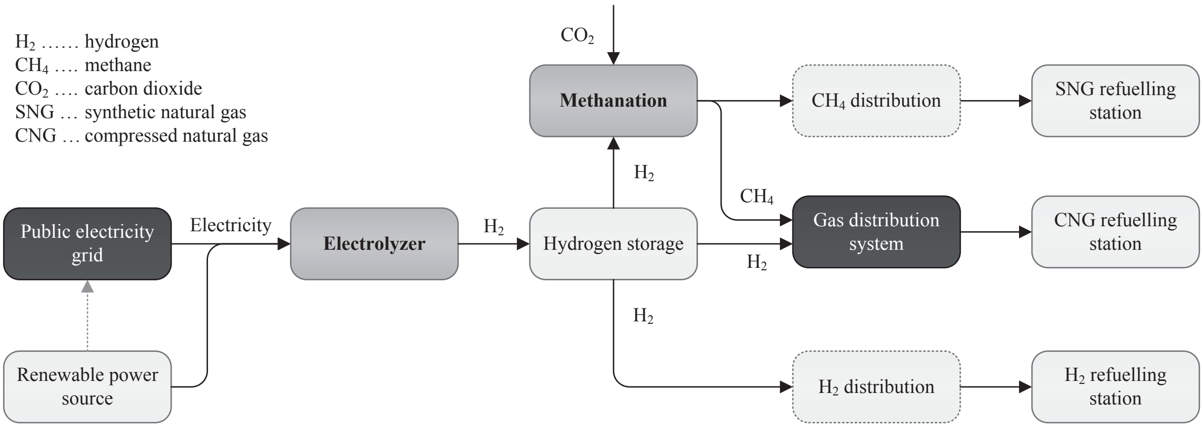

Figure 1. Pathways for application of power-to-gas for alternative fuel production.

If the produced hydrogen is further synthesized to methane, carbon dioxide has to be available. There are numerous potential CO_2 sources such as flue gas from fossil power plants, industrial processes in lime and cement industry, biotechnological processes or even extraction from the ambient air.[10, 11] The produced synthetic methane could also be fed into the gas distribution system with the advantage that there are no restrictions on the allowed amount since it is nearly identical to natural gas. The advantage of employing the gas distribution system for energy transport is that production and consumption are decoupled. Therefore both an optimum site for production with availability of renewable resources and carbon dioxide and an optimum site for consumption with storage infrastructure, refuelling station and fuel demand can be chosen.

Another option is to provide the SNG directly at a refuelling station. It can be applied in conventional CNG refuelling stations and CNG cars where natural gas is currently used and which are state-of-the-art technologies. If the refuelling station is not on-site, the synthetic methane could also be transported to the site of application.

MAIN COMPONENTS

The two main components of a power-to-gas system are the water electrolyzer and the methanation reactor in case that synthetic methane is produced.

There are various types of water electrolyzers that are characterized by the applied electrolyte. A detailed evaluation of electrolyzer technologies is provided by Ursua et al., 2012[12] and by Smolinka et al., 2011[13]. Here only the main characteristics of the alkaline (AEC), proton exchange membrane (PEMEC) and the solid oxide electrolysis cell (SOEC) are described. AEC have an aqueous alkaline electrolyte and are the most developed electrolyzer types. They are commercially available at high capacities of up to 760 Nm^3/h and represent the cheapest of electrolyzer technologies. Their performance is good if operated continuously but problems occur when AEC are operated with strongly fluctuating power input.[14] PEMEC have a simpler design and employ a polymer electrolyte membrane. They are in a pre-commercial stage and are only available for small capacities of up to 30 Nm^3/h. PEM electrolyzers are better suited for operation with fluctuating power input as they have faster reaction to load changes and a better hydrogen quality in part load. One of the main challenges is the limited lifetime and the high initial costs due to noble metal catalysts.[15] SOEC are at an early stage of development and are operated with additional thermal energy input, which reduces the required amount of electricity and therefore increases efficiency. Due to the high temperatures, there is no need for expensive catalysts on the one hand, but on the other hand several material problems arise.[16] When operated with fluctuating power input, all types of electrolyzers have problems with efficiency, reliability and decreased durability.

Synthetic methane can be produced from hydrogen and CO or CO_2 in a methanation reactor. CO methanation is applied in large-scale coal gasification processes. CO_2 methanation is a combination of the water-gas shift reaction and the CO methanation. The synthesis reactor operates at temperatures from 180 to 350 °C and at pressures of around 8 bar.[17] Typically applied catalyst materials are Ni or Ru. One big advantage of CO_2 methanation is the additional environmental benefit of the reuse of the greenhouse gas CO_2. The CO_2 methanation reactor is under development and although comparable efficiencies (83 %[18]) to the CO methanation are achieved, challenges

10. Rubin E-S, Mantripragada H, Marks A, Versteeg P, Kitchin J, The outlook for improved carbon capture technology. Progress in Energy and Combustion Science 2012, 38(5), 630–671. DOI 10.1016/j.pecs.2012.03.003.

11. Breyer CH, Rieke S, Sterner M, Schmid J, Hybrid PV-Wind-Renewable Methane Power Plants. European Photovoltaic Solar Energy Conference, Hamburg, Germany, 2011. http://www.q-cells.com/uploads/tx_abdownloads/files/6CV.1.31_Breyer2011_HybPV-Wind-RPM-Plants_paper_PVSEC_preprint.pdf, accessed 17.12.2012.

12. Ursua A, Gandia LM, Sanchis P, Hydrogen Production from water electrolysis: current status and future trends. Proceedings of the IEEE 2012; Vol. 100, No. 2: 410-426. DOI 10.1109/JPROC.2011.2156750.

13. Smolinka T, Günther M, Garche J, Stand und Entwicklungspotenzial der Wasserelektrolyse zur Herstellung von Wasserstoff aus regenerativen Energien. Kurzfassung NOW-Studie. Fraunhofer ISE, FCBAT, 2011. http://www.now-gmbh.de/fileadmin/user_upload/RE-Mediathek/RE_Publikationen_NOW/NOW-Studie-Wasserelektrolyse-2011.pdf, accessed 17.12.2012.

14. Smolinka et al., 2011

15. Smolinka et al., 2011

16. Ursua et al., 2012

17. Breyer et al., 2011

18. Dickinson RR, Battye DL, Linton VM, Ashman PJ, Nathan GJ, Alternative carriers for remote renewable energy sources using existing CNG infrastructure. Int J Hydrogen Energy 2012, 35 (3): 1321-1329. DOI 10.1016/j.ijhydene.2009.11.052

arise with long-term stability and poisoning of catalysts and heat management.[19]

Carbon dioxide for the methanation process can be obtained from various renewable and non-renewable sources. CO_2 can be sequestered from flue gas in power plants with combustion processes or is produced in industrial processes like in lime or cement production. Renewable CO_2 sources are biomass gasification, fermentation process in biogas plants or other biotechnological production processes. With a high energy input, CO_2 could even be extracted from the ambient air.[20] CO_2 capture technologies are described in more detail in IPPC, 2005[21] or Li et al. 2013[22].

REALIZED POWER-TO-GAS DEMONSTRATIONS FOR TRANSPORT APPLICATIONS

Numerous power-to-gas pilot plants for transport applications have already been realized or are planned in Europe and some of them are shown in Table 1[23, 24]. The projects are categorized by type of fuel and additional application. Seven of the realized pilot plants were built for stationary applications such as electricity production in a fuel cell and have an additional refuelling station for a small number of hydrogen vehicles. Five of the pilot plants are going to feed in hydrogen into the gas distribution grid and three pilot plants are going to produce synthetic methane that is fed into the gas distribution grid. All of these projects that are going to feed in hydrogen or synthetic methane are located in Germany and have been recently realized or are planned for the next years. Power-to-gas pilot plants that produce H_2 for refuelling stations have been realized since the year of 1991 and are located in several European countries.

Power-to-gas pilot plants have been evaluated by Gahleitner, 2013,[25] and some of the main conclusions of the projects are shortly summarized. Alkaline electrolyzers are mainly applied since they are commercially available and occurring problems are for instance low hydrogen purity and high stack degradation. PEM electrolyzers are increasingly utilized in the last few years as they are better suited for fluctuating input but problems with short lifetimes and rapid degradation were reported. Other challenges are the lack of mass-produced hydrogen components, low reliability and problems with fluctuating and intermittent power input. Further research is required to improve efficiency, lifetime and costs of hydrogen components. System integration should be addressed and pilot plants should be operated continuously over years to gather long-term experiences.

ECOLOGIC EVALUATION

In this section, the environmental impacts of applying power-to-gas for mobility purposes are evaluated. The primary energy demand for hydrogen and synthetic methane is compared to other transportation fuels and the overall greenhouse gas emissions are assessed from the life cycle perspective with the system boundary well-to-wheel. The environmental impact of H_2 and synthetic CH_4 produced in power-to-gas plants mainly depends on the origin of electricity and carbon dioxide.

CO_2 can either be obtained from renewable or fossil sources. Allocation of CO_2 is not discussed in this article, but if carbon dioxide is sequestered from fossil point sources such as flue gas from coal combustion, it has to be considered. The power-to-gas approach is only relevant as CO_2 storage strategy if the CO_2 balance of the resulting product is negative (net CO_2 consumption) over its entire life cycle. From an ecological perspective the product life cycle time and thus the duration of the binding of CO_2 and the possibly substituted fossil based reference product play an important role. The use of synthetic methane from power-to-gas instead of natural gas or diesel in transport applications additionally imposes co-benefits in reduced PM (particulate matter), SO_x, HCl and HF emissions. However, additional emissions and resource consumption of sorbent, strong increase in water consumption and increase in primary energy use (approximately 15–45 %) are reported for carbon capture technologies, especially for post-combustion capture.[26] All of these aspects have to be traded off by resource substitution through synthetic methane from captured CO_2 and the associated co-benefits for fossil fuel substitution.

Table 2[27] presents greenhouse gas emissions for various electricity sources in Austrian electricity labelling, showing that no emissions are allocated to renewable power sources.

Comparing environmental impacts of different automotive fuels, the whole life cycle from raw material extraction, fuel production, distribution and utilization in vehicles has to be considered. The evaluated impacts of different transportation fuels from well-to-wheel are taken from Edwards et al., 2011.[28]

Figure 2[29] shows the primary energy demand of different fuels for transportation, based on data for the year 2010 and distinguishing between fossil and renewable primary energy input. It shows that conventional fossil fuels such as gasoline, diesel and CNG have nearly the same primary energy input per 100 km. The primary energy input is considerably higher (+87 % on average) for biofuels such as biodiesel, ethanol or biogas but mainly originates from renewable sources. One of the highest primary energy input with 434 MJ per 100 km is obtained for compressed hydrogen produced via electrolysis with the conventional EU-mix electricity as input power source.

A comparison of overall greenhouse gas emissions is provided in Figure 3[30]. The highest GHG emissions per km are obtained with compressed H_2 produced in electrolysis with EU-mix electricity. Even conventional gasoline vehicles have lower impact, although representing the highest GHG emis-

19. Project homepage iC4 – Integrated Carbon Capture, Conversion and Cycling. http://www.ic4.tum.de/index.php?id=1235, accessed 17.12.2012.

20. Breyer et al., 2011

21. IPPC, Carbon dioxide capture and storage. Cambridge University Press, 2005.

22. Li B, Duan Y, Luebke D, Morreale B, Advances in CO2 capture technology: A patent review. Appl Energ 2013; 102: 1439 – 1447. DOI 10.1016/j.apenergy.2012.09.009.

23. Based on information from http://www.h2stations.org, accessed January 04, 2013.

24. Gahleitner, 2013

25. Gahleitner, 2013

26. Koornneef J, Ramirez A, Turkenburg W, Faaij A, The environmental impact and risk assessment of CO2 capture, transport and storage - An evaluation of the knowledge base. Progress in Energy and Combustion Science 2012, 38(1), 62–86. DOI 10.1016/j.pecs.2011.05.002.

27. Based on information from E-Control, Electricity Labelling Regulations. 2011. http://www.e-control.at/en/businesses/renewables/electricity-labelling-regulations, accessed 20.02.2013

28. Edwards et al., 2011

29. Based on information from Edwards et al., 2011.

30. Based on information from Edwards et al., 2011

Table 1. European power-to-gas pilot plants for transport applications.

Project Name	Country	Start-up	End
Power-to-gas pilot plants for stationary applications with hydrogen refuelling station			
SWB Project in Neunburg vorm Wald	Germany	1991	1999
Laboratory Plant Stralsund	Germany	1998	-
PURE Project at the island of Unst	United Kingdom	2005	-
Baglan Energy Park Wales	United Kingdom	2008	-
Hydrogen Mini Grid System Yorkshire	United Kingdom	2012	-
H2Herten	Germany	2012	-
RABH2	United Kingdom	n/a	-
Power-to-gas pilot plants with hydrogen fed into gas distribution grid			
Hybrid Power Plant Enertrag in Prenzlau	Germany	2011	-
RH2 WKA	Germany	2012	-
Demonstration Plant EON in Falkenhagen	Germany	2013	-
Demonstration plant Thüga in Laufen	Germany	2013	-
Windpark Suderburg Greenpeace Energy	Germany	n/a	-
Power-to-gas pilot plants with synthetic methane production			
Solar Fuel Beta-Plant Audi in Werlte	Germany	2013	-
R&D plant (methanation) in Karlsruhe	Germany	n/a	-
P2G plant Erdgas Schwaben	Germany	n/a	-
Power-to-gas pilot plants with hydrogen refuelling station			
Residential Home Friedli	Switzerland	1991	-
H2argemuc at Munich Airport	Germany	1999	2006
Grjótháls Hydrogen Station in Reikjavik	Iceland	2003	-
Hamburg CUTE	Germany	2003	-
WIV Hydrogen Station in Barth	Germany	2003	-
BP Cute Hydrogen Refuelling Station Barcelona	Spain	2003	2007
CUTE Station Amsterdam	Netherlands	2003	2008
Multifuel refuelling station Malmö	Sweden	2003	-
CUTE station Stockholm	Sweden	2003	2005
CEP Aral Station Berlin Messedamm	Germany	2004	2008
Zero Emission Hydrogen Bus ENEA	Italy	2004	-
Volkswagen Technology Center Isenbüttel	Germany	2005	-
RES2H2 Attica in Greece	Greece	2006	-
AGIP Mulitenergy Station in Collesalvetti	Italy	2006	-
Mobile Filling Station of Fraunhofer Institute in Dresden	Germany	2006	-
Samsoe non road - Energy Academy	Denmark	2006	-
ITHER - Green hydrogen from Wind and Solar for Mobile Applications	Spain	2007	-
Expo Zaragoza 2008	Spain	2008	-
Solar Hydrogen Station Fronius	Austria	2009	-
Althytude Dunqerqe	France	2009	-
ITM Power Green Hydrogen Refuelling at Nottingham University	United Kingdom	2009	-
Hydrohybrid at ITC Gran Canaria	Spain	2009	-
CEP Total Station Berlin Holzmarktstraße	Germany	2010	-
H2Seed	United Kingdom	2010	-
Walqa Hydrogen Filling Station (ITHER)	Spain	2010	-
Las Columnas, Hynergreen	Spain	2010	-
Hynor Lillestrom hydrogen station	Norway	2010	-
Stand-alone power system in Thessaloniki	Greece	2011	-
H2 moves Oslo	Norway	2011	-
WaterstofNet Station Halle in Brussels	Belgium	2012	-
Aargau Chic Station 1 in Brugg	Switzerland	2012	-
Hamburg Hafen City CEP	Germany	2012	-
H2 Move at ISE Fraunhofer	Germany	2012	-
Stuttgart EnBW Station	Germany	2012	
Hydrogen Refuelling at Arctic Driving Center	Finland	2012	-
Loughborough hyrogen refuelling	United Kingdom	2012	-
Hynor CHIC Oslo Bus Station	Norway	2012	-
Refuelling Station at Golden Horn Estuary in Istanbul	Turkey	2012	-
Hynor Lyngdal	Norway	2013	-
IDYLHYC	France	n/a	-

Table 2. Greenhouse gas emissions for various electricity sources from the Austrian electricity labelling.

Energy Vector	GHG emissions [g/kWh$_{el}$]
Solid or liquid biomass	0
Biogas	0
Geothermal energy	0
Wind power	0
Solar energy	0
Hydro power	0
Natural gas	440
Oil	645
Coal	882
Nuclear energy	0
Others	650

sions among fossil fuels. As a consequence, hydrogen or synthetic methane production by utilizing EU-mix electricity should not be favoured. If 100 % wind electricity is utilized for H_2 production, only 9 g_{CO2eq} are emitted per kilometre and substantial reduction in greenhouse gases could be achieved.

Figure 3 only provides information on GHG emissions of H_2 but not of synthetic methane as such WTW calculations were not performed by Edwards et al., 2011[31]. Supposing that both electricity and CO_2 originate from renewable sources, a rough estimation of overall GHG emissions of synthetic methane could be obtained by including a methanation efficiency of 80 %. This results in 11.3 g_{CO2eq} per kilometre, which is still lower than for all the other fuels. Based on this result, a reduction of about 93 % in greenhouse gas emissions can be achieved with synthetic methane compared to diesel. A more detailed well-to-wheel analysis should be performed in future research.

Besides the low greenhouse gas emissions per kilometre, other advantages of fuel production from power-to-gas are the long-term storage of excess electricity, the higher operation times of renewable power sources and the reduced effort for the public electricity grid as energy transport is shifted to the gas distribution grid.

OVERALL POTENTIAL

The overall potential of the technology power-to-gas for transport or other applications is depending on various parameters and trends. Since power-to-gas could be employed for energy storage, the overall potential of the technology depends on the future storage demand for electricity. The energy storage demand is influenced on the one hand by the percentage of fluctuating renewables in the overall electricity generation and on the other hand on the efficiency, costs and availability of alternative storage technologies such as pumped hydro, compressed air, flywheels, or batteries.

Another influencing parameter is the desired percentage of renewables in the transport sector. Due to the lack of renewable alternative fuels with adequate potential, H_2 or SNG from power-to-gas could be interesting alternatives to replace fossil fuels. The future potential in transport applications also depends on the development of CNG infrastructure (refuelling stations, cars) and H_2 infrastructure.

The quality of the power network also influences the potential of power-to-gas technology as in weak grids there is a stronger need for energy storage and balancing power. Especially in remote areas, for instance near large offshore wind parks, the local electricity demand is low and the grid often cannot absorb the total amount of generated electricity. Since the power grid expansion is time consuming and very often accompanied by strong public resistance, energy transport via the gas distribution grid and application for transport could be an interesting alternative.

If SNG is produced via power-to-gas technology, the availability of an adequate carbon dioxide source is decisive too. Theoretically, CO_2 could be extracted from ambient air but the energy input for these processes is very high.

Case Study Austria

In the case study for an Austrian public bus fleet, production costs of SNG via power-to-gas are calculated for the mid-term and the long-term perspective. Operational costs for a whole CNG bus fleet are calculated and compared to the operation with conventional diesel buses. Taxes and charges for the gas distribution system and the public electricity grid are outlined and the influence of certain parameters such as full load hours, investment costs and operation mode of the power-to-gas plant are discussed. H_2 is not considered as transportation fuel for this case study as SNG has the great advantage that it can be fed into the gas distribution without restrictions and that CNG refuelling stations and buses are state-of-the-art technologies.

SYSTEM DESIGN AND DEMAND

For the design of the power-to-gas system, a bus fleet with 70 buses is assumed. Table 3[32, 33, 34] shows the main parameters of the bus fleet and the required power-to-gas system with information on efficiency, nominal power and consumables. When assuming 6,000 full load hours per year, a power-to-gas plant with a nominal capacity of 8.9 MW_{el} is required for supplying a bus fleet with 70 buses. The calculations were performed for a lower heating value for synthetic methane of 10.4 kWh/Nm^3 and a density of 0.8 kg/Nm^3. Carbon dioxide has a density of 1.977 kg/m^3 and oxygen has a density of 1.43 kg/m^3. With an energy efficiency of 50 % the power-to-gas plant consumes about 53,000 MWh_{el} electricity per year. This is comparable to the yearly produced electricity of four 7 MW_{el} wind turbines in Austria with approximately 2,000 full load hours per year. Compared to the overall electricity that is produced from wind energy in Austria (1.9 million MWh_{el}[35]) 2.7 % would be re-

31. Edwards et al., 2011

32. Table 3 Fuel demand remark: Fokkens E, Final report: Analysis of different production processes, which produce biogas with a higher amount of hydrogen. 2012. http://www.balticbiogasbus.eu/web/Upload/Supply_of_biogas/Act_4_4/WP%204%204_Final%20report_310812.pdf, accessed 20.02.2013

33. Table 3 Efficiency power-to-gas plant remark: Rieke S, Regenerative Vollversorgung – von der Vision zur Praxis. Hannover, 2011. http://www.bee-ev.de/_downloads/bee/2011/HannoverMesse/20110404_HMI_SoarFuel_Rieke_Vollversorgung.pdf, accessed 17.12.2012.

34. Table 3 Heat utilization remark: Rieke, 2011

35. Statistics Austria, Energy Balances Austria 1970 to 2011. http://www.statistik.at/web_en/statistics/energy_environment/energy/energy_balances/index.html, accessed 08.01.2013

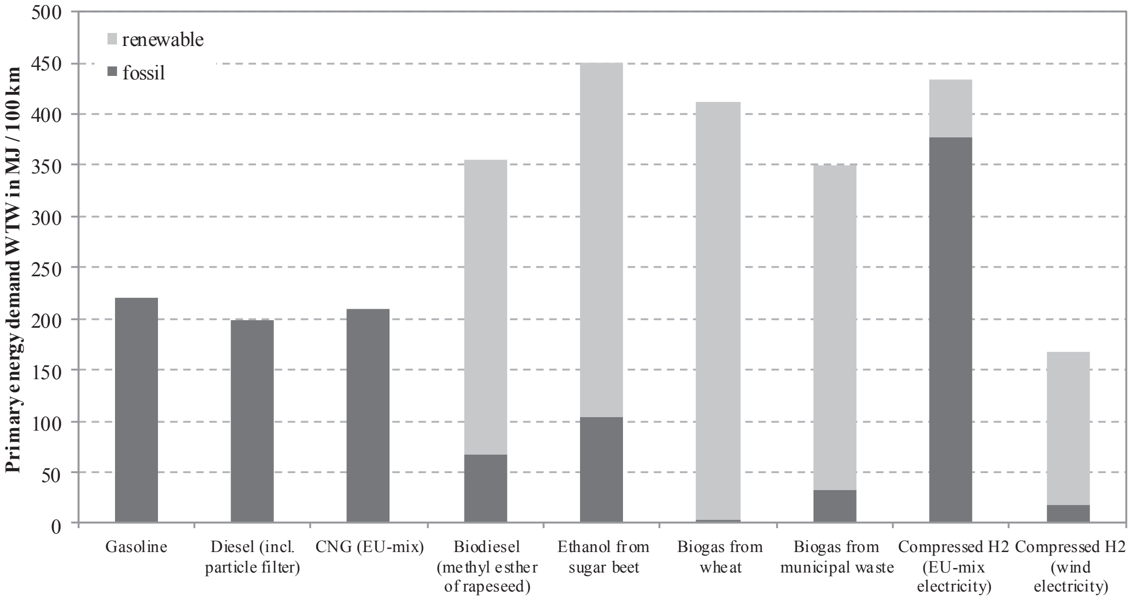

Figure 2. Primary energy demand WTW of various automotive fuels.

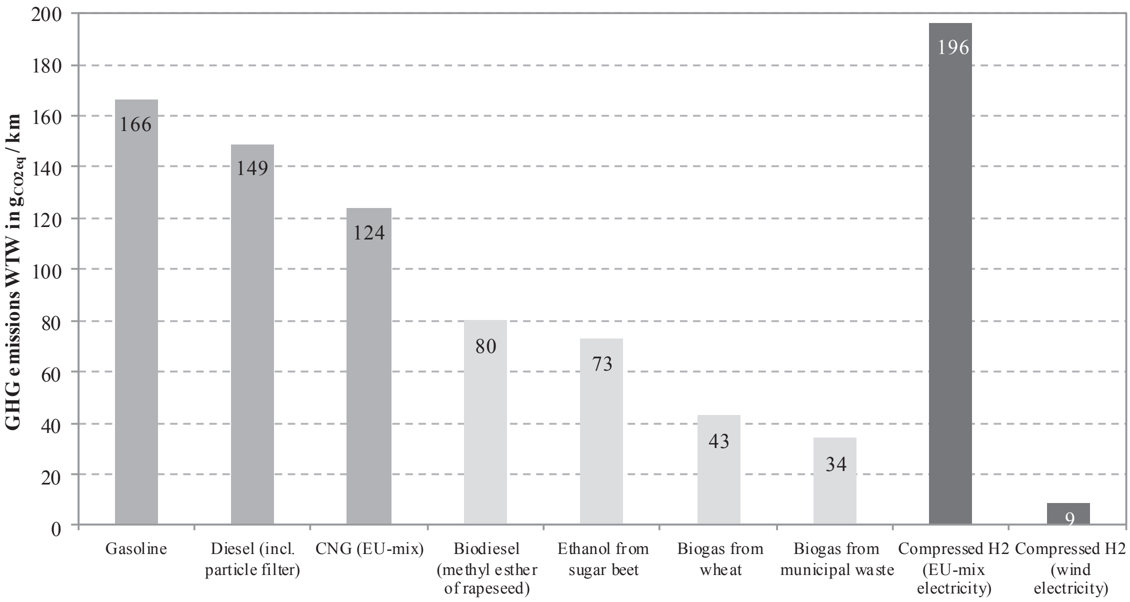

Figure 3. Greenhouse gas emissions WTW for various automotive fuels.

quired for the power-to-gas system. Heat and oxygen are useful by-products of power-to-gas plants that could decrease the fuel production costs.

PRODUCTION COSTS

This section provides calculations on the production costs for SNG from power-to-gas plants. The calculations are based on economic data from peer-reviewed articles and data from manufacturers. Three cases are considered in the evaluation of fuel production costs.

The first case 1a represents the production costs for the mid-term perspective with some exemptions from payment of electricity system charges. The second case 1b includes the current charges for the gas distribution system and the public electricity grid. The third case 2 represents the fuel production costs for the long-term perspective without charges for the electricity and gas system and decreased investment costs. The main assumptions for the different cases are displayed in Table 4[36, 37, 38]. The calculations of the production costs for synthetic methane from power-to-gas consider a component lifetime of 12 years and a rate of interest of 5 %. The yearly costs in case 1a are 4.4 million Euro

36. Table 4 Investment power-to-gas plant remark: Rieke, 2011

37. Table 4 Carbon dioxide remark: Grollmisch C, Regelenergie und Power to Gas. Systemstabilisierung im deutschen Stromübertragungsnetz durch Nachfragesteuerung und Bewertung der wirtschaftlichen Effekte am Beispiel einer Methanerzeugungsanlage. 2011. www.praktikumspark.hszigr.de/download/Vortrag-ConradGrollmisch-20111018.pdf, accessed 13.6.2012.

38. Table 4 Oxygen remark: Grollmisch, 2011

Table 3. Main parameters for the bus fleet design of power-to-gas system.

Parameter	Value	Unit	Remark
Bus fleet			
Amount of buses	70	-	Typical bus fleet for Austrian city
Driven distance per year	65 000	km / (a bus)	Information according to local public transport systems
Fuel demand per 100 km	45	kg/100 km	Typical fuel demand of CNG buses
Total fuel demand per year	2 559 375	Nm³/a	
Power-to-gas system			
Full load hours power-to-gas plant	6 000	h/a	Author's assumption
Efficiency power-to-gas plant	50%		according to manufacturer information
Heat utilization	15%		according to manufacturer information
Capacity power-to-gas plant	427	Nm³/h	
Nominal power	8.9	MW_{el}	
Consumables and by-products			
Electricity	53 235	MWh_{el}/a	
Carbon dioxide	5 060	t/a	Approximately 1 Nm³ CO_2 per Nm³ CH_4
Heat	8 108	MWh_{th}/a	
Oxygen	7 315	t/a	Approximately 2 Nm³ O_2 per Nm³ CH_4

Table 4. Main parameters for the calculation of fuel production costs.

Parameter	Case 1a	Case 1b	Case 2		Remark
Investment power-to-gas plant	2 000	2 400	1 000	€/kW_{el}	According to manufacturer information
Operation and maintenance costs	2%	4%	2%		Author's assumption
Carbon dioxide	20	50	20	€/t_{CO2}	Assumption according to
Electricity	50	90	50	€/MWh_{el}	Author's assumption
Public electricity grid (Austria)*					
Electricity system charge (power)	0	34.92	0	€/kW_{el}	* Charges and fees are taken from the Austrian regulation on system charges 2012, the Austrian regulation on green electricity 2012 and the Austrian electricity tax act.
Grid provision charge (network level 5)	0	101.48	0	€/kW_{el}	
Grid utilization charge (power)	0	0.0014	0	€/kW_{el}	
Metering fee, load-profile	900	900	900	€/a	
Green electricity fee	5 200	5 200	5 200	€/a	
Electricity system charge (energy)	0	0.00800	0	€/kWh_{el}	
Transmission loss charge (network level 5)	0	0.00120	0	€/kWh_{el}	
Electricity tax	0	0.01500	0	€/kWh_{el}	
Grid utilization charge (energy)	0	0.00023	0	€/kWh_{el}	
Gas distribution system (Austria)					
Grid provision and access charge	0	0	0	€/kW	Assumed to be available
Grid utilization charge	0	117 212	0	€/a	Austrian regulation on gas system charges 2008 (2012)
Metering fee	0	270	0	€/a	
Natural gas tax	0.066	0.066	0.066	€/m³	Assumption according to biogas
Additional costs - carbon capture	0	0.229	0	€/Nm³	
Heat	20	0	20	€/MWh_{th}	Author's assumption
Oxygen	50	0	50	€/t_{O2}	Assumption according to

which result in production costs for SNG of 17 Eurocent per kWh. For case 1b that includes all charges that have to be paid currently, the overall costs sum up to 10.8 million Euro per year and fuel production costs of 41 Eurocent per kWh. In the long-term perspective, represented by case 2, total annual costs of 3.4 million Euro and fuel production costs of 13 Eurocent per kWh could be achieved. Figure 4 shows the fuel production costs for SNG according to the type of investment.

For the power-to-gas plant in the Austrian case study, electricity costs account for the largest share. Whereas in case 1a, the investment costs for the power-to-gas plant sum up to a high percentage too, the investment costs are not so dominant in the other two cases. In case 1b it is obvious that the gas distribution system and the public electricity system charges lead to high fuel production costs as they account for 31 % of the overall costs. These system charges should be reduced to a minimum to make power-to-gas more competitive as fuel for transportation purposes. Another important aspect is that the costs for CO_2 only account to a very small amount between 2 % and 3 % of overall production costs. A small reduction in costs could additionally be achieved by selling heat and oxygen that are produced as by-products.

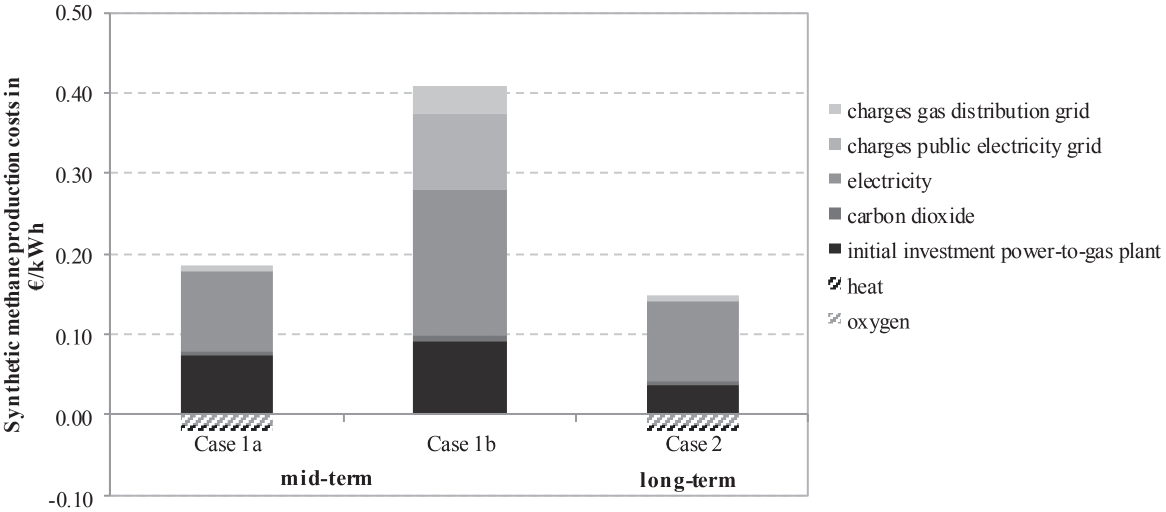

Figure 4. Fuel production costs for synthetic methane from power-to-gas.

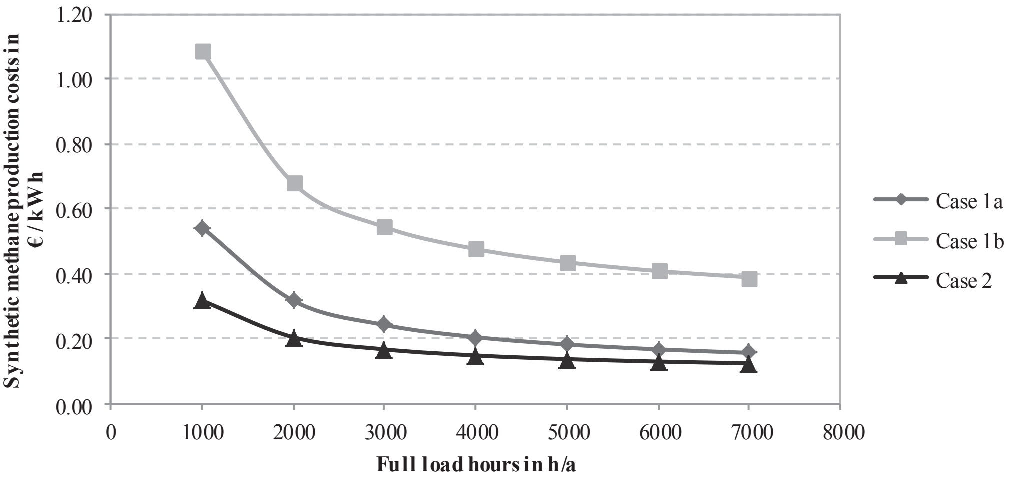

Figure 5. Sensitivity analysis of synthetic methane production costs against full load hours.

Figure 5 shows a sensitivity analysis of the SNG production costs as a function of annual full load hours.

It is evident in Figure 5 that the production costs of SNG via power-to-gas strongly depend on the achievable full load hours. Since case 1b has the highest initial investment costs, this is the case for which the fuel production costs depend most on the full load hours. For being cost competitive on a long-term perspective, full load hours for power-to-gas systems should reach a minimum of 3,000 hours per year.

OVERALL COSTS

The overall costs for a public bus fleet do not only depend on the fuel production costs but also on the investment and maintenance costs of the buses, which are higher for CNG buses than for conventional diesel buses at the moment. The calculations again are based on a lifetime of 12 years and a rate of interest of 5 %. The CNG demand is determined with 45 kg per 100 km and the diesel demand is 45 l per 100 km. The lower heating value of diesel is 10.0 kWh/l and the density is 0.85 kg/l. Schloffer et al., 2010[39] state that the initial capital investment for a CNG bus is 304,750 Euro and the initial costs for a diesel bus are 265,000 Euro. The annual costs for maintenance and operation (without fuel costs) are determined to be 4 % of the initial investment costs. Table 5[40, 41] provides information on the fuel costs applied in the calculation of overall costs in each case.

The overall annual costs for CNG buses with fuel production via power-to-gas lie between 6.7 and 14.1 million Euro for case 2 and 1b respectively. The overall costs for operation with fossil CNG are lower and range between 5.0 and 5.8 mil-

39. Schloffer M et al., Alternative Treibstoffe und umweltfreundliche Antriebssysteme im öffentlichen Regionalverkehr. Programmlinie "A3plus" – eine Initiative des Bundesministeriums für Verkehr, Innovation und Technologie (BMVIT) – Endbericht, Kapfenberg, 2010. www2.ffg.at/verkehr/file.php?id=248, accessed 08.01.2013.

40. Table 5 CNG remark: http://www.oeamtc.at/?id=2500%2C%2C1340655%2C, accessed 08.01.2013.

41. Table 5 Diesel remark: http://www.oeamtc.at/?id=2500%2C%2C1340655%2C, accessed 08.01.2013.

Table 5. Fuel costs for the calculation of overall costs.

Fuel	Case 1a	Case 1b	Case 2	Unit	Remark
SNG from power-to-gas	0.17	0.41	0.13	€/kWh	See calculation of fuel production costs
CNG	0.06	0.07	0.10	€/kWh	Assumptions according to
Diesel	0.10	0.12	0.20	€/kWh	Assumptions according to

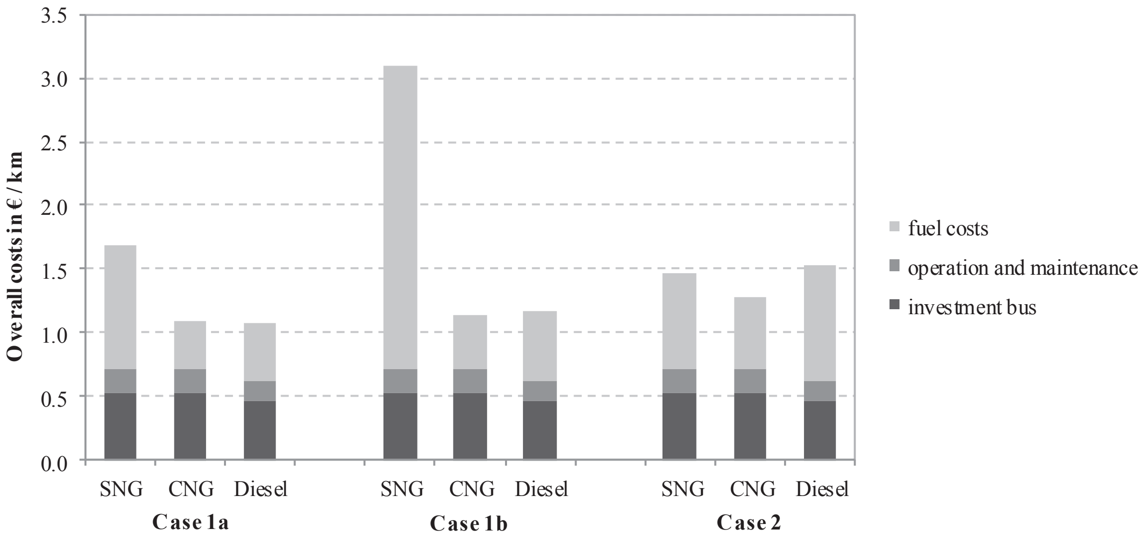

Figure 6. Overall costs for operating the bus fleet with SNG, CNG or diesel.

lion Euro per year. Operation with conventional diesel buses entails total costs between 4.9 and 6.9 million Euro per year. Figure 6 illustrates the overall costs for the public bus fleet per kilometre.

Figure 6 shows that in the mid-term (cases 1a and 1b) the costs for SNG produced from power-to-gas plants are considerably higher than for conventional fuels such as CNG and diesel. These results from the higher fuel production costs as the investment and operational costs are nearly the same for all of the three fuel types. With an adaptation of the legal framework and a reduction in investment costs for the power-to-gas plant due to technological improvements, the production costs of SNG could be significantly reduced. Therefore, synthetic methane could be competitive in the long-term as represented by case 2.

Conclusions

For reducing overall greenhouse gas emissions in the transportation sector, not only efficiency improvements, but also alternative renewable fuels are required. Power-to-gas could be one possible technology for providing renewable fuel and at the same time utilize overproduction from renewable power sources. There are various pathways that could be realized with power-to-gas as hydrogen or synthetic methane can be produced out of excess electricity. Both energy vectors can be either directly utilized in a refuelling station or be fed into the gas distribution grid for utilization elsewhere. For the synthesis of methane out of hydrogen, carbon dioxide is required that could be obtained from fossil or renewable sources such as flue gas from coal combustion or biogas plants respectively. Challenges for electrolyzers, being the main component of power-to-gas systems, arise especially with fluctuating power input as it leads to decreased durability and efficiency. The overall potential of power-to-gas depends on various parameters such as energy storage demand, percentage of renewables in electricity and transportation sector or quality of the power grid.

The overview of realized and planned European power-to-gas pilot plants for transport applications show that H_2 refuelling stations with on-site production via electrolysis have been built since 1991. Feeding hydrogen or synthetic methane into the gas distribution has not yet been realized but several pilot plants are planned for the next years in Germany. Reported problems are the unreliable operation with fluctuating power input, low efficiencies, high stack degradation and high investment costs.

The ecological evaluation of transportation fuels from power-to-gas shows that the origin of electricity and CO_2 has strong influence on the ecological performance. The comparison of various automotive fuels shows that H_2 produced from EU-mix electricity causes the highest greenhouse gas emissions per 100 km. Therefore it is indispensable that only renewable electricity is utilized for production of transportation fuels via power-to-gas. From an ecological perspective the additional resource consumption for CO_2-capture and the power-to-gas-conversion process have to be traded off by the substituted emissions of fossil fuel transport systems.

The case study for an Austrian public bus fleet provides information on synthetic methane production costs and overall costs for a CNG bus fleet. It is shown that the greatest part of production costs result from electricity costs and initial investment for the power-to-gas system. Charges for the energy infrastructure (gas distribution system and public electricity grid) sum up to considerable costs too and so an adaptation of the legal framework is necessary. A sensitivity analysis shows that full load hours of the power-to-gas plant have great influence on the production costs and a minimum of 3,000 hours per year should be achieved. Overall costs for operation of a bus fleet are compared for SNG via power-to-gas, conventional CNG and diesel as transportation fuels. In the mid-term SNG cannot compete against conventional fuels due to the high initial investment costs. However, it could be cost-competitive in the long-term when reduction of initial investment and adaptation of the legal framework in Austria could be achieved.

Future research should focus on the comparison of fuels from power-to-gas with other renewable transportation technologies such as the utilization of biofuels or electric vehicles powered by renewable electricity. Especially for excess renewable electricity as input the power-to-gas concept offers ecological benefits which should be addressed by comprehensive well-to-wheel studies. Further work is also required on the allocation of carbon dioxide that is obtained from fossil sources. Additionally, the optimum system integration into the energy infrastructure has to be addressed as power-to-gas is suited for both, electricity storage and fuel production.

References

Ajanovic A, Biofuels versus food production: does biofuels production increase food prices?, Energy 2011, 36 pp. 2070–2076. DOI 10.1016/j.energy.2010.05.019.

Breyer CH, Rieke S, Sterner M, Schmid J, Hybrid PV-Wind-Renewable Methane Power Plants. European Photovoltaic Solar Energy Conference, Hamburg, Germany, 2011. http://www.q-cells.com/uploads/tx_abdownloads/files/6CV.1.31_Breyer2011_HybPV-Wind-RPM-Plants_paper_PVSEC_preprint.pdf, accessed 17.12.2012.

Dickinson RR, Battye DL, Linton VM, Ashman PJ, Nathan GJ, Alternative carriers for remote renewable energy sources using existing CNG infrastructure. Int J Hydrogen Energy 2012, 35 (3): 1321-1329. DOI 10.1016/j.ijhydene.2009.11.052.

E-Control, Electricity Labelling Regulations. 2011. http://www.e-control.at/en/businesses/renewables/electricity-labelling-regulations, accessed 20.02.2013.

Edwards R, Larivé J-F, Beziat J-C, Well-to-wheel analysis of future automotive fuels and power trains in the European context. Report Version 3c. European Commission, Joint Research Center, Institute for Energy and Transport, Luxembourg, 2011. doi:10.2788/79018.

Fokkens E, Final report: Analysis of different production processes, which produce biogas with a higher amount of hydrogen. 2012. http://www.balticbiogasbus.eu/web/Upload/Supply_of_biogas/Act_4_4/WP%204%204_Final%20report_310812.pdf, accessed 20.02.2013.

Gahleitner G, Hydrogen from renewable electricity: An international review of power-to-gas pilot plants for stationary applications, International Journal of Hydrogen Energy 2013, DOI 10.1016/j.ijhydene.2012.12.010.

Grollmisch C, Regelenergie und Power to Gas. Systemstabilisierung im deutschen Stromübertragungsnetz durch Nachfragesteuerung und Bewertung der wirtschaftlichen Effekte am Beispiel einer Methanerzeugungsanlage. 2011. www.praktikumspark.hszigr.de/download/Vortrag-ConradGrollmisch-20111018.pdf, accessed 13.6.2012.

http://www.h2stations.org, accessed January 04, 2013.

http://www.oeamtc.at/?id=2500%2C%2C1340655%2C, accessed 08.01.2013.

IPPC, Carbon dioxide capture and storage. Cambridge University Press 2005.

Koornneef J, Ramirez A, Turkenburg W, Faaij A, The environmental impact and risk assessment of CO_2 capture, transport and storage – An evaluation of the knowledge base. Progress in Energy and Combustion Science 2012, 38(1), 62–86. DOI 10.1016/j.pecs.2011.05.002.

Li B, Duan Y, Luebke D, Morreale B, Advances in CO_2 capture technology: A patent review. Appl Energ 2013; 102: 1439–1447. DOI 10.1016/j.apenergy.2012.09.009.

Müller B, Müller K, Teichmann D, Arlt W, Energiespeicherung mittels Methan und energietragenden Stoffen – ein thermodynamischer Vergleich. Chemie Ingenieur Technik 2011, 83, No. II, 2002-2013. DOI 10.1002/cite.201100113.

Mueller-Syring G, Henel M, Power-to-Gas: Konzepte, Kosten, Potenziale. DBI Fachforum: Energiespeicherkonzepte und Wasserstoff, 2011. http://www.dbi-gti.de/fileadmin/downloads/5_Veroeffentlichungen/Tagungen_Workshops/2011/H2-FF/07_Mueller-Syring_DBI_GUT.pdf, accessed 17.12.2012.

Project homepage iC4 – Integrated Carbon Capture, Conversion and Cycling. http://www.ic4.tum.de/index.php?id=1235, accessed 17.12.2012.

REN21, Renewables 2012 Global Status Report. Paris, 2012, REN21 Secretariat. http://www.map.ren21.net/GSR/GSR2012.pdf, accessed 17.12.2012.

Rieke S, Regenerative Vollversorgung – von der Vision zur Praxis. Hannover, 2011. http://www.bee-ev.de/_downloads/bee/2011/HannoverMesse/20110404_HMI_SoarFuel_Rieke_Vollversorgung.pdf, accessed 17.12.2012.

Rubin E-S, Mantripragada H, Marks A, Versteeg P, Kitchin J, The outlook for improved carbon capture technology. Progress in Energy and Combustion Science 2012, 38(5), 630–671. DOI 10.1016/j.pecs.2012.03.003.

Schloffer M et al., Alternative Treibstoffe und umweltfreundliche Antriebssysteme im öffentlichen Regionalverkehr. Programmlinie "A3plus" – eine Initiative des Bundesministeriums für Verkehr, Innovation und Technologie (BMVIT) – Endbericht, Kapfenberg, 2010. www2.ffg.at/verkehr/file.php?id=248, accessed 08.01.2013.

Smolinka T, Günther M, Garche J, Stand und Entwicklungspotenzial der Wasserelektrolyse zur Herstellung von Wasserstoff aus regenerativen Energien. Kurzfassung NOW-Studie. Fraunhofer ISE, FCBAT, 2011. http://www.

now-gmbh.de/fileadmin/user_upload/RE-Mediathek/RE_Publikationen_NOW/NOW-Studie-Wasserelektrolyse-2011.pdf, accessed 17.12.2012.

Statistics Austria, Energy Balances Austria 1970 to 2011. http://www.statistik.at/web_en/statistics/energy_environment/energy/energy_balances/index.html, accessed 08.01.2013.

Söderberg C, Eckerberg K, 2012, Rising policy conflicts in Europe over bioenergy and forestry, Forest Policy and Economics 2012. DOI 10.1016/j.forpol.2012.09.015.

Ursua A, Gandia LM, Sanchis P, Hydrogen Production from water electrolysis: current status and future trends. Proceedings of the IEEE 2012; Vol. 100, No. 2: 410-426. DOI 10.1109/JPROC.2011.2156750.

Acknowledgements

The support of this work by the association Energy Institute at the Johannes Kepler University, Austrian Federal Ministry of Economy, Family and Youth and Austrian Center of Competence in Mechatronics (ACCM) is gratefully acknowledged.

Ökonomische und ökologische Prozessbewertung des Technologiekonzeptes Power-to-Gas

Gerda Reiter, Johannes Lindorfer
Energieinstitut an der Johannes Kepler Universität Linz, 4040 Linz, Altenberger Straße 69
reiter@energieinstitut-linz.at, lindorfer@energieinstitut-linz.at

Kurzfassung

Die Technologie Power-to-Gas kann durch Umwandlung von Strom in Wasserstoff bzw. in weiterer Folge auch in synthetisches Methan elektrische Energie aus fluktuierenden Erneuerbaren wie Windkraft und Photovoltaik speichern. In diesem Artikel werden wesentliche Ergebnisse aus der ökonomischen und ökologischen Technologiebewertung von Power-to-Gas vorgestellt. Fokus der Technologie liegt auf der chemischen Speicherung von erneuerbarem Strom in Zeiten eines Angebotsüberschusses. Bei ausschließlicher Nutzung von Stromüberschüssen ergeben sich jedoch aufgrund der geringen Volllaststunden hohe Gestehungskosten für H_2 und CH_4. Um diese zu reduzieren ist es aus wirtschaftlicher Sicht vorteilhaft auch Grundlaststrom zu beziehen und so die Auslastung der Power-to-Gas Anlage zu erhöhen. Die Art der Strombereitstellung hat dabei große Auswirkungen auf die ökologische Performance: Um im Vergleich zu herkömmlichen fossilen Referenztechnologien das Treibhausgaspotential von H_2 bzw. CH_4 zu senken, ist der Bezug von Strom aus vorwiegend erneuerbaren Quellen erforderlich. Bei der Herstellung von CH_4 beeinflusst die Art der CO_2-Quelle zusätzlich die Umweltwirkung.

Einleitung

Erneuerbare Energiequellen wie Windkraft und Solarenergie weisen substanzielles Potential zur Senkung der Treibhausgasemissionen in der Stromerzeugung auf. Sie unterliegen jedoch starken Schwankungen, weshalb eine erhöhte Implementierung im Energiesystem mit großen Herausforderungen konfrontiert ist. Power-to-Gas ist eine aktuell vieldiskutierte Technologie, welche die Speicherung von Strom in Zeiten eines Überangebots ermöglichen und so die starke Fluktuation erneuerbarer Stromerzeugung ausgleichen soll. Dabei wird Wasser mit elektrischem Strom in einem Elektrolyseur in Wasserstoff (H_2) und Sauerstoff (O_2) gespaltet. H_2 kann unter bestimmten Bedingungen direkt in das bestehende Erdgasnetz eingespeist, oder in der Methanisierung (Sabatier-Prozess) mit Kohlendioxid (CO_2) in Methan (CH_4) umgewandelt werden. Die Synthese von CH_4 ist zwar mit einem weiteren Wirkungsgradverlust verbunden, im Gegensatz zu H_2 ist eine Einspeisung in das Erdgasnetz aber ohne große Einschränkungen möglich. Durch die Einspeisung werden Strom- und Gasnetz gekoppelt und die hohe Speicherfähigkeit der Erdgasinfrastruktur zugänglich gemacht. Die Energieträger H_2 und CH_4 können in der Industrie, als Kraftstoffe oder zur Erzeugung von Wärme und Strom verwendet werden. Details zu den Hauptkomponenten, möglichen CO_2-Quellen sowie technischen Parametern sind in Steinmüller et al. [1] oder Reiter et al. [2] beschrieben.
Effizienzparameter der wichtigsten Prozessschritte im Power-to-Gas System sind in Tabelle 1 dargestellt. Mögliche Verbesserungen der Gesamtenergieeffizienz können durch Abwärmenutzung bzw. Nutzung des O_2 aus der Elektrolyse erzielt werden (hier nicht berücksichtigt). Die erzeugten Energieträger H_2 und CH_4 sollten prioritär direkt als Kraftstoffe oder in der chemischen Industrie eingesetzt werden, da eine erneute Rückverstromung mit hohen Umwandlungsverlusten behaftet ist. Die Effizienz der

Rückverstromung von eingespeistem H_2 liegt beispielsweise über die gesamte Prozesskette bei 26 % bis 48 %. Ist für die Einspeisung in das Erdgasnetz eine Methanisierung erforderlich, verringert sich die Effizienz der Gesamtkette bei Rückverstromung auf 19 % bis 41 %. Verwertungspfade, die H_2 nutzen haben grundsätzlich eine höhere Effizienz als jene mit CH_4. Da der Volumenanteil von H_2 im Erdgas aber begrenzt ist, kann je nach Standort eine Methanisierung erforderlich sein.

Prozessschritt	Effizienz (LHV)	Anmerkungen
Elektrolyse	55 % - 70 %	Elektrolyseur inkl. Peripherie (PEMEC, AEC)
Methanisierung	72 % - 85 %	Abwärmenutzung möglich
Einspeisung in das Erdgasnetz	98,5 %	Verdichtung und Einspeisung
H_2-Tankstelle	93 %	Verdichtung und Abfüllung von H_2 bei 350 bar
CNG Tankstelle	95 %	Verdichtung und Abfüllung von CH_4 bei 250 bar
Brennstoffzelle	48 % - 70 %	PEM-Brennstoffzelle

Tabelle 1: Effizienz einzelner Prozessschritte im Power-to-Gas System, Quelle: [3-10]

Methoden

Für die ökonomische Bewertung der Technologie Power-to-Gas wurden Gestehungskosten von H_2 und CH_4 in Cent je kWh_{LHV} mittels Annuitätsmethode nach VDI 2067 [11] berechnet. Die jährlichen Gesamtkosten setzen sich dabei aus den kapitalgebundenen, bedarfsgebundenen, betriebsgebundenen und sonstigen Kosten zusammen. Die kapitalgebundenen Kosten sind von den Investitionskosten, der Lebensdauer der jeweiligen Komponenten und dem Kapitalzinssatz abhängig, der mit 5 % festgelegt wurde. Die jährlichen bedarfsgebundenen Kosten beinhalten die Energiekosten sowie Betriebsstoffe und Hilfsenergie. Die jährlichen betriebsgebundenen Kosten für Bedienen und Instandhalten der Anlage liegen bei 2 % - 3 % der Investitionskosten. Sonstige Kosten beinhalten die Planung, Versicherung, Abgaben und Verwaltung. [11]
Die ökologische Bewertung der Technologie Power-to-Gas erfolgte anhand eines Life Cycle Assessment (LCA) nach ISO 14040 (2006) [12]. Eine LCA besteht demnach aus vier grundlegenden Schritten. In der Zieldefinition werden die Systemgrenzen festgelegt, die funktionelle Einheit definiert sowie die Wirkungskategorien ausgewählt. Als zweiter Schritt werden im Rahmen der Sachbilanz Inputs (Ressourcen) sowie Outputs (Abfallprodukte, Emissionen) der relevanten Prozessschritte quantifiziert. Abbildung 1 zeigt die relevanten Energie- und Stoffströme im Power-to-Gas System.

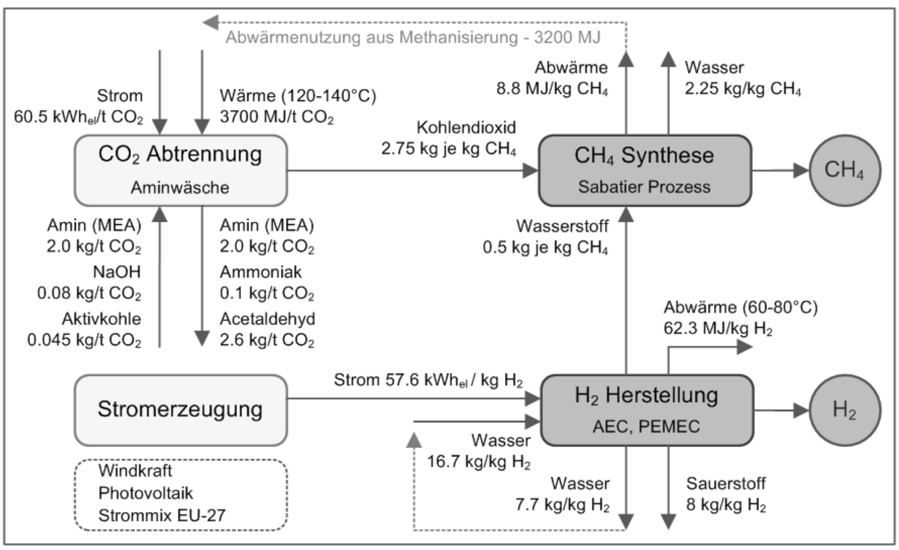

Abbildung 1: Energie- und Stoffströme im Power-to-Gas System, nach [13]

Im dritten Schritt, der Wirkungsabschätzung, werden die Umweltauswirkungen der betrachteten Technologie in den unterschiedlichen Wirkungskategorien analysiert. Der vierte und letzte Schritt einer LCA beschäftigt sich mit der Interpretation und Validierung der Ergebnisse. Die hier durchgeführte LCA wurde mit der Software GaBi modelliert (PE International, siehe http://www.gabi-software.com).

Ergebnisse und Diskussion

Ökonomische Aspekte

Für die Berechnung der Produktgestehungskosten wurde eine Power-to-Gas Anlage mit 1 MW_{el} Nennleistung festgelegt. Die Kosten sind in Tabelle 2 zusammengefasst und wurden im Zuge verschiedener Projekte aus Herstellerangaben und umfangreichen Literaturanalysen ermittelt (siehe [1]). Für die Nutzung von Überschüssen wird aufgrund der erforderlichen dynamischen Betriebsweise ein PEM-Elektrolyseur (PEMEC) verwendet, bei höheren Volllaststunden und konstanter Betriebsweise kann ein alkalischer Elektrolyseur (AEC) verwendet werden.

Parameter	2014	2030
Gesamtinvestition PEMEC	2,62 Mio €	1,99 Mio €
Gesamtinvestition AEC	1,63 Mio €	1,14 Mio €
Lebensdauer Elektrolyse	10 Jahre	15 Jahre
Gesamtinvestition Methanisierung	1,45 Mio €	1,27 Mio €
Kosten Kohlendioxid	90 €/t	

Tabelle 2: Parameter der Power-to-Gas Anlage für die ökonomischen Betrachtungen

Die eigentliche Intention des Systems Power-to-Gas ist die chemische Speicherung von Überschüssen aus fluktuierenden erneuerbaren Stromerzeugern. Aktuell besteht in gewissen Regionen zwar bereits die Notwendigkeit Windkraftanlagen temporär vom Netz zu nehmen, dies erfolgt aber derzeit nur in kurzen Zeitfenstern. Obwohl für den Strombezug in diesen Zeiten keine Kosten anfallen (Annahme: 0 € / kWh_{el}), da es sich um Überschüsse aus erneuerbaren Stromquellen handelt sind die spezifischen Gestehungskosten für H_2 und CH_4 sehr hoch. Bei 200 h/a Vollastbetrieb der Power-to-Gas Anlage ergeben sich mit aktuellen (2014) Rahmenbedingungen Kosten von 4 € je kWh_{LHV} für H_2 bzw. 7,2 € je kWh_{LHV} für CH_4. Auch durch die Berücksichtigung einer Investitionskostenreduktion durch Skaleneffekte und Lernkurven bis 2030 und möglichen höheren Volllaststunden von 1000 h/a können diese Kosten nur auf 0,6 € je kWh_{LHV} für H_2 bzw. 1,2 € je kWh_{LHV} für CH_4 gesenkt werden.
Um die Volllaststunden zu erhöhen und dadurch die Gestehungskosten zu reduzieren, kann zusätzlich Grundlaststrom bezogen werden. Je höher die angestrebten Volllaststunden der Power-to-Gas Anlage sind, desto höher sind dabei aber auch die Strombezugskosten, da sich der Strombezug immer mehr in Richtung Grundlast verschiebt. Unter der Annahme von 5000 h/a und Strombezugskosten von 5 - 10 Cent je kWh_{el} (Energiepreis) ergeben sich die in Abbildung 2 dargestellten spezifischen Gestehungskosten für H_2 und CH_4 aus Power-to-Gas.
Verglichen mit den Ergebnissen bei reiner Überschussstromnutzung liegen die Gestehungskosten von H_2 und CH_4 in Abbildung 2 aufgrund der höheren Volllaststunden deutlich niedriger. Durch die reduzierte Gesamteffizienz und die höhere Gesamtinvestition sind die Gestehungskosten von CH_4 höher als jene von H_2. Vorteile ergeben sich aber im Transport und der Anwendung, da die Infrastruktur für Erdgas bereits etabliert und weit verbreitet ist. Die Ergebnisse der ökonomischen Bewertung zeigen, dass Power-to-Gas derzeit bzw. mittelfristig aus rein betriebswirtschaftlicher Sicht mit den fossilen Alternativen

nicht konkurrieren kann. Erfüllt Power-to-Gas durch Speicherung elektrischer Energie aus fluktuierenden Erneuerbaren allerdings einen übergeordneten Nutzen für das Energiesystem, oder kann eine Reduktion von Treibhausgasemissionen durch die Produktion erneuerbarer Produkte erreicht werden, so ist dies ebenfalls zu beachten.

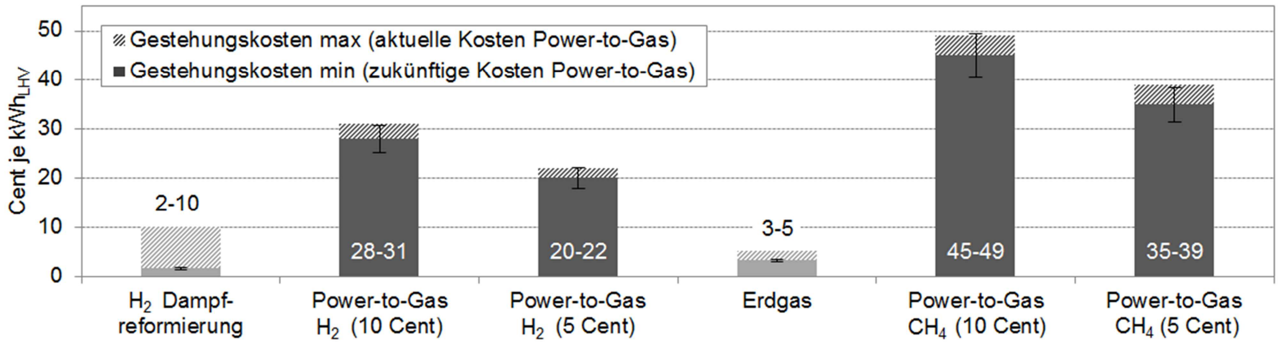

Abbildung 2: Gestehungskosten von H_2 und CH_4 aus Power-to-Gas bei 5000 h/a

Ökologische Aspekte

Wird eine Power-to-Gas Anlage nur zur Speicherung von Überschussstrom aus Erneuerbaren eingesetzt, so ist die verwendete elektrische Energie mit keinerlei Treibhausgasemissionen aus der Vorkette behaftet. Benchmarks für die ökonomische aber auch ökologische Bewertung stellen dann herkömmliche Speichertechnologien wie Pumpspeicher oder Druckluftspeicher dar.

Liegt der Fokus der Power-to-Gas Anlage hingegen auf der Erzeugung eines erneuerbaren Produktes und wird kein Überschuss- sondern Grundlaststrom eingesetzt, ist eine Bewertung der ökologischen Performance in Abhängigkeit des Strominputs notwendig. Neben den mit der Herstellung der Energieträger verbundenen Emissionen müssen dabei auch die direkten Emissionen im Betrieb berücksichtigt werden. Während die Umwandlung von H_2 in Endenergie keine direkten CO_2 Emissionen freisetzt, wird bei der Umwandlung von CH_4 das vorher gebundene CO_2 wieder freigesetzt. Die Dauer der Bindung des CO_2 ist demnach begrenzt und die Auswirkungen auf das Treibhausgaspotential nur geringfügig verschoben. Da nicht nur biogene sondern auch fossile CO_2-Quellen für den Power-to-Gas Prozess in Frage kommen und die Abtrennung mit einem bestimmten Energieaufwand verbunden ist, ist eine Allokation der CO_2-Emissionen erforderlich. In Abbildung 3 ist das Treibhausgaspotential für die Abtrennung und verursacht durch direkte Emissionen im Betrieb separat ausgewiesen.

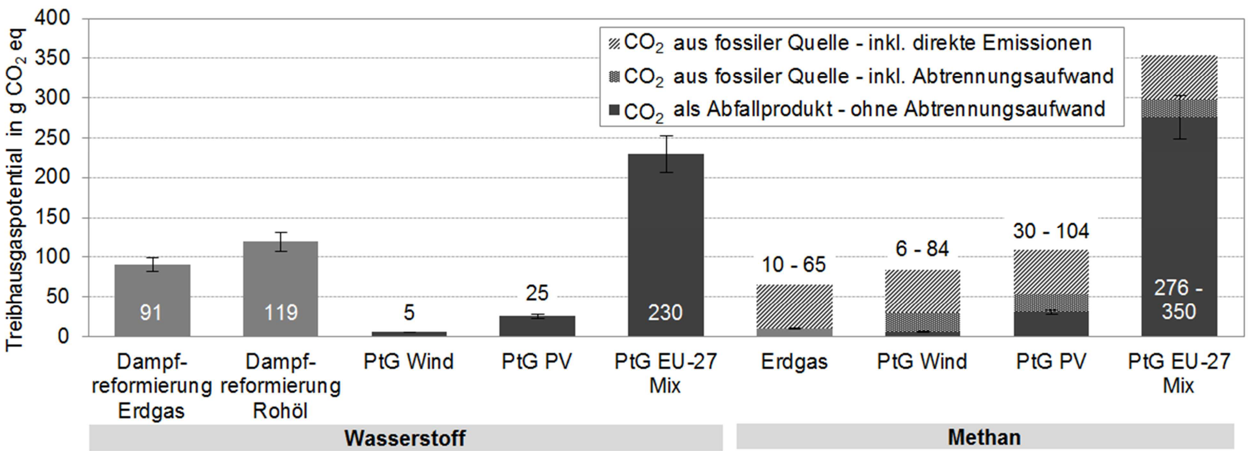

Abbildung 3: Treibhausgaspotential von 1 MJ H_2 bzw. CH_4 im Vergleich zu den jeweiligen Referenztechnologien (nach Reiter et al. [13])

Durch die Produktion von H_2 und CH_4 aus Power-to-Gas ist bei Einsatz erneuerbaren Stroms im Vergleich zu fossilen Referenzsystemen eine deutliche Reduktion des Treibhausgaspotentials erreichbar. Bei der Herstellung von Wasserstoff könnten beispielsweise rund 75 % bis 95 % der Treibhausgasemissionen eingespart werden [13]. Den größten Einfluss auf die ökologische Performance hat die Herkunft des Strominputs und so kommt es zu einer deutlichen Erhöhung der Umwelteinflüsse bei Einsatz von Strommix der EU-27 Länder. Ergebnisse aus Reiter et al. [13] zeigen, dass der Carbon Footprint des Stroms für die Produktion von H_2 via Power-to-Gas 190 g CO_2 je kWh_{el} nicht übersteigen darf, da ansonsten der fossile Benchmark geringere CO_2-Äquivalente aufweist. Aufgrund der Effizienzverluste bei der Methanisierung liegt der ökologische Benchmark für den Strominput zur CH_4-Produktion bei 113 g CO_2 je kWh_{el} wenn CO_2 als Abfallprodukt in die Methanisierung eingeht. Bei Berücksichtigung des Aufbereitungsaufwandes liegt der Grenzwert bei 73 g CO_2 per kWh_{el} und bei zusätzlicher Allokation der gesamten direkten Emissionen ist dieser negativ – trotz Strominput aus Erneuerbaren ist das Treibhausgaspotential also höher als für den Benchmark Erdgas.

Zusammenfassung

Der Fokus der Technologie Power-to-Gas liegt auf der chemischen Speicherung von erneuerbarem Strom in Zeiten eines Angebotsüberschusses. Bei alleiniger Nutzung von Überschussstrom in einer Power-to-Gas Anlage fallen zwar keine Strominputkosten an, aufgrund der geringen Volllaststunden liegen aber die Gestehungskosten von H_2 und CH_4 sehr hoch. Durch den zusätzlichen Bezug von Grundlaststrom können höhere Volllaststunden erreicht und die Gestehungskosten deutlich gesenkt werden. Dabei muss allerdings auch die Art der Stromerzeugung und deren Einfluss auf die ökologische Performance von H_2 und CH_4 aus Power-to-Gas berücksichtigt werden. Bei Einsatz von EU-27 Strommix liegt das Treibhausgaspotential von H_2 und CH_4 deutlich über jenem der herkömmlichen Produktionsverfahren aus fossilen Rohstoffen. Strombezug aus erneuerbaren Quellen ist daher für eine Reduktion der Treibhausgasemissionen essentiell. Bei der Herstellung von CH_4 aus Power-to-Gas hat auch die Art der CO_2-Quelle einen entscheidenden Einfluss auf das resultierende Treibhausgaspotential. Aufgrund des niedrigen Wirkungsgrades ist die direkte Verwendung der produzierten Energieträger H_2 und CH_4 in der Industrie oder im Mobilitätsbereich einer Rückverstromung vorzuziehen.

Literatur

[1] Steinmüller H, Tichler R, Reiter G et al. Power to Gas – Eine Systemanalyse. Markt- und Technologiescouting und -analyse. Im Auftrag des BMWFJ - Endbericht, 2014.

[2] Reiter G, Lindorfer J, Möglichkeiten der Integration von Power-to-Gas in das bestehende Energiesystem. In: Steinmüller H, Schneider F, Hauer A (Hrsg.) Jahrbuch Energiewirtschaft 2013, NWV-Verlag, Wien.

[3] Ursua A, Gandia LM, Sanchis P. Hydrogen Production from water electrolysis: current status and future trends. Proceedings of the IEEE 2012; 100(2): 410-426.

[4] Smolinka T, Günther M, Garche J. Stand und Entwicklungspotenzial der Wasserelektrolyse zur Herstellung von Wasserstoff aus regenerativen Energien. Kurzfassung NOW-Studie. Fraunhofer ISE, FCBAT, 2011.

[5] Rieke S. Regenerative Vollversorgung – von der Vision zur Praxis. Hannover, 2011. http://www.bee-ev.de/_downloads/bee/2011/HannoverMesse/20110404_HMI_Soar Fuel_Rieke_Vollversorgung.pdf, Zugriff am 17.Dezember 2012.

[6] Mueller-Syring G, Henel M. Power-to-Gas: Konzepte, Kosten, Potenziale. DBI Fachforum: Energiespeicherkonzepte und Wasserstoff, 2011. http://www.dbi-gti.de/fileadmin/downloads/5_Veroeffentlichungen/Tagungen_Workshops/2011/H2-

FF/07_Mueller-Syring_DBI_GUT.pdf, Zugriff am 17.Dezember 2012
[7] HySociety. Technology Database for Hydrogen Pathways. Electronic database of the HySociety project, 2004. http://www.eu.fhg.de/h2database/index.html
[8] Lee J-Y, Cha K-H, Lim T-W, Hur T. Eco-efficiency of H2 and fuel cell buses. Int J Hydrogen Energ 2011; 36: 1754-1765.
[9] Ulleberg O, Nakken T, Ete A. The wind/hydrogen demonstration system at Utsira in Norway: Evaluation of system performance using operational data and updated hydrogen energy system modeling tools. Int J Hydrogen Energ 2010; 35:1841-1852.
[10] Edwards PP, Kuznetsov VL, David WIF, Brandon NP. Hydrogen and fuel cells: Towards a sustainable energy future. Energ Policy 2008; 36:4356-4362.
[11] Richtlinie VDI 2067 - Blatt 1 “Wirtschaftlichkeit gebäudetechnischer Anlagen – Grundlagen und Kostenberechnung”. Verein Deutscher Ingenieure, 2012.
[12] ISO 14040:2006 Environmental management – Life cycle assessment – Principles & framework. International Organization for Standardization, Geneva, Switzerland.
[13] Under Review (International Journal of Life Cycle Assessment): Reiter G, Lindorfer J, Environmental assessment of hydrogen and methane production from renewable electricity via power-to-gas technology. 2014.