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Bundesamt für Energie BFE
Sektion Energieversorgung und Monitoring

Stromspeicherung und Wasserstoff – Technologien, Kosten und Auswirkungen auf das Klima

Einschliesslich Aufdatierung der Kosten und Potenziale von Photovoltaik und Windenergie; Bericht auf Englisch mit Zusammenfassung auf Deutsch und Französisch

Datum: September 2022

Ort: Bern

Auftraggeberin: Bundesamt für Energie BFE, 3003 Bern

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Für den Inhalt und die Schlussfolgerungen sind ausschliesslich die Autoren dieses Berichts verantwortlich. Die Gestehungskosten für die verschiedenen Energietechnologien wurden vor dem Sommer 2021 erarbeitet, so dass der Anstieg der Rohstoffpreise und die Marktunsicherheiten seit dem Herbst 2021 in der Studie nicht berücksichtigt sind.

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PSI - PAUL SCHERRER INSTITUT

Electricity storage and hydrogen – technologies, costs and impacts on climate change

Including updates of costs and potentials of photovoltaics and wind power in Switzerland

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September 17, 2022

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This report has been prepared by PSI on behalf of the Swiss Federal Office of Energy (SFOE).

Contents

Abbreviations

(AA-)CAES	Advanced Adiabatic Compressed Air Energy Storage
ATR	Autothermal Reforming
BTM	Behind the meter (residential scale)
CAPEX	Capital Expenditures
CH2	Compressed hydrogen
CPP	Circulating Power Plant
FTM	Front of the meter (utility scale)
GH2	Gaseous hydrogen
H_2	Hydrogen
HHV	Higher HEating Value
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
LCA	Life Cycle Assessment
LCI	Life Cycle Inventory
LCIA	Life Cycle Impact Assessment
LCOE	Levelized Cost of Electricity
LCoH	Levelized Cost of Hydrogen
LFP-C	Lithium Iron Phosphate/graphite
LH2	Liquefied hydrogen
LHV	Lower Heating Value
LIB	Lithium Ion Battery
LIB	Lithium Ion Battery
LOHC	Liquid Organic Hydrogen Carriers
LTO	Lithium Titanate Oxide
MENA	Middle East North Africa
MOF	Metal-organic framework
MSWI	Municipal solid waste incineration
NCA-C	Lithium Nickel Cobalt Aluminium Oxide/graphite
NG	Natural Gas
NMC-C	Lithium Nickel Manganese Cobalt Oxide/graphite
OPEX	Operational Expenditures
P2G / PtG	Power-to-Gas
P2H	Power-to-Hydrogen
P2L	Power-to-Liquids
P2M	Power-to-Methane
P2P	Power-to-Power
PEM	Proton Exchange Membrane
PHES	Pumped Hydro Electricity Storage
PSPP	Pumped Storage Power Plant
PV	Photovoltaic
PWM	Pipelines without modification
SMR	Steam Methane Reforming
SNG	Synthetic Natural Gas
SOFC	Solid Oxide Fuel Cell
tbd	Tonnes per day
TES	Thermal Energy Storage
TRL	Technology Readiness Level
VRF	Vanadium Redox Flow
VRFB	Vanadium Redox Flow Battery
VRLA	Valve Regulated Lead Acid
WWT	Wastewater treatment

1 Summary

This report is an extension or continuation of the technology monitoring of the Swiss Federal Office of Energy (Bauer *et al.*, 2017, 2019) and covers – after electricity production – two additional technological areas: Hydrogen (production, storage and transport, conversion with CO_2 into methane) and electricity storage (batteries, compressed air and pumped hydro storage, re-electrification of hydrogen in fuel cells). In addition, an update of costs and potentials of electricity production with photovoltaic systems and wind turbines in Switzerland is provided. Fact sheets regarding further technologies are provided in the appendix.

The cost analysis for the various energy technologies was performed before the summer of 2021, so that the increase in commodity prices and the market uncertainties since the fall of 2021 have not been taken into account in the present study. This applies in particular to the power generation costs of natural gas-fired power plants (section 21.5), for which a natural gas price for large consumers in Switzerland of 5-7 Rp./kWh (natural gas) was assumed until 2050, based on the IEA scenarios.

The report contains an overview of the current state of the art and the expected future development of hydrogen and electricity storage technologies. It also provides information on the corresponding costs and their development up to 2050, as well as life-cycle greenhouse gas emissions. System aspects – i.e. answering the question what role hydrogen and electricity storage will play in the overall energy system of the future – are not subject of this report. For this, we refer to the recently published Energy Perspectives (Kirchner *et al.*, 2020) and similar analysis (Panos *et al.*, 2021).

Hydrogen

Hydrogen (H_2) is an energy carrier that can be produced from different resources and in different ways. Today, mainly fossil resources are used, for example natural gas, from which hydrogen is produced via steam reforming. Today, the use of natural gas and coal in this way is associated with high greenhouse gas emissions, which is why other, low-CO_2 ways of hydrogen production will be needed in the future: production via electrolysis with low-carbon electricity, from biomass and from natural gas, provided that the associated CO_2 emissions can be significantly reduced. This is possible by means of natural gas pyrolysis[1], a process that produces carbon in solid form, or with capture of gaseous CO_2 during natural gas reforming and subsequent permanent geological CO_2 storage ("Carbon Capture and Storage" – CCS). Natural gas based production pathways also require low methane emissions from the gas supply chain. Colors are often assigned to these types of hydrogen production: green stands for electrolysis with electricity from renewable resources (and sometimes for biomass conversion), blue for natural gas reforming with CCS, turquoise for natural gas pyrolysis, grey and brown for the use of fossil resources. Finally, pink hydrogen represents production in nuclear power plants; the thermochemical processes use very high reactor temperatures as they are produced in Generation IV reactors, for which, however, there is no commercial application yet.

Three technologies are available for electrolysis – the splitting of water into hydrogen and oxygen using electricity: Alkaline electrolysis, PEM electrolysis[2], and solid oxide electrolysis ("SOEC"). Alkaline and PEM electrolysis are ready for the market today, while solid oxide electrolysis is still in the development stage. While alkaline electrolysis is cheapest today, PEM electrolysis offers greater flexibility in conjunction with fluctuating renewable electricity production. SOEC electrolysis promises higher efficiencies, i.e. lower power consumption, but requires steam instead of liquid water as input, runs at high temperatures (500-1000°C) and does not exist at industrial scale today. Main current shortcomings concern electrolyzer lifetime and flexible operation. Average efficiencies (electrolysis system) today are about 67% (alkaline), 61% (PEM) and 82% (SOEC), corresponding to electricity consumptions of about 50 kWh/kg_{H2}, 55 kWh/kg_{H2} and 43 kWh/kg_{H2}.[3] These efficiencies and also the

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[1] Not yet commercialized, as opposed to electrolysis and reforming of natural gas.

[2] PEM: «Proton Exchange Membrane»

[3] Including compression of hydrogen to 40 bar.

lifetimes of the plants will increase in the future – the average values estimated here for 2050 are 71% (alkaline), 73% (PEM) and 90% (SOEC). Accordingly, the electricity demand will decrease.

Investment costs for electrolyzers today are around 1000 CHF/kW (alkaline), 1200 CHF/kW (PEM) and 2700 CHF/kW (SOEC). By 2050, a reduction to about 300-400 CHF/kW (alkaline and PEM) and 600 CHF/kW (SOEC) is expected. The most important factors determining the cost of producing hydrogen by electrolysis are, in addition to the investment costs and the level of electricity consumption, the utilization of the plant and the cost of electricity. The longer the period of low electricity prices, the more economic operating hours can be achieved and electrolysis is correspondingly more profitable. This leads to large ranges in the estimated hydrogen production costs in Switzerland: these range from about 3.5-12 CHF/kg_{H2} today (equivalent to 10.5-36 Rp./kWh_{H2}) and 3-9.5 CHF/kg_{H2} (9-28.5 Rp./kWh_{H2}) in 2050 (at electricity costs of 5-15 Rp./kWh, see Table 8.17). The economic viability of green hydrogen depends on the price of the electricity used, but also on the annual operating hours: if an electrolyzer powered by solar electricity is discontinuously operated during the day, it achieves significantly fewer annual operating hours than an electrolyzer that runs continuously, which increases hydrogen production costs. Hydrogen production costs of natural gas reforming on the other hand are very sensitive to natural gas prices: At “historical gas prices” (before the major increase of energy prices in Europe starting mid 2021) of around 20-25 Euro/MWh, H_2 costs of steam methane reforming plants were in the range of 1.5-2 CHF/kg_{H2}. With CCS, those H_2 production costs were estimated to be in a range of about 2-2.5 CHF/kg_{H2}. Recent increases of natural gas prices to levels around 100 Euro/MWh lead to roughly a tripling of natural gas based hydrogen production costs, which brings hydrogen from electrolysis and natural gas reforming to similar price levels. This is especially true for electrolysis sites, where wind and photovoltaic power plants have very high yields throughout the year and thus low electricity production costs. Uncertainty factors here are future natural gas and CO_2 prices on the one hand and electricity prices, prices of electrolyzers and availability of scarce metals on large scale such as Iridium.

Hydrogen can only represent a low-carbon energy carrier, if its production is associated with low greenhouse gas emissions from a life cycle perspective. This is the case with production from sustainably produced or residual biomass (via pyrolysis, wood gasification and reforming of biomethane), via electrolysis with low-carbon electricity, and with advanced processes for natural gas reforming with CCS, which have high CO_2 removal rates in the order of 90% or above. Further, natural gas supply must be associated with low methane emissions (around 1% or below), which – on a global scale – requires investments into natural gas infrastructure to reduce those emissions. If biomass utilization is coupled with CCS, even negative greenhouse gas emissions result, i.e. permanent removal of CO_2 from the atmosphere. However, the biomass potential that can be used sustainably for this purpose is limited.

Figure 1.1 shows representative costs and life cycle GHG intensities of hydrogen production with different current technologies (potentially) operated today.

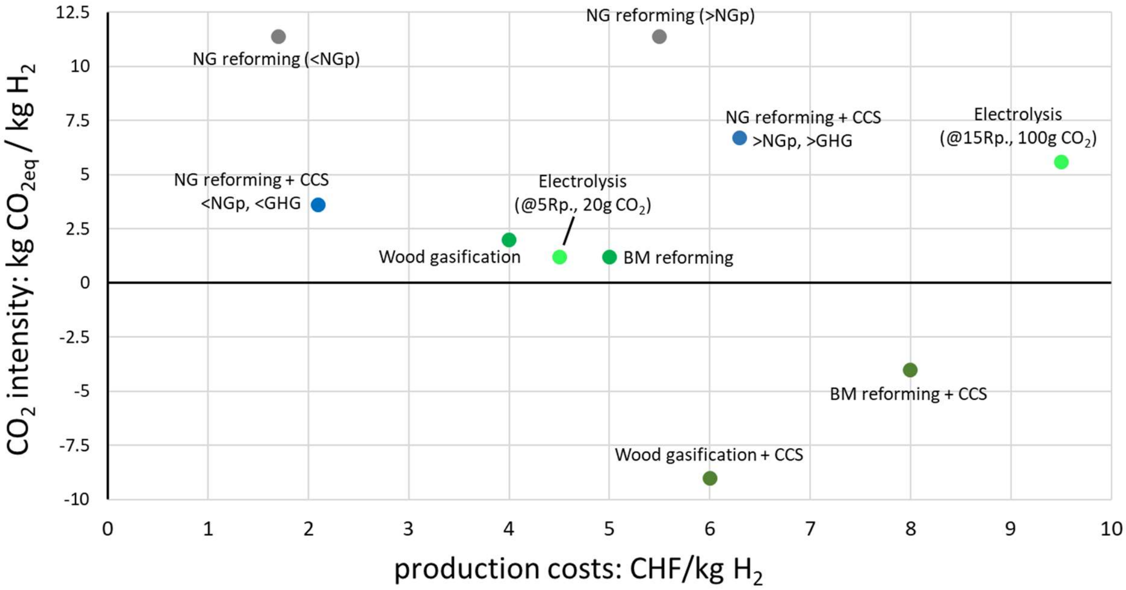

Figure 1.1: Today's costs vs. life-cycle greenhouse gas emissions (GWP100) of hydrogen production (excluding costs for CO_2 emissions, e.g. for natural gas reforming). Representative values – ranges can be substantial. For natural gas reforming, a methane emission rate along the supply chain of 1.3% is assumed here, representative for European supply today[4]. For NG reforming, two price scenarios are distinguished: ">NGp" represents the current situation with about 100 Euro/MWh$_{NG}$, "<NGp" low NG prices as before 2021 of around 20 Euro/MWh$_{NG}$. For NG reforming with CCS, life-cycle GHG emissions are provided for two distinctly different reforming technologies: ">GHG" represents steam methane reforming with a low overall CO_2 removal rate of about 55%, while "<GHG" represents autothermal reforming with a high CO_2 removal rate of 93%[5]. For electrolysis, electricity prices and GHG emissions (life-cycle based, i.e. including those originating from electricity generation infrastructure) per kWh of electricity input for electrolysis are given in each case; typical values for wind and PV power in Switzerland today would be around 20 and 40 g CO_2-eq./kWh, respectively. NG: Natural Gas; BM: Biomethane. Wood gasification with CCS is not yet commercially available, therefore indicated costs and GHG emissions to some extent speculative.

Apart from life cycle GHG emissions and costs, the Ukraine crisis has shown that geopolitical aspects regarding the supply chain of all the resources needed for hydrogen production and supply may become an equally important aspect when comparing different hydrogen supply chains.

Like other energy carriers, hydrogen must also be (temporarily) stored. Although hydrogen has a high gravimetric (mass-related) energy density, its volumetric (volume-related) energy density is extremely low. Therefore, storage requires an increase in this energy density. This can be achieved in various ways: by compression as a gas, by cooling and thus liquefaction, by liquefaction and additional compression ("cryo-compression") and by hydrogenation (binding of hydrogen to other molecules). So-called "metal hydrides", "metal-organic framework compounds" and liquid organic hydrogen carriers are suitable for hydrogenation. Hydrogen can also be bound to nitrogen and thus stored as ammonia. All these types of conversion, storage and reconversion involve considerable energy input. In addition, special materials are required in some cases. Both issues are reflected in high storage and transport costs compared with liquid and gaseous hydrocarbons, which is why it seems important to produce hydrogen as locally as possible and at the time of demand.

Storage as a gas under high pressure is widely used today. For example, in tanks of fuel cell vehicles at 350 bar or 700 bar in steel or composite cylinders. From a technical point of view, storage in liquid form as pure hydrogen and ammonia is also feasible today. All other forms and processes are still at the research or demonstration stage. How and in what form hydrogen is preferably stored and transported depends, among other things, on the intended use, the quantity to be stored and the storage duration as well as transport distances. For mobile applications, storage density plays a much

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[4] Today, these methane emissions vary between almost zero and a few percent of the delivered gas, depending on its origin.

[5] See (Bauer, Treyer, Antonini, Bergerson, Gazzani, Gençer, Gibbins, Mazzotti, S. McCoy, *et al.*, 2022) for further details.

greater role than for stationary applications. While tanks are used for short- to medium-term storage, geological structures such as salt deposits seem to be the most promising for storing large quantities for long periods (seasonal). Whether such structures are available in Switzerland needs to be investigated further.

Hydrogen can be transported in different forms (gaseous, liquid, and bonded) and by different means (truck, rail, ship, pipelines). Trucks are already used for small quantities and short distances (up to a few hundred kilometers), pipelines (for pure hydrogen and blends of natural gas and hydrogen) as well, but for larger quantities and also for medium distances (up to a few thousand kilometers). Marine transport is best suited for long distances (from a few thousand kilometers on) and is accordingly attractive for future intercontinental routes. By truck, hydrogen is mostly transported as a compressed gas in tanks today. For marine transport, higher energy densities are required, and liquid form is more likely. In small quantities, hydrogen can also be fed into the natural gas grid and thus mixed with natural gas. The permitted blending levels are country-specific, but all in the range of a few percent by volume as, above all, the distribution grids and the measurement and compression technologies have not yet been fully tested for higher blending levels. The existing natural gas network can in principle be used for the transport of pure hydrogen – but only with upgrades to the infrastructure and increased maintenance costs.

Concrete costs of hydrogen transport and storage are highly scale-dependent, i.e. they are determined by the quantities to be transported and stored, as well as by transport distances and storage periods. In general, especially when hydrogen production costs are favorable, these costs can account for high shares of hydrogen costs at the end user (in the range of 50% and more), especially when hydrogen is used as a fuel for cars (where it is currently not subject to the mineral oil tax) due to the required infrastructure. The environmental impact of hydrogen transport and storage depends mainly on the energy consumption of each conversion step.

There are several challenges to overcome in the context of hydrogen storage and transport. Materials used for storage and transport media must be resistant to embrittlement and corrosion, and allow as little hydrogen diffusion as possible. Volumetric and gravimetric energy densities of storage solutions must be further increased to enable commercial deployments. Contamination of the hydrogen during storage and transport must be avoided, as otherwise expensive purification steps will be required. Also for these reasons it is advantageous to produce hydrogen locally, as close to the consumer as possible.

Hydrogen can be converted – together with CO_2 – into synthetic methane[6], which can serve as a substitute for natural gas. Just like natural gas, synthetic methane can be easily stored and used in heating systems, engines and industry. Thus, hydrogen production from water electrolysis and subsequent conversion to SNG allows for compensating temporal and spatial mismatches of renewable electricity production and energy demand. This advantage is offset by the disadvantage of relatively inefficient processes along the production and utilization chain. Energy losses are also one of the reasons for currently high production costs, which are mainly determined by the investment for electrolysis and methanation, electricity costs for electrolysis and costs of CO_2. The source of CO_2 not only influences costs, but is also important in terms of greenhouse gas balance: only CO_2 that is taken directly from the atmosphere or comes from biomass enables a CO_2 cycle closed within a short time frame and thus climate neutrality. If the CO_2 originates from combustion processes of fossil energy carriers, the CO_2 is chemically bound in the SNG, but ultimately remains fossil CO_2 during use, as it is simply emitted with a temporal delay. Thus, from a system perspective, a reduction in CO_2 emissions of at most 50% results when natural gas is replaced with SNG whose CO_2 originates from fossil sources. For the quantification of product-specific CO_2 footprints, it must be determined whether the CO_2 emissions from SNG use are allocated to this end use or to the original emission source.

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[6] SNG – Synthetic Natural Gas

When implementing a large-scale hydrogen economy in addition to the direct electrification of appropriate applications, the question will arise whether hydrogen production should occur domestically, or whether hydrogen should be imported and to which extent both options will be complementary.[7] This depends on many factors including quantities required and (trade) policy, but also (inter-)national production potentials and costs. With regard to costs, it is not yet possible to predict with certainty that an import from countries with better production conditions, i.e. low-cost electricity from wind and sun, will be cheaper than production in Switzerland, since specific analyses on this are not available. In the "ZERO base scenario", the Energy Perspectives 2050+ assume that 9 PJ of renewable hydrogen will be imported in 2050 (mainly from the MENA region) and 7 PJ will be produced domestically (Kirchner *et al.*, 2020). Studies for Germany and Central Europe indicate that hydrogen can be imported at lower cost. Regardless of the cost, however, the potential for electricity production from renewables in Switzerland is limited, so the import option will come into play if green hydrogen is supposed to be widely deployed. This is true for blue hydrogen anyway.

Electricity Storage

The stationary storage of electricity will become more important in the future with a significant increase in electricity production from fluctuating sources such as wind and solar energy. Among the most promising technologies for storing electricity are batteries, pumped storage hydropower plants, compressed air storage, and the reconversion of hydrogen produced via electrolysis in fuel cells. Lithium-ion batteries are widely used today in the electronics sector and increasingly in the automotive sector. They are also suitable for stationary electricity storage, preferably for decentralized applications, i.e. for rather small amounts of electricity to be stored over short periods of time (up to a few days). Other types of batteries currently have only very minor market shares or are in the development stage, for example redox-flow batteries and sodium-ion batteries. These do not use metals such as cobalt, the use of which can be problematic from a scarcity and environmental perspective. Redox-flow batteries are also suitable for storing larger amounts of electricity. However, today's alternatives to lithium-ion batteries all have drawbacks, whether in electricity storage efficiency, lifetime, or energy storage density and cost. Lithium-ion batteries have seen significant technical progress in recent years, particularly in terms of increasing durability and energy storage density, as well as decreasing production costs. The environmental impact associated with manufacturing has also been reduced thanks to more efficient production on an ever larger scale. It can be assumed that the development observed in the past will continue in the coming years. In addition, industrial recycling processes will be established. However, the environmental burdens of these future recycling processes are not yet known in detail. The current cost of stationary lithium-ion batteries for centralized use by electric utilities is estimated at around 200 CHF/kWh and 160 CHF/kW. These costs increase for home applications (i.e. for batteries with low storage capacity). By 2050, cost reductions to about 45-110 CHF/kWh and 35-90 CHF/kW can be expected. Production-related greenhouse gas emissions from lithium-ion batteries are currently around 100 kg $CO_{2\text{-eq.}}$ per kWh of storage capacity; by 2050, these emissions are expected to be reduced to around 40-60 kg $CO_{2\text{-eq.}}$ per kWh of storage capacity for stationary batteries or even below, if material supply chains could be decarbonized.

Advanced compressed air storage systems, which use thermal energy from the storage process and do not require fossil fuels, are suitable for medium-term storage (in the range of days up to weeks) and are currently at the development stage. From a technical and environmental perspective, they are promising. Pumped storage power plants, also suitable for electricity storage over periods of up to weeks, are efficient and well established. However, the potential to install additional pumped storage in Switzerland seems to be limited due to economic and social constraints. The reconversion of stored hydrogen (generated via electrolysis), either in direct form via fuel cells, or in the form of SNG via gas turbines or cogeneration plants, can be used for seasonal electricity storage. Direct

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[7] This is also relevant for hydrogen-based synthetic fuels.

storage of large quantities of hydrogen, however, requires suitable geological structures such as salt caverns – whether these are available in Switzerland, needs to be further investigated. Although energy losses and costs are high overall, there are currently few alternatives for storing electricity over a period of months – at best, storage lakes could be increased by raising dams to enable more seasonal storage.

The costs and environmental impacts of electricity storage generally depend on the application of the storage and the origin of electricity to be stored. The more storage cycles over which the production-related costs and environmental impacts can be "amortized", the lower they will be per unit of electricity stored.

Electricity production – photovoltaics (PV) and wind power

Electricity production by means of photovoltaic systems has by far the highest potential in Switzerland among all types of new renewable energy resources; furthermore, compared to hydro and wind power plants, administrative and legal procedures of new installations are far less complex, which is reflected by the comparatively higher installation rates of new PV units over the last decade. In addition, the costs of this type of electricity production have decreased the most in the past. Accordingly, it is important to regularly update both potentials and costs.

Literature evaluated within the scope of this report estimates the annual electricity production potential with rooftop PV on existing buildings in Switzerland today to be in the range of 20-30 TWh. Installing PV modules with improved performance in the future will increase this potential by several TWh/a. Other studies for rooftop installations quantify potentials as high as 50 TWh per year, which highlights the fact that these potentials depend a lot on the methodology used for their quantification and certain assumptions. Differences are mainly due to the way factors that limit the installation of PV systems or reduce the yield (building structure, shading, etc.) are considered. However, recent work also shows that it can make a lot of sense to install PV systems in mountainous areas because it can partially shift the summer production peak into the winter. Lower temperatures, reflections from snow surfaces and better irradiation thanks to the altitude itself have a positive effect in the form of a higher yield from such plants. The potential of ground-mounted systems in Switzerland is large: the available area is estimated to be about three times as large as that for roof systems.

The cost of PV electricity production with rooftop systems in Switzerland has decreased in recent years – more substantially for larger installations than for smaller ones – and is in the range of 15-25 Rp./kWh for the small systems, around 10 Rp./kWh for systems with capacities above 300 kW and even below for the largest installations with capacities above 1 MW. By 2050, these costs can be expected to decrease to 10-15 Rp./kWh and 4-6 Rp./kWh, respectively, for the smallest and the largest systems. The often cited differences in PV electricity costs between Switzerland and countries such as Germany or the USA are due on the one hand to higher module prices and installation costs in Switzerland, and on the other hand to the comparatively low system capacities here. Furthermore, differences in annual yields have to be considered in such comparisons. The new curves of electricity production costs vs. potentials show that most of the PV potential today has costs of 15-25 Rp./kWh. By 2035, this range will drop to just under 10-20 Rp./kWh.

New figures are also available for the costs and potentials of electricity production with wind turbines in Switzerland. Compared to previous estimates, the potentials increased and the costs decreased – mainly by taking into account new wind turbines, which can produce significantly more electricity at comparatively low wind speeds as in Switzerland. These new estimates result in an ecological wind energy potential of up to 30 TWh per year at electricity production costs in the range of 7-13 Rp./kWh for turbines that are in the planning stage today and could be built in 2025, and of about 5-8 Rp./kWh in 2050. The potential that can be realized by 2050 is estimated at 9 TWh per year, of which 6 TWh would be generated in winter.

2 Zusammenfassung

Dieser Bericht stellt eine Erweiterung beziehungsweise Fortsetzung des Technologiemonitorings des Bundesamts für Energie dar[8] und deckt – nach der Stromproduktion – zwei zusätzliche technologische Bereiche ab: Wasserstoff (Produktion, Speicherung und Transport, Umwandlung mit CO_2 in Methan) und Stromspeicherung (Batterien, Druckluft- und Pumpspeicher, Re-Elektrifizierung von Wasserstoff in Brennstoffzellen). Zusätzlich erfolgt eine partielle Aktualisierung von Kosten und Potenzialen der Stromproduktion mit Fotovoltaik- und Windkraftanlagen in der Schweiz. Die Faktenblätter der weiteren Technologien finden sich im Anhang.

Die Gestehungskosten für die verschiedenen Energietechnologien wurden vor dem Sommer 2021 erarbeitet, so dass der Anstieg der Rohstoffpreise und die Marktunsicherheiten seit dem Herbst 2021 in der Studie nicht berücksichtigt sind. Dies gilt insbesondere für die Stromgestehungskosten in Gaskraftwerken (Abschnitt 21.5), für welche bis 2050, basierend auf den IEA-Szenarien, mit einem Grossverbraucherpreis in der Schweiz von 5 bis 7 Rp./kWh (Erdgas) gerechnet wurde.

Der Bericht gibt einen Überblick über den aktuellen Stand der Technik und die zu erwartende zukünftige Entwicklung bezüglich Wasserstofftechnologien und Stromspeicherung, sowie über entsprechende Kosten und deren Entwicklung bis 2050 und Lebenszyklus-Treibhausgasemissionen. Systemaspekte – also etwa die Beantwortung der Frage, welche Rollen Wasserstoff und Stromspeicher im Gesamtenergiesystem der Zukunft spielen werden – sind nicht Gegenstand der vorliegenden Arbeit. Hierzu sei auf die kürzlich veröffentlichten Energieperspektiven 2050+ (Kirchner *et al.*, 2020) und ähnliche Analysen (Panos *et al.*, 2021) verwiesen.

Wasserstoff

Wasserstoff (H_2) ist ein Energieträger, der aus unterschiedlichen Ressourcen und auf verschiedene Arten erzeugt werden kann. Heute werden vorwiegend fossile Ressourcen genutzt, beispielsweise Erdgas, aus dem via Dampfreformierung Wasserstoff gewonnen wird. Die derartige Nutzung von Erdgas und Kohle ist heute mit hohen Treibhausgasemissionen verbunden und deswegen werden in Zukunft andere, CO_2-arme Wege der H_2-Produktion benötigt: die Herstellung via Elektrolyse mit CO_2-armem Strom, aus Biomasse sowie aus Erdgas, sofern die damit verbundenen CO_2-Emissionen deutlich gesenkt werden können. Dies ist möglich mittels Erdgas-Pyrolyse[9], bei welcher der Kohlenstoff in fester Form anfällt, oder durch Erdgasreformierung mit Abscheidung von gasförmigem CO_2 und anschliessender permanenter, geologischer CO_2-Speicherung («Carbon Capture and Storage» – CCS). Um als CO_2-arm gelten zu können, braucht Wasserstoff aus Erdgas auch niedrige Methanemissionen über die gesamte Gasversorgungskette. Oft werden die verschiedenen Arten der H_2-Produktion Farben zugeordnet: grün steht für Elektrolyse mit Strom aus erneuerbaren Ressourcen (und teilweise Biomasseumwandlung), blau für Erdgasreformierung mit CCS, türkis für Erdgas-Pyrolyse, grau und braun für die Nutzung fossiler Ressourcen. Weiter spricht man von rosa Wasserstoff, welcher in Kernkraftwerken erzeugt wird; thermochemische Prozesse nutzen dabei die sehr hohen Temperaturen wie sie in Reaktoren der Generation IV erzeugt werden, wozu es aber noch keine kommerzielle Anwendung gibt.

Zur Elektrolyse – also der Spaltung von Wasser in Wasserstoff und Sauerstoff unter Einsatz von Strom – stehen drei Technologien zur Verfügung: Alkalische Elektrolyse, PEM-Elektrolyse[10], und Festoxid-Elektrolyse («SOEC»[11]). Alkalische und PEM-Elektrolyse sind heute marktreif, Festoxid-Elektrolyse befindet sich noch im Entwicklungsstadium. Während alkalische Elektrolyse heute am günstigsten ist, bietet PEM-Elektrolyse eine höhere Flexibilität im Zusammenspiel mit fluktuierender erneuerbarer Stromproduktion. SOEC-Elektrolyse verspricht höhere Wirkungsgrade, also einen geringeren

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[8] Im Anschluss an die beiden Berichte aus 2017 und 2019: (Bauer *et al.*, 2017, 2019).

[9] Im Gegensatz zu Elektrolyse und Erdgasreformierung ist Erdgaspyrolyse noch nicht kommerziell verfügbar.

[10] PEM: «Proton Exchange Membrane»

[11] SOEC: «Solid Oxide Electrolysis Cell»

Stromverbrauch, benötigt allerdings Wasserdampf anstatt flüssigem Wasser als Input, läuft bei hohen Temperaturen ab (500-1000°C) und ist heute vor allem noch hinsichtlich Lebensdauer der Elektrolyseure sowie eines flexiblen Betriebs limitiert. Durchschnittliche Wirkungsgrade (Elektrolyse-System) heute liegen bei etwa 67% (alkalisch), 61% (PEM) und 82% (SOEC), was Stromverbräuchen von rund 50 kWh/kg_{H2}, 55 kWh/kg_{H2} und 43 kWh/kg_{H2} entspricht[12]. Diese Wirkungsgrade und auch die Lebensdauern der Anlagen werden in Zukunft steigen – die hier ermittelten Durchschnittswerte für 2050 liegen bei 71% (Alkalisch), 73% (PEM) und 90% (SOEC). Dementsprechend wird der Strombedarf sinken.

Investitionskosten für Elektrolyseure liegen heute bei rund 1000 CHF/kW (alkalisch), 1200 CHF/kW (PEM) und 2700 CHF/kW (SOEC). Bis 2050 wird mit einer Reduktion auf etwa 300-400 CHF/kW (alkalisch und PEM) bzw. 600 CHF/kW (SOEC) gerechnet. Die wichtigsten Faktoren, welche die Kosten der Herstellung von Wasserstoff mittels Elektrolyse bestimmen, sind neben den Investitionskosten und der Höhe des Stromverbrauchs die Auslastung der Anlagen sowie die Strombeschaffungskosten. Je länger der Zeitraum tiefer Strompreise, umso mehr wirtschaftliche Betriebsstunden können erzielt werden und entsprechend kostengünstiger ist die Elektrolyse. Aus diesem komplexen Zusammenspiel von Einflussfaktoren auf die Wasserstoffproduktionskosten ergeben sich grosse Bandbreiten für Anlagen in der Schweiz: Diese bewegen sich in Bereichen von etwa 3.5-12 CHF/kg_{H2} heute (entspricht 10.5-36 $Rp./kWh_{H2}$) sowie 3-9.5 CHF/kg_{H2} (9-28.5 $Rp./kWh_{H2}$) im Jahr 2050 (bei Strompreisen von 5-15 Rp./kWh, siehe Table 8.17). Die Wirtschaftlichkeit von grünem Wasserstoff hängt einerseits vom Preis des verwendeten Stroms ab, andererseits aber auch von den jährlichen Betriebsstunden der Elektrolyse: wird ein mit Solarstrom betriebener Elektrolyseur im Tagesgang hoch- und runtergefahren, erreicht dieser deutlich weniger Betriebsstunden als ein Elektrolyseur, welcher im Dauerbetrieb läuft. Dadurch steigen die Wasserstoffproduktionskosten. Die Wasserstoff-produktionskosten der Erdgasreformierung hingegen sind sehr empfindlich gegenüber den Erdgaspreisen: Bei "historischen Gaspreisen" (vor dem starken Anstieg der Energiepreise in Europa ab Mitte 2021) von etwa 20-25 Euro/MWh lagen die H_2-Kosten von Methandampfreformierungsanlagen im Bereich von 1.5-2 CHF/kg_{H2}. Mit CCS liegen diese H_2-Produktionskosten schätzungsweise in einer Grössenordnung von 2-2.5 CHF/kg_{H2}. Der jüngste Anstieg der Erdgaspreise auf ein Niveau von etwa 100 Euro/MWh führt zu einer Vervierfachung der Kosten für die Wasserstoffproduktion auf Erdgasbasis, wodurch sich die Preise für Wasserstoff aus Elektrolyse und Erdgasreformierung angleichen. Dies gilt vor allem für Elektrolyse-Standorte, an denen Wind- und Fotovoltaikkraftwerke über das ganze Jahr sehr hohe Erträge und damit tiefe Stromgestehungskosten aufweisen. Unsicherheitsfaktoren dabei sind künftige Erdgas- und CO_2-Preise auf der einen und Strompreise, Preise von Elektrolyseuren und die Verfügbarkeit von kritischen Metallen wie Iridium in grossem Massstab auf der anderen Seite.

Wasserstoff kann nur dann als CO_2-armer Energieträger bezeichnet werden, wenn seine Herstellung mit geringen Lebenszyklus-Treibhausgasemissionen verbunden ist. Dies ist der Fall bei der Herstellung aus nachhaltig produzierter oder Abfall-Biomasse (Pyrolyse, Holzvergasung und Reformierung von Biomethan), via Elektrolyse mit CO_2-armem Strom sowie bei fortgeschrittenen Verfahren zur Erdgasreformierung mit CCS, welche hohe CO_2-Abscheideraten im Bereich von 90% und mehr aufweisen. Dabei ist auch eine geringe Methanemissionsrate (im Bereich von 1% oder darunter) über die gesamte Erdgasversorgungskette nötig. Wird die Wasserstoff-Gewinnung aus Biomasse mit CCS gekoppelt, resultieren sogar negative Treibhausgasemissionen, also eine permanente Entfernung von CO_2 aus der Atmosphäre. Das dafür nachhaltig nutzbare Biomassepotenzial ist allerdings beschränkt.

Abbildung 1 zeigt repräsentative Gestehungskosten und die Treibhausgas-Intensität der Wasserstoff-herstellung mit verschiedenen Technologien für den (potenziellen) Einsatz heute.

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[12] Inklusive Kompression des Wasserstoffs auf 40 bar.

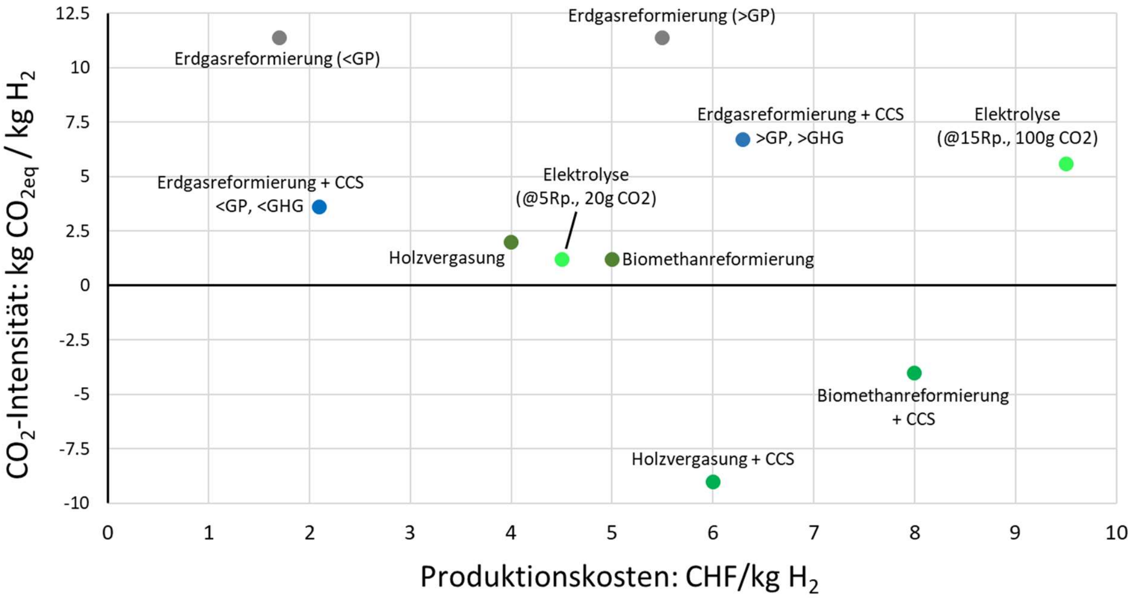

Abbildung 1: Heutige Kosten vs. Lebenszyklus-Treibhausgasemissionen (GWP100) der Wasserstoffproduktion (ohne Berücksichtigung von Kosten für allfällige CO_2-Emissionen, beispielsweise bei der Erdgasreformierung). Repräsentative Werte – die Bandbreiten können erheblich sein. Für Erdgasreformierung wurde für die Erdgasversorgung eine Methanemissionsrate von 1.3% angenommen, repräsentativ für die Europäische Versorgung heute.[13] Für die Erdgas-Reformierung werden zwei Preisszenarien unterschieden: ">GP" repräsentiert die aktuelle Situation mit etwa 100 Euro/MWh_{NG}, "<GP" niedrige Erdgaspreise wie vor 2021 von etwa 20 Euro/MWh_{NG}. Für die Erdgasreformierung mit CCS werden die Lebenszyklus-Treibhausgasemissionen für zwei deutlich unterschiedliche Reformierungstechnologien angegeben: ">GHG" steht für die Methandampfreformierung mit einer niedrigen Gesamt-CO_2-Entfernungsrate von etwa 55%, während "<GHG" für die autothermale Reformierung mit einer hohen CO_2-Entfernungsrate von 93% steht.[14] . Bei Elektrolyse sind jeweils Strompreise und THG-Emissionen (basierend auf Ökobilanzen, d.h. beispielsweise inkl. jenen aus dem Bau der Infrastruktur zur Stromproduktion) pro kWh Strominput angegeben; typische Werte für Strom aus Wind und PV in der Schweiz liegen heute im Bereich von 20 bzw. 40 g CO_2-eq./kWh. Holzvergasung mit CCS existiert heute noch nicht in industriellem Massstab – Kosten und THG-Emissionen sind demnach bis zu einem gewissen Grad spekulativ.

Abgesehen von den Lebenszyklus-Treibhausgasemissionen und den Kosten hat die Ukraine-Krise gezeigt, dass geopolitische Aspekte in Bezug auf die Bezugskette aller für die Wasserstoffproduktion und -versorgung benötigten Ressourcen zu einem ebenso wichtigen Aspekt beim Vergleich verschiedener Wasserstoffversorgungsketten werden können.

Wie andere Energieträger muss auch Wasserstoff (zwischen)gespeichert werden. Wasserstoff weist zwar eine hohe gravimetrische (massenbezogene) Energiedichte auf, die volumetrische (aufs Volumen bezogene) Energiedichte ist aber äusserst gering. Deshalb erfordert die Speicherung eine Erhöhung dieser Energiedichte. Dies kann auf verschiedene Arten erreicht werden: durch Kompression als Gas, über Kühlung und damit Verflüssigung, durch Verflüssigung und zusätzliche Verdichtung («cryo-compression») sowie mittels Hydrierung (das Binden von Wasserstoff an andere Moleküle). Zur Hydrierung eigenen sich so genannte «Metallhydride», «Metallorganische Gerüstverbindungen» und flüssige organische Wasserstoffträger. Wasserstoff kann auch an Stickstoff gebunden und so als Ammoniak gespeichert werden. All diese Arten der Umwandlung, Speicherung und Rückumwandlung sind mit nennenswertem Energieaufwand verbunden. Ausserdem sind zum Teil spezielle Materialen erforderlich. Beides schlägt sich – im Vergleich zu flüssigen und gasförmigen Kohlenwasserstoffen – in hohen Speicher- und Transportkosten nieder, weshalb es wichtig erscheint, Wasserstoff möglichst vor Ort und zum Zeitpunkt der Nachfrage zu produzieren.

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[13] Heute schwanken diese Methanemissionen je nach Herkunft des Erdgases zwischen nahe Null und einigen Prozenten des gelieferten Gases.

[14] Siehe (Bauer, Treyer, Antonini, Bergerson, Gazzani, Gençer, Gibbins, Mazzotti, S. McCoy, *et al.*, 2022) bzgl. Details.

Die Speicherung als Gas unter hohem Druck wird heute breit angewandt. Beispielsweise in Tanks von Brennstoffzellenfahrzeugen bei 350 bar oder 700 bar in Stahl- oder Verbundmaterial-Zylindern. Aus technischer Sicht ist auch die Speicherung in flüssiger Form als reiner Wasserstoff und Ammoniak heute schon gut machbar. Alle anderen Formen und Verfahren befinden sich noch im Forschungs- oder Demonstrationsstadium. Wie und in welcher Form Wasserstoff vorzugsweise gespeichert und transportiert wird, hängt unter anderem vom Einsatzzweck, der zu speichernden Menge und der Speicherdauer sowie der Transportdistanz ab. Bei mobilen Anwendungen spielt die Speicherdichte eine deutlich grössere Rolle als bei stationären Anwendungen. Während für die kurz- bis mittelfristige Speicherung Tanks zum Einsatz kommen, scheinen geologische Strukturen wie Salzlagerstätten für die Speicherung von grossen Mengen während langer Zeit (saisonal) am vielversprechendsten zu sein. Ob solche in der Schweiz verfügbar sein werden, ist Gegenstand von Untersuchungen.

Der Transport von Wasserstoff kann in verschiedenen Formen (gasförmig, flüssig, gebunden) und mit unterschiedlichen Transportmitteln (LKW, Bahn, Schiff, Pipelines) geschehen. LKW kommen heute schon für kleine Mengen und kurze Distanzen (bis zu einigen Hundert Kilometern) zum Einsatz, Pipelines (für reinen Wasserstoff oder Gemische mit Erdgas) ebenso, allerdings für grössere Mengen und auch bei mittleren Distanzen (bis zu einigen Tausend Kilometern). Schiffstransport eignet sich am besten für lange Distanzen (ab einigen Tausend Kilometern) und ist dementsprechend attraktiv für zukünftige interkontinentale Routen. Per LKW wird Wasserstoff heute meist in Tanks komprimiert als Gas transportiert. Für den Schiffstransport sind höhere Energiedichten nötig, was für Wasserstoff in flüssiger Form spricht. In geringen Mengen kann Wasserstoff auch ins vorhandene Erdgasnetz eingespeist und somit Erdgas beigemischt werden. Die erlaubten Beimischungsniveaus sind länderspezifisch, aber alle im Bereich von einigen wenigen Volumenprozenten, da vor allem auch die Verteilnetze und die Mess- und Verdichtungstechnologien noch nicht vollständig erprobt sind bzgl. höherer Beimischung. Das bestehende Erdgasnetz kann grundsätzlich für den Transport von reinem Wasserstoff genutzt werden – teilweise allerdings nur mit Aufrüstung der Infrastruktur, entsprechenden technischen Anpassungen und erhöhtem Wartungsaufwand und dementsprechend zusätzlichen Kosten.

Konkrete Kosten von H_2-Transport und -Speicherung sind stark skalenabhängig, das heisst sie werden bestimmt von den zu transportierenden und zu speichernden Mengen, ebenso von Transportdistanzen und Speicherzeiträumen. Generell können diese Kosten, vor allem bei günstigen H_2-Produktionskosten, hohe Anteile an den H_2-Kosten beim Endverbraucher ausmachen – wegen der erforderlichen Infrastruktur insbesondere dann, wenn Wasserstoff als Treibstoff für Autos eingesetzt wird (wo er heute noch von der Mineralölsteuer befreit ist). Die Umweltauswirkungen von H_2-Transport und -Speicherung sind vor allem vom Energieverbrauch der einzelnen Umwandlungsschritte abhängig.

Im Zusammenhang mit H_2-Speicherung- und Transport gilt es einige Herausforderungen zu meistern. Materialien, die für Speicher- und Transportmedien genutzt werden, müssen widerstandsfähig sein gegen Versprödung und Korrosion sowie möglichst wenig Wasserstoff diffundieren lassen. Volumetrische und gravimetrische Energiedichten von Speicherlösungen müssen weiter erhöht werden, um kommerzielle Einsätze zu ermöglichen. Vermieden werden müssen Verunreinigungen des Wasserstoffs während Speicherung und Transport, da andernfalls aufwändige Reinigungsschritte erforderlich werden. Auch aus diesen Gründen ist es vorteilhaft, Wasserstoff möglichst verbrauchergerecht vor Ort zu produzieren.

Wasserstoff kann – zusammen mit CO_2 – zu synthetischem Methan (SNG)[15] umgewandelt werden, welches als Ersatz von Erdgas dienen kann. Synthetisches Methan kann genau wie Erdgas einfach gespeichert und in Heizungen, Motoren und der Industrie genutzt werden. Die Wasserstofferzeugung durch Wasserelektrolyse und die anschließende Umwandlung in SNG ermöglicht es, zeitliche und räumliche Diskrepanzen zwischen der Stromerzeugung aus erneuerbaren Energien und dem

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[15] «Synthetic Natural Gas» – SNG

Energiebedarf auszugleichen. Diesem Vorteil steht der Nachteil von vergleichsweise ineffizienten Umwandlungsprozessen entlang der Herstellungs- und Nutzungskette gegenüber. Energieverluste sind auch einer der Gründe für derzeit hohe Produktionskosten, welche vor allem durch die Investitionskosten für Elektrolyse und Methanisierung, Strombeschaffungskosten für die Elektrolyse und Kosten des CO_2 bestimmt werden. Die Quelle des CO_2 beeinflusst nicht nur Kosten, sondern ist auch hinsichtlich Treibhausgasbilanz wichtig: Nur CO_2, welches direkt der Atmosphäre entnommen ist oder aus Biomasse stammt, ermöglicht einen kurzfristig geschlossenen CO_2-Kreislauf und somit Klimaneutralität. Stammt das CO_2 aus Verbrennungsprozessen fossiler Energieträger, wird das CO_2 zwar zwischenzeitlich chemisch gebunden, bleibt aber letztlich bei der Nutzung fossiles CO_2, da es einfach zeitlich verzögert emittiert wird. So resultiert aus Systemperspektive eine Reduktion der CO_2-Emissionen von höchstens 50%, wenn Erdgas mit SNG, dessen CO_2 aus fossilen Quellen stammt, ersetzt wird. Für die Erstellung produktspezifischer CO_2-Bilanzen muss festgelegt werden, ob die CO_2-Emissionen aus der SNG-Nutzung dieser Endnutzung oder der ursprünglichen Emissionsquelle zugeordnet werden.

Bei der Umsetzung einer Wasserstoffwirtschaft in grossem Massstab als Ergänzung zur direkten Elektrifizierung der geeigneten Anwendungen wird sich die Frage stellen, ob die H_2-Produktion im Inland stattfinden, oder ob Wasserstoff importiert werden soll bzw. zu welchem Ausmass sich beide Optionen ergänzen.[16] Dies hängt von vielen Faktoren ab, unter anderem den nachgefragten Mengen und (handels-)politischen Zusammenhängen, aber auch (inter-)nationalen Produktionspotenzialen und Kosten. Hinsichtlich der Kosten ist heute noch nicht mit Sicherheit absehbar, dass ein Import aus Ländern mit besseren Produktionsbedingungen, also günstigem Strom aus Wind und Sonne, günstiger sein wird als eine verbrauchsnahe Produktion in der Schweiz, bei welcher Transportkosten eingespart werden können. Die Energieperspektiven 2050+ gehen im Basisszenario ZERO für das Jahr 2050 davon aus, dass 9 PJ erneuerbarer Wasserstoff importiert (vor allem aus der MENA Region) und 7 PJ inländisch hergestellt werden (Kirchner *et al.*, 2020). Studien für Deutschland und Mitteleuropa weisen darauf hin, dass Wasserstoff kostengünstiger importiert als inländisch produziert werden kann. Unabhängig von den Kosten ist allerdings das Potenzial an Stromproduktion aus erneuerbarer Energie in der Schweiz beschränkt (Bauer *et al.*, 2017, 2019), sodass bei einem breiten Einsatz von grünem Wasserstoff die Importvariante ins Spiel kommen wird. Für blauen Wasserstoff gilt dies ohnehin.

Stromspeicher

Die stationäre Speicherung von Strom wird in Zukunft bei einer deutlichen Steigerung der Stromproduktion aus fluktuierenden Quellen wie Wind- und Solarenergie an Bedeutung gewinnen. Zu den vielversprechendsten Technologien zur Stromspeicherung gehören Batterien, Pumpspeicherkraftwerke, Druckluftspeicher, und die Rückumwandlung von via Elektrolyse erzeugtem Wasserstoff in Brennstoffzellen. Lithium-Ionen Batterien werden heute breit eingesetzt im Elektronik- und zunehmend auch im Fahrzeugsektor. Sie eignen sich auch für stationäre Stromspeicherung, am besten für dezentrale Anwendungen, das heisst für eher kleine Strommengen zur Speicherung über kurze Zeiträume (bis zu einigen Tagen). Andere Arten von Batterien führen derzeit ein Nischendasein bzw. befinden sich im Entwicklungsstadium, beispielsweise Redox-Flow Batterien und Natrium-Ionen Batterien. Diese kommen ohne Metalle wie Kobalt aus, deren Nutzung aus Knappheits- und Umweltperspektive problematisch sein kann. Redox-Flow Batterien eignen sich auch für die Speicherung von grösseren Strommengen. Die heutigen Alternativen zu Lithium-Ionen Batterien haben aber auch alle Nachteile, sei es bei der Effizienz der Stromspeicherung, bei der Lebensdauer, oder der Energiespeicherdichte und bei den Kosten. Bei Lithium-Ionen Batterien war in den letzten Jahren ein deutlicher technischer Fortschritt sichtbar, vor allem hinsichtlich zunehmender Haltbarkeit und Energiespeicherdichte sowie abnehmender Produktionskosten. Auch die mit der Herstellung verbundenen Umweltbelastungen konnten reduziert werden dank effizienterer Herstellung in immer

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[16] Dies gilt auch für wasserstoffbasierte, synthetische Energieträger.

grösserem Massstab. Man kann davon ausgehen, dass sich die in der Vergangenheit beobachtete Entwicklung auch in den nächsten Jahren fortsetzen wird. Zudem werden sich industrielle Recyclingverfahren etablieren, deren Umwelt- und Kostenbilanz derzeit jedoch nicht im Detail bekannt ist. Die heutigen Kosten von stationären Lithium-Ionen Batterien für zentrale Anwendung durch Stromversorger werden auf rund 200 CHF/kWh und 160 CHF/kW geschätzt. Diese Kosten nehmen bei Heimanwendung (d.h. für Batterien mit geringer Speicherkapazität) zu. Bis 2050 kann mit Kostenreduktionen auf etwa 45-110 CHF/kWh und 35-90 CHF/kW gerechnet werden. Die produktionsbedingten Treibhausgasemissionen von Lithium-Ionen Batterien liegen heute bei rund 100 kg $CO_{2\text{-eq.}}$ pro kWh Speicherkapazität; bis 2050 wird mit einer Reduktion dieser Emissionen auf etwa 40-60 kg $CO_{2\text{-eq.}}$ pro kWh Speicherkapazität für stationär genutzte Batterien gerechnet oder auch darunter, falls Materialgewinnung und -versorgung CO_2-arm gestaltet werden können.

Fortgeschrittene Druckluftspeicher, welche thermische Energie aus dem Speicherprozess nutzen und ohne fossile Brennstoffe auskommen, eignen sich für eine mittelfristige Speicherdauer (im Bereich von Tagen bis zu Wochen) und befinden sich heute im Entwicklungsstadium. Aus technischer und ökologischer Perspektive sind sie vielversprechend. Pumpspeicherkraftwerke, ebenfalls geeignet für die Stromspeicherung über Zeiträume von bis zu Wochen, sind effizient und etabliert. Allerdings scheint das Potenzial, in der Schweiz zusätzliche Pumpspeicher zu installieren, aus wirtschaftlichen sowie gesellschaftlichen Gründen beschränkt zu sein. Die Rückverstromung von gespeichertem Wasserstoff (erzeugt via Elektrolyse), entweder in direkter Form mittels Brennstoffzellen, oder in Form von SNG mittels Gasturbinen oder Blockheizkraftwerken, kann zur saisonalen Stromspeicherung genutzt werden. Zur direkten Speicherung grosser Mengen an Wasserstoff bedarf es allerdings geeigneter geologischer Strukturen wie Salzkavernen – ob diese in der Schweiz vorhanden sein könnten, bedarf weiterer Abklärungen. Energieverluste sowie Kosten sind gesamthaft betrachtet zwar hoch, allerdings sind derzeit die Alternativen zur Stromspeicherung über Monate rar – allenfalls könnten Speicherseen über Erhöhung von Staumauern aufgestockt werden, um eine höhere saisonale Speicherung zu ermöglichen.

Die Kosten und Umweltauswirkungen der Stromspeicherung hängen generell von der Anwendung der Speicher sowie von der Art der ursprünglichen Stromproduktion ab. Über je mehr Speicherzyklen die herstellungsbedingten Kosten und Umweltauswirkungen «amortisiert» werden können, desto geringer fallen sie pro gespeicherter Einheit Strom aus.

Stromproduktion – Potenziale und Kosten von Fotovoltaik (PV) und Windenergie

Die Stromproduktion mittels Fotovoltaikanlagen weist in der Schweiz unter allen Arten der neuen erneuerbaren Energieressourcen das weitaus grösste Potenzial auf. PV-Anlagen haben im Vergleich zu Wasserkraft und Windenergie einfache Bewilligungsverfahren, was sich im vergleichsweise stärkeren Zubau über die letzten Jahre wiederspiegelt. Und die Kosten dieser Art der Stromproduktion sind in der Vergangenheit am stärksten zurückgegangen. Dementsprechend ist es wichtig, sowohl Potenziale als auch Kosten regelmässig zu aktualisieren.

Dieser Bericht geht von Schätzungen des jährlichen Stromproduktionspotenzials mit PV-Dachanlagen heute auf bestehenden Gebäuden in der Schweiz im Bereich von 20-30 TWh aus. Die Installation von PV-Anlagen mit geringerem leistungsbezogenem Flächenbedarf wird in Zukunft dieses Potenzial um einige TWh pro Jahr ansteigen lassen. Andere Berechnungen für solche Dachanlagen liegen bei bis zu 50 TWh/a, was aufzeigt, wie stark solche Ergebnisse von den jeweiligen Annahmen und der angewandten Methodik abhängen. Unterschiede lassen sich hauptsächlich zurückführen auf die Art der Berücksichtigung von Faktoren, welche die Installation von PV-Anlagen einschränken oder den Ertrag reduzieren (Gebäudestruktur, Beschattung, etc.). Neue Arbeiten zeigen aber auch, dass es sehr sinnvoll sein kann, PV-Anlagen in Berggebieten zu errichten, weil damit die Produktionsspitze des Sommers teilweise in den Winter verschoben werden kann. Positiv in Form eines höheren Ertrags solcher Anlagen wirken sich geringere Temperaturen, Reflektionen von Schneeoberflächen und eine bessere Einstrahlung dank der Höhenlage an sich aus. Das Potenzial von Freiflächenanlagen in der

Schweiz ist gross – die verfügbare Fläche wird als etwa dreimal so gross wie jene für Dachanlagen geschätzt.

Die Kosten der PV-Stromproduktion mit Dachanlagen sind in der Schweiz in den letzten Jahren gesunken – für grössere Anlagen stärker als für kleine Anlagen – und liegen bei den kleinen Anlagen im Bereich von 15-25 Rp./kWh, bei Anlagen mit Kapazitäten von etwa 300 kW bei rund 10 Rp./kWh und bei sehr grossen Anlagen von 1 MW und mehr auch darunter. Bis 2050 kann mit einem Rückgang dieser Kosten auf 10-15 Rp./kWh bzw. 4-6 Rp./kWh gerechnet werden für die kleinsten bzw. grössten Anlagen. Die oft zitierten Unterschiede in den PV-Stromkosten zwischen der Schweiz und Ländern wie Deutschland oder den USA liegen einerseits an höheren Modulpreisen und Installationskosten in der Schweiz, andererseits an den hier vergleichsweise geringen Anlagenleistungen. Weiter sind in solchen Vergleichen Unterschiede in den jährlichen Erträgen zu berücksichtigen. Die neuen Kurven von Stromproduktionskosten gegenüber den Potenzialen zeigen, dass der Grossteil des PV-Potenzials heute Kosten von 15-25 Rp./kWh aufweist. Bis 2035 wird diese Bandbreite auf knapp 10-20 Rp./kWh sinken.

Für die Kosten und Potenziale der Stromproduktion mit Windturbinen in der Schweiz sind ebenfalls neue Zahlen vorhanden. Im Vergleich zu früheren Abschätzungen nahmen die Potenziale zu und die Kosten ab – vor allem durch die Berücksichtigung neuer Windkraftanlagen, welche bei vergleichsweise geringen Windgeschwindigkeiten wie in der Schweiz deutlich mehr Strom produzieren können. Aus diesen neuen Abschätzungen ergibt sich ein ökologisches Windenergiepotenzial von bis zu 30 TWh pro Jahr bei Stromproduktionskosten im Bereich von 7-13 Rp./kWh für Anlagen, die heute in Planung gehen und 2025 errichtet werden könnten sowie von ca. 5-8 Rp./kWh im Jahr 2050. Das bis 2050 realisierbare Potenzial wird auf 9 TWh pro Jahr geschätzt, davon 6 TWh im Winter.

3 Résumé

Le présent rapport complète, ou prolonge, le rapport de veille technologique de l'Office fédéral de l'énergie (Bauer *et al.*, 2017, 2019). Outre la production d'électricité, il couvre deux domaines technologiques supplémentaires, à savoir l'hydrogène (production, stockage et transport, conversion en méthane en combinaison avec le CO_2) et le stockage de l'électricité (accumulateurs, air comprimé et stockage de la force hydraulique via le pompage-turbinage, reconversion de l'hydrogène en électricité via des piles à combustible). De plus, les coûts et le potentiel de production d'électricité d'origine photovoltaïque et éolienne en Suisse sont actualisés.

Les fiches techniques des autres technologies se trouvent en annexe. Les coûts de production des différentes technologies énergétiques ont été calculés avant l'été 2021, de sorte que la hausse des prix des matières premières et les incertitudes du marché depuis l'automne 2021 ne sont pas prises en compte dans l'étude. Cela s'applique en particulier aux coûts de production d'électricité dans les centrales électriques au gaz, pour lesquels un prix de gros à la consommation en Suisse de 5 à 7 Rp/kWh a été calculé d'ici 2050, sur la base des scénarios de l'AIE.

Le rapport dresse un état des lieux et offre un aperçu du développement attendu des technologies en matière d'hydrogène et de stockage de l'électricité. Il fournit également des informations sur les coûts correspondants et leur évolution d'ici à 2050, ainsi que sur les émissions de gaz à effet de serre sur l'ensemble du cycle de vie. Le présent rapport n'aborde pas les aspects liés au système énergétique dans sa globalité tels que la question du rôle que sont appelés à jouer l'hydrogène et le stockage de l'électricité dans le système énergétique à l'avenir. Sur ce point, nous renvoyons aux Perspectives énergétiques 2050+ parues récemment (Kirchner *et al.*, 2020) et autres analyses similaires (Panos *et al.*, 2021).

Hydrogène

L'hydrogène (H_2) est un agent énergétique pouvant être produit à partir de différentes ressources et par divers procédés. À l'heure actuelle, on emploie principalement des énergies fossiles, telles que du gaz naturel, dont l'hydrogène est extrait par vaporeformage. Or, le recours au gaz naturel et au charbon dans ce contexte engendre des émissions élevées de gaz à effet de serre. C'est pourquoi d'autres modes de production de l'hydrogène, émettant peu de CO_2, seront nécessaires à l'avenir, tels que la production par électrolyse opérée à partir d'électricité faiblement carbonée ou de la biomasse, ou à partir du gaz naturel à condition que les émissions de CO_2 associées puissent être sensiblement réduites. Des possibilités résident dans la pyrolyse du gaz naturel[17], un procédé qui produit du carbone solide, ou dans la capture du CO_2 gazeux pendant le reformage du gaz naturel, puis dans le stockage géologique permanent de ce CO_2 (captage et stockage du carbone, CSC). Les modes de production basés sur le gaz naturel impliquent également que les émissions de méthane liées à la chaîne d'approvisionnement en gaz soient maintenues à un faible niveau. On attribue souvent des couleurs à ces différents modes de production de l'hydrogène: le vert représente l'électrolyse utilisant de l'électricité provenant de sources renouvelables (et parfois une conversion de la biomasse), le bleu le reformage de gaz naturel accompagné de procédés CSC, le turquoise la pyrolyse du gaz naturel, le gris et le brun le recours à des ressources fossiles. Enfin, l'hydrogène rose représente la production dans les centrales nucléaires ; les procédés thermochimiques utilisent des températures de réacteur très élevées car ils sont produits dans des réacteurs de génération IV, pour lesquels il n'existe toutefois pas encore d'application commerciale.

Trois technologies sont disponibles pour l'électrolyse, qui désigne la séparation de l'eau en hydrogène et en oxygène par le recours à l'électricité: l'électrolyse alcaline, l'électrolyse PEM[18] et l'électrolyse à oxyde solide (*solid oxide electrolysis cell*, SOEC). L'électrolyse alcaline et l'électrolyse PEM sont

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[17] Contrairement à l'électrolyse et au reformage de gaz naturel, ce procédé n'est pas encore commercialisé.

[18] PEM est l'abréviation de *proton exchange membrane* (membrane échangeuse de protons).

aujourd'hui prêtes à être commercialisées, tandis que l'électrolyse à oxyde solide se trouve encore en phase de développement. Tandis que l'électrolyse alcaline est aujourd'hui la moins coûteuse, l'électrolyse PEM offre davantage de flexibilité dans le contexte d'une production d'électricité renouvelable sujette à variation. L'électrolyse SOEC promet quant à elle de meilleurs résultats en termes d'efficacité, tels qu'une consommation d'électricité réduite, mais elle est alimentée par de la vapeur et non par de l'eau liquide, se déroule à haute température (de 500 à 1000°C) et n'est pas disponible à une échelle industrielle. Les principaux écueils à l'heure actuelle concernent la durée de vie des électrolyseurs et la flexibilité d'utilisation. L'efficacité moyenne des systèmes d'électrolyse avoisine actuellement 67% (alcaline), 61% (PEM) et 82% (SOEC), ce qui correspond à une consommation d'électricité d'environ 50 kWh/kg_{H2}, 55 kWh/kg_{H2} et 43 kWh/kg_{H2}[19]. Tout comme la durée de vie des installations, ces niveaux d'efficacité devraient progresser à l'avenir pour atteindre des valeurs moyennes estimées à 71% (alcaline), 73% (PEM) et 90% (SOEC) en 2050. Par conséquent, la demande en électricité diminuera.

Aujourd'hui, les électrolyseurs représentent un coût d'investissement d'environ 1000 CHF/kW (alcaline), 1200 CHF/kW (PEM) et 2700 CHF/kW (SOEC). D'ici à 2050, une réduction est attendue et les coûts devraient avoisiner 300 à 400 CHF/kW (alcaline et PEM) et 600 CHF/kW (SOEC). Outre les coûts d'investissement et le niveau de consommation d'électricité, les principaux facteurs déterminant le coût de production de l'hydrogène par électrolyse sont l'utilisation des installations et le coût de l'électricité. Plus les prix de l'électricité sont durablement bas, moins ils pèsent sur les heures d'exploitation et plus l'électrolyse devient avantageuse. Il en résulte de larges plages de variation dans l'estimation des coûts de production de l'hydrogène en Suisse: celles-ci sont de l'ordre de 3,5 à 12 CHF/kg_{H2} aujourd'hui (soit 10,5 à 36 $ct./kWh_{H2}$) et de 3 à 9,5 CHF/kg_{H2} (soit 9 à 28,5 $ct./kWh_{H2}$) en 2050 (pour un coût d'électricité allant de 5 à 15 ct./kWh, voir Table 8.17). La rentabilité de l'hydrogène vert dépend d'une part du prix de l'électricité consommée, mais d'autre part aussi des heures de fonctionnement annuelles : si un électrolyseur fonctionnant à l'énergie solaire est démarré et arrêté au courant de la journée, il réalise moins d'heures de fonctionnement annuelles qu'un électrolyseur fonctionnant en continu. Cela augmente les coûts de production d'hydrogène.

Les coûts de production de l'hydrogène par le reformage du gaz naturel dépendent en outre, dans une large mesure, de l'évolution des prix du gaz naturel: au «prix du gaz historique» (avant la flambée des prix de l'énergie en Europe qui a débuté au milieu de l'année 2021) d'environ 20 à 25 EUR/MWh, les coûts de production de l'hydrogène dans des installations de reformage du méthane à la vapeur étaient de l'ordre de 1,5 à 2 CHF/kg_{H2}. En incluant le procédé CSC, ces coûts de production du H_2 ont été estimés à environ 2 à 2,5 CHF/kg_{H2}. Les récents pics atteints par les prix du gaz naturel, à des niveaux avoisinant 100 EUR/MWh, reviennent à multiplier approximativement par trois les coûts de production de l'hydrogène à partir de gaz naturel, ce qui met l'hydrogène obtenu par électrolyse et celui obtenu par reformage du gaz naturel au même niveau de prix. C'est particulièrement vrai pour les sites d'électrolyse bénéficiant d'installations éoliennes ou photovoltaïques offrant un très haut rendement tout au long de l'année et partant, où la part de l'électricité dans les coûts de production est faible. Les facteurs d'incertitude dans ce domaine sont, d'un côté, les prix du gaz naturel et du CO_2 à l'avenir et, de l'autre, les prix de l'électricité, les prix des électrolyseurs et la disponibilité à grande échelle de métaux rares tels que l'iridium.

L'hydrogène ne peut constituer un agent énergétique faiblement carboné que si sa production occasionne de faibles émissions de gaz à effet de serre dans la perspective de l'ensemble du cycle de vie. C'est le cas si la production repose sur de la biomasse d'origine durable ou sur de la biomasse résiduelle (obtenue par pyrolyse, gazéification de biomasse ligneuse ou reformage de biométhane), sur l'électrolyse au moyen d'électricité faiblement carbonée ou sur des processus avancés de reformage du gaz naturel combinés à la CSC qui permettent d'atteindre des niveaux élevés de capture du CO_2 de l'ordre de 90% ou plus. En outre, l'approvisionnement en gaz naturel doit être associé à de

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[19] Y compris la compression de l'hydrogène à 40 bars.

faibles émissions de méthane (environ 1% ou moins), ce qui, à grande échelle, requiert des investissements dans l'infrastructure de gaz naturel afin de réduire ces émissions. L'utilisation de la biomasse combinée à la CSC peut même aboutir à des émissions de gaz à effet de serre négatives, par exemple par le retrait permanent de CO_2 de l'atmosphère. Néanmoins, le potentiel de la biomasse pouvant être exploité de manière durable à cette fin est limité. On parle ensuite d'hydrogène rose si celui-là est généré dans les centrales nucléaires; le processus thermochimique utilise les températures de réacteur très élevées qui sont générées dans les réacteurs de génération IV. Jusqu'à présent il n'y a pas encore d'application commerciale pour cela.

La figure ci-dessous montre des plages représentatives des coûts et des émissions de gaz à effet de serre pour la production d'hydrogène au moyen de différentes technologies courantes (potentiellement) utilisées aujourd'hui.

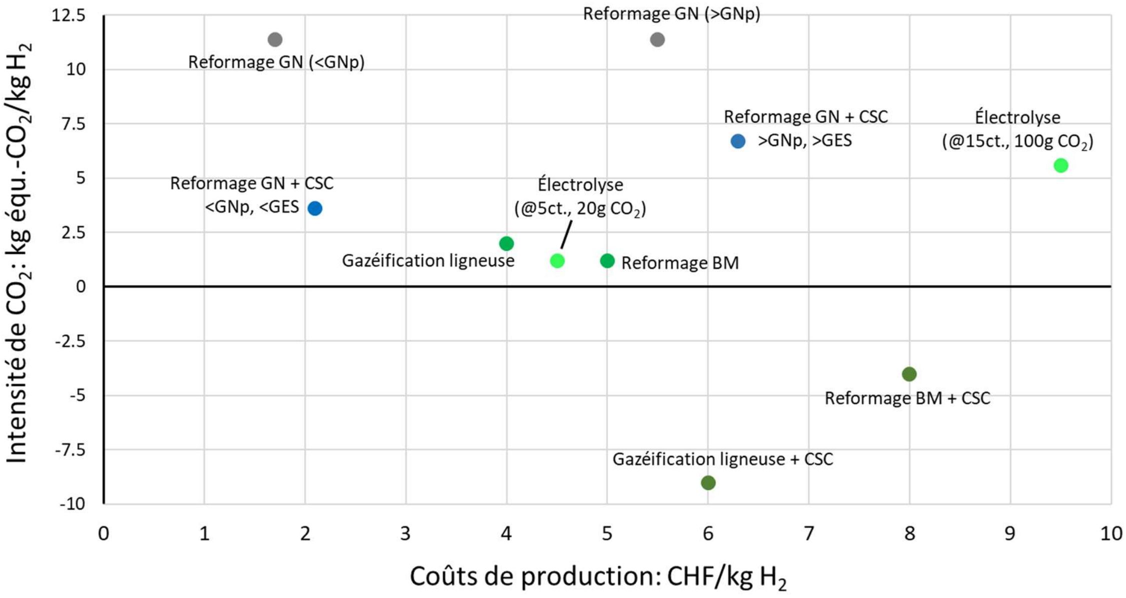

Figure 3.1: Relation entre les coûts actuels et les émissions de gaz à effet de serre sur l'ensemble du cycle de vie (potentiel de réchauffement global: GWP100) dans la production d'hydrogène (hors coûts des émissions de CO_2 liées p. ex. au reformage de gaz naturel). Les écarts dans les valeurs représentatives peuvent être considérables. Pour le reformage de gaz naturel, on part de l'hypothèse d'un taux d'émission de méthane de 1,3% sur l'ensemble de la chaîne d'approvisionnement, ce qui est représentatif de l'approvisionnement actuel en Europe[20]. Pour le reformage de GN, deux scénarios de prix distincts sont envisagés: «>GNp» représente le niveau de prix actuel aux environs de 100 EUR/MWh_{GN}, «<GNp» les prix bas pour le GN d'avant 2021, soit approximativement 20 EUR/MWh_{GN}. Pour le reformage de GN avec CSC, les émissions de gaz à effet de serre (GES) sur l'ensemble du cycle de vie sont exposées pour deux technologies de reformage clairement différentes: «>GES» présente le reformage de méthane par vapeur avec un faible taux global de capture du CO_2 d'environ 55%, tandis que «<GES» représente le reformage autothermique ayant un taux élevé de capture du CO_2 de 93%[21]. Pour l'électrolyse, les prix de l'électricité et les émissions de GES (basés sur le cycle de vie, incluant les émissions liées à l'infrastructure de production d'électricité) par kWh d'électricité introduite pour l'électrolyse sont indiqués dans chaque cas de figure; des valeurs typiques pour les installations éoliennes ou photovoltaïques en Suisse se situeraient aujourd'hui à environ 20 respectivement 40 g d'éq-CO_2/kWh. GN: gaz naturel; BM: biométhane. Le procédé de gazéification de biomasse ligneuse avec CSC n'est pas encore commercialisé. Les coûts et les émissions de gaz à effet de serre indiqués renferment par conséquent une part de spéculation.

Outre les émissions de GES sur l'ensemble du cycle de vie et les coûts, la crise en Ukraine a montré que des aspects géopolitiques liés à la chaîne d'approvisionnement de toutes les ressources nécessaires à la production d'hydrogène et à l'approvisionnement en hydrogène peuvent devenir un

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[20] À l'heure actuelle, ces émissions provenant du méthane varient de presque zéro à quelques pourcents du gaz livré, en fonction de son origine.

[21] Voir (Bauer, Treyer, Antonini, Bergerson, Gazzani, Gençer, Gibbins, Mazzotti, S. T. McCoy, *et al.*, 2022) pour plus de détails.

aspect tout aussi important lorsqu'on compare différentes chaînes d'approvisionnement en hydrogène.

À l'instar d'autres agents énergétiques, l'hydrogène doit être stocké (temporairement). Or, en dépit de sa haute densité énergétique gravimétrique (liée à la masse), sa densité énergétique volumétrique (liée au volume) est extrêmement faible. Par conséquent, qui dit stockage dit augmentation de cette densité énergétique. Plusieurs méthodes sont possibles: on peut comprimer l'hydrogène gazeux, le refroidir pour le liquéfier, le comprimer après l'avoir liquéfié (on parle alors de *cryo-compression*) ou encore procéder par hydrogénation (ajout d'hydrogène à d'autres molécules). Les métaux hybrides, les cadres organométalliques *(metal-organic frameworks)* et les transporteurs d'hydrogène organique liquide *(liquid organic hydrogen carriers)* se prêtent à l'hydrogénation. L'hydrogène peut également être associé à l'azote et stocké sous forme d'ammoniac. Tous ces procédés de conversion, de stockage et de reconversion requièrent un apport considérable d'énergie. Qui plus est, des matériaux spéciaux sont parfois nécessaires. Ces deux enjeux expliquent les coûts élevés du stockage et du transport si on les compare aux hydrocarbures liquides ou gazeux. C'est pourquoi il paraît important de produire l'hydrogène autant que possible localement et au moment de la demande.

Le stockage sous la forme d'un gaz comprimé est aujourd'hui largement répandu, par exemple à 350 bars dans les réservoirs ou les piles à combustible de véhicules ou à 700 bars dans des réservoirs cylindriques en acier ou en matériau composite. Aujourd'hui, le stockage sous forme liquide à l'état d'hydrogène pur ou d'ammoniac est également techniquement faisable. Le stockage sous toutes les autres formes et par d'autres procédés est encore au stade de la recherche ou de la démonstration. Le procédé et la forme choisis pour le stockage de l'hydrogène vont dépendre, entre autres, de l'usage prévu, des quantités, de la durée du stockage et des distances à parcourir. La densité du stockage joue un rôle beaucoup plus important dans les applications mobiles que dans les applications stationnaires. Les réservoirs sont utilisés pour le stockage à court et moyen terme, tandis que les structures géologiques telles que des cavernes de sel semblent les plus prometteuses pour stocker des quantités importantes sur de longues périodes (stockage saisonnier). Des études plus poussées doivent être menées afin de déterminer si de telles structures sont disponibles en Suisse.

L'hydrogène peut être transporté sous différentes formes (gazeuse, liquide et en combinaison avec d'autres éléments) et par différents moyens (route, rail, mer, pipeline). Des camions sont déjà utilisés pour acheminer de petites quantités d'hydrogène sur de courtes distances (jusqu'à quelques centaines de kilomètres), tandis que les pipelines transportent des quantités plus importantes (d'hydrogène pur ou mélangé à du gaz naturel) sur de moyennes distances (jusqu'à quelques milliers de kilomètres). Le transport maritime, mieux adapté aux longues distances (plusieurs milliers de kilomètres au moins), est donc privilégié pour les futurs itinéraires intercontinentaux. Actuellement, le transport d'hydrogène par route se fait généralement dans des réservoirs sous la forme de gaz comprimé. La forme liquide sera en principe privilégiée pour le transport maritime, où des densités énergétiques supérieures sont nécessaires. De l'hydrogène peut également être injecté en faibles quantités dans le réseau de gaz naturel et mélangé à celui-ci. Les niveaux d'hydrogène admis dans le mélange gazeux varient d'un pays à l'autre, mais ils sont toujours de l'ordre d'un faible pourcentage du volume, notamment parce que les réseaux de distribution et les technologies de mesure et de compression ne sont pas encore entièrement testés pour des mélanges avec des taux d'hydrogène plus importants. Le réseau de gaz naturel existant peut en principe être utilisé pour le transport d'hydrogène pur, à condition toutefois que l'infrastructure soit mise à niveau et en prenant en compte des coûts de maintenance accrus.

Dans la pratique, les coûts du transport et du stockage de l'hydrogène dépendent essentiellement des quantités acheminées et stockées, des distances parcourues et de la durée du stockage. Généralement, surtout lorsque les coûts de production de l'hydrogène sont favorables, ces coûts peuvent représenter une part prépondérante du coût de l'hydrogène pour l'utilisateur final (de l'ordre de 50% ou plus). C'est en particulier le cas de l'hydrogène employé comme carburant automobile (pour l'heure exempté de l'impôt sur les huiles minérales) en raison de l'infrastructure requise. L'impact environnemental du transport et du stockage de l'hydrogène dépend principalement de la consommation d'énergie à chaque étape de la conversion.

Le stockage et le transport de l'hydrogène recèlent un certain nombre de défis. Les matériaux utilisés pour le stockage et le transport doivent résister aux contraintes et à la corrosion et limiter autant que possible les pertes de diffusion. Les densités énergétiques volumétrique et gravimétrique des solutions de stockage doivent encore être améliorées pour permettre un usage commercial. Il s'agira de prévenir toute contamination de l'hydrogène pendant le stockage et le transport pour éviter de coûteuses étapes de purification. Pour ces raisons, il est avantageux de produire l'hydrogène localement, au plus près du lieu de consommation.

L'hydrogène additionné de CO_2 peut être transformé en méthane de synthèse[22], pouvant servir de substitut du gaz naturel. Le méthane de synthèse, comme le gaz naturel, peut être aisément stocké et utilisé dans des chauffages, des moteurs et dans l'industrie. Ainsi, la production d'hydrogène par électrolyse de l'eau et sa conversion ultérieure en gaz naturel de synthèse permettent de compenser les décalages temporel et spatial entre la production d'électricité d'origine renouvelable et la demande en énergie. Néanmoins, cet avantage ne fait pas le poids face à l'inconvénient de processus relativement peu performants le long de la chaîne de production et d'utilisation. Les pertes d'énergie sont une des raisons pour lesquelles les coûts de production sont actuellement élevés, ceux-ci étant déterminés en premier lieu par l'investissement fourni pour l'électrolyse et la méthanation, les coûts d'électricité pour l'électrolyse et les coûts du CO_2. La source du CO_2, d'une part, influe sur les coûts et, d'autre part, pèse dans le bilan de gaz à effet de serre: seul le CO_2 capturé directement dans l'atmosphère ou provenant de la biomasse permet de boucler le cycle du CO_2 à brève échéance et contribue donc la neutralité climatique. Si le CO_2 provient de processus de combustion d'agents énergétiques fossiles, il est chimiquement lié au sein du gaz naturel synthétique (GNS), mais en fin de compte il demeure du CO_2 fossile pendant son utilisation, car il est simplement émis avec un décalage temporel. Ainsi, dans la perspective du système dans son ensemble, la réduction des émissions de CO_2 ne dépasse pas 50% lorsque le gaz naturel est remplacé par du GNS dont le CO_2 provient de sources fossiles. Pour la quantification des empreintes carbone spécifiques au produit, il convient de déterminer si les émissions de CO_2 provenant du recours au GNS sont rattachées à cette utilisation finale ou à la source d'émission originale.

La mise en place d'une économie à large échelle basée sur l'hydrogène soulèvera des questions, en plus de l'électrification directe d'applications appropriées: faut-il une production d'hydrogène indigène, ou l'hydrogène doit-il être importé? Dans quelle mesure ces deux options seront-elles complémentaires?[23] De nombreux facteurs entrent en jeu, notamment les quantités requises et les politiques (commerciales), mais aussi les potentiels et les coûts de production aux niveaux national et international. S'agissant des coûts, en l'absence d'analyses portant spécifiquement sur le sujet, il n'est pas encore possible de prévoir avec certitude qu'une importation provenant de pays offrant de meilleures conditions de production, notamment de l'électricité d'origine éolienne ou solaire à faible coût, sera plus avantageuse qu'une production en Suisse. Dans le scénario «ZÉRO base» des Perspectives énergétiques 2050+, on estime à 9 pétajoules (PJ) la quantité d'hydrogène renouvelable qui sera importée en 2050 (principalement de la région du Moyen-Orient et d'Afrique du Nord) contre 7 PJ de production indigène (Kirchner *et al.*, 2020). Selon des études réalisées en Allemagne et en Europe centrale, l'importation d'hydrogène serait plus avantageuse. Indépendamment du coût, le potentiel de production d'électricité à partir de sources renouvelables en Suisse étant limité, l'importation deviendra nécessaire si le recours à l'hydrogène vert est appelé à se généraliser. C'est d'ores et déjà le cas pour l'hydrogène bleu.

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[22] GNS est l'abréviation de *gaz naturel synthétique.*

[23] Cela s'applique également aux combustibles synthétiques basés sur l'hydrogène.

Stockage d'électricité

Le stockage d'électricité dans des installations stationnaires gagnera en importance à l'avenir, avec une hausse significative de la production d'électricité provenant de sources fluctuantes, telles que l'énergie éolienne ou solaire. Parmi les technologies les plus prometteuses pour le stockage de l'électricité figurent les accumulateurs, les centrales hydroélectriques à pompage-turbinage, le stockage d'air comprimé et la reconversion de l'hydrogène produit par électrolyse dans des piles à combustible. Les batteries lithium-ion sont aujourd'hui couramment utilisées dans l'électronique et, de plus en plus, dans le secteur de l'automobile. Elles se prêtent également au stockage d'électricité stationnaire, de préférence pour des applications décentralisées, autrement dit plutôt pour stocker de faibles quantités d'électricité pendant de courtes périodes de quelques jours au plus. D'autres types de batteries ne représentent à l'heure actuelle qu'une faible part de marché, ou sont au stade du développement. C'est par exemple le cas des batteries à flux redox et des batteries sodium-ion. Celles-ci sont exemptes de métaux tels que le cobalt, qui posent problème en raison de leur rareté et pour des motifs environnementaux. Les batteries à flux redox se prêtent également au stockage de plus grandes quantités d'électricité. Néanmoins, les alternatives actuelles aux batteries lithium-ion présentent toutes des inconvénients en matière d'efficacité du stockage d'électricité, de durée de vie, d'intensité du stockage d'énergie ou de coûts. Les batteries lithium-ion ont connu des progrès techniques significatifs ces dernières années et présentent en particulier une meilleure durabilité et une densité accrue de stockage d'énergie, ainsi qu'un recul des coûts de production. L'impact environnemental lié à la production a également été réduit grâce à une efficacité accrue déployée à une échelle de plus en plus grande. On peut partir du principe que les développements récents se poursuivront ces prochaines années. Qui plus est, des processus de recyclage industriel s'établiront. Cependant, on ne connaît pas encore en détail la charge environnementale de ces futurs processus de recyclage. Les coûts actuels des batteries lithium-ion stationnaires pour une utilisation centralisée par des infrastructures électriques sont estimés à environ 200 CHF/kWh et 160 CHF/kW. Ces coûts sont plus élevés pour la domotique (p. ex. batteries offrant de faibles capacités de stockage). D'ici à 2050, une baisse des coûts est attendue et ceux-ci devraient s'établir à environ 45 à 110 CHF/kWh et 35 à 90 CHF/kW. Les émissions de gaz à effet de serre liées à la production de batteries lithium-ion avoisinent actuellement 100 kg d'équivalent CO_2 par kWh de capacité de stockage. D'ici à 2050, ces émissions devraient baisser pour s'établir à environ 40 à 60 kg d'équivalent CO_2 par kWh de capacité de stockage pour les batteries stationnaires, voire moins si les chaînes d'approvisionnement en matériaux peuvent être décarbonées.

Des systèmes de stockage d'air comprimé sophistiqués utilisant de l'énergie thermique tirée du processus de stockage et ne nécessitant pas de combustibles fossiles se prêtent à un stockage à moyen terme (de quelques semaines au plus); ils sont actuellement au stade de développement. Ils sont prometteurs d'un point de vue technique et environnemental. Les centrales hydroélectriques à pompage-turbinage, qui se prêtent également au stockage d'électricité sur des périodes allant jusqu'à plusieurs semaines, sont efficaces et bien établies. Néanmoins, le potentiel pour la réalisation d'installations de pompage supplémentaires en Suisse est limité en raison de contraintes économiques et sociales. La reconversion de l'hydrogène stocké (généré par électrolyse) soit sous forme directe, soit par le biais de piles à combustible, ou sous la forme de GNS via des turbines à gaz ou des centrales de cogénération, peut servir au stockage d'électricité saisonnier. Le stockage direct de grandes quantités d'hydrogène requiert toutefois des structures géologiques adaptées, telles que des cavernes de sel. Or, des études approfondies doivent être menées afin de déterminer s'il en existe en Suisse. Même si les pertes d'énergie et les coûts sont globalement élevés, il n'existe à l'heure actuelle que peu d'alternatives pour stocker de l'électricité sur une période de plusieurs mois. Au mieux, on pourrait accroître les capacités des lacs en rehaussant des murs de barrages pour permettre un stockage saisonnier supplémentaire.

Les coûts et l'impact environnemental du stockage d'électricité dépendent généralement de l'usage qui en est fait et de l'origine de l'électricité stockée. Plus on compte de cycles de stockage contribuant à «amortir» les coûts de production et les impacts environnementaux, moins ils pèseront dans chaque unité d'électricité stockée.

Production d'électricité d'origine photovoltaïque et éolienne

La production d'électricité par des systèmes photovoltaïques est, et de loin, la ressource offrant le plus grand potentiel parmi toutes les nouvelles énergies renouvelables en Suisse. En outre, les démarches administratives et juridiques pour de nouvelles installations sont bien moins complexes que pour des centrales hydroélectriques ou des éoliennes, ce qui explique le taux relativement élevé d'installation de nouveaux modules photovoltaïques (PV) au cours de la dernière décennie. De plus, c'est dans cette catégorie que les coûts de production d'électricité ont le plus baissé dans le passé. Il est donc important de réexaminer régulièrement tant les potentiels que les coûts.

Selon ce rapport, le potentiel de production annuelle d'électricité avec des installations PV en toiture sur des bâtiments existants en Suisse est de l'ordre de 20 à 30 TWh. L'installation de modules PV hautement performants à l'avenir permettra d'augmenter ce potentiel de plusieurs térawattheures par an. D'autres estimations pour les installations en toiture atteignent 50 TWh/an, ce qui montre à quel point ces résultats dépendent des hypothèses retenues et de la méthodologie utilisée. Les différences s'expliquent principalement par la façon de prise en compte de facteurs qui restreignent l'installation de modules PV ou qui réduisent le rendement (structure des bâtiments, ombrage, etc.). Néanmoins, des travaux récents montrent que l'installation de systèmes PV dans des régions montagneuses peut être très judicieuse car elle permet de déplacer en partie le pic de production de l'été vers l'hiver. Les températures plus basses, la réflexion du rayonnement solaire sur le manteau neigeux et une radiation accrue due à l'altitude permettent un meilleur rendement des installations. En Suisse, les systèmes montés au sol recèlent un potentiel important: on estime que la surface disponible au sol est près de trois fois supérieure à celle disponible en toiture.

Le coût de la production d'électricité photovoltaïque par des systèmes en toiture a diminué en Suisse ces dernières années, surtout pour les grandes installations. Il est de l'ordre de 15 à 25 ct./kWh pour les petites installations, d'environ 10 ct./kWh pour les installations d'une capacité supérieure à 300 kW, voire inférieur pour les plus grandes installations d'une capacité dépassant 1 MW. D'ici à 2050, ces coûts devraient reculer pour s'établir entre 10 et 15 ct./kWh pour les petites installations et entre 4 et 6 ct./kWh pour les plus grandes. L'écart souvent évoqué dans les coûts de l'électricité photovoltaïque entre la Suisse et des pays tels que l'Allemagne ou les États-Unis s'explique, d'une part, par le prix des modules et les coûts d'installation, plus élevés en Suisse et, d'autre part, par les capacités comparativement faibles des systèmes chez nous. De plus, les différences dans les rendements annuels doivent être prises en compte dans les comparaisons de ce type. Les courbes récentes reflétant la relation entre les coûts de production d'électricité et les potentiels montrent que la majeure partie du potentiel PV s'inscrit aujourd'hui dans un ordre de prix de 15 à 25 ct./kWh. D'ici à 2035, cette catégorie de prix s'abaissera juste en deçà de 10 à 20 ct./kWh.

Des chiffres récents sont également disponibles pour les coûts et les potentiels de production d'électricité d'origine éolienne en Suisse. En comparaison avec des estimations antérieures, les potentiels progressent et les coûts diminuent, surtout si l'on considère les nouvelles éoliennes, qui peuvent produire beaucoup plus d'électricité à des vitesses de vent comparativement faibles, comme celles qui prévalent en Suisse. Avec ces nouvelles estimations, le potentiel écologique de l'éolien s'élève jusqu'à 30 TWh/an pour un coût de production de l'électricité de l'ordre de 7 à 13 ct./kWh avec des turbines actuellement au stade de planification, qui pourraient être construites en 2025, et de l'ordre de 5 à 8 ct./kWh en 2050. Le potentiel réalisable d'ici 2050 est estimé à 9 TWh par an, dont 6 TWh en hiver.

4 Data sheet – Hydrogen production

Table 4.1 provides a summary of hydrogen production costs and associated life-cycle greenhouse gas (GHG) emissions of different production pathways and their Technology Readiness Level (TRL). Specific numbers are supposed to represent average and representative results of own calculations; potential ranges of those are provided in the associated sections of the report. Ranges in this table represent literature data or a range of technology options with details provided in the associated sections. Data for CAPEX and OPEX of hydrogen production except for electrolysis is scarce, heterogenous and very case specific; therefore, these are not included in this table for pathways other than electrolysis, but only in the associated sub-sections of the report.

Table 4.1: Overview of hydrogen production costs and life-cycle GHG emissions (GWP100) for different production routes. n.a.: not available. Sources: a (Pinsky et al., 2020), b (Schneider et al., 2020), c (Bianchi and Bosio, 2021), d (Royal Society, 2018), e (Albrecht et al., 2015), f (Charnock et al., 2019), g (Antonini et al., 2021a), h (Bauer, Treyer, Antonini, Bergerson, Gazzani, Gençer, Gibbins, Mazzotti, S. McCoy, et al., 2022).

				TRL (2020)	**2020**	**2035**	**2050**
Electrolysis	Efficiency (system level)	% (LHV_{H2}/total energy input)*100	Alkaline	9 [a,f]	67	69	71
			PEM	7-9 [a,f]	61	69	73
			SOEC	5-7 [a,c,f]	82	86	90
	electricity consumption	kWh/kgH_2@40 bar	Alkaline		50	49	48
			PEM		55	49	46
			SOEC		43	41	39
	CAPEX	CHF/kW_{el}	Alkaline		988	676	462
			PEM		1182	592	297
			SOEC		2710	1256	582
	OPEX	CHF/kg H_2	all		depends on electricity price		
	H_2 production costs[7]	CHF/kgH_2@5Rp/kWh_{el}	Alkaline		3.6	3.3	3.1
			PEM		4.1	3.1	2.7
			SOEC		6.4	3.5	2.9
		CHF/kgH_2@15Rp/kWh_{el}	Alkaline		8.7	8.2	7.8
			PEM		9.6	8.2	7.4
			SOEC		10.7	7.6	6.9
	GHG emissions	kg CO_{2eq}/kg H_2 (hydro[1])	PEM		0.44	0.4	0.38
		kg CO_{2eq}/kg H_2 (PV[2])	PEM		2.9	2.6	2.4
		kg CO_{2eq}/kg H_2 (EUmix[3])	PEM		23.8	n.a.	n.a.
Methane reforming	H_2 production costs	CHF/kg H_2		9 [a,f]	1-2* ca. 5.5**	n.a.	n.a.
	GHG emissions[4]	kg CO_{2eq}/kg H_2			ca. 10.5-14[h,6]		
Methane reforming w/ CCS	H_2 production costs	CHF/kg H_2		7-8 [d,f]	1.5-3* ca. 6**	n.a.	n.a.
	GHG emissions	kg CO_{2eq}/kg H_2			2.5-9[6]		
Wood gasification	H_2 production costs	CHF/kg H_2		7-9 [e,f,g]	2.5-6.7	n.a.	n.a.
	GHG emissions	kg CO_{2eq}/kg H_2			1.3	n.a.	n.a.
Wood gasification w/ CCS	H_2 production costs	CHF/kg H_2		4-6 [d,g]	no data available		
	GHG emissions	kg CO_{2eq}/kg H_2			-9	n.a.	n.a.
Methane pyrolysis[5]	H_2 production costs	CHF/kg H_2		3-8 [b,f]	1.5-5.1*	n.a.	n.a.
	GHG emissions	kg CO_{2eq}/kg H_2			6-18	n.a.	n.a.

[1] ca. 6 g CO_{2eq}/kWh; [2] ca. 50 g CO_{2eq}/kWh; [3] ca. 420 g CO_{2eq}/kWh; [4] assumed to be constant over time, substantial change cannot be expected; [5] not yet commercialized; performance depends on technology and type of heat supply; [6] for CO_2 removal rates between 55% and 93% and methane emission rates of the NG supply chain of 0-4 (Bauer, Treyer, Antonini, Bergerson, Gazzani, Gençer, Gibbins, Mazzotti, S. McCoy, *et al.*, 2022); [7] average values for continuous operation. Cost ranges are provided in Table 8.17.

* At "historical" natural gas prices of 20-25 CHF/MWh.

** At current natural gas prices of around 100 CHF/MWh.

5 Data sheet – Electricity storage

Table 5.1 provides an overview about key characteristics as well as costs and life-cycle greenhouse gas emissions associated with the production of the storage units. Costs of electricity supply from these storage units depend on their operation, which is out of scope of this analysis and therefore not provided. More detailded information is provided in the associated sub-sections.

Table 5.1: Overview of electricity storage key characteristics, costs and life-cycle greenhouse gas emissions of their production. n.a.: not available or not assessed. Sources – a: (Charnock *et al.*, 2019), b: (Olympios *et al.*, 2021).

		TRL (2020)			**2020**	**2035**	**2050**
Batteries	Li-ion	9	round-trip efficiency	%	85-95		
			lifetime	years	10-15		
			CAPEX	CHF/kW	160/1600[2]	80/800[2]	60/600[2]
				CHF/kWh	200	100	75
			OPEX	CHF/kW/a	0/10[2]		
			GHG emissions	kg CO_{2eq}/kWh[1]	ca. 100	75	50
	Lead-acid	9	round-trip efficiency	%	70-80		
			lifetime	years	ca. 10		
			CAPEX	CHF/kW	250-400 / 1000-1500[2]	n.a.	n.a.
				CHF/kWh	100-500	n.a.	n.a.
			OPEX	CHF/kW/a	0/10[2]		
			GHG emissions	kg CO_{2eq}/kWh[1]	50-90	n.a.	n.a.
	Vanadium-Redox-Flow	7 [a]	round-trip efficiency	%	60-70		
			lifetime	years	ca. 20		
			CAPEX	CHF/kW	1000-1600	n.a.	n.a.
				CHF/kWh	300-800	n.a.	n.a.
			OPEX	CHF/kW/a	40	n.a.	n.a.
			GHG emissions	kg CO_{2eq}/kWh[1]	ca. 160	n.a.	n.a.
Compressed Air Energy Storage	AA-CAES	5-6 [b]	round-trip efficiency	%	60-75		
			lifetime	years	20-60		
			CAPEX	CHF/kW	1000-1200	n.a.	n.a.
				CHF/kWh	200-300	n.a.	n.a.
			OPEX	$\%_{CAPEX}$	2.5	n.a.	n.a.
			GHG emissions	kg CO_{2eq}/kWh	small: in the order of few grams per kWh delivered		
Pumped Hydropower	Alpine	9	round-trip efficiency	%	70-85		
			lifetime	years	40-120		
			CAPEX	CHF/kW	2150[3] (500-5000)	n.a.	n.a.
				CHF/kWh$_{\text{storage capacity}}$	10-100	n.a.	n.a.
			OPEX	CHF/kW/a	2-10	n.a.	n.a.
			GHG emissions	kg CO_{2eq}/kWh	small: in the order of few grams per kWh delivered		

[1] per kWh storage capacity; [2] large-scale/small-scale; [3] average based on two recent large projects in Switzerland.

6 Preface and introduction

6.1 Goal and scope

This report provides an overview of technologies relevant for hydrogen production, transmission, storage, and use for re-electrification as well as of selected electricity storage technologies and their associated costs and life-cycle environmental burdens (focusing on greenhouse gas (GHG) emissions) with a time horizon of up to the year 2050. In addition and as a follow-up of previous analysis (Bauer *et al.*, 2019), costs and potentials of roof-top solar photovoltaic (PV) electricity generation as well as wind power in Switzerland are addressed in order to cover the quick development in the PV and latest findings regarding electricity generation potentials. The same holds true for wind power, for which the update is largely based on inputs from experts from SFOE. Collected data and information on the technology level are supposed to represent a basis for further work, e.g., energy system modeling, analyzing the potential role of both hydrogen and electricity storage within a decarbonized Swiss energy system and economy.

This overview serves as an input to the technology monitoring activities of the Swiss Federal Office of Energy (SFOE), who has commissioned this work.

The report has been published in the first half of 2022. To a large extent, it represents state-of knowledge and published literature per June 2021. After that, the work has been reviewed by the Federal administration and revised accordingly based on their feedback, but major updates have not been performed.

6.2 Acknowledgement

The authors thank the Swiss Federal Office of Energy (SFOE) and PSI’s Energy System Integration platform for funding this work. In particular, we thank Lukas Gutzwiller from SFOE for his accurate project management and the coordination of SFOE activities supporting this research. Content related inputs from Lukas Gutzwiller, Stefan Oberholzer, Olivier Baillifard, Markus Geissmann, Guido Federer and Wieland Hintz, and feedback regarding draft versions of this report were very much appreciated.

7 Methodology

7.1 Hydrogen: key parameters and characteristics

Table 7.1 provides an overview about conversion factors and key parameters of hydrogen. These figures are applied throughout this study.

Table 7.1: Hydrogen – properties, characteristics and conversion factors

Melting point	13.99 -259.16	°K °C
Boiling point	20.27 -252.88	°K °C
Density gas (at 0°C and 1bar) liquid	0.08988 71	g/liter g/liter
Lower heating value (LHV)	120.0 33.3 10.8	MJ/kg kWh/kg MJ/m^3
Higher heating value (HHV)	141.8 39.4 12.7	MJ/kg kWh/kg MJ/m^3

7.2 Temporal and geographical scope

The techno-economic and environmental assessment of hydrogen and electricity storage technologies includes an evaluation of both current and future technologies with a time horizon of up to the year 2050. Thus, the expected development of technologies as well as their costs and environmental burdens within the next three decades is reflected.

The evaluation focuses on Switzerland, taking into account primarily national boundary conditions wherever relevant. However, the European environment as well as global market developments and regulations are also addressed, since Switzerland is a small market and developments of technologies and their costs will primarily depend on the European and global development.

7.3 Economic assessment

7.3.1 Hydrogen

The economic assessment consists of a step-wise approach to determine hydrogen costs of various hydrogen production pathways. This step-wise approach is categorized into a literature review, definition of main uncertainties and key parameters, definition of performance indicators and the calculation of country-specific electrolysis based hydrogen costs for Switzerland. Other production pathways are evaluated based on literature only.

7.3.1.1 Literature review

A literature review is conducted to determine the economic potential of the hydrogen supply chain for the current situation (year 2020) – and future situations (up to year 2050).

Both scientific articles and 'grey' literature are included, such as hydrogen reports from the (International Energy Agency, 2019) and (IRENA, 2019). Different search queries are used in Scopus, Google Scholar and search engines on the web. The literature search has been executed from November 2019 to March 2021, where we give preference to the most recent literature. Literature sources before 2015 have been excluded, since hydrogen production technologies are rapidly evolving and significant costs improvements have been made in recent decades (International Energy Agency, 2019).

An inflation rate is applied for some literature reviews on costs. However, the inflation rate for Switzerland turns out to be relatively stable – sometimes even negative – with a negligible inflation over the past five years (BFS, 2020). Hence, we decided to do not apply an inflation factor in this cost assessment, because the effect would be way below the intrinsic uncertainties in cost calculations. The following conversion factors – see Table 7.2 - are used for the conversion of foreign currencies to Swiss Francs (CHF), which are based on the average currency exchange rate over the past 5 years.

Table 7.2: Conversion factors used in the cost assessments, based on rounded average conversion factors – using 2 significant digits - from the past 5 years (OFX, 2020).

Conversion factors
1 CHF = 1 USD
1 CHF = 0.90 EUR
1 CHF = 1.4 AUD
1 CHF = 0.79 GBP

7.3.1.2 Key parameters

Main uncertainties and key parameters – *i.e.* the parameters that mainly influence the life-cycle costs – are determined based on our literature review. Further, a cost harmonization is performed to determine the most realistic and reliable costs for different hydrogen pathways. Next, economic performance indicators are quantified to compare hydrogen electrolysis pathways.

7.3.1.3 Country-specific hydrogen cost calculations

Country-specific results are calculated for Switzerland. For our own cost calculations, the primary focus is on electrolysis, since it is perceived as an environmentally friendly future option to store large amounts of intermittent (renewable) electricity. Policy incentives and financial benefits – specified for Switzerland – are not included, since these assumptions could hamper both the interpretation of the results as well as the implementation of recommendations (Christensen, 2020).

The economic results are structured per hydrogen production technology and therefore we first present the performance indicators in the methodology section. Cost parameters are adopted from different literature sources.

7.3.1.4 Economic performance indicators and calculations

Economic performance indicators are required to compare hydrogen production pathways. Herein, we use the Levelized Cost of Hydrogen (LCoH) as the main performance indicator. This indicator has been widely used in the scientific community and it therefore improves the comparability of competing hydrogen technologies and production pathways (Kuckshinrichs, Ketelaer and Koj, 2017). The LCoH includes all life-cycle costs – including capital, operation and end-of-life costs over the lifetime of a hydrogen plant considering the time-value of money. The LCoH can be determined with the following equation (Minutillo *et al.*, 2020), considering the annualized investment costs ($C_{inv,a}$), annualized replacements costs ($C_{rep,a}$), Operation and Maintenance (O&M) costs ($C_{O\&M}$) and possible revenues (R_a) from electricity generators, for example from selling oxygen or excess electricity to an electricity grid provider (Minutillo *et al.*, 2020):

$$LCoH = \frac{C_{inv,a} + C_{rep,a} + C_{O\&M} - R_a}{M_{H_2,annual}},$$

where $M_{H_2,annual}$ is the amount of hydrogen produced per year.

The annualized investment costs includes the total capital investment considering an interest rate (*r*) over the lifetime of the plant (*n*) – *i.e.* using the capital recovery factor - and can be calculated as follows (Minutillo *et al.*, 2020):

$$C_{inv,a} = \frac{r \cdot (1+r)^n}{(1+r)^n - 1} \cdot C_{inv}.$$

The electrolysis based hydrogen system consists of several system components – such as an electrolyzer and compressor – with different lifetimes. Replacement of system components – accounting for different lifetimes – is considered when the lifetime of a system component is smaller than the lifetime of the hydrogen plant. For the sake of simplicity, no economic compensation is considered for components with extended lifetimes longer than the system lifetime. The annualized replacement costs of system components can be calculated with the following equation (Minutillo *et al.*, 2020):

$$C_{rep,a} = \frac{r \cdot (1+r)^n}{(1+r)^n - 1} \cdot \frac{C_{re}}{(1+r)^t},$$

where C_{rep} is the replacement cost for the technology replacement in replacement year t.

First, the capital expenditures are determined and include costs for the electrolyzer, balance of system, piping and the compression unit. Most cost parameters are obtained from a recent work of (Christensen, 2020), since this work is comprehensive and showed the importance to include all costs needed for the hydrogen production system; such as the balance of system, piping and the compression unit.

Hence, the system boundaries of this cost assessment includes hydrogen production and compression (from operating pressure to 40 bar (Christensen, 2020)) to be ready to be fed into a storage or distribution network. We assume that PEM is a high-pressure electrolyzer unit and it thereby avoids the installation of a hydrogen compressor unit in this system configuration. Three electrolyzer technologies are considered in the country-specific cost assessment: Alkaline electrolyzers, PEM and SOEC. Further, three cost scenarios are considered with different assumptions for the CAPEX, efficiency and CAPEX annual improvement of the electrolyzer; minimum (*min*), average (*avg*) and maximum (*max*).

Further, future efficiency, CAPEX (of electrolyzer and PV) and lifetime improvements are considered, and are specified per electrolyzer technology. These future improvements are linearly scaled up to year 2050, except for the CAPEX improvement of the electrolyzer since an annual percentage improvement is expected as more realistic compared to a linear cost improvement (Glenk and Reichelstein, 2019). The hydrogen plant lifetime is assumed to be 30 years and a depreciation rate of 5% has been applied. For simplicity, a generic 50% of the CAPEX of the initial CAPEX rate is applied for replacement costs of the electrolyzer (Brynolf *et al.*, 2018; Christensen, 2020), hence, specific technological improvements in a replacement year are not considered. Besides, additional revenue of selling oxygen – generated as by-product of water electrolysis – is not considered, due to the uncertain market and cost potential of oxygen. Further, additional heat – required as high temperature heat for SOEC – is not included in the electrical efficiency for SOEC, and is therefore assumed to come from cost- and burden free heat. For the sake of simplicity, CO_2 emission prices and an efficiency decrease, due to partial electrolyzer load, are not considered in this analysis.

Table 7.3 provides and overview regarding key parameters.

Table 7.3: Cost and other key parameters used for water electrolysis based hydrogen production. Min, avg and max refer to minimum, average and maximum performance values of cost and performance parameters. Note that min and max do not always refer to the highest number but to the corresponding cost scenario, for example a higher efficiency corresponds to the low cost scenario (min). CAPEX of electrolyzer includes the stack and power supply unit.

Performance parameter	Alkaline	PEM	SOEC	unit	Source
Electrolyzer					
CAPEX (min)	571	385	677	CHF/kW$_{el}$	(Christensen, 2020)
CAPEX (avg)	988	1182	2710[24]	CHF/kW$_{el}$	(International Energy Agency, 2019; Christensen, 2020; PIK, 2021)
CAPEX (max)	1268	2068	3500[24]	CHF/kW$_{el}$	
CAPEX improvement (max)	0.5	2.5	3	%/year	-2% from avg. scenario
CAPEX improvement (avg)	2.5	4.5	5	%/year	Data from (PIK, 2021), and validated with results from (Glenk and Reichelstein, 2019)
CAPEX improvement (min)	4.5	6.5	7	%/year	+2% from avg. scenario
OPEX	50	50	50	CHF/kW$_{el}$	(Christensen, 2020)
Lifetime (2020)	75000	60000	20000	Hours	(Christensen, 2020)
Lifetime (2050)	125000	125000	87500	Hours	(Christensen, 2020)
Efficiency (2020, min, LHV)	58	58	81	%	Minimum of (Christensen, 2020) and q1 of (PIK, 2021)
Efficiency (2020, avg, LHV)	67	61	82	%	Average of (Christensen, 2020; PIK, 2021)
Efficiency (2020, max, LHV)	70	65	83	%	Maximum of (Christensen, 2020) and q3 of (PIK, 2021)
Efficiency (2050, min, LHV)	61	70	88	%	Minimum of (Christensen, 2020) and q1 of (PIK, 2021)
Efficiency (2050, avg, LHV)	71	73	90	%	Average of (Christensen, 2020; PIK, 2021)
Efficiency (2050, max, LHV)	80	74	90	%	Maximum of (Christensen, 2020) and q3 of (PIK, 2021)
BoS investment	50	50	50	CHF/kW$_{el}$	(Christensen, 2020)
Electricity consumption (@100% efficient electrolyzer)	0.03	0.03	0.03	kg H$_2$/kWh	(Christensen, 2020)
Electricity consumption (system) (2020, avg)	50	55	41	kWh/kg H$_2$	Calculated
Water cost	0.08	0.08	0.08	CHF/kg H$_2$	(Christensen, 2020)
Output pressure electrolyzer	18	40	1	bar	(Christensen, 2020) for Alkaline and PEM, (Jensen *et al.*, 2016; Riedel *et al.*, 2020) for SOEC
Compression (to 40 bar)					
CAPEX	Section 7.3.1.3; 'Compression'			CHF	(Christensen, 2020)
OPEX	8	n.a.	8	%	(Minutillo *et al.*, 2020)
Electricity req.	~0.41	0	~2.35	kWh/kg H$_2$	Calculated, from output pressure to 40 bar
Lifetime	10	10	10	years	(Minutillo *et al.*, 2020)
PV					
CAPEX (2020)	1000	1000	1000	CHF/kW$_p$	Section 20.3, for large PV systems
CAPEX (2050)	500	500	500	CHF/kW$_p$	(Bauer *et al.*, 2017)
OPEX	0.02	0.02	0.02	CHF/kWh	Section 20.3, for large PV systems
Lifetime	30	30	30	years	Section 20.3
General					
Plant lifetime	30	30	30	years	(Christensen, 2020)
Depreciation rate	5	5	5	%	(Christensen, 2020)

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[24] The electrolyzer investment of SOEC (avg) from (Christensen, 2020) is low compared to other literature. Hence, ~2710 CHF/kW$_e$ (avg) has been assumed based on cost data from the (International Energy Agency, 2019) and https://h2foroveralls.shinyapps.io/H2Dash/ (26.01.2021) (~2710 CHF/kW$_e$,). 3500 CHF/kW$_e$ has been used as own estimation for a worst case scenario regarding SOEC.

Compression

The electricity consumption for compression can be determined with the following equation (Christensen, 2020):

$$P = Q\left(\frac{1}{24 \cdot 3600}\right)\frac{ZTR}{M_{H_2}\eta}\,\frac{N\gamma}{(\gamma-1)}\left(\left(\frac{P_{out}}{P_{in}}\right)^{\frac{(\gamma-1)}{N\gamma}} - 1\right),$$

where *P* is the power requirement for compression (kW), *Q* is the mass flow rate of hydrogen (kg/day), *Z* is the hydrogen compressibility factor (1.03198), *T* is the inlet temperature of hydrogen in the compressor (310.95 K), *R* is the ideal gas constant (8.314 $\frac{J}{mol \cdot K}$), M_{H_2} is the molecular mass of hydrogen (2.15 g/mol), η is the efficiency of the compressor (75%), *N* is the number of compressor stages (2 stages considered), γ is the ratio of specific heat (or adiabatic index) (1.4), P_{out} is the outlet pressure and P_{in} is the inlet pressure. The total electrical power requirement is calculated by considering an overall motor efficiency of 95% (η_{motor}) (Christensen, 2020). The compressor size (P_{comp}) can be determined by oversizing the compressor with 10% (η_{motor}) (Christensen, 2020).

The following cost relation has been applied to determine the investment costs of the compression unit (Christensen, 2020):

$$C_{compressor} = 1.19\ \cdot 19207\ \cdot\ P_{comp}^{0.6089},$$

where $C_{compressor}$ is the CAPEX of the compressor (CHF) and P_{comp} is the rated power of the compressor.

Additional costs for and piping is indicated as a generic amount of 50 CHF/kW$_{el}$ (Christensen, 2020), without considering future cost improvements. This value is added to the electrolyzer investment cost per kW$_{el}$.

System configurations

Different system configurations are considered for electrolysis based hydrogen production with an average daily hydrogen production of 200 kg hydrogen/day (a 330-480 kW$_e$ electrolyzer in a full grid scenario); a 'medium' capacity hydrogen production system (Minutillo *et al.*, 2020).

Photovoltaics (PV) electricity is considered as (main) electricity source for (self-)generated (renewable) electricity, since PV electricity is one of the cheapest and well-developed renewable electricity sources nowadays, and installation and system costs are expected to decrease even further into the coming decades, see Section 20.3. Besides, PV generation systems can be easily installed, while wind energy is not considered due to comparably low capacity factors in Switzerland. The following system configurations are considered:

- Full Grid: electricity consumption of the hydrogen production system is provided by the electricity grid, assuming a capacity factor of 100%. A generic electricity price of 15 Rp./kWh is assumed, based on Swiss data applicable for larger power consumers in the Swiss electricity system[25] (Eidgenössische Elektrizitätskommission ElCom, 2021). A sensitivity analysis is conducted on different electricity prices: 20 Rp./kWh, 10 Rp./kWh and 5 Rp./kWh (*i.e.* representing the day-ahead market electricity price).
- Full Renewable: electricity consumption is entirely supplied by PV electricity (100%). Hence, no grid charges or grid fees apply to this scenario. However, the capacity factor of the hydrogen production system corresponds to the capacity factor of the renewable electricity generator. The capacity factor for the PV system is obtained from annual (hourly) data of PV

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[25] https://www.strompreis.elcom.admin.ch/Map/ShowSwissMap.aspx: estimation for year 2021 based on category H6 and H7, total price for standard product.

GIS[26] resulting in a capacity factor of ~0.14 applicable for Bern (Switzerland) (Huld, Müller and Gambardella, 2012). For simplicity, the electrolyzer and PV system are assumed to have the same power size, to ensure that the maximum PV power can be used by the electrolyzer. Note that this results in an oversized electrolyzer. For the sake of simplicity, annual improvements in the capacity factor and a reduction in PV efficiency are excluded in this cost analysis. Only Alkaline and PEM electrolyzers are considered in the full renewable system lay-out. The latter electrolyzers show quick response times and sufficient flexibility for fluctuations of renewable electricity (IRENA, 2020), while the flexibility of SOEC is limited and their start-up time comparably long (up to 0.2h) (Vad Mathiesen *et al.*, 2013).

In reality, many other configurations are possible: electrolyzers can be coupled with run-of-river power plants and convert their electricity production at times with low electricity market prices. They can also be coupled with wind turbines, which exhibit higher load factors than PV installations. The sizing of electrolyzers can be optimized from an economic perspective, when electricity not used for electrolysis can be fed into the grid. And electrolyzers using grid-electricity can be operated depending on electricity price profiles to reach an economic optimum. Analyzing such cases in detail and performing cost-optimization is beyond the scope of this report.

7.3.2 Electricity storage

For electricity storage, the same approach has been used as with the hydrogen assessment. However, only step one and two are performed. Economic assessments and reports of electricity storage are widely available and have been recently published. Hence, a literature review has been conducted and key parameters and uncertainties were identified.

7.4 Environmental assessment – impacts on climate change

Environmental burdens of hydrogen production, transport, storage, and re-electrification as well as electricity storage are evaluated from a life-cycle perspective applying Life Cycle Assessment (LCA) (ISO, 2006a, 2006b). Thus, entire material and energy supply chains are taken into account. Since the environmental burdens of electricity storage strongly depend on the application (i.e. use case) of storage technologies, the focus here is on manufacturing related burdens, and not on the use phase. This evaluation focuses on Greenhouse Gas (GHG) emissions as main environmental indicator representing impacts on climate change and quantified using Global Warming Potentials with a time horizon of 100 years according to IPCC (Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, 2013).

Quantification of life cycle GHG emissions builds mainly upon recently published literature as well as own analysis. Prospective quantifications are hardly available and therefore, estimations of emissions of future technologies often rely on expert judgement, mainly supposed to represent expected technology development, but not reflecting changes in production processes over time in detail.

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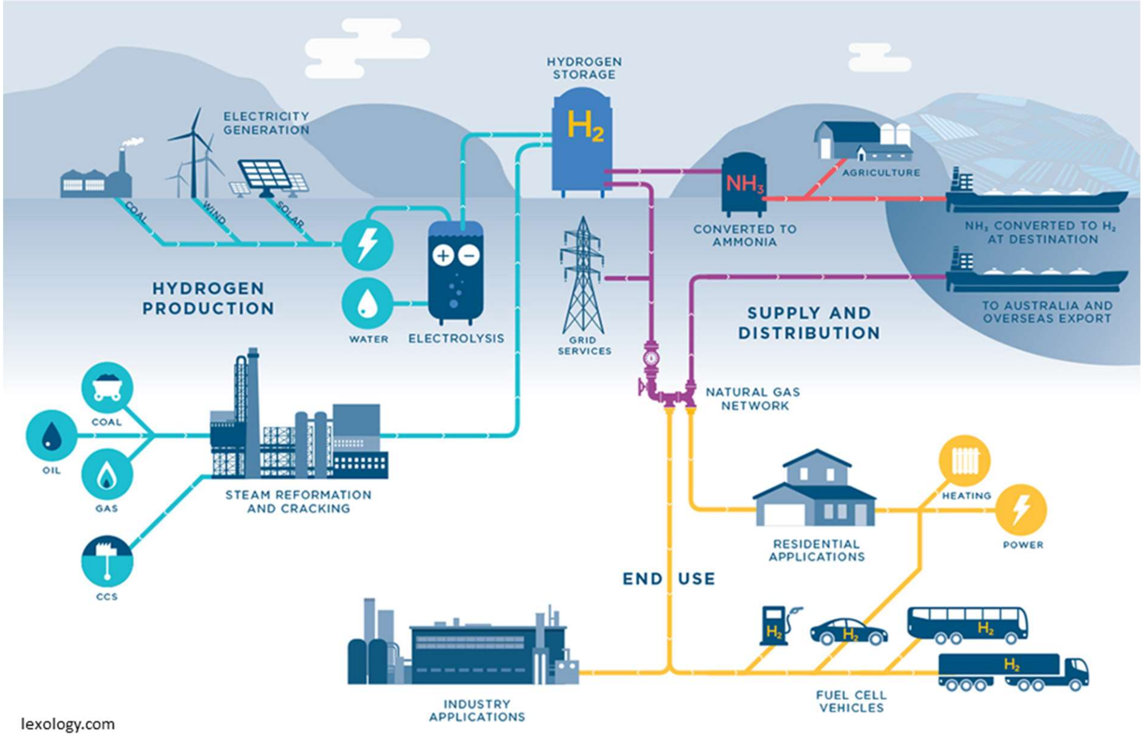
[26] https://re.jrc.ec.europa.eu/pvg_tools/en/#PVP: annual hourly PV data per 1 kW_p has been obtained from PV GIS for year 2015 using the PVGIS-SARAH database, considering Crystalline silicon, standard configurations and applying an optimized slope and azimuth.

Hydrogen



lexology.com

8 Hydrogen production

Hydrogen can be produced with a large portfolio of production processes based on a variety of fuels, energy carriers and feedstock materials, as visualized in Figure 8.1 (potential application of carbon capture and storage (CCS) is not shown). In this report, techno-economic and environmental assessment of production processes will focus on a) electrolysis, b) natural gas and biomethane reforming (including CCS), and c) biomass gasification (including CCS) as most promising options for large-scale and sustainable roll-out – which is in line with both the Swiss energy perspectives and hydrogen strategies of the European Union as well as Germany (European Commission, 2020; Kirchner *et al.*, 2020) (Bundesministerium für Wirtschaft und Energie (BMWi), 2020). Additional process options for biomass conversion are described and comparatively evaluated in detail in (Lepage *et al.*, 2021).

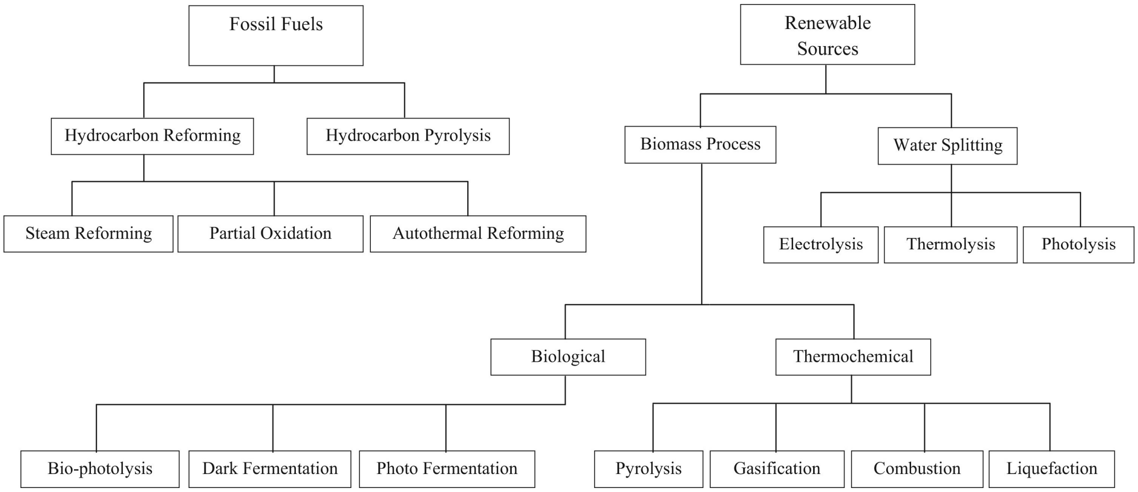


Figure 8.1: Overview of hydrogen production processes (Nikolaidis and Poullikkas, 2017).

8.1 Technologies

Hydrogen production refers to the generation of gaseous hydrogen at various purities and pressures. As of 2020, roughly 95% of the worldwide hydrogen production is based on fossil fuels, namely via reforming of natural gas (48%), partial oxidation of methane, oil-based processes (30%), and coal gasification (18%) (Voldsund, Jordal and Anantharaman, 2016). Today, hydrogen is mostly used in the refining and ammonia production sectors. However, hydrogen can be produced from a variety of feedstock materials and by many processes, and is a core element for decarbonization of the energy system and thus may be used as energy carrier in the power, heating, and mobility sector as well as for many industrial applications (European Commission, 2020; Kirchner *et al.*, 2020).

Depending on the production technology and feedstock, hydrogen is often assigned with specific colors (Figure 8.2): “Grey hydrogen” is generated from fossil fuels without Carbon Capture and Storage (CCS), while the addition of CCS will turn it into “blue hydrogen”. “Green hydrogen” refers to the use of (excess) renewable electricity to power water electrolysis. “Turquoise hydrogen” is produced from thermal splitting of methane, but nowadays doesn’t seem to be likely to become a major player. This assignment of colors should not distract from the fact that the carbon intensity of all electricity-based, fossil-based and biomass-based hydrogen depends largely on the exact technology settings and feedstock or electricity source used, so that direct correlations between impacts on climate change colors are not always given. It is rather recommended to assess the hydrogen production designs individually.

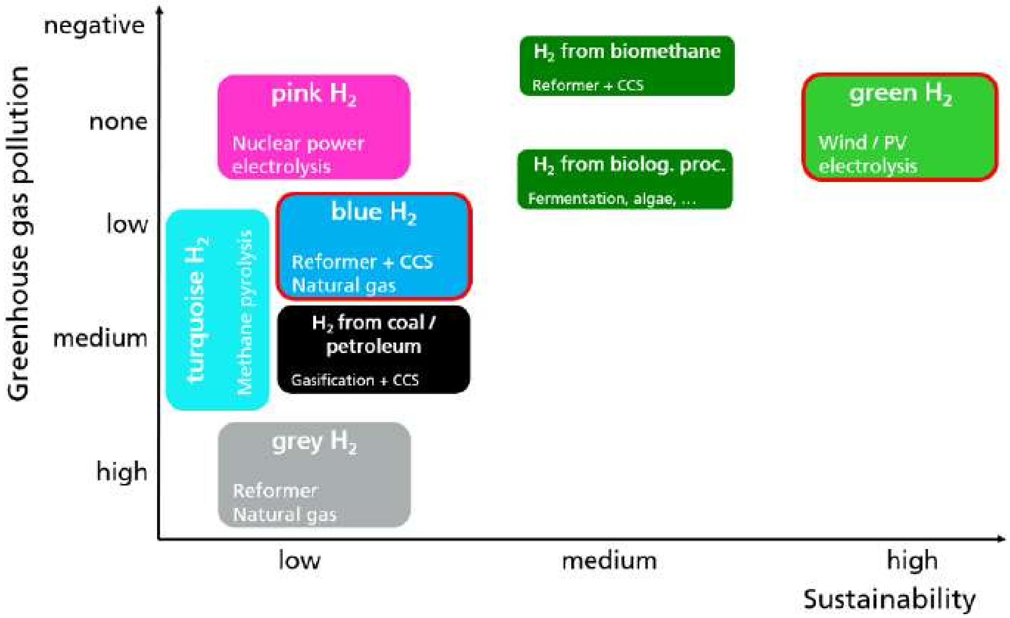


Figure 8.2: Sustainability and greenhouse gas emission intensity of various hydrogen production pathways, expressed in colors. Taken from (Gerhardt *et al.*, 2020) Biomethane can be generated from a range of biogenic feedstock options and pathways (Antonini *et al.*, 2020a; Zhang *et al.*, 2020)**. Electricity for green hydrogen production could also be supplied from waste incineration plants; equipped with CCS, the biogenic waste fraction would deliver negative CO_2 emissions.**

Further, it is important to consider that the requirements for hydrogen purity and pressure vary with the intended application of the hydrogen (e.g. in ammonia production, combustion, use in fuel cells, use in refineries), and the resulting technology and energy demands may have an important influence on the techno-economic-environmental performance of specific technologies. Table 8.1 provides an overview regarding required hydrogen purity levels for different applications (Dawood, Anda and Shafiullah, 2020). Purity of the hydrogen must be high when used in fuel cells, but may be lower for other applications (Walker, Madden and Tahir, 2018). Details regarding contamination by single species, measurement procedures, etc. are available in the corresponding ISO norm ISO 14687:2019.[27]

Table 8.1: Fuel hydrogen types, applications and associated purity levels (Dawood, Anda and Shafiullah, 2020).

Hydrogen type	Purity level [%], expressed as minimum mole fraction	Application
Gaseous	98.0	Internal combustion engines for transport Residential or commercial applications (All applications except Fuel Cells)
	99.9	Industrial fuel (power generation or heat energy source)
	99.995	Aircraft and space-vehicle ground support systems
	99.97	Fuel Cells for vehicles
Liquid	99.995	Aircraft and space-vehicle on board propulsion systems and electrical energy requirements Land vehicles except Fuel Cells
	99.97	Fuel Cells for transportation
Slush[28]	99.995	Aircraft and space-vehicle on board propulsion

It is a clear strategy of the European Union to include a hydrogen economy into the European Green Deal Strategy for a carbon-neutral Europe by 2050 (European Commission, 2020). As such, only low-

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[27] https://www.iso.org/obp/ui/#iso:std:iso:14687:ed-1:v1:en (22.6.2021).

[28] Slush hydrogen is a combination of liquid hydrogen and solid hydrogen at the triple point with a lower temperature and a higher density than liquid hydrogen. It is commonly formed by repeating a freeze-thaw process (https://slush-ish-english.com/technology11.html).

carbon hydrogen production pathways shall be acceptable. In this context, it is important to consider also geopolitical and energy resource related aspects. Large European countries such as Germany, the UK, and France, but also Switzerland, are unlikely to be able to cover their demand for green hydrogen with domestic resources, if low-carbon hydrogen would be a core component of net-zero CO_2 economies (Kirchner *et al.*, 2020; Panos *et al.*, 2021). On the other hand, few regions with high resource potential, but comparatively low demand such as Southern America, Middle East and North Africa and Australia, could act as hydrogen exporters (Figure 8.3).

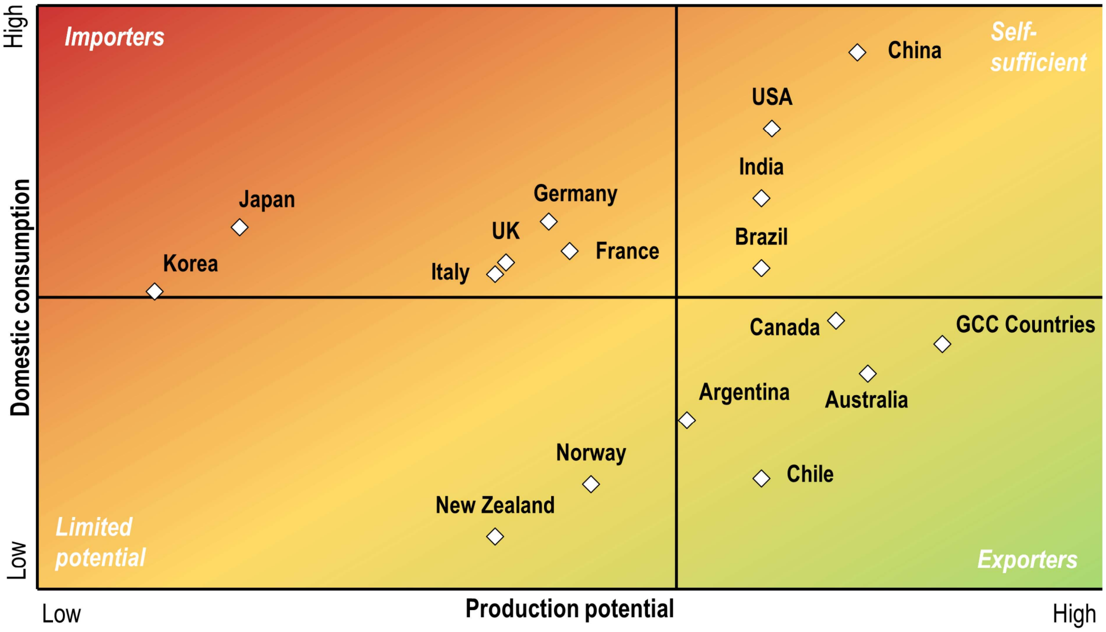


Figure 8.3: Hydrogen domestic consumption and green production potential (Noussan et al., 2021).

Depending on the production technology, hydrogen is produced at different pressure levels – typically between 10 and 40 bar. These have to be adjusted to the subsequent fate of the hydrogen, i.e. either direct use in a process, storage, transportation, or distribution. Often, compression will be needed (Staffell *et al.*, 2019). As per definition, we include the energy-intensive compression step into the assessment of hydrogen production up to a level of 40 bar, to provide a product which is fully ready for further use at the production plant's doors. Potential further compression would be part of further conversion steps.

Hydrogen production pathways differ in terms of efficiencies (i.e. energy content of hydrogen vs. energy content of feedstock/energy carrier converted). Table 8.2 provides a basic overview.

Table 8.2: Conversion efficiencies of different hydrogen production processes today (Staffell et al., 2019; Antonini et al., 2020a, 2021a).

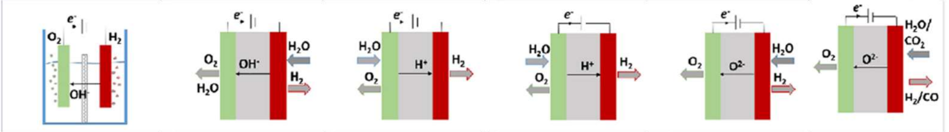
	Efficiency (LHV)
Methane reforming	72% (65-78%)
Electrolysis	61% (51-70%)
Coal gasification	56% (45-65%)
Biomass gasification	55% (44-70%)

8.1.1 Electrolysis

Water electrolysis uses electricity to split water molecules into hydrogen and oxygen. The process is thus an example for a power-to-gas (P2G) chain, and turns (excess) electrical energy into chemical energy which can be stored, or used for coupling of different sectors within the energy system. There exist three technologies: Alkaline electrolysis, polymer-electrolyte membrane (PEM) electrolysis, and solid oxide electrolysis (SOE). These differ by their design, operating temperature and choice of liquid or solid electrolyte (i.e. type of ionic agent (OH^-, H^+, O^{2-})). Table 8.3 gives an overview of the major electrolysis pathways used or developed today and their characteristics.

Continuous operation of AE and PEM, e.g. powered by hydropower, are well-developed for various sizes up to large capacities of 200 MW_e. Flexible operation powered by intermittent renewables is more challenging for large units, but already operational in the 0-1 MW_e size range. While PEMECs are able to deal with rapid load changes, their system efficiency suffers compared to large SOEC systems. The latter would however suffer from thermal stress when being shut down completely (Levels *et al.*, 2019).

Table 8.3: Operating schemes, temperature range, and main KPI of alkaline electrolysis, proton-exchange membrane (PEM) electrolysis, and solid oxide water electrolysis. Specifics of the three major electrolysis pathways used or developed today. Adapted and extended from (Sapountzi et al., 2017) with information from (Walker, Madden and Tahir, 2018; Levels et al., 2019). In the meantime, PEM can be considered as commercial technology with installations worldwide.

	Low Temperature Electrolysis			High Temperature Electrolysis		
	Alkaline (OH^-) electrolysis		Proton Exchange (H^+) electroysis		Oxygen ion (O^{2-}) electrolysis	
	Liquid	Polymer Electrolyte Membrane		Solide Oxide Electrolysis (SOE)		
	Conventional	Solid alkaline	H^+ - PEM	H^+ - SOE	O^{2-} - SOE	Co-electrolysis
Operation principles						
Operating Temperature	20-80 °C	20-200°C	20-200°C	500-1000°C	500-1000°C	750-900°C
Electrolyte	Liquid	Solid (polymeric)	Solid (polymeric)	Solid (ceramic)	Solid (ceramic)	Solid (ceramic)
Efficiency	59-70%		65-82%	Up to 100%	Up to 100%	-
Hydrogen purity	99.5-99.9 operation dependent, *	99.5-99.9 operation dependent, *		>99.5%, *>99.995% also possible with DeOxo drier		
Typical output pressure	20 – 30 bar, with research aiming to > 60 bar	20 – 30 bar, with research aiming to > 80 bar				
Minimum partial load	5 – 40%	0 – 10%		3%		
Maintenance requirements	<20 h/a	< 200 h/a		No data		
Applicability / Operational experience (TRL)	Commercial for >80 years	Laboratory scale	Near-term commercialisation	Laboratory scale	Demonstration	Laboratory scale
TRL	9	8		5		
Advantages	Low capital cost, relatively stable, mature technology	Combination of alkaline and H+-PEM electrolysis	Compact design, fast response/start-up => open for flexible load, high-purity H2	Enhanced kinetics, thermodynamics: lower energy demands, low capital cost		+ direct production of syngas
Disadvantage	Corrosive electrolyte, gas permeation, slow dynamics	Low OH- conductivity in polmeric membranes	High cost polymeric membranes; acidic: noble metals	Mechanically unstable electrodes (cracking), safety issues: improper sealing Less suitable for cycling due to high T required.		
Challenges	Improve durability/realitibilit; and Oxygen Evolution	Improve electrolyte	Reduce noble-metal utilization	Microstructural changes in the electrodes: delamination, blocking of TPBs, passivation		C deposition, microstructural change electrodes

Hydrogen is further produced as a by-product from chlor-alkali electrolysis. This is an industrial process widely used for the production of chlorine and sodium hydroxide. Due to the limitation of the H_2 production directly linked to a demand of chlorine and sodium (thus not being able to react to an increased demand of hydrogen), this technology is not described further in this report.

8.1.1.1 Alkaline electrolysis

An alkaline electrolyser consists of two half cells separated by hthe diaphragm, and ion-conducting membrane. Potassium hydroxide (KOH) mixed with water acts as the alkaline, liquid electrolyte. Alkaline electrolyzers have been built from 0.01 MW size up to a large 200 MW_e installation (Aswan Dam for the Egyptian Chemical Industries) (Levels *et al.*, 2019). Alkaline electrolyzers suffer from an efficiency decrease when frequently started up and shut down (Levels *et al.*, 2019). Operating pressures are usually below 30 bar (Sánchez *et al.*, 2020), even if higher pressures have been reported (Grigoriev *et al.*, 2020).

8.1.1.2 PEM electrolysis

It is the proton exchange membrane between the two electrodes which lends the PEM electrolyser its name. The total of this setting is called membrane electrode assembly (MEA). A solid polymer acts as acid, solid electrolyte. One advantage of PEMEC is that they do not have to be kept at operating temperature and the electrolysis can start immediately without preheating phase, so that they are open for flexible load (Levels *et al.*, 2019). Balance of plant include drier, cooling, de-oxy equipment, and de-ionization (Walker, Madden and Tahir, 2018). PEM electrolyzers can more easily operate at higher pressures than alkaline electrolyzers – a range of up to 700 bar has been reported (Grigoriev *et al.*, 2020).

8.1.1.3 Solid oxide electrolysis (SOE)

SOEC is a high-temperature (steam) electrolysis process. The electrolyte is solid, and superheated steam is reacting with the electrons. In contrast to AE and PEM electrolysis, SOE reaches higher conversion efficiencies, but cannot yet be considered as a mature technology. Demonstrators have reached a size of ca. 10-100 kW_e (Walker, Madden and Tahir, 2018). SOE electrolyzers suffer from a quick degradation of the materials (solid electrolytes) used, so that research focuses lowering the operating temperature by using solid electrolytes which allow this (Levels *et al.*, 2019). Operating pressures are currently below those of alkaline and PEM electrolyzers and in a range of 1-5 bar (Grigoriev *et al.*, 2020). Higher operating pressures, however, seem to be possible and figures of up to 25 bar have been reported (Jensen *et al.*, 2016; Hauch *et al.*, 2020; Riedel *et al.*, 2020).

8.1.1.4 Anion exchange membrane (AEM) electrolysis

Anion exchange membrane electrolysis is still a developing technology and therefore, with the goal to using it to eventually achieve commercially viable hydrogen production, AEM electrolysis requires further investigation and improvements, specifically regarding its power efficiency, membrane stability, robustness, ease of handling, and cost reduction. One of the major advantages of AEM water electrolysis is the replacement of conventional noble metal electrocatalysts with low cost transition metal catalysts (Vincent and Bessarabov, 2018).

8.1.1.5 Co-electrolysis

Co-electrolysis is SOE which produces gaseous H_2 and CO from parallel reduction of O_2 and CO_2 to produce syngas (H_2 + CO) and O_2. Syngas may act in energy storage as energy carrier, or can be used for generation of chemicals or liquid fuels. The advantage lies in the utilization of CO_2, turning it into a value-added chemical or fuel (Zheng *et al.*, 2017; Herranz *et al.*, 2020). This technology has mostly only reached laboratory scale so far, and may also be designed in various ways (Küngas, 2020).

8.1.2 Fossil and biomass feedstock: Reforming and pyrolysis of natural gas (methane) and biomethane, conversion of solid fuels (coal, wood, waste)

8.1.2.1 Reforming

Reforming for hydrogen production uses methane to produce a hydrogen-rich syngas. Nowadays, state-of-the-art technologies use steam to react with the methane (Steam Methane Reforming SMR) or make use of oxygen to oxidize the methane (Auto-thermal Reforming ATR). Both may be combined with CO_2 separation and capture for subsequent usage or storage. While in ATR the only source of CO_2

is the combustion of tail gas, SMR plants have two carbon dioxide sources, one from the chemical reactions during the gasification process, and one from the combustion of fuels in the reformer furnace for heat production. The latter is not needed in ATR due to a self-heating mechanism. Carbon capture is not yet implemented commercially in H_2 production plants, but technologies exist to remove the CO_2 from the syngas. They are mostly amine based, but research is performed on other removal technologies (Antonini *et al.*, 2020a). The captured CO_2 may be utilized or stored permanently in a geological storage site. Capture rates are typically at 90%, while also 98% capture rates may be possible (Antonini *et al.*, 2020a).

8.1.2.2 Gasification

Gasification of coal has been mainly performed in countries with large domestic coal reserves. However, due to the large amounts of carbon in the coal and low efficiency of the process, high emissions of CO_2 are related to this production technology. The use of dry biomass (wood) thus does not eliminate the direct CO_2 emissions of the gasification process chain per se, but this is biogenic carbon which had previously been removed from the atmosphere in the past years due to growth of biomass. The carbon balance may therefore be neutral, or even negative, when applying CCS (Antonini *et al.*, 2021a). Several gasification processes exist, which differ in terms of reactor technology and oxidizing agent (Lepage *et al.*, 2021).

8.1.2.3 Processing of waste

Also waste can be used as feedstock for hydrogen production – various thermochemical (gasification and pyrolysis) and biochemical (fermentation and photolysis) processes can be used (Lui *et al.*, 2020). Current bottlenecks include expensive production and operation processes, heterogeneous feedstock, and low process efficiencies. Potential improvements to hydrogen yields and production rates are related to feedstock processing and advanced energy efficiency processes such as torrefaction of feedstock (Lui *et al.*, 2020).

8.1.2.4 Pyrolysis of natural gas

Methane pyrolysis is the thermal decomposition of methane in an endothermic process, which ideally produces solid carbon and gaseous hydrogen. Solid carbon can either be stored or used in production of steel, aluminum, or other products. Thus, it does not enter the atmosphere as CO_2 and act as greenhouse gas. A recent publication provides a state-of-the-art technology overview of different options for pyrolysis of natural gas and discusses challenges and technology status (Schneider *et al.*, 2020). Methane pyrolysis processes can be divided into three categories: Thermal, plasma and catalytic decomposition. Thermal decomposition requires temperatures well above 1000°C, plasma decomposition up to 2000°C, and catalytic decomposition about 800-900°C. A common feature of all dedicated hydrogen production pathways via pyrolysis of natural gas is their low Technology Readiness Level (TRL), in the order of 3-4. Technological challenges include the transfer of experimental and theoretical results on methane pyrolysis to the use of natural gas, which contains other compounds than methane, soot and carbon deposits on hot surfaces, deactivation of catalysts after short time, and incorporation of carbon in the catalysts (Schneider *et al.*, 2020).

Nevertheless, pyrolysis of natural gas as a potential low-carbon hydrogen production route has recently gained attention and several research, demonstration and pilot plants are set up or operated, e.g., by BASF[29], TNO[30], and Monolith[31]. Also within the public discussion in some countries such as Germany, natural gas pyrolysis is partially considered to represent an option to be seriously taken into account in a future hydrogen economy as an alternative to hydrogen from electrolysis[32], since

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[29] https://www.fona.de/de/massnahmen/foerdermassnahmen/wasserstoff-aus-methanpyrolyse.php (28.4.2021).

[30] https://www.tno.nl/en/focus-areas/energy-transition/roadmaps/towards-co2-neutral-industry/hydrogen-for-a-sustainable-energy-supply/optimising-production-hydrogen/ember-methane-pyrolysis/ (28.4.2021).

[31] https://monolithmaterials.com/solutions/hydrogen (28.4.2021).

[32] https://www.welt.de/debatte/kommentare/article225157581/Wasserstoff-Deutschland-hatte-schon-immer-Angst-vor-risikobehafteten-Technologien.html (28.4.2021).

capacities of both electrolyzers and renewable electricity represent bottlenecks for a rapid scale up of low-carbon hydrogen production.

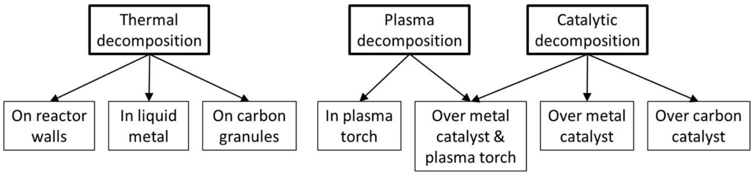

Figure 8.4: Categories of methane pyrolysis processes (Schneider *et al.*, 2020).

8.1.2.5 Geological CO_2 storage

Hydrogen production with CCS requires geological storage of CO_2. According to most recent estimates, the potential for such storage sites in Switzerland is limited to around 50 Mt (Diamond *et al.*, 2020). Thus, large scale CO_2 capture will have to rely on the option of exporting CO_2 to foreign storage sites, ideally using a trans-European pipeline network. Norway and the UK currently appear as most promising options with associated activities already in place. Several projects for geological CO_2 storage in Europe are operating or planned, as summarized in Table 8.4. A more recent overview has been provided by the International Association of Oil and Gas Producers (International Association of Oil & Gas Producers, 2021).

Table 8.4: Geological CO_2 storage – overview of projects in Europe (Ess *et al.*, 2021).

CCS project	Country	Start of operation (planned)	CO_2 storage capacity (Mt CO_2/a)	Industry
Sleipner CO_2 Storage	NO	1996	1.0	Natural gas processing
Snøhvit CO_2 Storage	NO	2008	0.70	Natural gas processing
Norway Full Chain CCS	NO	2023 - 2024	0.80 – 5	various
Acorn Scalable CCS	GB	2020´s	3.0 – 4.0	Oil refinery
Caledonia Clean Energy	GB	2024	3.0	Energy supply
HyNet North West	GB	mid 2020´s	1.5	Hydrogen production
Northern Gas Network H21 North of England	GB	2026	1.5	Hydrogen production
Teesside Collective	GB	2020´s	0.8	various
The Clean Gas Project	GB	2025	0.4 – 3	Energy supply
Drax - BECCS	GB	2027	4 - 16	Energy supply
Ervia Cork CCS	IE	2028	2.5	Energy supply, oil refinery
Hydrogen 2 Magnum (H2M)	NL	2024	2.0	Energy supply
Port of Rotterdam CCUS Backbone Initiative (Porthos)	NL	2023	2 - 5	various
Stockholm Exergi AB - BECCS	SE	2025	2	Energy supply

8.1.3 Use of nuclear energy

Electricity from nuclear power plants can be used to generate hydrogen via electrolytic water splitting. In addition, there are thermochemical cycles and other options using nuclear energy to generate hydrogen (Safari and Dincer, 2020; Eun *et al.*, 2021; IAEA, 2021; Fraser *et al.*, 2022). These differ in terms of level of technological maturity and their analysis has been out of scope of the present study.

8.2 Costs

8.2.1 Electrolysis

8.2.1.1 System configurations

Hydrogen cost assessments are usually categorized on the type of electrolyzer used to produce hydrogen, as for example in (International Energy Agency, 2019), (IRENA, 2019) and the work of (Schmidt, Gambhir, *et al.*, 2017). Alternatively, hydrogen costs can be categorized on the type of system configuration, such as stand-alone and grid connected electrolyzer configurations (Christensen, 2020). Stand-alone system configurations refer to electrolyzers which are not connected to the electricity grid but are connected to a (renewable) electricity generator. Without hydrogen storage, stand-alone configurations with intermittent renewables lead to intermittent hydrogen generation as well as lower annual load hours, due to the intermittent nature of (renewable) electricity sources (Bertuccioli *et al.*, 2014). On the contrary, grid connected system configurations could offer a more stable supply of hydrogen and higher annual load hours compared to stand-alone system configurations (Bertuccioli *et al.*, 2014; Christensen, 2020).

One beneficial characteristic of some electrolyzers is their operational flexibility, such as rapid response times (Bertuccioli *et al.*, 2014). Hence, electrolyzers can be integrated with renewable electricity sources and can offer grid services (Bertuccioli *et al.*, 2014).

Hydrogen production systems can be classified on the type of configuration or connection as well as associated annual load hours. For example, (Christensen, 2020) proposed three type of system configurations with implications on hydrogen cost calculations:

1. *Grid connected* system configuration, unlimited grid electricity consumption: 100% capacity factor of electrolyzer. Transmission and distribution charges are included.
2. *Direct connection (stand-alone)* system configuration, connected to a renewable electricity generator: coupled to renewable electricity, no transmission and distribution fee apply for the electricity grid. The capacity factor applied is that of the renewable electricity generator.
3. *Curtailed grid electricity* system configuration, solely consumption of curtailed grid electricity. In this way, the electrolyzer functions as a load balancer and storage medium, whereby it is assumed that electricity costs are zero and is in operation for 4 hours per day.

Table 8.5 presents hydrogen costs for the current situation in Europe and the United States per system configuration. This table shows large cost differences between geographical scopes as well as the hydrogen production system configuration. No distinction has been made between different electrolyzer technologies herein, while different literature also shows substantial costs differences between electrolyzer technologies (Bertuccioli *et al.*, 2014; Schmidt, Gambhir, *et al.*, 2017). Next, the main cost - and other key - parameters are discussed for hydrogen production with electrolysis.

Table 8.5: Hydrogen production costs in 2020 according to (Christensen, 2020).

		Europe	United States	unit
1. Grid connected	min	4.83; 14.5	6.06; 18.2	CHF/kg H_2; Rp/kWh H_2
	median	13.11; 39.4	8.81; 26.5	CHF/kg H_2; Rp/kWh H_2
2. Direct connection (stand-alone)	min	4.06: 12.2	4.56; 13.7	CHF/kg H_2; Rp/kWh H_2
	median	19.23; 57.8	10.61; 31.9	CHF/kg H_2; Rp/kWh H_2
3. Curtailed grid electricity	min	5.97; 17.9	6.10; 18.3	CHF/kg H_2; Rp/kWh H_2
	median	10.85; 32.6	11.02;33.1	CHF/kg H_2; Rp/kWh H_2

8.2.1.2 Cost parameters and categorization on the type of electrolyzer

The economic results from electrolysis based hydrogen is also driven by the system boundaries applied for hydrogen production costs (Christensen, 2020). We aim to include the entire life-cycle for hydrogen production from cradle (i.e. raw material requirements) to gate; where the hydrogen is ready for transport after compression (from operating pressure to 40 bar). The costs and environmental burdens of storage, utilization and transportation will be described in sections 8.3.1 and 11. The costs for hydrogen electrolysis also depends on the type of electrolyzer technology installed, its associated operating hours and electricity costs (International Energy Agency, 2019; IRENA, 2019; Christensen, 2020; Yukesh Kannah *et al.*, 2021). The conversion efficiency of the electrolyzer is another essential parameter for hydrogen production (Christensen, 2020). Consequently, the electrolyzer lifetime and annual load hours are crucial parameters for hydrogen electrolysis costs (Schmidt, Gambhir, *et al.*, 2017; IRENA, 2019; Christensen, 2020). A distinction has been made between the electricity sources (e.g. from solar, wind and nuclear) used for electrolysis in this section, since we expect them to have a significant influence on the total costs. Special attention is given to the following parameters in our literature review and in our cost calculations:

- Annual load hours or capacity factor
- Application & electricity source
- Conversion efficiency of the electrolyzer
- Electricity price (and geographical location)
- Electrolyzer capital expenditures
- Energy requirements to produce hydrogen
- Lifetime of electrolyzer (number of operating hours)

Waste heat from electrolysis could be valorized, if local boundary conditions are appropriate. Waste heat from alkaline and PEM electrolysis would be at a temperature level of around 60-70°C and with current electrolyzer capacities unly available in relatively small quantities, which might make use in a heat distribution network unattractive from an economic perspective. If local, small consumers would be available, this heat could be “upgraded” to higher temperature, if necessary.

Solid oxide electrolyzers operate at temperatures of up to 1000°C, which makes their integration into industrial processes such as synthetic fuel production using direct air capture of CO_2 and Fischer-Tropsch synthesis attractive. Heat integration and management is key for the energy efficiency and thus for both the economics, but also the environmental performance of such a combination of processes.

Potential valorization of waste heat from electrolysis has not been considered in the generic quantification of hydrogen production costs in this report – case-specific assessments would be required.

The next sections show the costs categorized for the three most popular and commercialized electrolyzer technologies: Alkaline, PEM and SOEC electrolysis. A couple of representative cost studies are presented per electrolysis technology, followed by a discussion on general cost parameters.

8.2.1.3 Alkaline electrolysis

(Kuckshinrichs, Ketelaer and Koj, 2017) presented an economic assessment of (advanced) grid-coupled alkaline electrolysis in three European countries: Austria, Germany and Spain, with a detailed analysis of key performance parameters as well as tax and financial measures. The lowest hydrogen costs were generated in Germany with 4.0 CHF/kg H_2, due to comparably low costs of German grid electricity. (Nguyen *et al.*, 2019) showed a techno-economic assessment of large-scale hydrogen electrolysis for 8 geographical locations (Canada, Germany and the USA) with two types of electrolyzers – Alkaline and PEM – and applied variable wholesale market prices and a flat rate price scheme. The results showed lower hydrogen costs for the operation in the wholesale market, and lowest hydrogen costs – for alkaline electrolyzers – were achieved with a scenario using underground hydrogen storage in Ontario (2.9-3.2 CHF/kg H_2). Table 8.6 provides an overview of cost studies on Alkaline electrolysis.

8.2.1.4 PEM electrolysis

(Shaner *et al.*, 2016) presented a techno-economic analysis of hydrogen production using solar energy and considered two system configurations: photo-electrochemical water splitting and PV electrolysis. The results demonstrated slightly higher hydrogen costs for PV electrolysis with 12.1 CHF/kg H_2 compared to photo-electrochemical water splitting (11.4 CHF/kg H_2). While grid-coupled electrolysis PEM systems could achieve hydrogen costs of 5.5 CHF/kg H_2. A study of (Nguyen *et al.*, 2019) showed that the implementation of large-scale hydrogen plants - with underground hydrogen storage - could achieve hydrogen costs as low as 2.7-3.5 CHF/kg H_2. Hence, PEM approaches SMR costs (2.5-2.8 CHF/kg H_2) and can be expected to become cheaper than SMR in the near future considering further cost improvements. Table 8.7 provides an overview of cost studies on PEM electrolysis, again, with a large variety of assumptions and associated costs.

Table 8.6: Hydrogen costs and essential parameters for Alkaline electrolysis partly based on (Yates et al., 2020).

Ref.	Electricity source/application	Electrolyzer costs [CHF/kW$_e$]	Electrolyzer efficiency [%]	Lifetime [hours]	Total costs [CHF kg^{-1} H_2]	Other essential parameters
(Bertuccioli *et al.*, 2014)	Grid connected Europe	1111-1333 (Today scenario)		60,000-90,000	3.6-6.6	Electrolyzer OPEX: 17-59 CHF/kW/year System energy req.: 50-78 kWhel/kg H_2
(Kuckshinrichs, Ketelaer and Koj, 2017)	Grid connected (Austria, Germany Spain)	944 (Direct depreciable capital cost)		83,000	4.0 (Germany)	Plant capacity: 6 MW Load hours: 8300 h/year H2 output: 118.25 kg H_2/hour Electricity price: 70-136 CHF/MWh Electricity consumption: 53.9 kWh/kg H_2
(Schmidt, Gambhir, *et al.*, 2017)	Intermittent Renewables injected in gas grid	611-1444 (50th percentile)	~65-75 (system efficiency HHV)	41,000-100,000 (50th percentile)		Plant capacity: 10 MWel Output pressure: 20-30 bar System energy req.: 4.0-5.5 kWhel/m^3 H_2
(Matute, Yusta and Correas, 2019)	Grid connected (Spain)	922		80,000		System energy req.: 52 kWh$_{el}$/kg H_2 Output pressure: 1-15 bar Plant capacity: 5 MW
(IRENA, 2019)	Renewable electricity generator	840	65 (HHV)		2.5-3.5 LCOE: 20 vs. 40 CHF/MWh	LCOE: 20 and 40 CHF/MWh Load factor: 48%
(Bruce *et al.*, 2018)	Grid connected (Base case)	1347		90,000 (Stack replacement Interval)	4.8-5.8	Electricity price: 60 CHF/MWh System energy req.: 58 kWh$_{el}$/kg H_2 Capacity factor: 85%
	Grid connected (Best case)	1012		90,000 (Stack replacement Interval)	2.5-3.1	Electricity price: 40 CHF/MWh System energy req.: 49 kWh$_{el}$/kg H_2 Capacity factor: 85%
(International Energy Agency, 2019)	Direct connection (stand-alone): PV + Wind	500-1400	63-70 (LHV)	60,000-90,000		Operating pressure: 1-30 bar
(Nguyen *et al.*, 2019)	Grid connected Germany, USA, Canada	600-1250	62 (HHV)	80,000	Flat price: 4.2-6.9 Wholesale market: : 2.9-6.0	Electricity energy charge: 24-58 CHF/MWh Electricity demand charge: 6.6-11.5 CHF/kW Plant capacity: 10-100 MW H_2 output: 4000-40,000 kg H_2/day

Ref.	Electricity source/application	Electrolyzer costs [CHF/kW$_e$]	Electrolyzer efficiency [%]	Lifetime [hours]	Total costs [CHF kg^{-1} H_2]	Other essential parameters
(Christensen, 2020)	Direct connection (stand-alone): PV + Wind	571-1268	70	75,000		
(Armijo and Philibert, 2020)	Direct connection (stand-alone): PV + Wind (Chile)	600	70 (LHV)	80,000	1.9-2.3	System lifetime: 30 years Electrolyzer OPEX: 2% CAPEX/year
(Yates *et al.*, 2020)	Direct connection (stand-alone): PV	682-886		70,000-90,000	3.4-4.7	System energy req.: 50-59 kWhel/kg H_2 Electrolyzer OPEX: 13.6-20.5 CHF/kW/year Plant capacity: 0.1-50 MW

Table 8.7: Overview of hydrogen costs – and essential parameters – for PEM electrolysis. This overview is partly based on the work of Yates et al. (2020).

Ref.	Electricity source/application	Electrolyzer costs [CHF/kW$_e$]	Electrolyzer efficiency [%]	Lifetime [hours]	Total costs [CHF kg^{-1} H_2]	Other essential parameters
(Bertuccioli *et al.*, 2014)[33]	Grid connected (100% load factor) Europe	2067-2578 (Today scenario)		20,000-90,000	6.0 (grid balancing services) to 9.6 (renewable electricity)	Electrolyzer OPEX: 31-78 CHF/kW/year System energy req.: 50-83 kWhel/kg H_2
(Shaner *et al.*, 2016)	Direct connection (stand-alone): PV	n.a.	61		12.1	Capacity factor PV: 0.204 Discount Rate: 12%
	Grid connected	1420	61		5.5	Electricity price: 70 CHF/MWh
(Schmidt, Gambhir, *et al.*, 2017)	Direct connection (stand-alone): Intermittent Renewables injected in gas grid	778-2139 (50th percentile)	~60-70% (system efficiency HHV)	41,000-70,000 (50th percentile)		Plant capacity: 10 MW$_{el}$ Output pressure: 20-30 bar System energy req.: 4.5-5.5 kWhel/m^3 H_2
(Bruce *et al.*, 2018)	Grid connected (Base case)	3496		120,000 (Stack replacement Interval)	6.1-7.4	Electricity price: 60 CHF/MWh System energy req.: 54 kWh$_{el}$/kg H_2
	Grid connected (Best case)	968		150,000 (Stack replacement Interval)	2.3-2.8	Electricity price: 40 CHF/MWh System energy req.: 45 kWh$_{el}$/kg H_2
(Matute, Yusta and Correas, 2019)	Grid connected (Spain) (2017 value)	1444		40,000		System energy req.: 61 kWh$_{el}$/kg H_2 Output pressure: 15-30 bar Plant capacity: 5 MW
(International Energy Agency, 2019)	Direct connection (stand-alone): PV + Wind	1100-1800	56-60 (LHV)	30,000-90,000		Operating pressure: 30-80 bar

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[33] This report is older than 2015, but is included herein since it corresponds to our research scope and presents comprehensive results.

Ref.	Electricity source/application	Electrolyzer costs [CHF/kW_e]	Electrolyzer efficiency [%]	Lifetime [hours]	Total costs [CHF kg^{-1} H_2]	Other essential parameters
(Nguyen *et al.*, 2019)	Grid connected Germany, USA, Canada	700-1800	64 (HHV)	40,000	Wholesale market: 2.7-6.2	Electricity charge: 24-58 CHF/MWh Electricity demand charge: 6.6-11.5 $/kW Plant capacity: 10-100 MW H_2 output: 4000-40,000 kg H_2/day
(Christensen, 2020)	Direct connection (stand-alone): PV + Wind	385-2068	60	60,000		
(Yates *et al.*, 2020)	Direct connection (stand-alone): PV	600-1700 (at 1 MW) (Suppl. Inf.)		60,000-100,000		System energy req.: 45-59 kWh_{el}/kg H_2 Electrolyzer OPEX: 14-21 CHF/kW/year Plant capacity: 0.1-100 MW

8.2.1.5 Solid oxide electrolysis (SOEC)

(Reytier *et al.*, 2015) showed that hydrogen costs of SOEC are in between ~3-8 CHF/kg H_2 for the 'advanced SOE' scenario. SOEC hydrogen costs turned out to be sensitive on the electricity price. SOEC showed the best economic performance – compared to Alkaline electrolysis and PEM – with electricity prices higher than 100 euro/MWh due to its comparably high energy conversion efficiency. A work of (Mohammadi and Mehrpooya, 2019) presented a thermodynamic and economic assessment of high-temperature SOEC in combination with the production of PV electricity by a parabolic through collector. The lowest achievable hydrogen cost for this system is 4.4 CHF/kg H_2, and 7.0 CHF/kg H_2 under design conditions. Table 8.8 provides an overview of cost studies on SOEC and essential assumptions used for the determination of SOEC hydrogen costs.

Table 8.8: Overview of hydrogen costs – and essential parameters used to calculate – hydrogen costs for SOEC.

Ref.	Electricity source/application	Electrolyzer costs [CHF/kW_e]	Electrolyzer efficiency [%]	Lifetime [cycles]	Total costs [CHF kg^{-1} H_2]	Other essential parameters
(Reytier *et al.*, 2015)	Grid connected (Europe)		60		~3-8 (fig. 6)	H2 output: 100 kg H_2/day Operating pressure: 13 bar
(Schmidt, Gambhir, *et al.*, 2017)	Direct connection: Intermittent Renewables injected in gas grid	1556-5556 (50th percentile)		9,000-95,000 (50th percentile)		Plant capacity: 10 MWel Output pressure: 20-30 bar
(Mohammadi and Mehrpooya, 2018)	Grid connected (Europe) with solar dish collector and compressed air energy storage (CAES)		61.7		9.1	Operating pressure: 1 bar H2 output: 41.5 kg H_2/day
(Mohammadi and Mehrpooya, 2019)	Direct connection: PV based, but with grid connection		62.6		4.4	Operating pressure: 1 bar El. price: 43 CHF/MWh H_2 output: 260 kg H_2/day
(International Energy Agency, 2019)	Direct connection (stand-alone): PV + Wind	2800-5600	74-81 (LHV)	10,000-30,000		Operating pressure: 1 bar
(Christensen, 2020)	Direct connection (stand-alone): PV + Wind	677-2285	81	20,000		

8.2.2 Co-electrolysis

High temperature SOEC can also be utilized for CO_2/H_2O co-electrolysis to produce syngas (H_2 + CO) and O_2 (Zheng *et al.*, 2017). The syngas can be subsequently used for the production of synfuel to be used for transportation purposes (Zheng *et al.*, 2017). In general, studies which present an economic assessment of co-electrolysis systems are limited due to the novelty of this technology. A couple of studies are discussed in the following paragraphs.

The work of (Jensen *et al.*, 2015) shows that a novel co-electrolysis system can be economically attractive for electricity storage, and is economically comparable with pumped hydro under certain circumstances, *e.g.* with roundtrip efficiencies of more than 70%. However, SOEC based co-electrolysis is currently not technologically and economically feasible for a large-scale implementation. Main challenges are associated with the degradation of SOEC stacks and the low conversion rate of CO_2 (Zheng *et al.*, 2017). A study of (Zheng *et al.*, 2017) compares high temperature co-electrolysis and steam electrolysis with CO_2-methanation. It turns out that electricity costs are the main contributor for both co-electrolysis and steam electrolysis costs. The study also found that capital, operation and maintenance costs are higher for co-electrolysis compared to steam electrolysis.

8.2.3 Reforming of natural gas and biomethane

The production costs of hydrogen from natural gas reforming crucially depend on natural gas prices. It has to be noted that the recent increase of natural gas prices is not properly reflected in the literature, which has been reviewed and is documented in this report. Hence, the majority of hydrogen production costs in this section 8.2 is based on historical natural gas prices of around 20-25 Euro/MWh (natural gas). The effect of recently observed increases of natural gas prices on costs of hydrogen production via reforming is briefly discussed at the end of section 8.2.7.

8.2.3.1 Natural gas w\ and w\o CCS

Production cost of hydrogen from the reforming of natural gas mainly depends on the fuel price of natural gas and the capital expenditures for Steam Methane Reforming (SMR) plant, the plant size and the geographical location. Hence, the costs for the reforming of natural gas are country-specific. Therefore, these parameters are included in Table 8.9, which presents an overview of useful SMR studies after year 2015.

Table 8.9: Reported hydrogen costs for SMR. *Using a HHV of 142 MJ kg^{-1} H_2, **Using 0.08988 kg H_2 per Nm^3 H_2.

Ref.	Application Location	Gas price [CHF/GJ]	Plant Size (tonnes H_2 per day)	CAPEX [Million CHF]	Total costs [CHF kg^{-1} H_2]
(Khojasteh Salkuyeh, Saville and MacLean, 2017)	Global SMR	2.65	630 (LHV) MW	241	1.1
(Collodi *et al.*, 2017)	Global SMR	6.7 (LHV)	216** (100,000 Nm^3/h H_2 production)	248	1.4**
(Keipi, Tolvanen and Konttinen, 2018)	Global SMR	6.2 (22 CHF/MWh)	216** (100,000 Nm^3/h H_2 production)	4000 CHF/kW (small scale) 500 CHF/kW (large scale)	1.9*, ** Energy requirement: 52 kWh/kg H_2
(International Energy Agency, 2019)	Global SMR	3-11 CHF/MBtu		500-900 per kW H_2	0.8-1.8

Further, GHG emissions can be reduced when steam methane reforming is combined with Carbon Capture and Storage (CCS) (Yan *et al.*, 2020). However, additional costs will be generated when CCS is coupled to SMR. Table 8.10 shows the most important parameters used in SMR w. CCS cost assessments and include the gas price, capture rate of CO_2, avoidance costs of CO_2, the costs of transport & CO_2 storage and the resulting hydrogen costs. It turns out that the capture rate differs significantly between studies; 60-100%. Further, also the avoidance costs of CO_2 is case-specific, and lower hydrogen costs are obtained with lower CO_2 capture rates (Collodi *et al.*, 2017; Yan *et al.*, 2020).

Table 8.10: Reported hydrogen costs for SMR w. CCS in literature. *Using a HHV of 142 MJ per kg H_2, **Using 0.08988 kg H_2 per Nm^3 H_2.

Ref.	Location	Gas price [CHF/GJ]	Capture rate [%]	CO_2 avoidance costs [CHF per t CO_2]	Transport & Storage cost [CHF per t CO_2]	Total costs [CHF per kg H_2]
(Khojasteh Salkuyeh, Saville and MacLean, 2017)	Global	2.65	90	136		2.2
(Collodi *et al.*, 2017)	Global	6.7	53-90	52-78	11	1.7-2.0**
(Keipi, Tolvanen and Konttinen, 2018)	Global	22 CHF/MWh	60	92		2.5** * (64 CHF/MWh)
(Yan *et al.*, 2020)	Sorption Enhanced SMR 468 tpd.	19.5	60-100	42-87 (zero carbon process)	24	With storage: 2.4-3.5 Without: 2.3-3.3

8.2.3.2 Biomethane

SMR can also be used to produce hydrogen from biomethane. In general, a smaller number of hydrogen cost studies are conducted on SMR with biomethane. Table 8.11 provides an overview of reported hydrogen production costs from SMR of biomethane – data are scarce. (Montenegro Camacho *et al.*, 2017) demonstrated that hydrogen production from biomethane is largely influenced by the size, the amortization time and the annual load hours of the hydrogen production plant.

Table 8.11: Reported hydrogen costs for biomethane SMR in literature. *Using LHV of hydrogen of 119.74 MJ/kg hydrogen (Madeira et al., 2017), **Using 0.08988 kg H_2 per Nm^3 H_2.

Ref.	Application Location	Biogas price [CHF/GJ]	Plant Size (tons H_2 per day)	CAPEX [Million CHF]	Total costs [CHF kg^{-1} H_2]
(Madeira *et al.*, 2017)	Cassava wastewater (Brazil)	(cost of biogas production was 0.051$ per kWh)	1.07 (44.48 kg/h)	3.1	3.0-8.0*
(Montenegro Camacho *et al.*, 2017)	Municipal Solid Waste (Europe)	0	0.2** (100 N m^3/h)	0.97 (100 N m^3/h)	4.8 (100 N m^3/h) 3.0-5.9 (700-50 N m^3/h) 1.9-6.0 (3-30 years Amortization time) 3.3-7.9 (5840-8030 annual load hours)
(Lachén *et al.*, 2018)		0.9			4.4-16.7
(Di Marcoberardino *et al.*, 2018)	Landfill and anaerobic digestion	Landfill biogas: 1.7 CHF/GJ Anaerobic digester: 3.8 CHF/GJ	0.1	Ranging from 0.16-0.31 for AD and LF, respectively (at 20 bar)	4.7-7.3 (conventional) 4.4-4.6 (Bionico)

Further, the combination of CCS with biomethane could potentially result in negative GHG emissions when CO_2 is captured during biomass conversion and subsequently stored in geological layers (Terlouw, Bauer, *et al.*, 2021). This production pathway is also known as Bioenergy with Carbon Capture and Storage (BECCS). Currently, no recent cost studies on biomethane w. CCS were found.

8.2.4 Biomass gasification

Table 8.12 provides current hydrogen production costs for biomass gasification according to recent literature.

Table 8.12: Reported hydrogen costs for biomass gasification in literature. *Using a HHV of 19.9 MJ/kg woodchips (Sheng and Azevedo, 2005).

Ref.	Feedstock	Biomass price [CHF/GJ]	Plant Size (tonnes H_2 per day)	CAPEX [Million CHF]	Fixed O&M (CHF per kW H_2 per year)	Total costs [CHF kg^{-1} H_2]
(Yao *et al.*, 2017)	Wood chips	5.4*	2.16	13.4	n.a.	Annual expenses of 4.8 million CHF and 8000 operating hours, result in: 6.7
(Miller, Raju and Roy, 2017)	Woody biomass	5.0*	50	112	n.a.	2.5
(Salkuyeh, Saville and MacLean, 2018)	Canadian Pine Wood	5.1	453.6	647 (FB gasification) 1229 (EF gasification)	n.a.	3.1 (FB gasification) 3.4 (EF gasification)
(Panos *et al.*, 2021)	Wood from Swiss forests	n.a.	n.a.	3‘000 CHF/kW H_2 (2020) 1’900 CHF/kW H_2 (2050)	300 (2020) 190 (2050)	n.a.

8.2.5 Pyrolysis of natural gas

Recent cost estimates for hydrogen production via pyrolysis of natural gas are scarce – probably due to the low TRL and a lack of industrial production facilities. Thus, also the available cost estimates are associated with comparatively high uncertainties. (Timmerberg, Kaltschmitt and Finkbeiner, 2020) calculated levelized hydrogen production costs for different natural gas pyrolysis options in comparison with SMR of natural gas and electrolysis. The estimates for pyrolysis are in the range of 1.5-2 € per kg hydrogen (with overall sensitivity ranges of 1.4-4.6 €/kg H_2), while their estimates for SMR with and without CCS are around 1 €/kg H_2, and for electrolysis between 2.5 and 3.5 €/kg H_2. In general, these estimates show a strong dependency on the energy costs.

8.2.6 Geological CO_2 storage

In this section, we present costs for CO_2 storage and capture. Geological CO_2 storage – and their associated costs - can be categorized in onshore and offshore storage. Geological storage costs are mainly associated to the injection wells, such as drilling, monitoring, exploration, well workovers, legacy of the field as well as costs required for the end of life of wells (Global CCS Institute, 2010; Irlam, 2017). A general cost breakdown is presented in Table 8.13, obtained from (Global CCS Institute, 2010).

Table 8.13: Cost categories for Geological CO_2 storage; table is obtained and adapted from (Global CCS Institute, 2010).

Cost phase	Description	Cost elements
Pre-Financial investment decision	Activities needed before decision to use injection wells and to proceed with project	Seismic survey, exploration of wells, injection testing, modelling of wells and permitting
Structure of CO_2 storage	Define and implement supporting construction for injection wells, such as off-shore platforms	Newly built or refurbished platforms
Injection wells	Construction of injection wells	Drilling, refurbishing and determining legacy of wells
Operation	Injection phase (~40 years)	Operation and maintenance expenditures (OPEX)
Monitoring	Monitoring activities needed for the injection and post-injection	Drilling of observation wells, monitoring OPEX and perform seismic survey at the end
End of Life	End of life activities and research	Decommissioning of wells and liability transfer

An older study (Global CCS Institute, 2010) presented costs ranges between 1-22 CHF t^{-1} CO_2 stored. Higher storage costs are generated with offshore CO_2 storage and aquifers, mainly due to comparably high capital expenditures. The most sensitive cost parameters are associated with the CO_2 storage field capacity, depth and injection rate (Global CCS Institute, 2010). Alternatively, the IEA applied a generic geological CO_2 storage cost of ~20 CHF t^{-1} CO_2 in their hydrogen report (IEA, 2019; International Energy Agency, 2019). Alternatively, (Bruce *et al.*, 2018) assumed a cost range of 10-40 CHF t^{-1} CO_2 for transportation and storage. Table 8.10 also shows costs of the transport and storage of CO_2 for the SMR w. CCS supply chain, and presents costs between 11-24 CHF t^{-1} CO_2. These cost ranges correspond to the cost estimates given by (Global CCS Institute, 2010). An ongoing study within the Swiss Energy perspectives 2050+ estimates costs of geological CO_2 storage to be in ranges of 1-12 Euro/t of CO_2 and 2-20 Euro/t of CO_2 for onshore and offshore storage facilities, respectively (Ess *et al.*, 2021). Specific cost estimates for Switzerland are scarce – a feasibility study for CO2 capture in Switzerland, CO_2 transport and storage in the North Sea indicates a cost of about 90 CHF/ton of CO_2 stored (Eckle, Spokaite and Krueger, 2021). This large range highlights the need for case-specific, detailed cost assessments for specific projects without relying on generic numbers.

8.2.7 Harmonization of global cost estimates in 2020

Table 8.15 shows an overview of current hydrogen production costs from different hydrogen production pathways as an outcome of harmonization of the available literature on hydrogen costs. We compare the results from this literature review with three recent, comprehensive hydrogen cost assessments presented in (Hosseini and Wahid, 2016), (Kayfeci, Keçebaş and Bayat, 2019) and (Parkinson *et al.*, 2019), see Table 8.14. The latter sources categorize electrolysis costs on the type of electricity source, but do not categorize on the type of electrolyzer as performed in the literature review of the previous sections.

Table 8.14: Harmonized hydrogen production costs for the year 2020 based on three hydrogen cost assessments in literature; (Hosseini and Wahid, 2016), (Kayfeci, Keçebaş and Bayat, 2019) and (Parkinson et al., 2019). N.a. = not available

Hydrogen production technology in [CHF per kg H_2]	(Hosseini and Wahid, 2016)	(Kayfeci, Keçebaş and Bayat, 2019)	(Parkinson *et al.*, 2019)
Water electrolysis: Wind	6.6	5.9-6.0	7.9 (4.6-10.0)
Water electrolysis: Solar	n.a.	5.8-23.3 (Solar PV) 5.1-10.5 (Solar thermal)	12.0 (7.1-14.9)
Reforming of natural gas	1.0	2.1	1.3 (1.0-2.2)
Reforming of natural gas w. CCS	1.2	2.3 (SMR) 1.5 (ATR)	2.1 (1.9-2.3)
Reforming of biomethane	n.a.	n.a.	n.a.
Biomass Gasification	4.6	1.8-2.1	2.2 (1.5-3.0) (biomass) 3.4 (3.2-3.6) (biomass + CCS)

Harmonized hydrogen production costs are presented in Table 8.15. The harmonized values are based on the values generated from our literature review and from hydrogen cost assessments presented in Table 8.14. We use two categorizations for electrolysis based hydrogen production; on either the electrolyzer technology or the type of electricity consumed needed for water electrolysis. Hydrogen cost harmonization for the latter categorization are based on the average of three comprehensive literature reviews – presented in Table 8.14 – the other categories consider the minimum and maximum hydrogen costs based on our literature review as presented in the previous sections.

Table 8.15: Minimum, maximum and average hydrogen production costs for the year 2020. Co-electrolysis is not included, due to limited data sources.

Category	Hydrogen production technology	Fuel	Minimum Literature [CHF kg^{-1} H_2]	Maximum Literature [CHF kg^{-1} H_2]	Average [year 2020] [CHF kg^{-1} H_2]
Electrolysis – technology	Alkaline	Water, renewable electricity	1.9	6.9	n.a.
	PEM	Water, renewable electricity	2.3	12.1	n.a.
	SOEC	Water, renewable electricity	3.0	9.1	n.a.
Electrolysis – type of electricity	Solar PV	Water, solar electricity	5.8	23.3	12
	Wind	Water, wind electricity	4.6	10.0	7
Reforming – natural gas	without CCS	Natural gas	0.8	1.9	1.5
	with CCS	Natural gas	1.7	3.5	2.5
Biomass based	Reforming of biomethane	Biomass (Biomethane)	3.0	16.7	5
	Biomass Gasification	Biomass	2.5	6.7	4
Pyrolysis of natural gas	Pyrolysis (Plasma, molten metal, thermal gas)	Natural gas	1.5	5.1	2.5

Table 8.15 and Figure 8.5 reveal average hydrogen costs for all considered hydrogen production pathways. Our review shows that the fossil-fuel based pathway – reforming of natural gas – is still the most economically attractive solution with 1.5 CHF kg^{-1} H_2 and 1.9 CHF kg^{-1} H_2 without and with CCS, respectively. Biomass gasification shows already a promising alternative with 2.9 CHF kg^{-1} H_2. A wide variability of costs for electrolysis based hydrogen production has been identified, within a big range of 1.9-23.3 CHF kg^{-1} H_2, mainly depending on the electricity source used for electrolysis as well as the electrolyzer technology. In general, wind-based electrolysis (~6.8 CHF kg^{-1} H_2) exhibits lower hydrogen costs compared to solar-based electrolysis (~12.0 CHF kg^{-1} H_2).

Further, we did not harmonize hydrogen costs based on electrolyzer technologies for the following reasons. First, our review showed the high variability and sensitivity of hydrogen costs due to a wide set of underlying assumptions. Second, we aimed to quantify Swiss-specific electrolysis costs in Section 8.2.9, and therefore these results show specific electrolysis costs for the Swiss situation.

Regarding electrolysis, some general findings are found from our literature review for the current situation in year 2020. Alkaline electrolysis is – from an economic perspective – the most attractive electrolyzer technology nowadays, although with a wide variability of hydrogen costs: ranging from 1.9-6.9 CHF kg^{-1} H_2. Hydrogen production pathways based on PEM and SOEC show higher hydrogen cost ranges, mainly due to the novelty of these electrolyzer technologies, especially for SOEC. The following section explores future hydrogen costs of electrolysis based hydrogen production pathways.

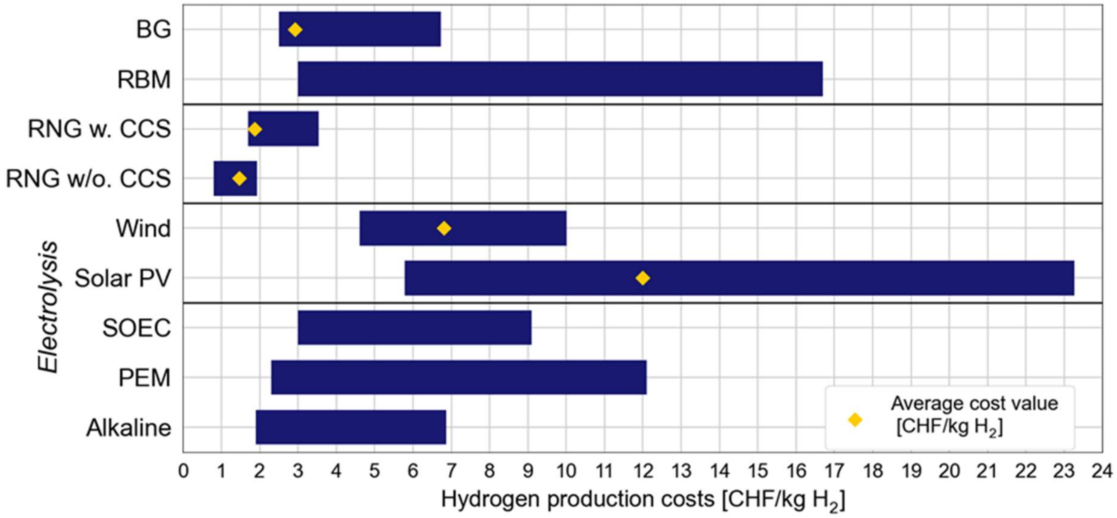


Figure 8.5: Ranges of hydrogen production costs based on available literature. BG= Biomass Gasification, RBM = Reforming of Biomethane, RNG w. CCS = Reforming of natural gas with CCS, RNG w/o. CCS = Reforming of natural gas without CCS. Costs for geological storage of CO_2 are generic and are likely to be higher in Switzerland.

Finally, the most recent review of hydrogen production costs published in November 2021 compiled a literature-based cost comparison of hydrogen from fossil resources with and without CCS and electrolysis (Longden *et al.*, 2021). Results are shown in Figure 8.6. These indicate that electrolysis based hydrogen will become cost-competitive at modest CO_2 prices, if low-cost electricity is available and electrolyzer costs can be reduced according to current expectations in the future.

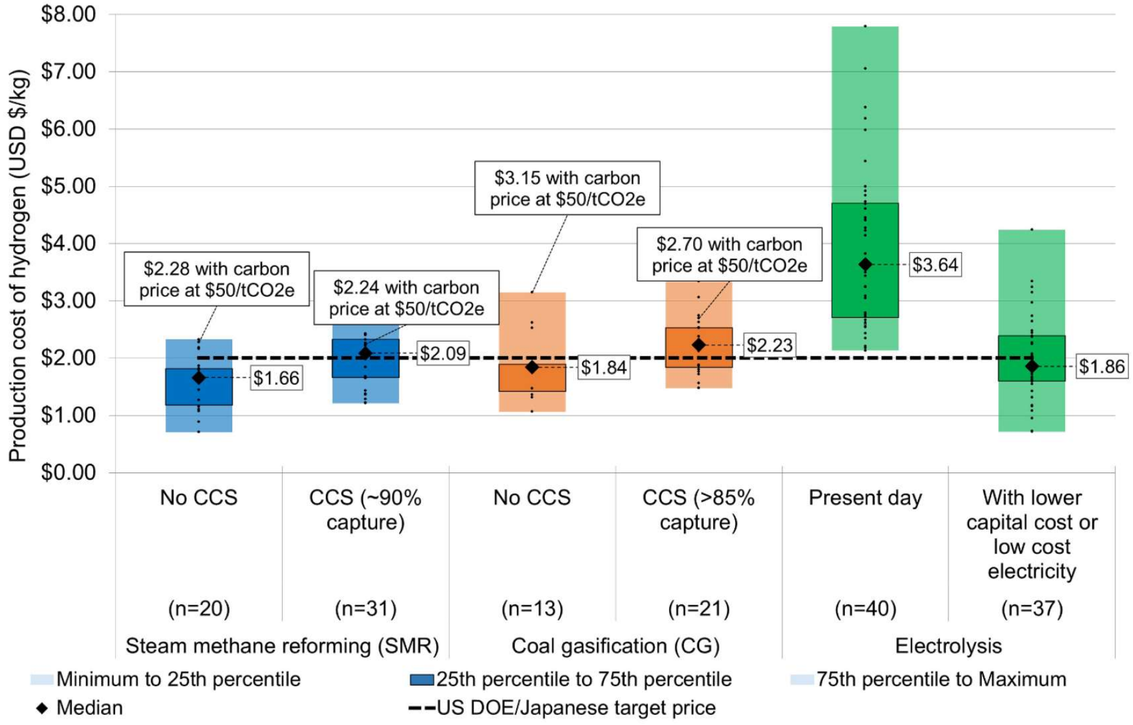


Figure 8.6: Literature-based overview of hydrogen production costs (Longden et al., 2021).

It has to be noted, however, that this overview does not take into account the recent substantial increases of natural prices and the effect on hydrogen production costs for natural gas reforming. Natural gas (spot market) prices started to increase in the second half of 2021 after a long period of relatively stable prices around 20-25 Euro/MWh and recently reached levels around 100 Euro/MWh with peaks of up to more than 200 Euro/MWh (Figure 8.7) (eex, 2022; Trading Economics, 2022).

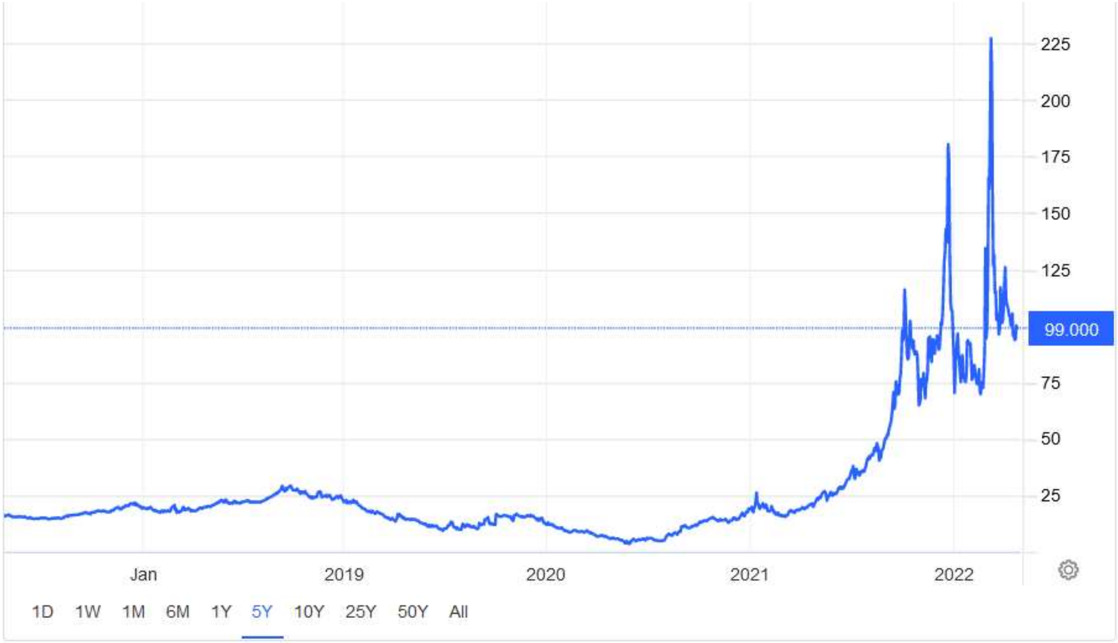
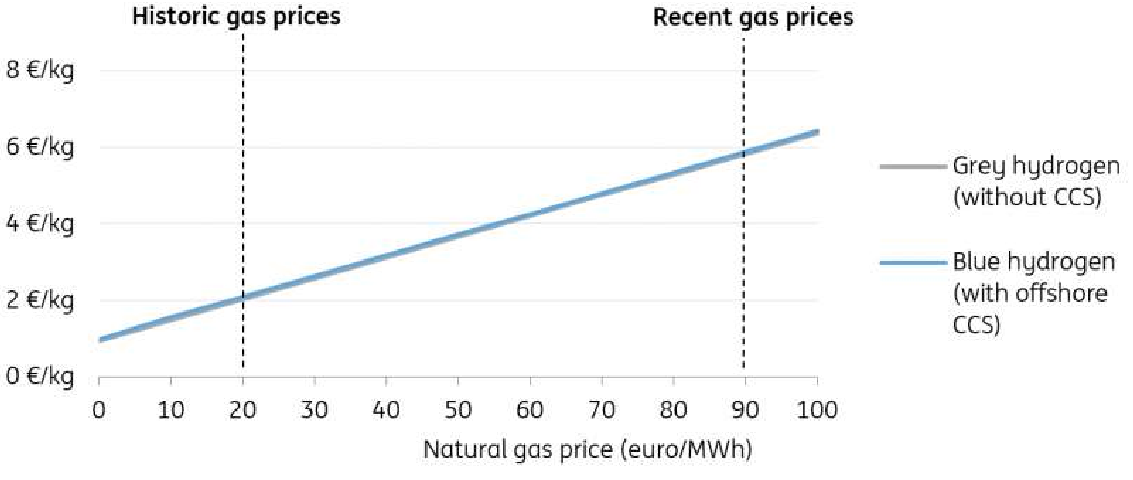


Figure 8.7: European spot market natural gas prices over the last five years (Trading Economics, 2022).

Increasing the natural gas price from 20 Euro/MWh to 100 Euro/MWh results in a more than three-fold increase in hydrogen production costs from methane reforming (Hieminga and Tillier, 2021). As a consequence, the cost-competitiveness of green hydrogen increases substantially, since already today, production costs of green hydrogen from electrolysis can often be below 6 Euro per kg of hydrogen (Figure 8.6).



* including distribution and storage of CO_2
** with a carbon price of 65 €/ton/CO_2

Figure 8.8: Production costs of grey and blue hydrogen as a function of the natural gas price (Hieminga and Tillier, 2021). Grey hydrogen production costs include costs for CO_2 emissions of 65 Euro/ton of CO_2, which results in cost-parity of grey and blue hydrogen.

The competitiveness of using nuclear power for electrolysis is mostly limited by high CAPEX of nuclear power plants (Figure 8.9). According to (Fraser *et al.*, 2022), "dedicated nuclear-based hydrogen could become a viable option only in regions with more limited renewables potential and higher costs, or if coal and gas prices remain high by historical standards".

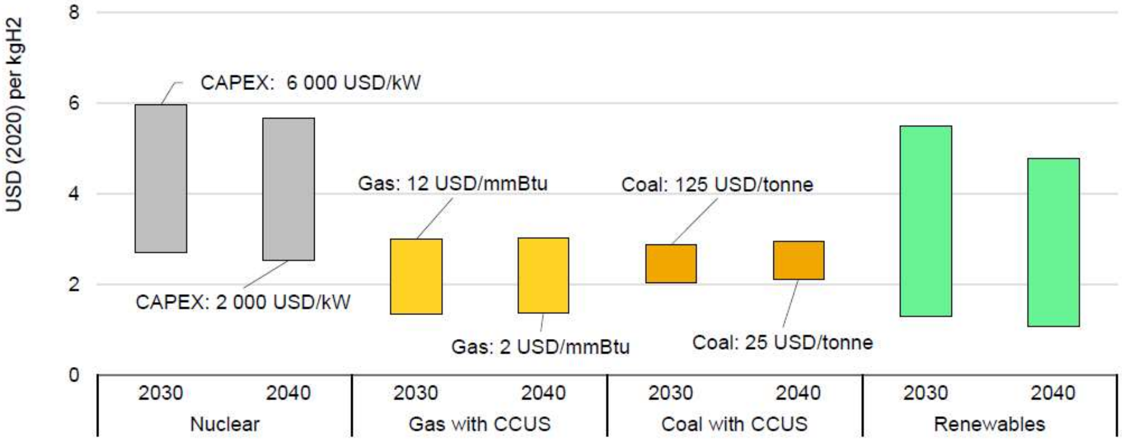


Figure 8.9: Levelised cost of hydrogen production by energy source/technology (Fraser et al., 2022).

8.2.8 Future hydrogen costs

This section explores future hydrogen costs developments until 2050 based on available literature. The main drivers for the reduction of hydrogen costs are expected from economies of scale – *i.e.* the scale up of manufacturing – of hydrogen production and its associated infrastructure (Hydrogen Council, 2020). The exploration of additional hydrogen applications could enhance the scale-up speed, for example due to the introduction of hydrogen vehicles, hydrogen boilers, industrial heating applying hydrogen, hydrogen storage and the implementation of grey hydrogen as transition fuel (Hydrogen Council, 2020). Especially for electrolysis, key characteristics to determine technology performance such as the electrolyzer efficiency as well as CAPEX are expected to improve significantly (Schmidt, Gambhir, *et al.*, 2017; Hydrogen Council, 2020). Electrolysis is perceived as the hydrogen production pathway with the largest future cost reduction as well as the most environmentally friendly option, hence we will focus on electrolysis based hydrogen production in this section.

8.2.8.1 Electrolyzers

Figure 8.10 and Figure 8.11 reveal expected capital expenditures and efficiencies (PIK, 2021)[34] – from year 2020 up to year 2050 – for the three most popular and commercialized electrolyzers: Alkaline, PEM and SOEC. Capital expenditures of the electrolyzer are the cheapest for Alkaline electrolysis nowadays, although relatively small cost improvement are expected for this electrolyzer technology. Further, the efficiency of Alkaline electrolyzers is comparably low (~61%), and comparably small efficiency improvements are expected in the coming decades. PEM electrolyzers have comparably high capital expenditures (~1280 CHF/kW) nowadays, although show large improvements in terms of capital expenditures; from ~1280 CHF/kW to ~320 CHF/kW in 2050. Besides, significant efficiency improvements are expected from 61% in 2020 to 72% in 2050. Electrolyzer costs are currently the highest for SOEC due to the novelty of this technology, however a significant future cost improvement is expected for this electrolyzer technology; from ~2710 CHF/kW in 2020 to ~580 CHF/kW in 2050. Besides, the efficiency of SOEC is comparably high with 81% and is expected to increase even further to 88% in 2050.

Based on curve fitting, the estimated average annual CAPEX reductions – from 2020 to 2050 – are indicated on 5.0%, 4.6% and 2.7% for SOEC, PEM and Alkaline, respectively. This corresponds well with

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[34] https://h2foroveralls.shinyapps.io/H2Dash/ (26.01.2021)

the annual cost reduction found in (Glenk and Reichelstein, 2019) between 2003 to 2016, with 4.8% and 3.0% for PEM and Alkaline electrolyzers, respectively.

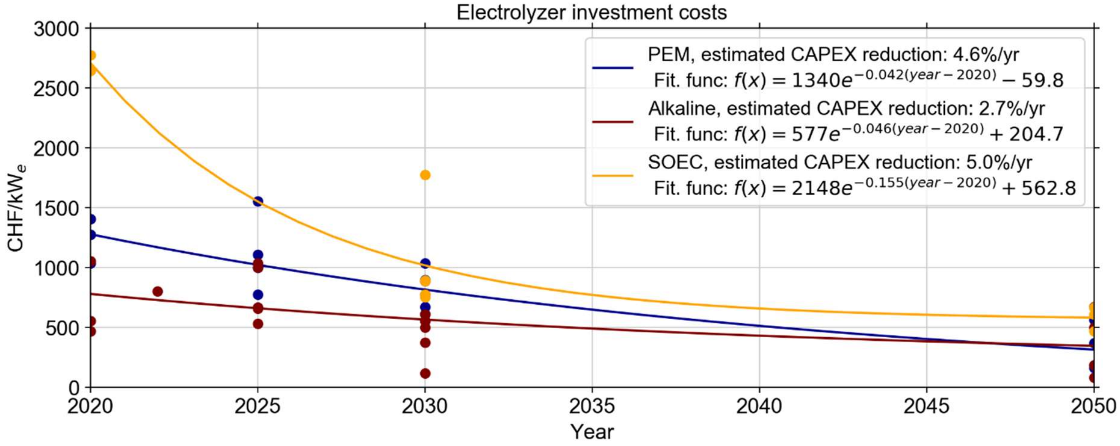

Figure 8.10: Figure is generated from data of (PIK, 2021)[34], and shows expected cost improvements of the three most commercialized electrolyzers. Cost values with associated cost assessment years are presented in this figure. Further, possible trend lines are presented and annual estimated CAPEX reductions are estimated based on these trend lines.

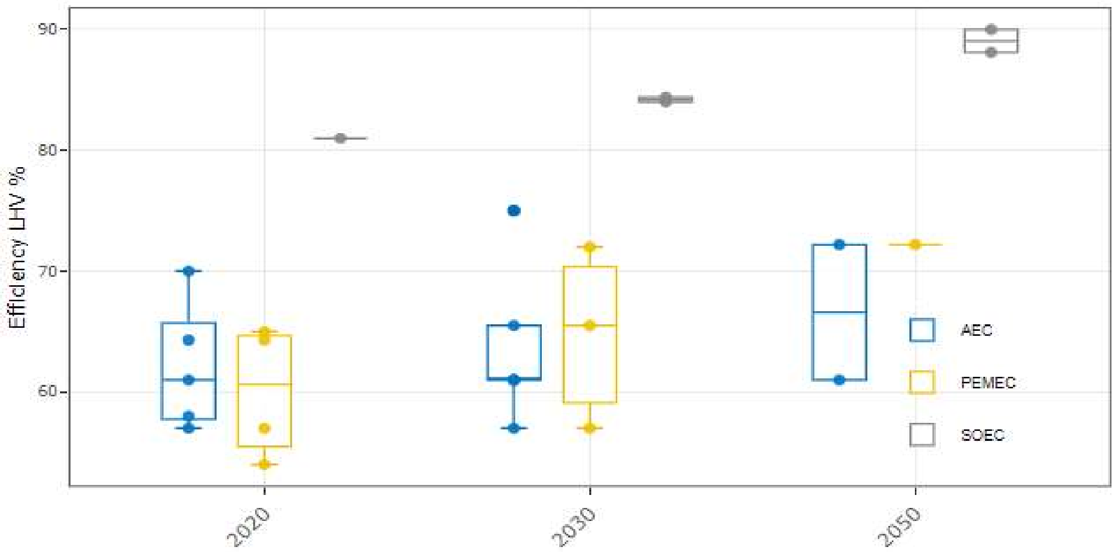

Figure 8.11: Efficiency improvements for three electrolyzer technologies (Alkaline, PEM and SOEC) up to year 2050, reproduced from (PIK, 2021).

Based on an expect elicitation study (also presented as data points in Figure 8.10 and Figure 8.11), (Schmidt, Gambhir, *et al.*, 2017) found much higher capital expenditures for SOEC in 2017 (~3300-5500 CHF/kW_{el}), though also found the biggest estimated cost reduction to ~1160-4700 CHF/kW_{el} in 2030. Alkaline electrolyzers demonstrated the smallest expected cost reduction from 900-1440 CHF/kW_{el} to ~830 CHF/kW_{el}, since this electrolyzer is a more mature technology. Capital expenditures developments of PEM could be reduced from ~1010-2160 CHF/kW_{el} to ~940-1830 CHF/kW_{el} in 2030.

The latter study also showed the very wide ranges of electrolyzer costs, efficiencies and lifetimes considering different R&D funding scenarios as well as situations without and with production scale-up (Schmidt, Gambhir, *et al.*, 2017). In general, significant cost improvements can be expected for electrolyzers and resulting hydrogen costs, although in a very case-specific way (International Energy Agency, 2019). These hydrogen production costs are also influenced by implemented policy measures (Schmidt, Gambhir, *et al.*, 2017).

8.2.8.2 Overall future hydrogen costs

(Christensen, 2020) conducted an economic assessment to determine prospective overall hydrogen costs for electrolysis, considering different configurations in Europe and the United States. Significant cost reductions are expected for 2050 – compared to 2020 - for all three configurations. The largest costs reduction were found for stand-alone (44-48%), grid-connected (32-41%) and curtailed grid electricity (22-46%) configurations, respectively.

Table 8.16: Results presented in Christensen (Christensen, 2020) for three type of system configurations for Europe and the United States representing electrolysis based hydrogen costs for 2020 compared to 2050.

		2020		**2050**		**year**
		Europe	United States	Europe	United States	unit
1. Grid connected	min	4.83; 14.5	6.06; 18.2	3.21; 9.6	4.15; 12.5	CHF/kg H_2; Rp/kWh H_2
	median	13.11; 39.4	8.81; 26.5	7.69; 23.1	5.77; 17.3	CHF/kg H_2; Rp/kWh H_2
2. Direct connection (stand-alone)	min	4.06: 12.2	4.56; 13.7	2.23; 6.7	2.44; 7.3	CHF/kg H_2; Rp/kWh H_2
	median	19.23; 57.8	10.61; 31.9	10.02; 30.1	5.97; 17.9	CHF/kg H_2; Rp/kWh H_2
3. Curtailed grid electricity	min	5.97; 17.9	6.10; 18.3	4.67; 14.0	4.75; 14.3	CHF/kg H_2; Rp/kWh H_2
	median	10.85; 32.6	11.02;33.1	6.08; 18.3	5.92; 17.8	CHF/kg H_2; Rp/kWh H_2

Alternatively, a recent report of the (IEA, 2020a) (p. 144) presented a more generic overview of potential hydrogen costs for different hydrogen production pathways using a Sustainable Development scenario. Their results demonstrates that electrolysis (1.5-3.4 CHF kg^{-1} H_2) might become cost-competitive with SMR and coal gasification hydrogen production in 2050, even if natural gas prices would drop to "historic levels" , although this scenario applies a relatively high CO_2 price in 2050 of 177 CHF/t CO_2. For example, (Christensen, 2020) found much higher hydrogen costs for electrolysis in 2050: 2.2-10.0 CHF kg^{-1} H_2 (see Table 8.16).

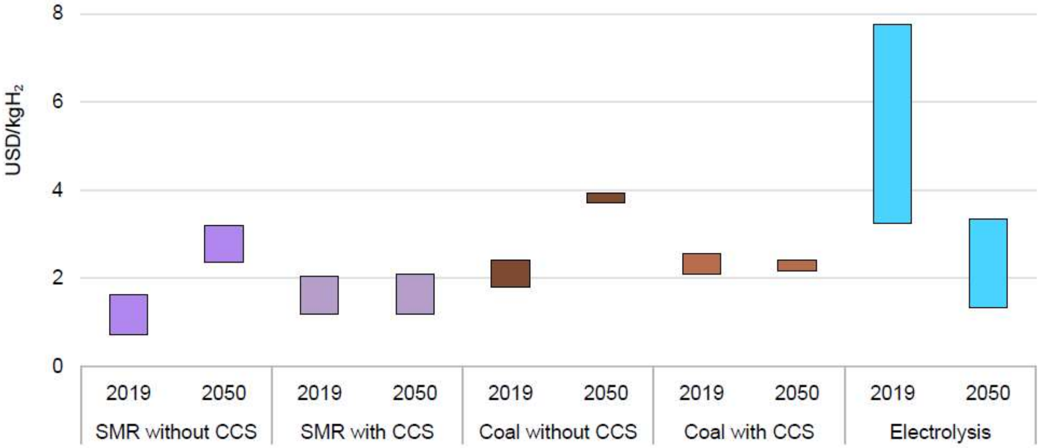

Figure 8.12: Figure obtained from the International Energy Agency (IEA, 2020a), showing hydrogen cost improvements for a Sustainable Development scenario for year 2050. Costs are presented in USD; however, the same currency value has been assigned to CHF. Hence, this figure is also valid to indicate costs in CHF. Steam methane reforming uses low "historic" natural gas prices.

We emphasize that future hydrogen costs depend on many factors and future developments, such as climate policy and regulations (Schmidt, Gambhir, *et al.*, 2017), natural gas prices, hydrogen applications (Hydrogen Council, 2020), capacity factors (Christensen, 2020), cost and performance improvements (Schmidt, Gambhir, *et al.*, 2017; Christensen, 2020) as well as the development of the overall hydrogen supply chain (Hydrogen Council, 2020). Hence, they are highly uncertain and case-specific and therefore we generate prospective electrolysis-based hydrogen costs up to year 2050, applicable for the Swiss situation.

8.2.9 Hydrogen costs for electrolysis in Switzerland

This section is committed to the determination of water-electrolysis based hydrogen costs for the Swiss situation nowadays and in the future, up to year 2050. The calculations are generated using the methodology described in Section 7.3.1.3. Two system configurations are considered to produce hydrogen with water-electrolysis: (1) an alternative consuming grid electricity and (2) an alternative using PV electricity.

8.2.9.1 Full grid water electrolysis

Figure 8.13 demonstrates hydrogen costs for three electrolyzer technologies - Alkaline, PEM and SOEC - nowadays up to year 2050 using the average cost scenario (*i.e.* parameters with 'avg' in Table 7.3). Further, a contribution analysis is presented in the same figure, and identifies annualized O&M costs (fixed and variable), replacement costs (REPEX,a) and capital expenditures (CAPEX,a).

Alkaline electrolyzer technology show the best economic performance nowadays with 8.7 CHF/kg H_2 for the full grid configuration, followed by PEM (9.6 CHF/kg H_2) and SOEC (10.7 CHF/kg H_2). Alkaline electrolyzers have comparably low capital expenditures and replacement expenditures nowadays, although the future technological and economical improvement is minor compared to SOEC and PEM. It turns out that the costs of the full grid configuration is largely driven by variable O&M costs, due to the consumption of grid electricity (0.15 CHF/kWh). SOEC is expected to become economically attractive from year 2030 on, mainly due to expected improvements in electrolyzer efficiency, lifetime hours and the CAPEX of SOEC. Especially the high efficiency (82% in 2020) – and its expected efficiency improvement (90% in 2050) - of SOEC is an important driver to reduce electricity consumption - and thus electricity costs - from the electricity grid. Hence, a sensitivity analysis has been conducted on different grid electricity cost values, see Section 8.2.9.1.2. On the other hand, SOECs exhibit comparably high replacement and investment costs in the first decade, due to comparably low lifetime hours of the electrolyzer stack during the first decade(s).

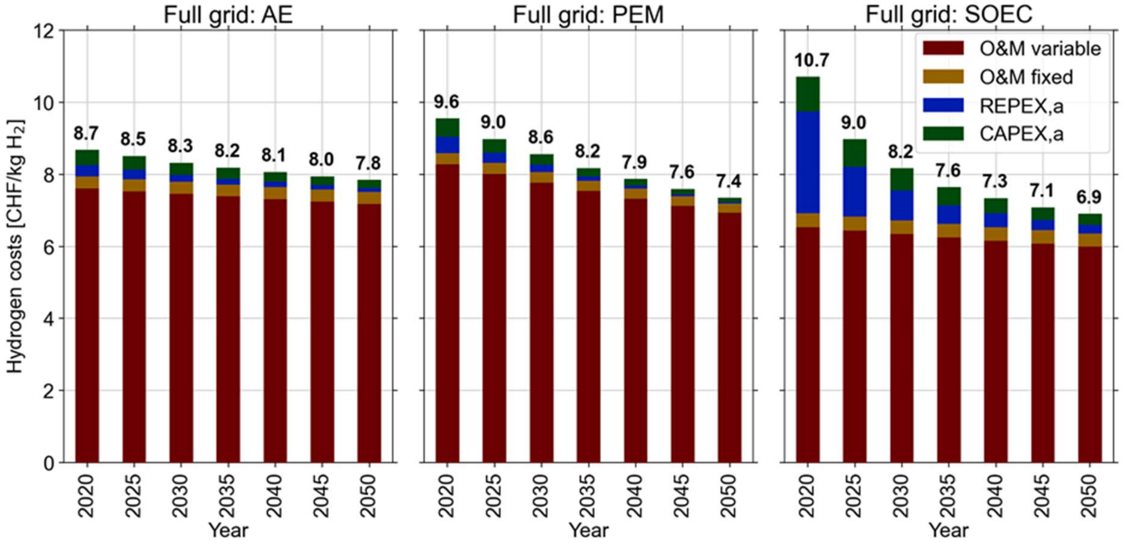

Figure 8.13: Hydrogen costs and contribution analysis for the full grid system configurations considering different electrolyzer technologies nowadays up to year 2050. Electricity price used for this calculation (and major contributor to "O&M variable"): 0.15 CHF/kWh. Reducing the electricity price would reduce "O&M variable" almost proportionally. Electricity related contributions decrease over time due to efficiency improvements (see Figure 8.11).

8.2.9.1.1 Worst and best case scenarios

Figure 8.14 shows different cost scenarios (min, avg, and max) for the three analyzed electrolyzer technologies for the full grid configurations nowadays and for the future, up to year 2050. Current hydrogen costs for all considered cost scenarios are roughly in between 8-12 CHF/kg H_2. Future cost reductions are mainly generated due to lower CAPEX, longer electrolyzer lifetime as well as higher electrolyzer efficiencies. However, grid electricity costs are assumed to be stable in the future, and therefore only a small reduction in hydrogen costs is expected (about 6.5-9.5 CHF/kg H_2), since hydrogen costs are mainly driven by grid electricity costs (for the full grid configuration). Indeed it can be expected that grid electricity costs further increase in the coming decades, which could lead to higher hydrogen costs than presented in Figure 8.14. This figure also confirms that SOEC (indicated by green colors in Figure 8.14) performs best after year ~2030, followed by AE and PEM.

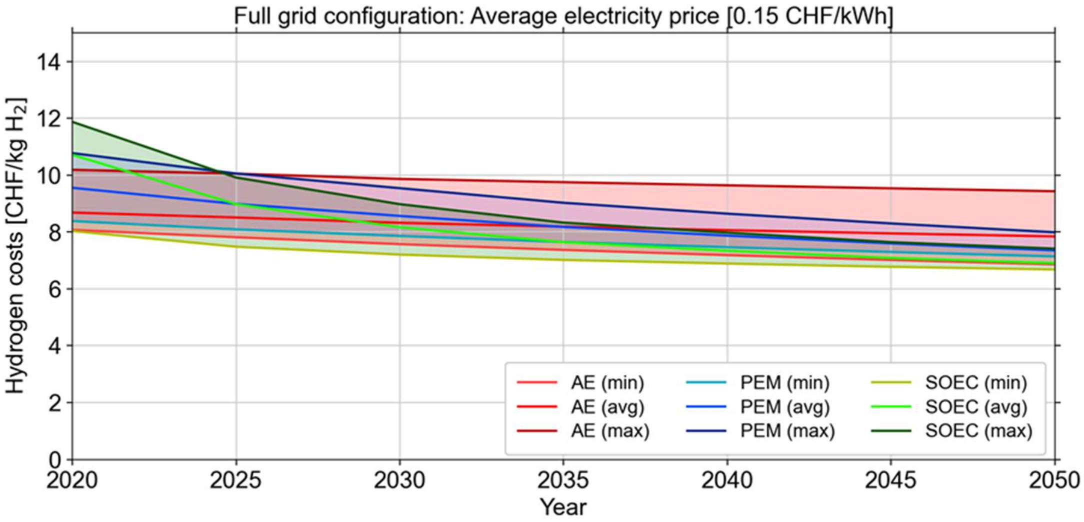

Figure 8.14: Hydrogen costs considering different electrolyzer CAPEX scenarios and improvements nowadays and up to year 2050 using a grid electricity price 0.15 CHF/kWh. Alkaline electrolyzers, PEM and SOEC are indicated by red, blue and green colors, respectively.

8.2.9.1.2 Grid electricity prices

Figure 8.15 demonstrates hydrogen costs for the three electrolyzer technologies nowadays and in the future, applying different electricity prices: a high electricity price (0.20 CHF/kWh), an average electricity price as used in the main analysis (0.15 CHF/kWh), a low electricity price (0.10 CHF/kWh) and a very low electricity price representative for the day-ahead market (0.05 CHF/kWh). The 'green funnel' indicates the entire range of hydrogen costs for the years up to 2050, considering all electrolyzer technologies and cost scenarios (*i.e.* min, avg and max).

These results show that the full grid configuration is very sensitive on the grid electricity price. While very high hydrogen costs (around 10-14 CHF/kg H_2 in 2020) will be generated with a high electricity price, logically low hydrogen costs can be generated with a very low electricity price; ~3.25-7.5 CHF/kg H_2 in 2020 to ~2.5-4 CHF/kg H_2 in 2050. Hence, the grid electricity price is a decisive factor for a grid-connected hydrogen system, and should be as low as possible to generate cost-competitive hydrogen.

In conclusion, the difference of hydrogen costs between electrolyzer technologies is small, with the best economic performance for Alkaline electrolyzers nowadays. The full grid configurations turned out be very sensitive on the grid electricity price. SOECs is expected to become economically beneficial from year 2030 on. SOECs revealed to be especially attractive in grid configurations with high electricity prices, due to its high energy conversion efficiency.

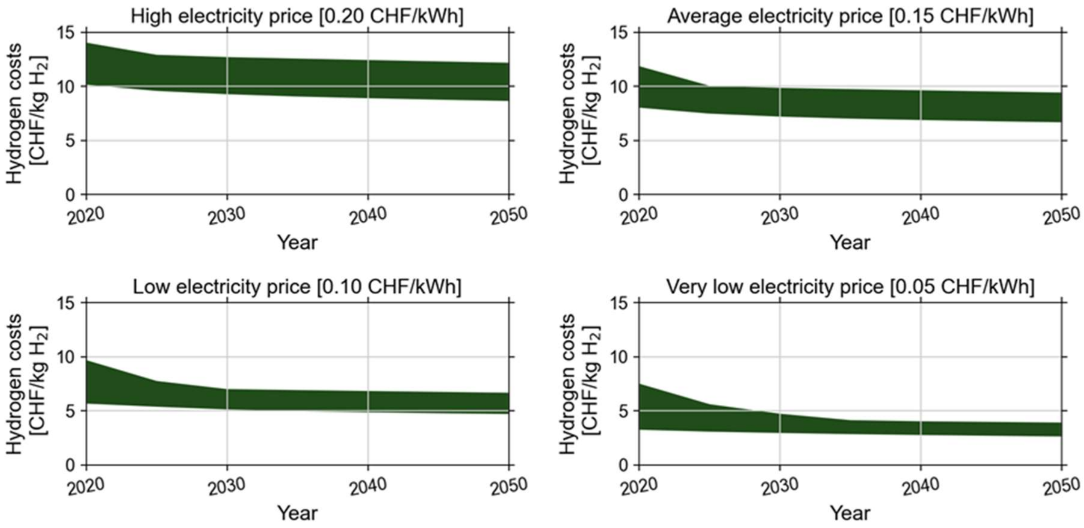

Figure 8.15: Sensitivity analysis applying different electricity prices for different costs scenarios (low, avg, max) considering three electrolyzer technologies nowadays and in the future, up to year 2050. Note that subplot 'Average electricity price [0.15 CHF/kWh]' presents the same hydrogen cost values as Figure 8.14.

8.2.9.2 Renewable PV water electrolysis

Figure 8.16 shows hydrogen costs using (renewable) PV water electrolysis for two electrolyzer technologies – Alkaline and PEM - nowadays and in the future, up to year 2050. Further, a contribution analysis is presented and identifies annualized O&M costs (fixed and variable), replacement costs (REPEX,a) and the initial capital expenditures (CAPEX,a). Hydrogen costs are mainly driven by capital expenditures for the PV system and the electrolyzer, while variable operational expenditures are very low - only generated by water costs – since it is assumed that PV electricity during operation is free as the investment already took place.

It turns out that Alkaline electrolyzers exhibit the lowest hydrogen costs (8.9 CHF/kg H_2) nowadays up to year 2030, due to its comparably low capital expenditures and replacement costs nowadays. PEM becomes economically attractive from year 2030 on, as a result of higher expected CAPEX improvements, efficiency improvements and an extended electrolyzer stack lifetime in the future. Hence, expected hydrogen costs are significantly lower for PEM in 2050 with 4.9 CHF/kg H_2 compared to 5.9 CHF/kg H_2 for Alkaline. Note that the electrolyzers are oversized to process the (potentially) high PV load and thereby the capacity factor is low. Consequently, additional electrolyzer stack replacements are not required. One benefit of PEM electrolyzers is the avoidance of an additional compressor, since it is assumed that the electrolyzer is a high pressurized PEM system.

The full-renewable configuration performs worse compared to the full grid configuration (the alternative with 0.15 CHF/kWh electricity) until year 2030, due to the high investments for the capacity requirements of the PV system and electrolyzer. However, the full renewable system configurations turns out to become economically beneficial from year 2030 on, since larger cost improvements can be generated due to expected cost reductions of (especially) the PV system.

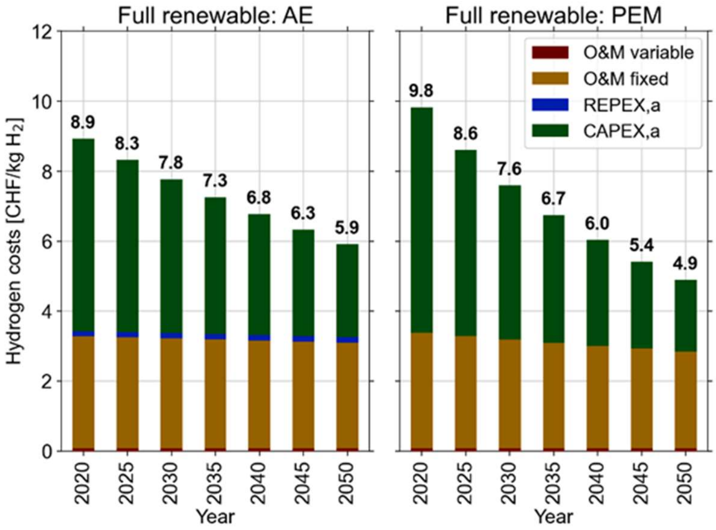

Figure 8.16: Hydrogen costs and contribution analysis for the full renewable system configurations considering different electrolyzer technologies nowadays and for the future, up to year 2050.

8.2.9.2.1 Worst and best case scenarios

Figure 8.17 shows all investigated cost scenarios (min, avg and max) for the two electrolyzer technologies nowadays and in the future. It turns out that hydrogen costs are high during the first decades ranging from about 7-13 CHF/kg H_2 in 2020, but are expected to decrease significantly to nearly ~4 CHF/kg H_2 in 2050. Further, the initial CAPEX differences of electrolyzer technologies are decisive in the coming years, but are becoming less influential in future years. Again, PEM (blue colors) exhibits the lowest hydrogen costs after year 2030.

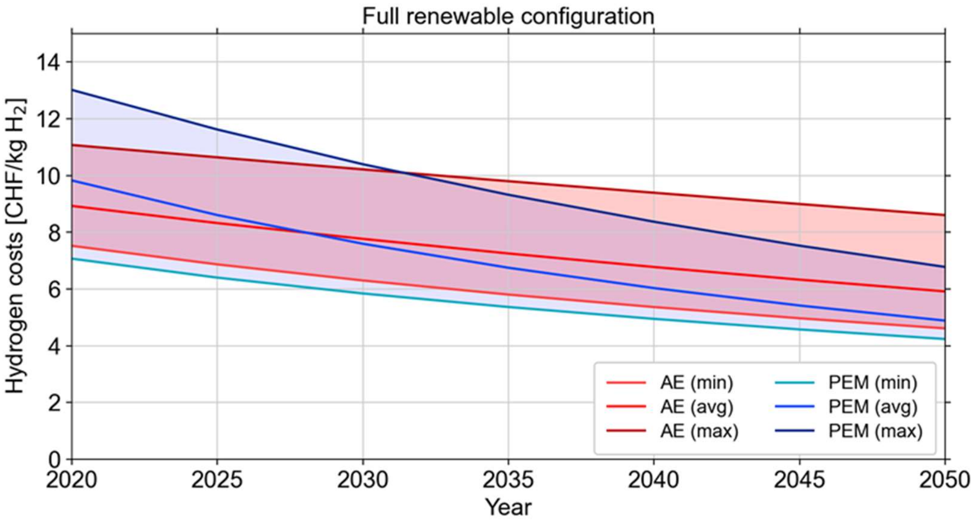

Figure 8.17: Hydrogen costs considering different electrolyzer CAPEX scenarios and improvements nowadays and up to year 2050. Alkaline electrolyzers, PEM and SOEC are indicated by red, blue and green colors, respectively.

Some conclusions can be generated for the renewable electricity driven electrolysis systems. Alkaline electrolyzers turned out to generate the lowest hydrogen costs until 2030, while PEM electrolyzers are expected to become economically attractive in electrolysis based systems with renewable electricity after 2030, due to their quick response time and expected improvements in CAPEXs as well as improved conversion efficiencies.

8.2.9.3 Comparison with literature

Figure 8.18 shows a comparison with the self-generated hydrogen costs of the previous section (applicable for Switzerland) and the harmonized hydrogen costs determined in Section 8.2.7. The self-generated hydrogen costs of the previous section are generally higher than other literature sources for individual electrolyzer technologies (SOEC, PEM and Alkaline, demonstrating all cost scenarios). This might be explained by the inclusion of a detailed economic analysis in this work, since this work also includes costs for compression as well as the balance of system, and therefore applies representative investments for the electrolyzer. Lowest hydrogen costs was found in 2020 for Alkaline electrolyzers in this work, which corresponds with the average cost values found in literature.

Hydrogen costs of solar PV are slightly lower than the average cost value in literature. This could be explained by the larger hydrogen production system applied in this work (200 kg H_2 per day) and associated lower investment costs of the PV system (1000 CHF/kW_p in 2020 and 500 CHF/kW_p in 2050). (Christensen, 2020) presented large hydrogen cost ranges for Europe and therefore can be hardly compared with this work, although our hydrogen costs are slightly lower than the median hydrogen costs presented in their work (see Table 8.16).

Further, this work estimated generally higher hydrogen costs for 2050 – around 4-9 CHF/kg H_2 – compared to other studies. For example, the (IEA, 2020a) estimated 1.5-3.5 CHF/kg H_2 (see Figure 8.12), although applied a more optimistic cost reduction for electrolyzers (269 CHF/kW_e) compared to this work (>580 CHF/kW_e in 2050 for all 'avg' scenarios) and seems to exclude representative costs for the balance of system and the compression unit. (IRENA, 2019) indicated potential hydrogen costs from electrolysis as low as 1.4 CHF/kg H_2 for 2050, although used a very high capacity factor of 48% for the renewable electricity generator - for example 14% is used for PV in this work - in combination with very low costs for the electrolyzer (200 CHF/kW_e). A recent analysis for hydrogen supply in Germany quantified electrolysis-based hydrogen production costs for different cases (location of production; electricity sources; operating hours; cost of capital) and came up with costs of hydrogen production in a range of around 5-12 €/kg H_2 in 2020 (Kreidelmeyer *et al.*, 2020). Lowest costs were estimated for production in the MENA region ("Middle East – North Africa").

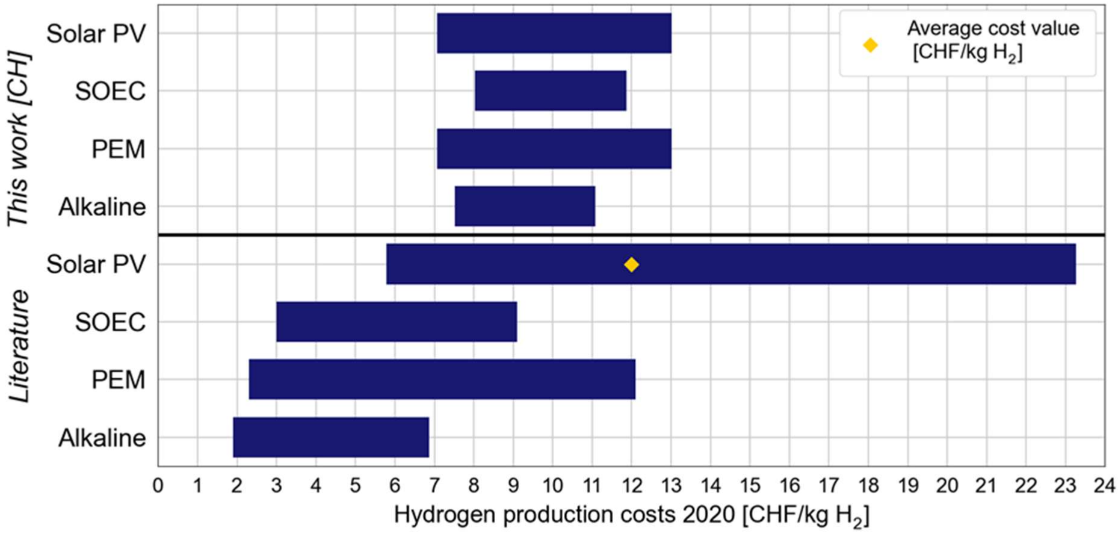

Figure 8.18: Comparison with average hydrogen cost values from Section 8.2.7 and self-generated hydrogen costs from previous Section 8.2.9. Note that the grid scenario with high electricity costs (0.15 CHF/kWh) is included in the cost ranges of this figure, the cost ranges would be bigger when the lowest and highest grid electricity costs scenario were included.

Future hydrogen production costs as estimated by (Kreidelmeyer *et al.*, 2020) are in the range of around 4-7 €/kg H_2 in 2050.

8.2.9.4 Summary: electrolysis based hydrogen costs for Switzerland

Table 8.17 presents an overview of current and expected (future) hydrogen costs for Switzerland from year 2020 up to year 2050 for two system layouts (Grid electricity and PV electricity) considering three electrolyzer technologies (Alkaline, PEM and SOEC).

Table 8.17: Summary of electrolysis based hydrogen costs in CHF/kg H_2 for Switzerland. Multiplying these numbers by 3 results in costs in Rp./kWh hydrogen.

Costs in CHF/kg H_2	Technology	2020	2025	2030	2035	2040	2045	2050
Grid electricity (0.15 CHF/kWh) capacity factor of 1	Alkaline	8.1-10.2	7.8-10.1	7.6-9.9	7.4-9.8	7.2-9.6	7-9.5	6.9-9.4
	PEM	8.4-10.8	8.1-10.1	7.9-9.5	7.6-9	7.5-8.6	7.3-8.3	7.1-8
	SOEC	8-11.9	7.5-9.9	7.2-9	7-8.3	6.9-8	6.8-7.6	6.7-7.4
Grid electricity (0.05 CHF/kWh) capacity factor of 1	Alkaline	3.3-4.4	3.1-4.3	3-4.2	2.9-4.1	2.8-4	2.7-4	2.7-3.9
	PEM	3.3-5	3.1-4.5	3-4.2	2.9-3.8	2.8-3.6	2.7-3.4	2.6-3.2
	SOEC	3.8-7.5	3.3-5.6	3.1-4.7	2.9-4.1	2.9-3.8	2.8-3.6	2.7-3.4
Solar PV capacity factor of 0.14	Alkaline	7.5-11.1	6.9-10.6	6.3-10.2	5.8-9.8	5.4-9.4	5-9	4.6-8.6
	PEM	7.1-13	6.4-11.6	5.8-10.4	5.4-9.3	4.9-8.4	4.6-7.5	4.2-6.8

8.3 Environmental burdens

8.3.1 Literature review

There exists a large number of life cycle assessment publications on environmental impacts of hydrogen production. However, as explained in detail in (Valente, Iribarren and Dufour, 2017), the comparability of the studies is hampered by differences in the choice of the functional unit, system boundaries, or technological parameter values. The functional unit may be given in energy (MJ) or mass (kg), and the purity and pressure of the product has to be known for meaningful comparison. In their harmonization effort, Valente et al. collected literature data on 139 original case studies for renewable hydrogen production via biomass input to reforming, partial oxidation of gasification (thermochemical hydrogen) on the one hand and alkaline or PEM water electrolysis with various electricity sources on the other hand (electrochemical hydrogen). Few studies on fermentation were further included.

Table 8.18 summarizes the findings on the climate change impacts calculated from the harmonized studies. In (Valente, Iribarren and Dufour, 2019), the same authors state that evaluation of more than 100 studies on life cycle sustainability assessment of hydrogen energy systems revealed that the most evaluated environmental indicators were global warming, cumulative energy demand, acidification, eutrophication, and ozone layer depletion.

Future technical improvements are mainly possible in terms of enhanced process efficiency, introduction of CCS as well as increased carbon capture rates. Further, decarbonisation of the energy systems in general will contribute to a decrease in overall life cycle climate change impacts of H_2 production. Such potential, feasible configurations in reforming of natural gas or biomethane are explored in detail in (Antonini *et al.*, 2020a). This technical analysis could prove that overall carbon removal at the H_2 plant may be increased from 55% (state-of-the art SMR with CCS) to 98% (ATR with specific configuration). With the latter, an overall reduction of GHG emissions over the whole life cycle of 80% may be reached. The net efficiency based on the Lower Heating Value (LHV) is calculated to be 78%. This corresponds exactly to the efficiency given in a prospective study on the carbon footprint of H_2 production options (Valente, Iribarren and Dufour, 2020). These authors assume that the efficiency may be further increased to 85% by 2030.

Recently, climate impacts of blue hydrogen production became a topic of great interest, as it becomes evident that – if large quantities of hydrogen will be required within short periods of time in order to comply with stringent climate policy goals – both blue and green hydrogen will be required, since substantial scale-up of both options will require time (International Energy Agency, 2021; Mac Dowell *et al.*, 2021).

Latest research shows that blue hydrogen can only be considered as low-carbon energy carrier or feedstock, if methane emissions along the natural gas supply chain are low and high CO_2 removal rates at the hydrogen production plant with CO_2 capture are implemented (Antonini *et al.*, 2020b, 2021b; Mac Dowell *et al.*, 2021; Bauer, Treyer, Antonini, Bergerson, Gazzani, Gençer, Gibbins, Mazzotti, S. McCoy, *et al.*, 2022). Further, the time horizon for quantification of global warming potentials can be important, since relative climate impacts of methane emissions increase by a factor of about three the using a 20-years time horizon (GWP20) instead of the usually applied 100-years time horizon (GWP100).

Table 8.18: Summary of the global warming potential as calculated from 139 harmonized case studies in (Valente, Iribarren and Dufour, 2017). The table further includes not harmonized results from recent LCA studies on various H_2 production technologies. Negative values indicate carbon removal from the atmosphere.

Category	**Hydrogen production process**	**Life-cycle GHG emissions ($kg\ CO_2$-eq/kg H_2), GWP100a**
According to (Valente, Iribarren and Dufour, 2017)		
Thermochemical	Reforming of bioethanol, biomethane, biogas, bio-oil	5 to 12
	ATR of bioethanol, biomethane, bio-oil	6 to 10
	Biomass gasficiation (various wood types)	-25 to 8
Electrochemical	Water electrolysis	PV: 1.7-7.5 Wind: 0.2-2 Hydro: 0.8 to 2
Biological	Fermentation of various biomass	2.4 to 7.4
Further studies		
Thermochemical, unharmonised	Steam methane reforming of natural gas	9 to 17 (without CCS)[1,3,5,7,9] 3-10 (with CCS)[1,9]
	Nuclear thermochemical water splitting Nuclear copper-chlorine cycle	0.5[3] 1 to 3[4, 8]
	Coal gasification	11[3] 24[6, 7]
	Biomass gasification	4[7]
	Partial oxidation of methane	5 (biomethane) to 11 (fossil methane)[5]
	Pyrolysis of natural gas	6-18 (depending on conversion technology and heat source)[9]
Own studies		
Thermochemical, own study[2]	Steam methane reforming/Autothermal reforming of natural gas	10.5-17* (without CCS) 2.5 to 12* (with CCS)
	Steam methane reforming of biomethane	1.2 (without CCS) -4 to -17 (with CCS)
	Gasification of wood	1 to 2 (without CCS) -9 to -18.5 (with CCS)
Electrochemical, own study[2, 10]	PEM electrolysis	PV: 2-5 Wind: ca. 1 Hydro: 0.3-3

[1] (Mehmeti *et al.*, 2018), [2] (Antonini *et al.*, 2021a), [3] (Cetinkaya, Dincer and Naterer, 2012), [4] (Hacatoglu, Rosen and Dincer, 2012), [5] (Hajjaji *et al.*, 2013), [6] (Mehmeti *et al.*, 2018), [7] (Siddiqui and Dincer, 2019), [8] (Bicer and Dincer, 2017), [9] (Timmerberg, Kaltschmitt and Finkbeiner, 2020), [10] (Bauer, Treyer, Antonini, Bergerson, Gazzani, Gençer, Gibbins, Mazzotti, S. McCoy, *et al.*, 2022).
* with metnae emission rates along the natural gas supply chain between zero and 8% (Bauer, Treyer, Antonini, Bergerson, Gazzani, Gençer, Gibbins, Mazzotti, S. McCoy, *et al.*, 2022).

8.3.2 Own work: Reforming of natural gas or biomethane and gasification of wood; electrolysis

Detailed Life Cycle Assessment (LCA) has been performed in (Antonini *et al.*, 2020a, 2021a) on H_2 production with reforming based on natural gas or biomethane from organic household waste, gasification of wood, and less detailed on electrolysis for which this study builds upon previous analysis performed (Zhang *et al.*, 2017). The technologies included are Steam Methane Reforming (SMR) and Autothermal Reforming (ATR) with natural gas or biomethane from anaerobic digestion of biogenic waste as well as gasification of wood from sustainable forestry. For reforming, a total of 70 configurations varying the CO_2 capture technology (Methyl-Diethylamine (MDEA) or a novel Vacuum pressure swing adsorption (VPSA) process developed in SPL), capture rate, water gas shift and similar were assessed. The feedstock natural gas or biomethane are nearly identical, and thus interchangeable in the reforming process. For the wood gasification, three technologies with a technology readiness level higher than 6 are explored: Heat pipe reformer (HPR), Entrained Flow Gasifier (EF), and sorption enhanced reforming gasifier (oxySER). The technologies differ in their design (fluidized bed or entrained flow), gasification agent (steam or oxygen), and direct or indirect heating.

The LCA includes all material, energy, infrastructure, and transport inputs related to the production of H_2 as depicted in Figure 8.19 showing the chosen system boundaries of the LCA. The functional unit is specified to be the production of 1 MJ hydrogen at a purity level of at least 99.9% at a pressure of 200 bar at ambient temperature.

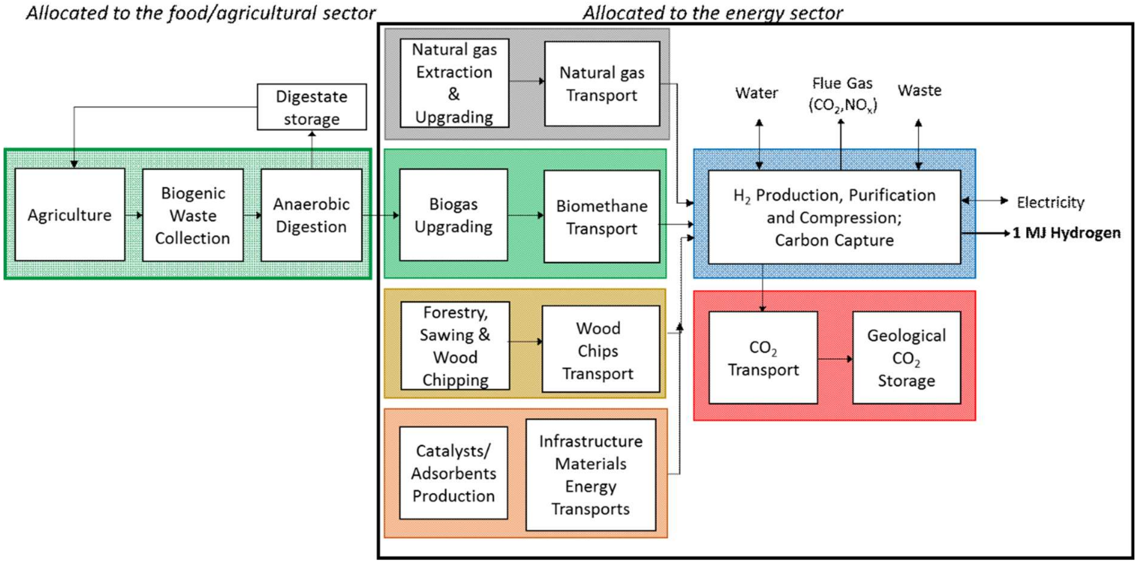

Figure 8.19: System boundaries chosen for LCA of hydrogen production from reforming of natural gas or biomethane from organic household waste as well as from gasification of wood. Taken from (Antonini *et al.*, 2021a)**.**

All environmental impacts originating from the supply chain of the wet waste biomass treated with anaerobic digestion to produce biogas and digestate are assigned to the food and agriculture sector – the anaerobic digestion is considered to represent a waste treatment activity[35]. CO_2 storage is assumed to take place in a saline aquifer after transportation in a pipeline over 200 km[36]. A detailed

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[35] This is a subjective modeling choice typical for Lie Cycle Assessment – alternative approaches, which might have a substantial impact on LCA results, are possible.

[36] If hydrogen production with CCS would take place in Switzerland, CO_2 is likely to be exported, since the domestic storage potential is small. However, the impacts of longer CO_2 transport distances on overall GHG emissions is small, as recently shown for DACCS (Terlouw, Treyer, *et al.*, 2021).

carbon balance was set up for the biomethane chain, including the natural variation of carbon content in the biogenic waste and uncertainties regarding the fate of the carbon in digestate (acting as carbon sink in the soil or disposal via incineration), which is reflected in the results as shown in Figure 8.20 with black range bars. For the wood residues from sustainable forestry species mix, constant average carbon content was assumed.

The resulting impacts on climate change, measured in life-cycle emissions of greenhouse gases per MJ of hydrogen produced, are shown in Figure 8.20. Additionally, the overall CO_2 removal rate at the H_2 production plant is shown at the right y-axis.

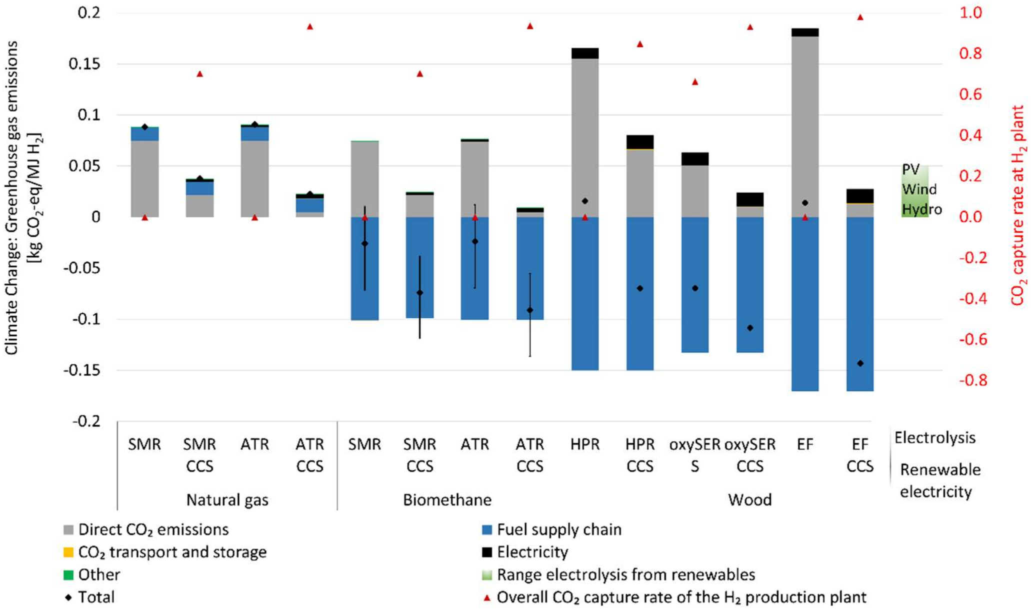

Figure 8.20: Climate change impacts (GWP100) of the production of hydrogen with natural gas, biomethane or wood as feedstock; with or without CCS. This is compared to electrolysis using electricity from renewables (solar PV, wind, hydropower). Based on (Antonini et al., 2021a) and (Antonini et al., 2020a).

The most important contributions to the total score originate from the direct CO_2 emissions of the hydrogen production process, which can be substantially decreased via the addition of a CCS system. The CO_2 transport and storage activities as such do not contribute to climate change in an important way, as the infrastructure needed is used for a big amount of CO_2. Further, CO_2 capture does not come along with a significant penalty in terms of additional electricity use (black bar), which is modelled with average electricity from the European power grid. In the case of wet or dry biomass as feedstock for reforming and gasification, respectively, net carbon removal from the atmosphere may be reached with permanent geological storage of CO_2 captured, i.e. this hydrogen production pathway can act as negative emission technology, since CO_2 is permanently removed from the atmosphere. H_2 production reaches nearly carbon neutrality even without CCS; in case of biomethane reforming, net removal of greenhouse gases might be possible even without CCS, if using digestate from biomass digestion is used as fertilizer and such application fixes carbon in the soil over a long time horizon[37]. However, biomass is a limited resource. When CCS is present, a blend of natural gas and biomethane would lead to carbon neutral hydrogen when around 35-50% of the feedstock needs are covered with biomethane. Gasification of wood also results in very low or negative emissions, with the case of the oxy-fired entrained flow gasifier leading to the highest CO_2 removal from the atmosphere among all cases analysed, while performing well in the other environmental impact categories except land

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[37] Whether such «soil carbon sequestration» can be accounted for depends on soil and climate conditions as well as the digestate composition and requires further research; also the assignment of this carbon sequestration to the hydrogen production represents a subjective choice in LCA.

occupation. This is due to the fact that the process as such is less efficient than the reforming processes, which gives the opportunity to capture and store a large amount of biogenic CO_2.

A comparison with electrolysis provides a few key insights. In general, the climate change impacts of the electrolyzer infrastructure are negligible, so that the greenhouse gas intensity of the electricity used for water splitting determines the climate performance of hydrogen from electrolysis (Bhandari, Trudewind and Zapp, 2014), (Zhang *et al.*, 2017). Figure 8.21 shows the impacts on climate change from the production of 1 MJ H_2 versus the greenhouse gas intensity of the input electricity. All renewable electricity sources exhibit a carbon footprint lower than 100 g CO_2-eq/kWh electricity. This results in climate change impacts (GWP100) between close to 0 and 0.05 kg CO_2-eq/MJ H_2 produced (0.2 to 5 kg CO_2-eq/kg H_2). Carbon intensive grid mixes or technologies (natural gas power plants) increase the burden on climate – using the average European grid mix leads to 0.2 kg CO_2-eq/MJ H_2 (24 kg CO_2-eq/kg H_2). The climate change intensities of reforming or gasification technologies are not sensitive to the input electricity source.

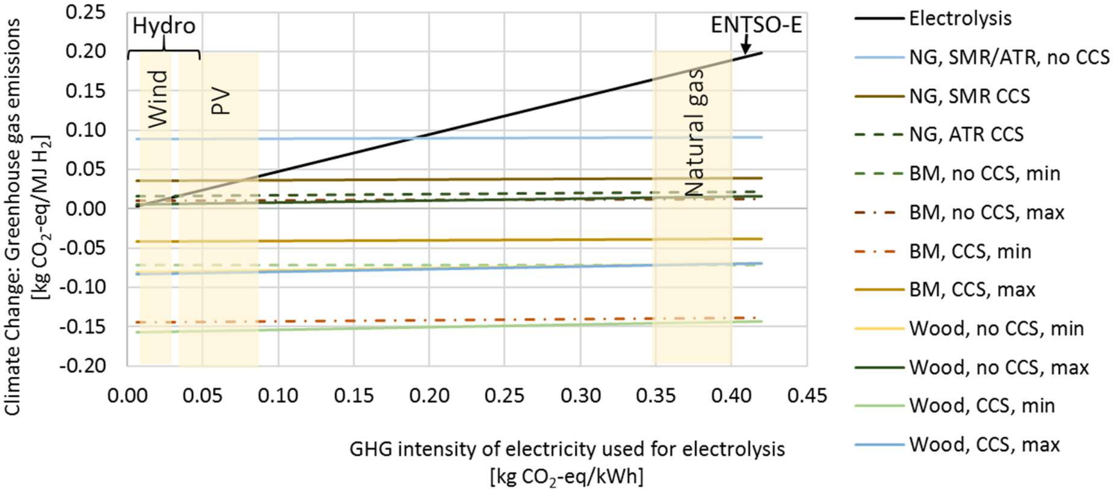

Figure 8.21: Climate change impacts (GWP100) of hydrogen production in a PEM electrolyzer in dependency of the source of electricity used and compared to biomass and natural gas based hydrogen production. Adapted from (Antonini et al., 2021a). NG: Natural Gas; BM: Biomethane; SMR: Steam Methane Reforming; ATR: Autothermal Reforming; ENTSO-E: Average European electricity supply.

However, climate impacts of natural gas reforming with and without CCS are very sensitive to the methane emission rate along the natural gas supply chain, and these methane emissions can vary substantially, in a range of close to zero in countries like Norway and The Netherlands to 8% in regions with a dysfunctional natural gas infrastructure liky Lybia (IEA, 2021). High overall methane emissions are often a consequence of few so-called “ultra-emitters”, and those emissions could actually be reduced to acceptable levels at comparatively low costs (Lauvaux *et al.*, 2022).

The current European natural gas supply mix exhibts a methane emission rate of about 1.3% (Meili, Jungbluth and Bussa, 2021). In case of high methane emissions, the time horizon considered for global warming potentials becomes relevant, as methane has a comparatively short lifetime in the atmosphere and therefore a much higher GWP for shorter time horizons (around 30 for 100 years vs. 90 for 20 years). This effect is shown in Figure 8.22, which shows life-cycle GHG emissions of hydrogen production as a function of methane emissions along the natural gas supply chain (Bauer, Treyer, Antonini, Bergerson, Gazzani, Gençer, Gibbins, Mazzotti, S. McCoy, *et al.*, 2022). This recent analysis demonstrates that blue hydrogen can only be considered as being “low-carbon”, if technologies with high CO_2 removal rates at the hydrogen production plant in the order of 90% or higher are used, and if methane emissions along natural gas supply chains are below 1%. If these conditions are met, such blue hydrogen can play a meaningful role in a future low-carbon economy.

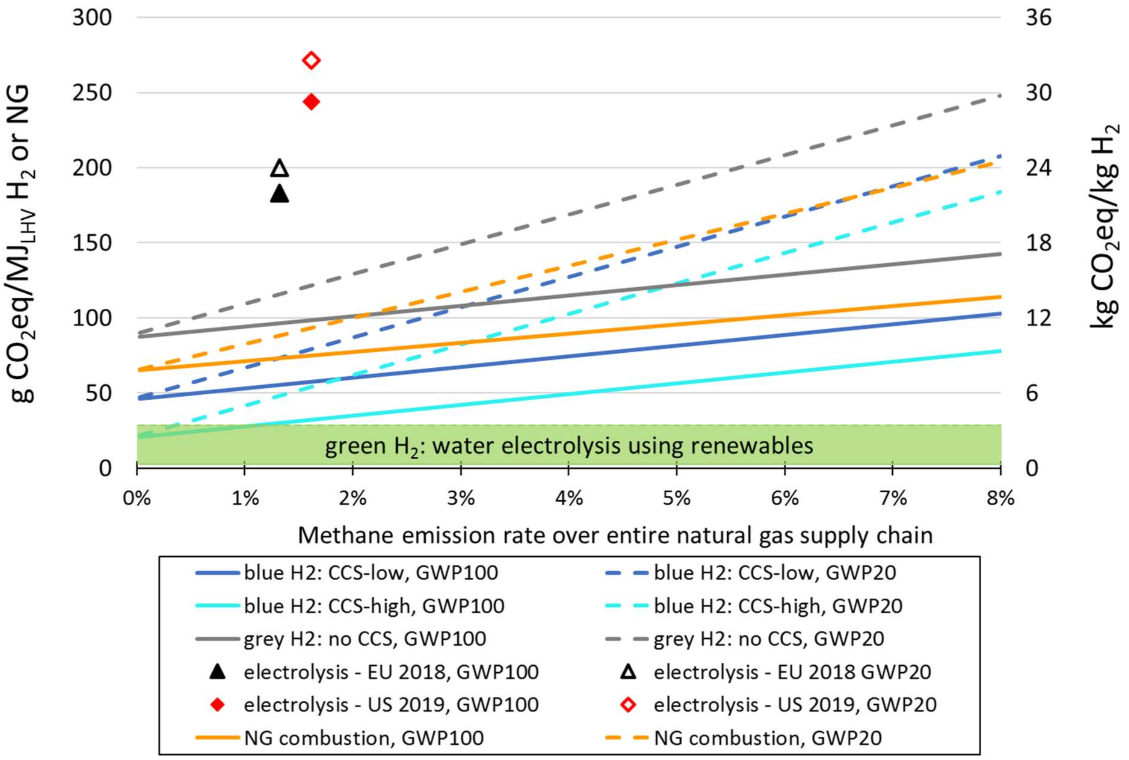

Figure 8.22: Impacts on climate change from blue and green hydrogen production (Bauer, Treyer, Antonini, Bergerson, Gazzani, Gençer, Gibbins, Mazzotti, S. McCoy, et al., 2022). Natural gas (NG) combustion emissions are quantified including natural gas supply. GWP: Global Warming Potential. NG: Natural Gas; CCS: Carbon Capture and Storage. "blue H2: CCS-low" and "blue H2: CCS-high" refer to NG reforming with low and high CO2 removal rates of around 55% and 93%, respectively; "electrolysis – EU2018 / US 2019" refers to hydrogen production via electrolysis using average European and US electricity from the grid in 2018/2019.

9 Hydrogen conditioning

Linking hydrogen production and use requires hydrogen transport from the production site to the user (section 10), potentially with hydrogen storage in between on various volume and time scales (section 11). For both transportation and storage, the hydrogen produced at site potentially needs to undergo conditioning, for instance to reach better stability, increased safety during handling, or increased volumetric energy density. The choice of hydrogen processing or conversion, transport modes, storage type – thus in general the design of the supply chain from production to use – depends on many considerations: for instance on quantities to be transported, available infrastructures, types of users, as well as geographical, economic and regulatory boundary conditions. Further, the overall efficiency of supply chains has to be considered. Figure 9.1 shows all processes which may be involved in hydrogen transport or storage.

After production of the hydrogen at a specific pressure, it usually undergoes further ***conversion or processing*** to prepare for transport, storage or use. This transformation may be physical or chemical. The hydrogen may on the one hand be physically processed, which means that no actual interaction with the storage media happens. This is the case during compression, liquefaction via extremely low temperatures, and cryo-compression. On the other hand, hydrogen conversion is chemical: Conversion into a chemical carrier such as ammonia, or absorbtion to either a liquid organic hydrogen carrier (LOHC), a metal organic framework (MOF), or to metal hydride compound structures. Hydrogen bound to MOF or metal hydrides comes as a solid, while LOHC, liquefaction and cryo-compression result in liquid hydrogen. The individual technologies are briefly explained further below, while chapters 10 and 11 go more into detail with regards to technical considerations, costs, and environmental impacts. Not all technologies will be presented in the same level of detail due to their different development stages and in some cases limited availability of data.

It should be noted that the final costs for complete, Swiss-specific hydrogen supply chains are not provided in this report. These depend on the combination of processing/conversion, transport, and storage, as well as on the hydrogen production pathway and end use. All different sorts of such combinations will influence the costs, depending on transport distances combined with storage durations, volume of hydrogen in a specific case study, and technical choices affecting the round-trip efficiency from hydrogen production to end use. Complete hydrogen supply chain case studies for Switzerland are out of scope for the present report, but would be an important element of future research or decision making processes, respectively. Currently, pure hydrogen is mostly used in refining and for ammonia production, and around 85% are produced and consumed on-site (International Energy Agency, 2019).

As of today, the most common hydrogen supply chain elements are gaseous or liquid hydrogen transported in trucks, trailers or in pipelines and stored in tanks. Pilot projects for instance include the use of natural gas networks for hydrogen transport and storage in caverns[38]. Interestingly, existing publications or hydrogen roadmaps put little focus on hydrogen conditioning, transport and storage, but mostly on hydrogen production and end use (e.g., (FCH, 2019; Hebling *et al.*, 2019; Commission, 2020; European Commission, 2020; FCHEA, 2020; International Energy Agency (IEA), 2020).

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[38] https://www.get-h2.de (4.5.2021)

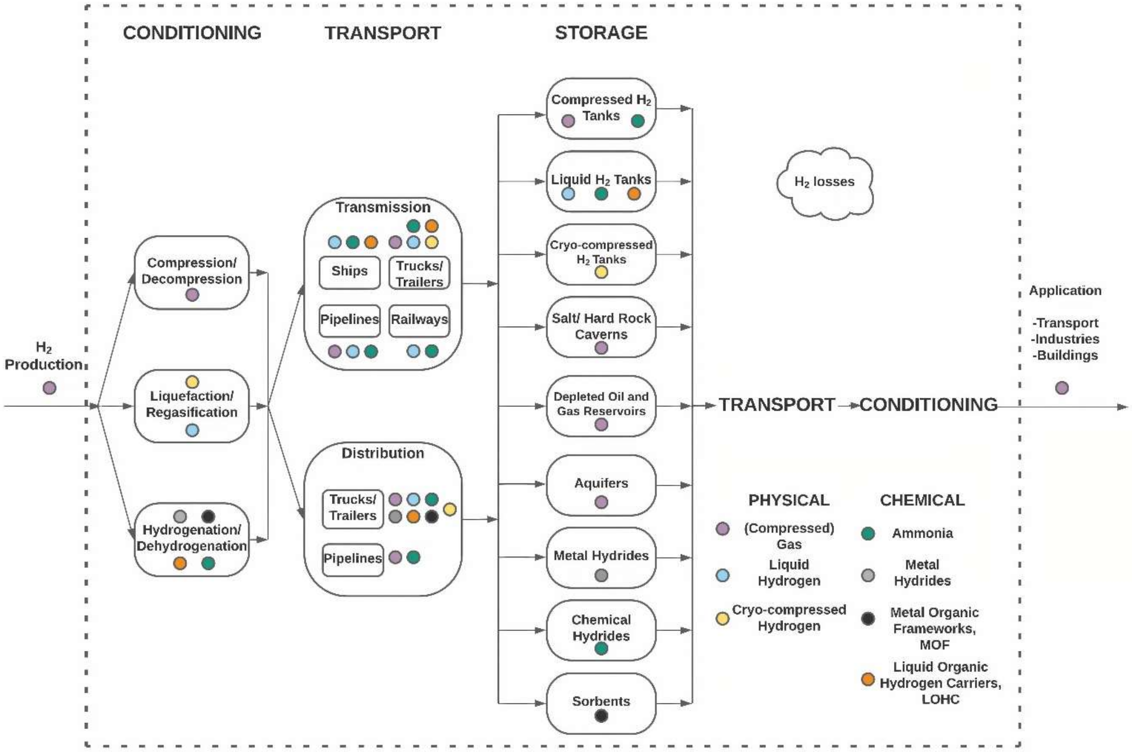

Figure 9.1: Conversion/processing, transmission, distribution, storage, and demand elements of various hydrogen forms in the value supply chain. Hydrogen production and end use are not within the system boundaries of this and the following chapters.

Losses of hydrogen[39] may occur at any moment in the hydrogen supply chain as leakage, boil-off losses in case of liquid hydrogen, or unintended conversion (e.g., methanation in underground storage). Specific hydrogen losses depend on system boundaries, supply chain design, and case specific assumptions, but are usually in the order of a few percent between production and consumption (without considering "losses" due to use of hydrogen as fuel or energy carrier for e.g. its own transportation and conversion) (Hank *et al.*, 2020; Raab, Maier and Dietrich, 2021). The expected total energy efficiency of supply chains are heavily affected by the design choices of each specific supply chain.

Processing or conversion activities aims at high energy densities for transport and storage of the hydrogen (Figure 9.2 and Figure 9.3). Figure 9.2 illustrates that compression up to 700 bar already increases the energy density to 40 g/L, while liquefaction combined with compression (cryo-compressed hydrogen) reaches 81 g/L. Hydrogenation is a wide category of hydrogen conversion pathways, and thus the energy density which can be reached varies between 10 g/L and 150 g/L. Metal Organic Frameworks (MOFs) are still heavily under research regarding optimized combination of sorbent type and pressure. At ambient temperature and pressure, the volumetric density is around 10-15 g/L, while it increases significantly under pressure (Ahmed *et al.*, 2017).

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[39] Hydrogen losses – as opposed to losses of natural gas – during conversion, transport and storage only represent a direct economic issue, but not a direct issue in terms of impacts on climate change – the IPCC does not list hydrogen as greenhouse gas with a global warming potential (Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, 2013).

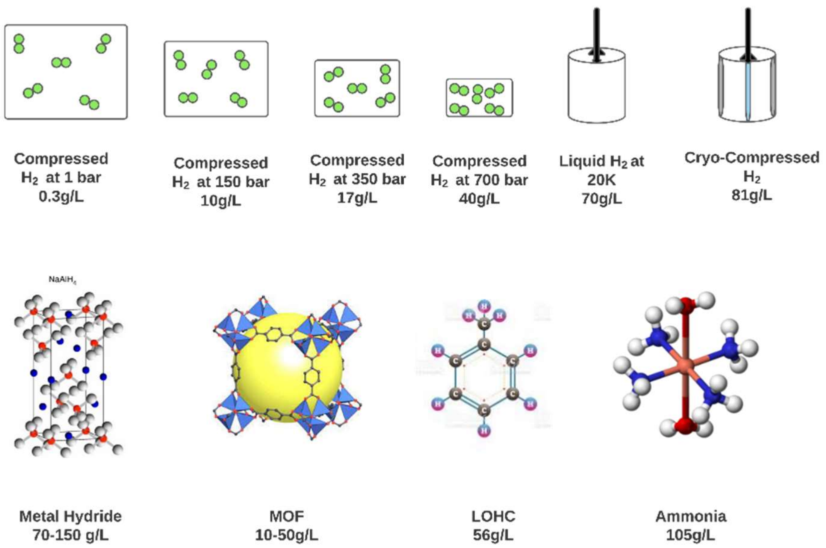

Figure 9.2: Qualitative illustration of hydrogen energy density (in g/L) related to its physical and chemical transformation. Based on (Ren *et al.*, 2015; Ahmed *et al.*, 2017; Baetcke and Kaltschmitt, 2018). Figures are own drawings or from (Peles *et al.*, 2004) (Metal Hydride), (Sun and Zhou, 2015) (MOF-5), web (LOHC[40], Ammonia[41]).

The effectiveness of hydrogen storage can be measured by comparing the gravimetric density (GD) with the volumetric density (VD) (Figure 9.3). While the GD shows the relation between the weight of the hydrogen stored and the total weight of the system (mass of stored hydrogen + mass of storing system), the VD indicates the mass of hydrogen per unit volume of the system (Tozzini and Pellegrini, 2013).

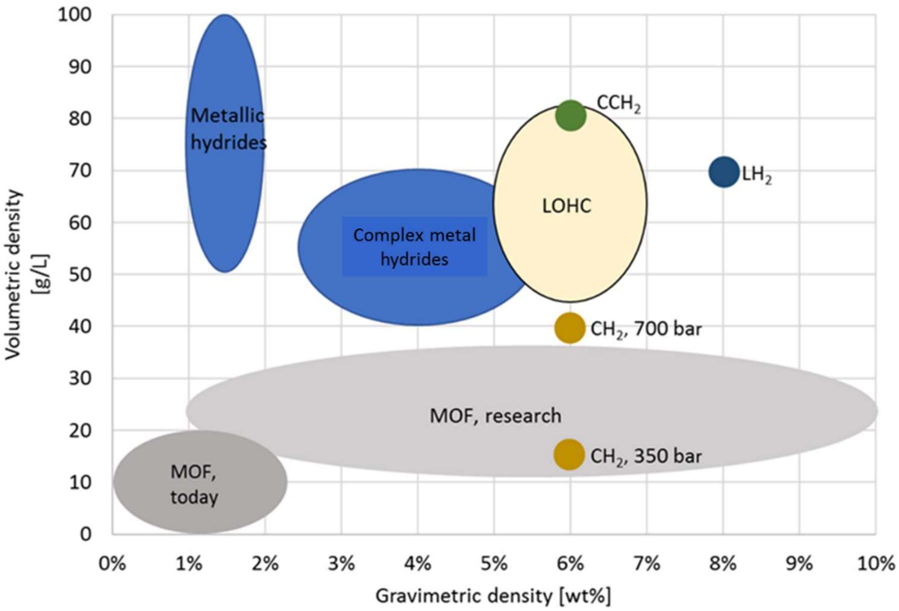

Figure 9.3: Mass vs. volumetric energy density of hydrogen. CH_2 = compressed gas hydrogen, LH_2 = liquid hydrogen, CCH_2 = cryo-compressed hydrogen, MOF = Metal Organic Framework. Ammonia is not shown in the figure – it exhibits a GD of 17% and a VD of 105 g/L. Based on (Schlapbach and Züttel, 2001; Ahmed *et al.*, 2017; Demirocak, 2017; Reuß *et al.*, 2017; Baetcke and Kaltschmitt, 2018).

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[40] https://www.123rf.com/photo_127729408_stock-vector-toluene-or-toluol-vector-illustration-labeled-structure-and-uses-diagram-infographic-scheme-of-liqui.html

[41] https://en.wikipedia.org/wiki/Ammonia

In terms of GD, some types of metal hydrides only reach around 2 wt% (Demirocak, 2017). However, they allow rather high volumetric energy densities. (El-Eskandarany, 2020) reports highest values reached by specific species for the volumetric energy density of 150 g/L, as well as a complex hydride with a gravimetric density of around 18%. Liquid and cryo-compressed hydrogen also show a good GD performance, while having the advantage of high VD. Both hydrides and MOFs are classes with huge variety of substances to be chosen, so that the variability in both VD and GD is still large. However, research focuses on finding most beneficial hydrides and MOFs for best adaptation to transport or storage needs and subsequent use of hydrogen.

Compression of hydrogen increases the volumetric energy density, and liquefaction even goes beyond that. Even more compactness can be reached by packing hydrogen within solid state systems as metal hydrides, which are investigated in many different varieties. However, increased energy density also comes with increased energy use for the conversion step to some extent, as Figure 9.4 shows for the complete round-trip of hydrogen conversion.

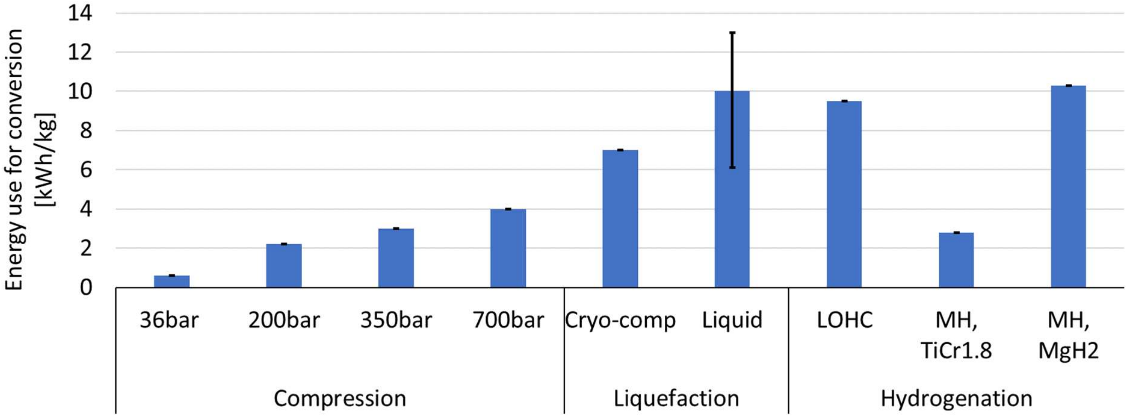

Figure 9.4: Energy requirement for various conditioning processes, representing the round trip conversion to a specific state and turning back into useable hydrogen where necessary in a specific hydrogen supply chain (Elgowainy, Reddi and Wang, 2013; Reuß *et al.*, 2017; Wulf *et al.*, 2018; Andersson and Grönkvist, 2019; Olabi *et al.*, 2020). The error bar for liquefaction shows the potential range of energy use per kg hydrogen.No information could be found on energy requirements with regards to MOFs. MH = Metal Hydride.

Compression of the hydrogen as a gas comes with higher energy use the higher the compression level is, with a steep increase in energy use per kg hydrogen for compression up to around 100 bar. The energy use happens at the compression stage, while decompressions is mostly performed via volume expansion. Liquefaction requires a lot of energy to convert gaseous hydrogen to liquid due to a temperature of as low as -252°C needed. In contrast, cryo-compression makes use of cooling the hydrogen at high pressure, which avoids the energy penalty from the liquefaction process. In case of LOHCs and metal hydrides, hydrogenation is a high energy consuming process and accounts for 30-40% of the hydrogen energy content. This is mostly due to the heating and cooling needed for the desorption and adsorption process, with a focus on the energy input to the endothermic desorption process. No data on the energy use for hydrogen storage in Metal Organic Frameworks (MOF) could be found in literature, with the adsorption process being exothermic and desorption being endothermic.

9.1 (De-) Compression

Compression is a very important step for storage and transport of gaseous hydrogen. While production of hydrogen usually supplies hydrogen at around 25 bar, various higher pressures may be needed depending on chosen storage technology and/or the mode of transport. As the energy use for compression increases with higher pressure (up to 4 kWh/kg for 700 bar), this in turn leads to higher compression costs. In contrast, decompression is an exogenous process releasing energy to the environment.

9.2 (De-) Liquefaction

Hydrogen in liquid form is ideally suitable for transport over longer distances due to its high volumetric density. Liquefaction is performed through cooling the hydrogen below its critical point, namely -253°C at a pressure of 1 bar. This is a rather energy-intensive process and requires ~10 kWh/kg of energy for converting the gaseous hydrogen into liquid form (Cardella, Decker and Klein, 2017). The specific energy consumption for the liquefaction plants is expected to decrease to about 6 kWh/kg by distinct improvement in the liquefaction technology. Subsequent transport or storage happens as a liquid in pressurized and thermally insulated containers. Such special infrastructure leads to increased investment cost. In case of cryo-compressed liquid hydrogen, the hydrogen is liquefied and cooled down to -253°C and then it is compressed at 250-300 bar which increases its volumetric density to ~81g/l.[42] As such, both the advantages of low temperatures as well as high pressures and high volumetric density together with a high gravimetric density are combined.

9.3 (De-) Hydrogenation

Hydrogenation is the reaction between molecular hydrogen and an organic or inorganic substrate. It is an exothermic reaction including a catalyst which takes place at high hydrogen partial pressures, but lower temperatures. Dehydrogenation on the other hand is a hydrogen-releasing process, which takes place at lower hydrogen partial pressure. It is an endothermic reaction and is favored at high temperatures.

Various substrates are under research for optimal hydrogenation of hydrogen. The most important of them are the two broad classes of metal hydrides and metal organic frameworks (MOFs), in addition the use of Liquid Organic Hydrogen Carriers (LOHC) and last but not least the well-known conversion of hydrogen to ammonia.

Metal hydrides are intermetallic alloys that form strong chemical bonds with hydrogen. The bonds are not easily broken compared to their easier formation. During hydrogenation of metal hydrides, hydrogen is exothermically absorbed to vacant spaces in metal hydrides. In contrast, a high level of energy is required to release the hydrogen from metal hydrides (~10-12 kWh/kg) to support the endothermic reaction at high temperatures at relatively low pressure. High storage densities can be reached at atmospheric conditions because of the strong bond between hydrogen and metals. A wide variety of metal hydride hydrogen storage solutions are being discussed within the three classes “ionic hydrides”, “covalent hydrides”, and “metallic hydrides” (Srinivasan and Demirocak, 2017). While some of them have already been studied extensively, others are currently under research, which makes this a rather heterogeneous class of potential hydrogen storage. Metal hydrides are – due to their unfavourable weight – not suited for mobility applications, but are still under research for other applications at TRL 7-9 (Bruce *et al.*, 2018).

MOFs are crystalline materials consisting of metal ions linked together by organic ligands which generate micropores (<2 nm) and channels. The hydrogen molecules are physisorbed on the surface of the pores of the materials. Physisorption or physical adsorption is an adsorption process in which the forces involved are intermolecular forces (van der Waals forces), which does not include a significant change in the electronic orbital patterns of the materials involved. It is a reversible process since no activation energy is involved and thus has a lower interaction energy. The hydrogen storage capacity mainly depends on the surface area and pore volume. The main limitation of their use is the weak intermolecular forces between hydrogen and the surface of the sorbents. These physisorption based materials have high storage capacities only at liquid nitrogen temperatures and high pressures and very low capacity at ambient temperature and pressure. Again, numerous candidates of MOFs for hydrogen storage exist. The most promising ones have “defined crystalline structures, extremely high

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[42] Liquid hydrogen is slightly compressible: at 21 K, the liquid density is 81 g/L at 240 bar compared to 70 g/L at 1 bar (Ahluwalia, Peng and Hua, 2016).

surface areas, and very high pore volumes" (Zou and Zhou, 2017). TRL is still very low at 2 (Bruce *et al.*, 2018).

LOHC systems are composed of pairs of hydrogen-lean and hydrogen-rich liquid organic compounds that store hydrogen by means of repeated, catalytic hydrogenation and dehydrogenation cycles (Reuß *et al.*, 2017). The main advantage of the LOHC technology is that it allows the storage of hydrogen in chemically bound form under ambient conditions which eliminates the requirement of high-pressure or super insulated tank. Furthermore, existing conventional infrastructure for (liquid) fossil fuels (e.g., tanker ships, rail trucks, road tankers and tank farms) can be used for this type of liquid hydrogen storage (Teichmann, Arlt and Wasserscheid, 2012; Niermann *et al.*, 2021). Hydrogenated LOHC can be transported over longer distances without any boil-off losses and is manageable in an easy way. To use the stored hydrogen at the destination, an endothermal dehydrogenation process is carried out at elevated temperatures and ambient pressure (Hank *et al.*, 2020). (Brückner *et al.*, 2014) show that the LOHC system dibenzyl-toluene (H0-DBT)/perhydro-dibenzyl-toluene (H18-DBT) is highly promising as its storage density is up to 6.3% weight of hydrogen with respect to the total carrier weight, it is easy to handle and its high cycle stability offer significant benefits (Reuß *et al.*, 2017). DBT-based LOHC is currently at a TRL of 6-7 (Bruce *et al.*, 2018).

Finally, **Ammonia** (NH_3) is a well-known basic building block for fertilizers based on hydrogen, which (in its traditional production route) is combined with nitrogen via the Haber-Bosch process. Ammonia exhibits a high hydrogen content with a gravimetric density of 17.7% (wt) and volumetric density of ~105g/L available in its liquid phase at 10 bars. Its production is associated with relatively high energy demand: 9.5 kWh and 12 kWh heat and electricity per kg of ammonia using natural gas reforming coupled with Haber-Bosch and electrolysis coupled with Haber-Bosch, respectively (Ghavam *et al.*, 2021). Dehydrogenation of ammonia is the most challenging part of using ammonia as a hydrogen storage medium. The process requires temperatures as high as 500-900°C and Ruthenium as a very costly catalyst. The process of dehydrogenation of ammonia requires ~7.9 kWh/kg of energy and high temperatures for the reaction to obtain hydrogen and nitrogen. Due to these difficulties, the use of hydrogen from an ammonia supply chain is not discussed in detail in the further chapters of this report.

The alternative to dehydrogenation of ammonia is its direct use as energy carrier or fuel. Use in internal combustion engines is possible, but associated with several drawbacks – low energy density compared to hydrocarbon fuels and toxicity among them. Most frequently, using ammonia in solid oxide fuel cells (SOFC) for power and heat generation is discussed (Afif *et al.*, 2016) as well as using it as fuel for ships, in both combustion engines and fuel cells (Cames, Wissner and Sutter, 2021).

9.4 Excursus: Risk/reliability issues of hydrogen systems

Based on a recent comprehensive review on risk and reliability analysis in the context of hydrogen storage and delivery (Moradi and Groth, 2019), the main challenges with this respect are briefly summarized here.

9.4.1 Material properties-related issues

Material property related challenges can be categorized as follows:

- **Hydrogen impact on materials**: hydrogen embrittlement and the associated loss of material strength is an important concern when it comes to steel used for e.g. pipelines and tanks. However, embrittlement might also affect the end users such as gas turbines, gas-fueled internal combustion engines and even household boilers and ovens in the long term. As an alternative to steel pipelines, the use of Fiber Reinforced Polymers (FRP) is investigated suffering from reduced pressure though. Overall, (Moradi and Groth, 2019) state that there is still a lack of actual operation or large scale experiments data to evaluate long-term impacts of hydrogen on materials.

- **Liner blistering in pressure vessels**: in pressure vessels, a polymer liner is assembled with a metallic boss and wrapped with carbon fiber composites. Liner is used to ensure that the vessel is sealed. Under high pressures, plastic liner absorbs hydrogen gas and if depressurization occur too fast, the accumulated gas cannot escape by diffusion and blistering happens. (Moradi and Groth, 2019) conclude that the question of how exactly blistering can affect leakage in pressure vessels needs to be addressed and a definitive measure for material and manufacturing process selection should be devised.
- **Damage mechanisms of carbon fibers**: the complex structures of carbon fiber materials make their behaviour under stress hard to predict. Use of probabilistic methods in the design process of carbon fiber structures such as hydrogen storage tanks is recommended.
- **Resistance to fire and high temperature in storage vessels**: whenever resins and polymers are used, the maximum operational temperature is of concern, since commonly these materials are much more vulnerable to high temperatures than metallic materials. Accordingly, fire protection and understanding the composite materials behavior in fire is of great importance for hydrogen storage devices.

9.4.2 Hydrogen handling-related issues

Hydrogen handling-related challenges can be categorized as follows:

- **Temperature variation**: Designing hydrogen storage devices needs to take into account hydrogen temperature variations inside tanks during filling and emptying, in nozzles used in fueling stations, and in pumps and compressors used to handle hydrogen. Temperature changes, in the long term, can result in a shorter lifetime of storage vessels unless design improvements be applied.
- **Hydrogen leakage**: hydrogen molecules are light and small and therefore, they can permeate through materials and/or penetrate in normally fine seals relatively easily. Leakage measurement has shown that the volume leakage rate of hydrogen in steel and ductile gas distribution systems is about three times higher than the leakage rate of natural gas.
- **Contamination**: if the current natural gas pipelines were going to be used to transport hydrogen, an important consideration would be the unknown amount of corroded spots in the pipelines. Hydrogen gas may become contaminated by the corroded materials, which would require purification for certain applications like fuel cells. Other sources of contamination can be lubricating oils in pumps and compressors, and water degas from polymer liners in composite storage vessels. (Moradi and Groth, 2019) state that there is no study evaluating the mentioned possible contamination sources and how they should be compensated for. In some types of underground storage, methanation is possible to happen, which in some settings may be a desired effect, but in other cases leads to unwanted contamination of the stored hydrogen.
- **Pressure fluctuations in pipelines**: evidence suggests that pressure fluctuations in pipeline networks used for hydrogen transport may severely damage the distribution network (Yu *et al.*, 2016). Bulk storage facilities would be required to balance the fluctuations and further studies are needed to estimate the amplitude of the expected fluctuations, characterize the impacts, and design the control scenarios (Moradi and Groth, 2019).

10 Hydrogen transport

As shown in Figure 9.1, hydrogen ***transport*** should be differentiated into hydrogen ***transmission*** over long distances and last mile, short-distance ***distribution***. Quantity to be delivered and the transport distance determine the most suitable means of hydrogen transportation. The major modes of hydrogen transport are trucks or trailers, ships, pipelines, or railways. Trucks are used for road transport over any distance up to 4000 km, while trailers (which are trucks that are loaded with several long cylinders filled with gaseous compressed hydrogen) only travel long distances. Rail and ships are used for long distances over 2000 km. Hydrogen in pipelines is most suited for transport at high pressure over medium to long distances, but may also exist at lower pressure for short distances. Compressed gas is transported using high-pressure cylinders, tube-trailers, or pipelines. Liquid hydrogen is transported using special double-walled insulated tanks to prevent boil-off of liquid hydrogen. Metal hydrides can be used for transport by absorbing hydrogen with a metal hydride, then loading the entire container onto a trailer or railcar for transport to the desired site. The transport of ammonia as such is well-known and established; however, using ammonia as transport medium for hydrogen does not represent a common option today.

Means of transport and transport vehicles, respectively, differ in terms of capacity, flexibility, costs, land requirements, etc. Table 10.1 provides a qualitative overview.

Table 10.1: Qualitative characterization of hydrogen transport options. Capacity: “Small” <2000 kg, “Medium” 1000-8000 kg, “Large” >8000 kg. Transport distance: “Short” <100 km; “Medium” 100-3000 km; “Long” >3000 km.

Transport mode	Hydrogen mode	Capacity	Transport Distance	Experience (deployment phase)	Comment
Transmission					
Truck/Trailers	Compressed gas	Small	Medium (< 300 km)	Established	Compression between 200 to 700 bar. Used for smaller quantities and shorter distance due to low volumetric density.
	Liquid	Medium	Medium to long	Established. Liquefaction usually applied for truck transport when transportation distance is more than 300 km.	Trailers with LH2 can carry up to 7700 kg[43] Insulation needed to prevent boil-offs.
	Cryo-compressed	Small to Medium	Medium	Near operational	Transported at 20K and 250-350 bar. Has higher volumetric density than liquid hydrogen. Less boil-off losses than liquid.
	LOHC	Small to Medium	Medium	Near operational	
	Ammonia	Large	Medium	Established	Usually not converted back to hydrogen for end use as ammonia cracking is energy-intensive.
	MOF	Small	Medium	In development	
Pipeline	Compressed gas	Large	Medium	Commercially available	Suitable for large mass flows of hydrogen and for intercity transmission. High Capex (unless natural gas infrastructure can be used), low Opex.
	Liquid	Large	Long	In development	
	Ammonia	Large	Long	Established	
Ship	Liquid	Large (>5000t)	Long (5000km)	In development. More complex supply chain and boil-off losses. Economically attractive with long distances.	A ship loaded with containers with liquid H_2 can carry large amounts of H_2.
	LOHC	Large	Long	In development	
	Ammonia	Large	Long	Established	
Railway	Liquid	Large	Long	Not widely used	
	Ammonia	Large	Long	Not widely used	
Distribution					
Truck	Compressed gas	Small	Short	Established	
	Liquid	Large	Short	Established	
	Cryo-compressed	Large	Short	Not widely used	
	MOF	Small	Short	Near operational	
	Ammonia	Large	Short	Established	
	LOHC	Large	Short	Near operational	
	Metal hydride	Small	Short	In development	
Pipeline	Compressed gas	Large	Short	Established	
	Ammonia	Large	Short	Established	

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[43] https://www.thechemicalengineer.com/features/hydrogen-transport/ (4.5.2021)

10.1 Technologies

The hydrogen transport technologies are presented by transport mode, with additions on specific physical states of hydrogen. More detailed description of LOHCs is provided in section 11.1.6.

10.1.1 Pipeline

Pipelines are regarded as the most efficient method of transporting large quantities of hydrogen over short to medium distances (Staffell *et al.*, 2019). Around 3000 km of high-pressure hydrogen pipelines are already in use in Europe and North America. The existing hydrogen pipelines are operated by industrial hydrogen producers and are mainly used to deliver hydrogen to chemical and refinery facilities. The United States count 2'600 km, Belgium 600 km and Germany just under 400 km of such industrial hydrogen pipelines (Bourne, 2012). To minimize diffusion leakages and to improve resistance to hydrogen embrittlement, materials must be chosen carefully to transport hydrogen via pipelines. For pipelines, the pressure is limited to 50 bar[44] to reduce the hydrogen leaks through diffusion and embrittlement of materials (d'Amore-Domenech, Leo and Pollet, 2021).

The inconsistent demand for hydrogen can be very costly for further pipeline development. Because of hydrogen embrittlement, existing high-carbon steel natural gas pipelines might fail if repurposed, so new high-grade steel construction would be required (van der Zwaan *et al.*, 2011). Polyethylene natural gas pipes being installed across the UK and Europe are hydrogen compatible and are limited to pressure up to 7 bar, but larger pipes up to 17 bar have been proposed. Hydrogen pipelines have expected long lifetimes (50-100 years), although the rate of embrittlement in steel pipelines can make this difficult to predict (Staffell *et al.*, 2019). Pipelines have low operational costs (Bourne, 2012). High capital costs and the need to acquire the rights of way are the major drawbacks of pipelines. Ammonia is often transported by pipeline, and new pipelines for ammonia would be cheaper than new pipelines for pure hydrogen. The transport of LOHCs via pipelines could use existing oil pipelines, but LOHCs are still technologically immature and expensive.

Natural gas pipeline reassignment for hydrogen represents a direction of research, which has received more attention recently, and (Cerniauskas *et al.*, 2020) have performed a techno-economic assessment for Germany evaluating different options. They assessed four different ways of converting natural gas pipelines to pure hydrogen pipelines:

1. Pipelines without modification (PWM)
2. Addition of gaseous inhibitors to the hydrogen gas
3. Coating of surfaces that are in direct contact with hydrogen
4. Specialized pipeline for hydrogen delivery within the pipeline (pipe-in-pipe approach)

Due to the prohibitively high costs of options 3 and 4, only the first two were evaluated in detail. The pipeline without modification approach mitigates hydrogen embrittlement through additional maintenance and repair procedures for the pipeline. Main strengths of this approach are the fact that only limited pipeline modifications are required, as only new hydrogen-adapted recompression and gas pressure regulation stations are installed. Furthermore, material fracturing can be diminished in the case of static load operation. However, the increased crack growth will have a negative impact on the material strength and thus on the O&M cost of the pipeline. In case of addition of gaseous inhibitors to the hydrogen gas, inhibitors such as oxygen, carbon monoxide or sulfur dioxide supplement the gas stream to undermine any reactions between the pipeline material and hydrogen. Thus, inhibitors act as protection layer against hydrogen-induced degradation effects, as admixed inhibitors prevent hydrogen adsorption by the pipeline material. Limited modification of the pipeline is required, as inhibitors can be easily admixed to the hydrogen stream. However, the drawbacks of the inhibitor approach are the toxicity and security risks associated with the specific inhibitor type used. Furthermore, depending on the subsequent hydrogen processing and application, an additional

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[44] For comparison: natural gas pressure in high-pressure long-distance pipelines is up to 220 bar (Machhammer, Henschel and Füssl, 2021).

hydrogen purification step may be required (Cerniauskas *et al.*, 2020). Challenging in this context are the facts that first, despite the existing industrial piping norms in the USA and EU, there is only a very limited body of knowledge about operating reassigned pipelines and second, there has been no utilization of larger steel pipeline diameters (>300 mm) operated at high hydrogen pressures so far. This obstacle would be especially important for pipeline reassignment projects, because typical transmission pipeline diameters (e.g., in Germany) range from 500 mm to 1400 mm. For these reasons, some large-scale testing and appropriate policy measures would be necessary (Cerniauskas *et al.*, 2020).

10.1.2 Trucks and trailers

Today, hydrogen transmission mostly relies on compressed gas trailer trucks for distances less than 300 km. The “last mile” of transportation to the end user is often conducted by a truck. Highly insulated liquid hydrogen tanker trucks show carrying capacities of 2000-7700 kg, transporting the hydrogen at greater density than in compressed gas transport (Staffell *et al.*, 2019). Distances over 4000 km are not suitable as the hydrogen potentially heats up, which causes a rise in pressure. Boil-off rates may be around 0.3-0.6% per day. Note that the total boil-off losses for application of liquid hydrogen in a small-scale fueling station may be substantially higher (5-15% of the hydrogen delivered, while this decreases to 0.7%-2% for larger stations) due to further operation steps at the fueling station, mainly pumping. Solutions for capturing such losses are under development (Petitpas, 2018).

Liquid hydrogen tanker trucks are often used where there is reliable demand and the liquefaction costs can be offset by the lower unit costs of hydrogen transport. Ammonia or LOHCs can be distributed using trucks in a broadly similar way (Bourne, 2012). Around 5000 kg of hydrogen in the form of ammonia or 1700 kg hydrogen in the form of LOHC can be moved in a road tanker. In the case of LOHC, a truck is needed to transport the carrier molecules back to the original destination after the hydrogen has been extracted from them (Bourne, 2012).

Tube-trailers or cylinder bundle trailers currently deliver hydrogen using pressure vessels made of steel or composites, which are mounted on a trailer and delivered via a truck to demand sites. Tube-trailers are used for low demand transport such as during the initial rollout. They have a capacity of up to 1000 kg at pressures of up to 500 bar (Teichmann, Arlt and Wasserscheid, 2012; Staffell *et al.*, 2019). These trailers can be used for direct refueling, which reduces the onsite storage and compression need. Hydrogen delivery using tube-trailers is considered to be the most economical option for early FCEV markets, when the daily demand is low (up to about 500 kg/day) (Elgowainy *et al.*, 2014). Tube-trailers are less economic for higher hydrogen demand and over longer distances. Their infrastructure costs and lower risk makes them an attractive option for near-term transport solution (Yang and Ogden, 2007).

Steel tube-trailers are limited in capacity because of on-road weight restrictions. They can transport a hydrogen payload of up to 300 kg in a single trip. Composite tube trailers use aluminum liner wrapped with carbon fiber composite (type III) or plastic polyethylene liner wrapped with carbon fiber composite (type IV) pressure vessels that are lighter in weight, can withstand higher pressures (currently up to 1000 bar), and thus can transport a greater hydrogen payload (Elgowainy *et al.*, 2014).

10.1.3 Rail/trains

Moving hydrogen using trains could be an inland option for some regions. The delivered-to-consumed energy ratio is more favorable for liquid hydrogen rail cars than for highway tank trucks, primarily because rail car tank capacity is much larger, and railroads are more efficient than highway trucks in terms of payload relative to fuel consumption (Cheng, 2010). The railroads connecting hydrogen production plants with fueling stations need to be installed, which is impractical and uneconomical. Vapor loss and venting is an issue when it comes to the use of current railroad logistics for hydrogen transport.

10.1.4 Ship

There are currently no ships that can transport pure hydrogen.[45] The ships to transport hydrogen would be similar to liquefied natural gas (LNG) tankers, but it would require the liquefaction of hydrogen before transport. Among hydrogen carriers, ammonia is the most developed in terms of intercontinental transmission, which relies on chemical and semi-refrigerated liquefied petroleum gas (LPG) tankers. LOHCs would be the easiest form to transport hydrogen by ship, because oil product tankers could be used, taking into consideration the cost of conversion and then reconversion back to hydrogen before use (Teichmann, Arlt and Wasserscheid, 2012). All shipping supply chains require the necessary infrastructure, including storage tanks, liquefaction and regasification plants, and conversion and reconversion plants, to be built at the loading and receiving terminals as appropriate.

The long-distance transport of compressed hydrogen is not attractive due to its low energy density and is not a feasible option in existing ships. For liquid hydrogen ship transport, the capital investment is very high because of the technologically complex insulation of cryogenic containers, which results in high annual depreciation (Teichmann, Arlt and Wasserscheid, 2012).

10.1.5 Blending Hydrogen into the Natural Gas grid

Hydrogen can be safely mixed in small quantities with natural gas and injected into the existing gas network, but administrative and technical constraints limit the permissible fraction of hydrogen (Staffell *et al.*, 2019). The level of hydrogen that could be safely added depends on the distribution system and end-use appliances. The main limit of blending is on the tolerance of the end-use devices rather than on infrastructure (Blanco *et al.*, 2018). Chapter 12 is dedicated to the transport of hydrogen in the natural gas grid as a blend.

10.2 Costs

The main parameters in the calculation of hydrogen transport costs (including the conversion step) are the following:

- Conversion: Capital costs for infrastructure and materials (e.g., compressor, liquefier, storage carrier materials); operating costs for conversion from energy use (electricity and/or heat). The efficiency of the compressor (compressed H_2) also affects the costs (the smaller, the lower the efficiency).
- Transport: Capital costs for transport vessels/pipelines, vehicle, pumps, compressor (for recompression), terminals; Operating costs for boil-off losses (liquid H_2), energy input for cooling/heating as well as pumps (liquid hydrogen) and recompression (gaseous hydrogen), labor costs (driver), fuel costs.

The importance of the individual cost elements differs by transportation mode and hydrogen state as well as the transport distance. Further, it should be noted that some of the transportation pathways might have to integrate some type of storage in between, which is not considered in this chapter dealing exclusively with the transport itself.

According to an analysis by the IEA (International Energy Agency, 2019), transmission of gaseous hydrogen by pipeline is generally the cheapest option for distances of less than about 1500 km. Higher distances come along with higher recompression activities which drive up the pipeline transport costs. For long distances or overseas transport, liquefaction, LOHC or ammonia seem to lead to lower transportation cost. However, the conditioning (both conversion before export as well as reconversion before use) will also add to the total costs. For short distances and small amounts, gas trucks are preferred today. For medium amounts of hydrogen and longer distances, liquid hydrogen truck

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[45] Kawasaki is currently launching a pilot project to ship liquefied hydrogen from Australia to Japan (https://www.reuters.com/article/us-japan-hydrogen-kawasaki-heavy-idUSKBN29V0SW (22.6.2021)).

delivery is preferred. For large amounts of hydrogen, pipeline distribution is preferred (Yang and Ogden, 2007).

Cost data in literature depend heavily on the chosen system boundaries (e.g., inclusion of hydrogen production, consideration of conversion steps, etc.) and literature data is not always transparent – therefore, correct interpretation can be difficult. All cost data presented below do not include hydrogen production and use cost, but focus on the transport related conversion and transportation steps between production and use (excluding any additional longer term storage needed). Further, cost data in general depend on the volume of hydrogen which needs to be transported as well as the transport distance. However, based on the currently available literature, a quantitative correlation between transport volumes and costs cannot be provided – corresponding transparent data are missing.

An overview on current or near-future hydrogen transmission cost is given in Figure 10.1.[46] MOF and metal hydrides have not been included due to their early development stage, which does not allow fair comparison. The import and export terminal represent any preparatory or handling work such as compression and related infrastructure. In case of the transport of liquid hydrogen in trucks, the reference does not differentiate between the import terminal and the liquefaction so that both are represented by the blue bar. The "import terminal" indicates the point of conditioning where the hydrogen is either compressed, liquefied or hydrogenated on the basis of the state of required hydrogen transportation. The "export terminal" involves either regasification, decompression or dehydrogenation once the hydrogen reaches the destination. LOHC-Tol is liquid organic hydrogen carrier based on Toluene which is a commercially available chemical and already used in demonstration projects. LOHC-DBT is LOHC based on Di-benzyl-Toluene, which shows advantageous physical properties in comparison to LOHC-Tol.

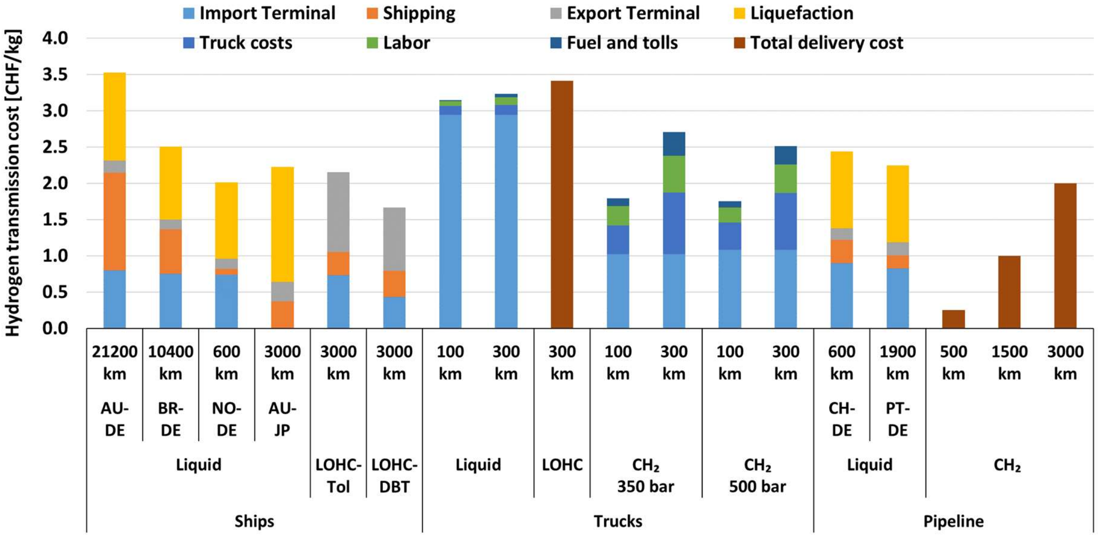

Figure 10.1: Hydrogen transmission costs with various modes (Ship, Trucks, Pipelines) and states (Liquid, LOHC, compressed hydrogen CH_2) over various distances, valid for the year 2020. Based on (HYSTOC, 2019b; Wijayanta *et al.*, 2019; Brändle, Schönfisch and Schulte, 2020; Hurskainen and Ihonen, 2020; Anastasopoulou *et al.*, 2021; Raab, Maier and Dietrich, 2021). In case of liquefied hydrogen transport per truck, the "import terminal" includes the liquefaction facitilyand its energy demand. AU = Australia, BR = Brazil, DE = Germany, NO = Norway, JP = Japan, PT = Portugal, Tol = Toluene, DBT = Dibenzyltoluene, CH_2 = (gaseous) compressed hydrogen.

The highest cost contribution in all the transportation cases usually stems from the conversion processes like liquefaction, compression, and hydrogenation. In case of ships and trucks, the cost

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[46] For comparison: typical natural gas transport costs per pipeline over a few thousand kilometers are in the order of 100 $ per ton of oil equivalent (https://blog.energybrainpool.com/tutorial-gasmarkt-teil_6-erdgastransport-und-speicherung/), which corresponds to about 0.3 CHF per kg H_2 equivalent.

contributions of vehicle fuel as well as labor or tolls increase with longer distance. Pipeline cost are driven by the infrastructure itself, increasing with higher distance in case of compressed hydrogen due to recompression activities. Transmission cost depend largely on whether new pipeline costruction or retrofitting an existing natural gas pipeline are considered (Brändle, Schönfisch and Schulte, 2020).

It should be noted that the (relative) importance of the transport cost within the full supply chain varies with the hydrogen production source and conditioning activities. While for example hydrogen from electrolysis is still much more expensive than reforming of natural gas (e.g., (Kreidelmeyer *et al.*, 2020)) so that transport cost would be less driving the overall hydrogen supply cost. Decreasing production cost will also put more pressure on the costs in the remaining supply chain.

10.2.1 Pipeline

The first transportation mode considered is hydrogen transportation by pipelines. Pipelines can only be economically attractive with high hydrogen mass flows, since the capital expenditures are higher compared to other transportation modes (Hydrogen Council, 2020), see also Table 10.1 (Staffell and Dodds, 2017). Capital expenditures can be reduced when for example natural gas pipelines can be adapted and re-used (International Energy Agency, 2019; Cerniauskas *et al.*, 2020). Pipelines can both be economically attractive for transmission over long distances as well as for the local distribution of hydrogen (International Energy Agency, 2019).

The Hydrogen Council (Hydrogen Council, 2020) reported hydrogen distribution costs of 1.6 CHF/kg H_2 when using new transmission pipelines, although the influence of the transportation volumes and distances is on this figure is unclear. A more thorough analysis and associated cost data is presented in a report of the IEA (IEA, 2019; International Energy Agency, 2019). The long-distance transmission costs – for pipeline transport – are presented in Figure 10.1, obtained from (International Energy Agency, 2019). It turns out that hydrogen transportation over longer distances is mainly influenced by capital expenditures and that costs scale with the transportation distance. Further, the most attractive transportation mode is case-specific and mainly depends on the transportation distance, mass flow of hydrogen (or volume) as well as the hydrogen application (International Energy Agency, 2019).

In general, pipelines are economically attractive for transportation distances of less than ~2000 km in combination with a high hydrogen mass flow, while ships become economically attractive when transportation distances are longer than ~2000 km.

According to (Cerniauskas *et al.*, 2020), reassigning natural gas pipelines for hydrogen can be cheaper than new hydrogen pipelines. The “Pipelines without modification (PWM)” concept (see section 10.1.1) was found to be economically most attractive, being able to reduce the hydrogen transmission costs by more than 60% compared to new hydrogen pipelines. However, the cost benefit crucially depends on transport volumes and mass flow rates, as visualized in Figure 10.2.

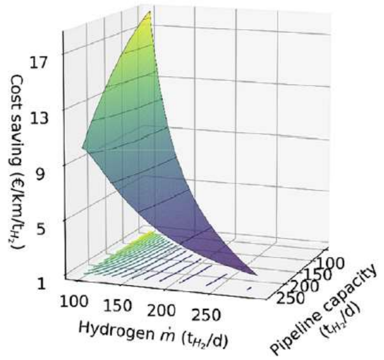

Figure 10.2: Cost savings by pipeline reassignment in comparison to a newly build H_2 pipeline for the PWM concept (Cerniauskas *et al.*, 2020).

However, (Cerniauskas *et al.*, 2020) stress the fact that with current cost structures, the high cost share of production and fueling diminishes the overall impact of pipeline reassignment, highlighting the challenges for a cost-competitive hydrogen supply concerning the low-cost hydrogen production and the improved utilization of the refueling station network (for automotive applications).

This observation is also supported by a recent analysis performed on behalf of a group of European gas Transmission System Operators (Jens *et al.*, 2021). Their vision of a "European Hydrogen Backbone" provides European hydrogen infrastructure maps for 2030, 2035 and 2040 with a dedicated hydrogen pipeline transport network largely based on repurposed existing gas infrastructure. The proposed network in 2040 with an overall pipeline length of about 40'000 km is expected to require a total investment of 43-81 billion Euro, based on using 69% of repurposed natural gas pipelines and 31% new pipeline stretches. Estimated levelised transportation costs for the entire pipeline network amount to 0.11-0.21 Euro per kg of hydrogen. The authors state that such a pipeline network represents "an attractive and cost-effective option for long-distance transportation of hydrogen, taking into account an estimated future production cost of 1-2 Euro per kg of hydrogen" (Jens *et al.*, 2021). These estimates are substantially lower tha others – which confirms the "economy of scale", i.e. the fact that a large-scale pipeline network designed and used for transporting large amounts of hydrogen reduces transport consts drastically in comparison to single dedicated pipelines.

10.2.2 Truck and trailers

Hydrogen can be transported as ***compressed gas*** on trailers trucks. This transportation mode is (especially) economically attractive for hydrogen distribution for relatively small transportation distances (<300 km) and volumes (International Energy Agency, 2019). In these cases, hydrogen can be compressed in tanks and loaded on gas trailer trucks; which results in ~1100 kg H_2 at 500 bar, although this hydrogen mass is hardly achieved in reality (International Energy Agency, 2019). Alternatively, cryogenic tankers can be used to transport ***liquefied*** hydrogen up to distances of more than 4000 km, and could also be used to transport much higher amounts of hydrogen (International Energy Agency, 2019). However, the liquefaction of hydrogen adds significant costs to overall hydrogen transportation costs.

Figure 10.3 demonstrates the costs of hydrogen distribution over short distances associated with hydrogen transport by trucks and pipes. Especially the transportation of liquefied hydrogen by trucks tends to be economically attractive with longer distances, while the transportation of gaseous hydrogen exhibits substantially higher costs.

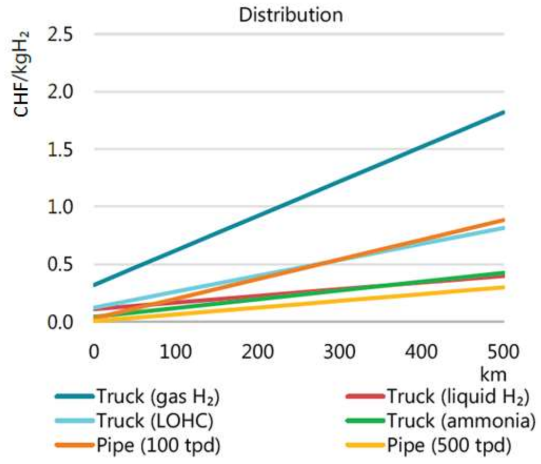

Figure 10.3: Costs of short-distance hydrogen distribution, reproduced from the (International Energy Agency, 2019). Tbd = Tonnes per day. System boundaries may not be the same as for the numbers shown in Figure 10.1.

Road transport of ***liquid hydrogen*** is slightly cheaper than transport of ***LOHCs*** due to the higher transport capacity of liquid hydrogen, but the liquefaction cost is higher, which cannot be ignored. The cost for storing hydrogen in dibenzyl toluene is much higher due to the cost for the chemical compound. The toluene chain has the lowest cost for storing hydrogen since it is much cheaper than dibenzyl toluene. Toluene, however, is much more toxic than dibenzyl toluene (DBT). This influences the clearance of the LOHCs for road traffic (Wulf and Zapp, 2018). The transport of liquid hydrogen is more expensive than of LOHCs due to high investments in the liquefaction facility.

In case of ***LOHC***, energy consumption as well as transportation costs are rather low compared to liquid hydrogen and gaseous hydrogen delivery. Long distance transport via ship seems promising due to the low-cost level and the possibility to use existing fleets of product tankers (Teichmann, Arlt and Wasserscheid, 2012).

Despite the high cost of liquefaction processes and comparatively efficient cost of transportation across long distances, the delivery of liquid hydrogen is cheaper than that of compressed gaseous hydrogen (Han, Ryu and Lee, 2012).

The comparison of the costs of compressed gas versus liquid hydrogen in transmission and distribution per truck is shown in Figure 10.4.

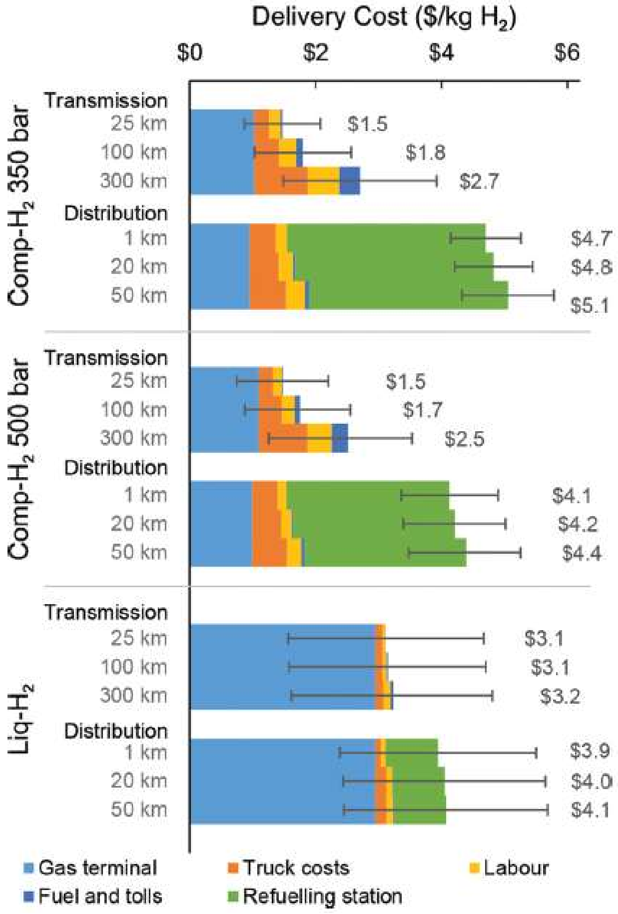

Figure 10.4: Hydrogen transmission and distribution cost as compressed gas or liquid per truck over selected distances. Taken from (Anastasopoulou et al., 2021). The "gas terminal" includes the liquefaction facility and its energy demand in case of liquefied hydrogen transport.

(Anastasopoulou *et al.*, 2021) have not only assessed the cost for compressed gas and liquid hydrogen, but also for two novel types of MOF-based truck transport.

During distribution, high costs occur at the refueling station. For both distribution and transmission, costs increase with increasing distance due to higher labor, fuel and truck costs. This finding is supported by (Lahnaoui *et al.*, 2019). As already discussed above, liquefaction of hydrogen comes with increased cost, which is shown by the "gas terminal" part in Figure 10.4. Compared to costs of around 1.5-3.2 \$/kg H_2 for liquid or compressed hydrogen, prospective cost estimates of two specific types of MOF vary between 6.5 \$/kg H_2 and 56.5 \$/kg H_2.

Under the most optimistic technical and market conditions, MOF are capable of attaining a levelized hydrogen transmission cost lower than that for liquid H_2 and comparable to that for compressed hydrogen at 350 bar (Anastasopoulou *et al.*, 2021).

10.2.3 Ship

Ship transport is economically attractive when the hydrogen transportation distance is very high, *i.e.* more than 2000 km (see Figure 10.1). This can be mainly explained by the high capital expenditures of ships, the requirement of hydrogen liquefaction as well as the requirement of hydrogen storage and associated boil-off losses (IEA, 2019; International Energy Agency, 2019). Ship transportation becomes more attractive over longer transportation distances, since the cost increase per additional kilometer is less decisive compared to hydrogen transportation by pipelines. Figure 10.1 shows that transportation costs by ships should be determined on a case-specific basis and is on the one hand influenced by the transportation distance of hydrogen. On the other hand, as pointed out before, a high energy density is required for ship transportation, so that the (de-)liquefaction cost are important (e.g. (Kreidelmeyer *et al.*, 2020)).

10.3 Environmental burdens

Literature on life cycle assessments of the various options for hydrogen transport is scarce. (Wulf *et al.*, 2018) have performed a Life Cycle Assessment of hydrogen transport and distribution options, including storage in caverns (gaseous H_2) or in an LOHC tank.

In general, the system elements which will add to the environmental impacts of hydrogen transport (including the conditioning step) are the following:

- Conditioning: Material and energy inputs for infrastructure and storage materials (e.g., compressor, liquefier, storage carrier materials); energy and material use during operation (electricity and/or heat), end of life of infrastructure.
- Transport: Material and energy for transport vessels, vehicles; Emissions to air from leakage/boil off, fuel use of vehicles (loaded and eventual empty trips back), recompression in pipelines.

Pipelines for hydrogen transport are usually made of steel or cast iron, similar to natural gas pipelines (Rödl, Wulf and Kaltschmitt, 2018). Tank materials are more diverse, depending on whether the vessel contains compressed or liquefied hydrogen, as the latter requires more complex tank design. Examples of such designs for compressed gas tanks and liquid hydrogen tanks are shown in (Demirocak, 2017) , which however does not specify the exact type of materials used. (Rödl, Wulf and Kaltschmitt, 2018) also give examples of compressed hydrogen tank types of various volume and hydrogen capacity as well as materials (steel, composites).

Due to the partially significant energy input needs for conditioning of the hydrogen, the origin of both electricity and heat will have an influence on the environmental performance of both transport and storage of hydrogen. The use of renewable or waste energy sources assumingly helps to keep environmental impacts on a low level. No information could be found in literature on environmental impacts from production of metal hydrides, organic carriers, or metal organic frameworks, so that no conclusions can be drawn on their importance within a Life Cycle Assessment.

(Rödl, Wulf and Kaltschmitt, 2018) assess the fossil energy use and greenhouse gas emissions for several case studies which include compressed and liquid hydrogen and various hydrogen production pathways. They find that the transport of the hydrogen (including conditioning) becomes the more important the less fossil energy is used during hydrogen production and the less greenhouse gas emissions are related to the hydrogen production including the energy feedstock (see also (Wulf *et al.*, 2018)). They further could show that the transport distance has little influence on the greenhouse gas emissions of liquid hydrogen, while it is important for various types of vessels for compressed hydrogen (Figure 10.5). The high energy input for the liquefaction process is thus outbalanced for longer distances due to higher fuel demand of the trucks moving around heavy steel vessels. This effect cannot be observed for lower-weight composite vessels, which can in addition take up larger amounts of hydrogen. Pipeline transportation peforms best even with re-compression every 100 km considered, and also when looking at the results on a per tkm basis as further shown in (Rödl, Wulf and Kaltschmitt, 2018).

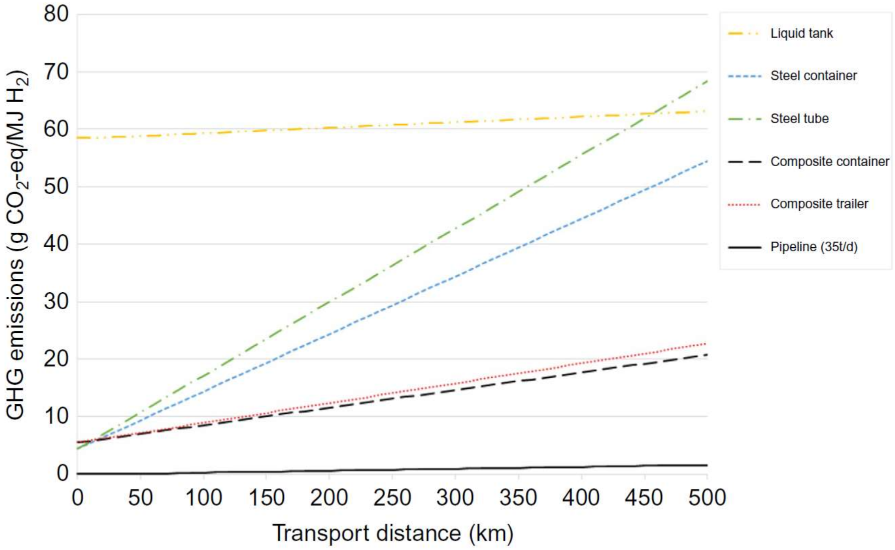

Figure 10.5: Relation between greenhouse gas emissions and transport distance for 1 MJ hydrogen transported in liquid form ("Liquid tank") or compressed gas in various vessels or a pipeline. Taken from (Rödl, Wulf and Kaltschmitt, 2018).

Further case studies have been performed by those authors. In (Wulf and Zapp, 2018) they analyse liquefaction based on either grid electricity or wind power as well as LOHC based transport again with dibenzyltoluene (DBT) and toluene. In (Wulf *et al.*, 2018) they investigate three supply chains based on LOHCs, compressed hydrogen storage in salt caverns, and compressed gas truck transport. In both studies, hydrogen production is modelled with an alkaline electrolyser powered by wind energy. Transport technologies include pipelines, gaseous H_2 trailers and LOHC trailers. They included various types of refueling stations. The study again concludes that transportation in pipelines comes with least environmental impacts in most environmental impact categories. Truck transportation may perform slightly better in few impact categories over distances <100km. This finding is mostly explained by scaling effects.

Depending on the transportation mode, different elements in the hydrogen supply chain gain more importance as contributors to life-cycle GHG emissions, as shown in Figure 10.6. While transport as compressed gas per truck is mostly driven by the transportation in the truck, the LOHC option is driven by the dehydrogenation process. The very low impacts on climate change from pipeline transport are driven by the hydrogen production itself, and in the case of electrolysis, the electricity source.

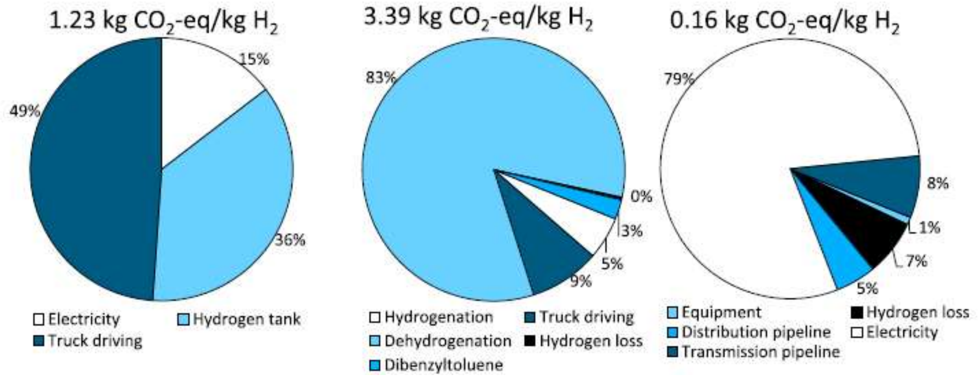

Figure 10.6: Breakdown of impacts on climate change from the supply chain of 1 kg H_2 at a refueling station (Wulf *et al.*, 2018). Left: compressed hydrogen per truck; middle: LOHC per truck; right: compressed hydrogen per pipeline.

The same authors have also calculated the global warming potential of various liquid and LOHC based supply chains (Figure 10.7).

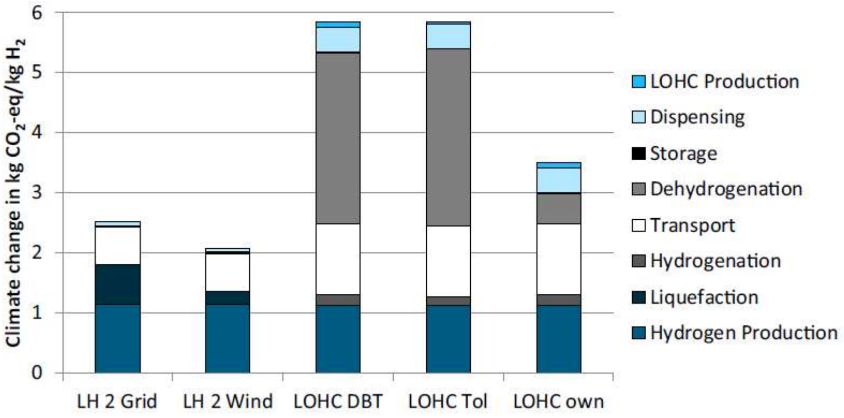

Figure 10.7: Breakdown of the impacts on climate change from the supply chain of 1 kg H_2 at a refueling station, comparing liquid hydrogen to various LOHC based supply chains. Taken from (Wulf and Zapp, 2018).

Same as for the previous figure, liquefaction and dehydrogenation take a leading role in driving the climate change impacts in the modelled supply chains. The assumptions on the energy input influence the results – in the presented case, it is heat from natural gas. An analysis of the relation of climate change impacts to the transport distance (Figure 10.8) reveals that LOHC shows a slightly steeper curve than liquid hydrogen, but both not having an important increase in climate change impacts with larger distances (as opposed to transport costs).

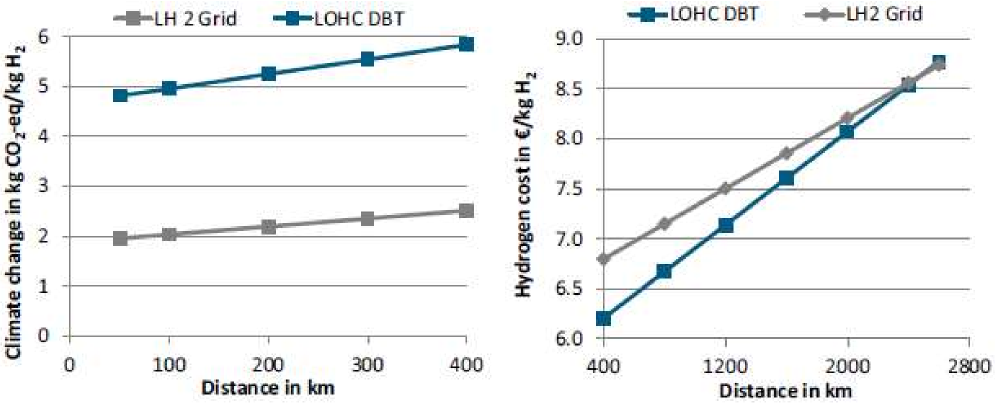

Figure 10.8: Variation of the transport distance for climate change (left) and cost (right). Taken from (Wulf and Zapp, 2018).

All these results underline the need for supply chain specific modelling of environmental impacts, taking into account the specific energy sources for conditioning and transportation as well as the transport distances and hydrogen amounts to be transported.

10.4 Excursus: Domestic hydrogen production versus import

10.4.1 General considerations

Achieving the goal of net-zero greenhouse gas emissions in Switzerland will require large scale application of hydrogen technologies in various sectors (Kirchner *et al.*, 2020; Panos *et al.*, 2021). Such a large-scale hydrogen economy is likely to require hydrogen imports, since domestic potentials for renewable electricity generation and thus green hydrogen are limited and will also be needed to cover direct electricity demand to a large extent (Bauer *et al.*, 2017; Panos *et al.*, 2021); the same holds true for many countries within the European Union (World Energy Council, 2021; van der Spek *et al.*, 2022). Therefore, the question to which extent hydrogen imports (or imports of other synthetic energy carriers) should be prioritized over domestic production and what the optimal supply chains from abroad would be become relevant.

In this context, several factors – many of them beyond the scope of this report – come into play: industrial policy, trade relationships, security of supply, geopolitics, costs, environmental and social concerns, etc. Addressing those and the interrelations between them requires a major analysis on its own, which has not been performed for Switzerland so far. However, since similar questions become relevant for neighboring countries as well and some evidence for Germany and France is available. Since – at least regarding costs and environmental issues in a qualitative way – findings for Germany and France regarding imports of hydrogen (or synthetic, electricity-based fuels in general) can to some extent be considered to be representative for Switzerland, these findings based on a few selected studies (Perner and Bothe, 2018; Brändle, Schönfisch and Schulte, 2020; Hank *et al.*, 2020; Kreidelmeyer *et al.*, 2020; Ram *et al.*, 2020; Ueckerdt *et al.*, 2021) are discussed and summarized in the following.

Perner and Bothe (Perner and Bothe, 2018) identify most promising candidates for becoming large-scale synthetic fuel producers supplying the European demand (Figure 10.9) on the basis of a range of criteria:

- Attitude of governments towards renewable energies – Governments of potential exporting countries that are open-minded with regard to renewable energy may also favor the development of a synfuels production infrastructure at scale.
- Fundamental export orientation of the economy – Economies with a strong export orientation and with corresponding technical and cost-related capabilities for synfuels production could support the development.
- Share of fossil fuel exports in national income – Countries which today finance a high proportion of their economic household through the export of fossil fuels may choose to replace fossil energy exports by synthetic fuels due to the necessary "defossilization" of global energy demand.
- Perspectives for economic development – Synfuel production at scale would allow countries with large renewable energy potential, but without significant energy exports to enter the circle of energy exporters and tap into a new source of revenue. This could be attractive especially for less developed countries.
- Potential energy exports vs. domestic energy demand – Large scale exports of synthetic fuels produced from renewable energy can only take place in the long term, if the renewable energy potentials exceed domestic energy requirements. Countries with high growth in energy demand, but limited renewable resources cannot be expected to be large scale PtX exporters.

Their country screening shows that worldwide, many countries fulfill the criteria above and at the same time exhibit vast potentials for electricity generation based on with and solar power. Countries closest to Switzerland are Iceland and Norway in the North, and Morocco and Algeria in the South. In general, import of hydrogen and synthetic fuels can be diversified to avoid dependencies on single suppliers.

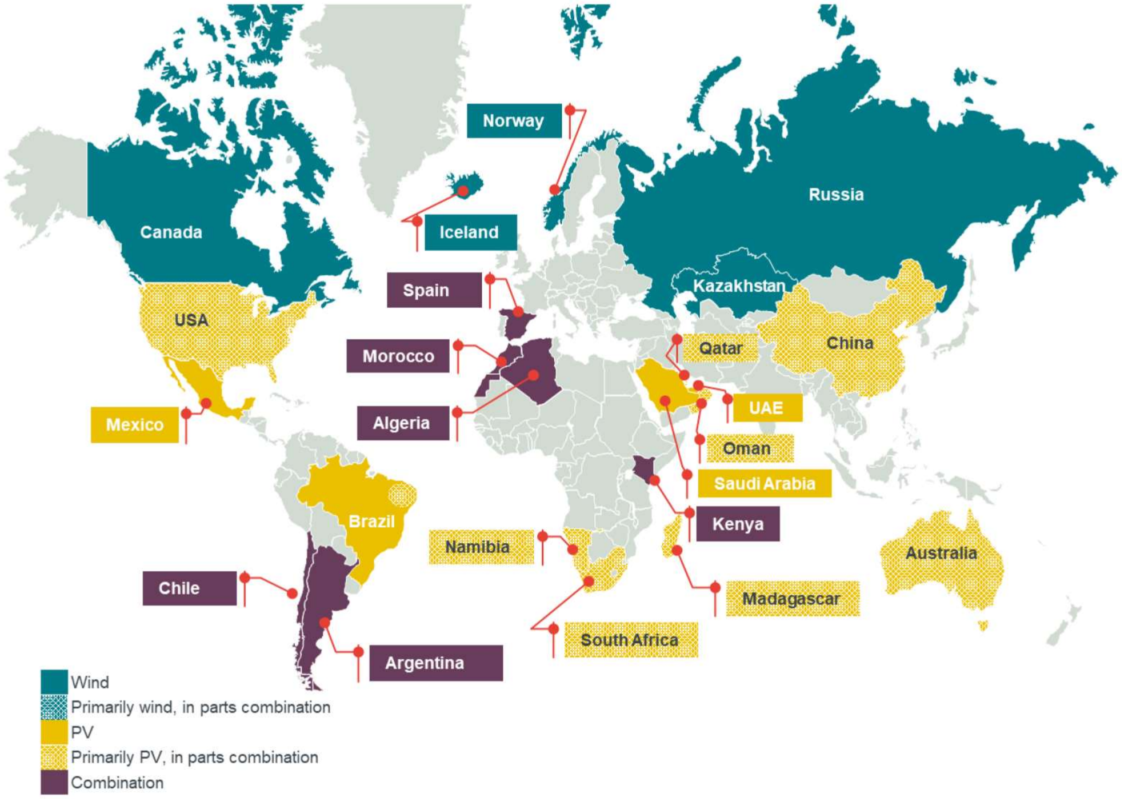

Figure 10.9: Strongest potential synfuel producers worldwide (Perner and Bothe, 2018).

10.4.2 Economic aspects

(P. Schmidt *et al.*, 2019) evaluated costs of hydrogen and synfuels supply for France, based on domestic production and imports from the MENA (Middle-East, North-Africa) region. They conclude that importing such fuels can be 20% cheaper than producing them domestically and that by 2030, many electricity-based fuels could be cost-competitive with fossil diesel for road transportation.

(Hank *et al.*, 2020) performed an economic analysis of importing electricity based fuels in various forms per ship to Germany (or central Europe), considering hydrogen imported in liquid state (LH_2), hydrogen shipped with liquid organic hydrogen carriers (LOHC) as transportation medium ($LOHC–H_2$), liquid methane (LCH_4), methanol (CH_3OH) and ammonia (NH_3). They estimate overall energy efficiencies (energy content of fuel available at the user divided by electricity needed for fuel production) in the range of about 40-50%, with liquefied hydrogen as the most efficient and methanol as the least efficient energy carrier. In terms of fuel production and supply costs and for the example of Morocco (production) and Germany (use), the different energy carriers show production costs in the range of 90-128 Euro/MWh$_{LHV}$ (LHV: Lower Heating Value) and 124-156 Euro/MWh$_{LHV}$, respectively. Individual cost contributions are shown in Figure 10.10 (Hank *et al.*, 2020).

Depending on the shipping distance, the ranking of energy carriers regarding their cost performance only slightly changes, partially due to energy demand for shipping, as shown in Figure 10.11 (Hank *et al.*, 2020). Ammonia is always cheapest; however, without potential reconversion into nitrogen and pure hydrogen. Liquid organic hydrogen carriers are always most expensive. Liquid hydrogen is only cost-competitive over short distances.

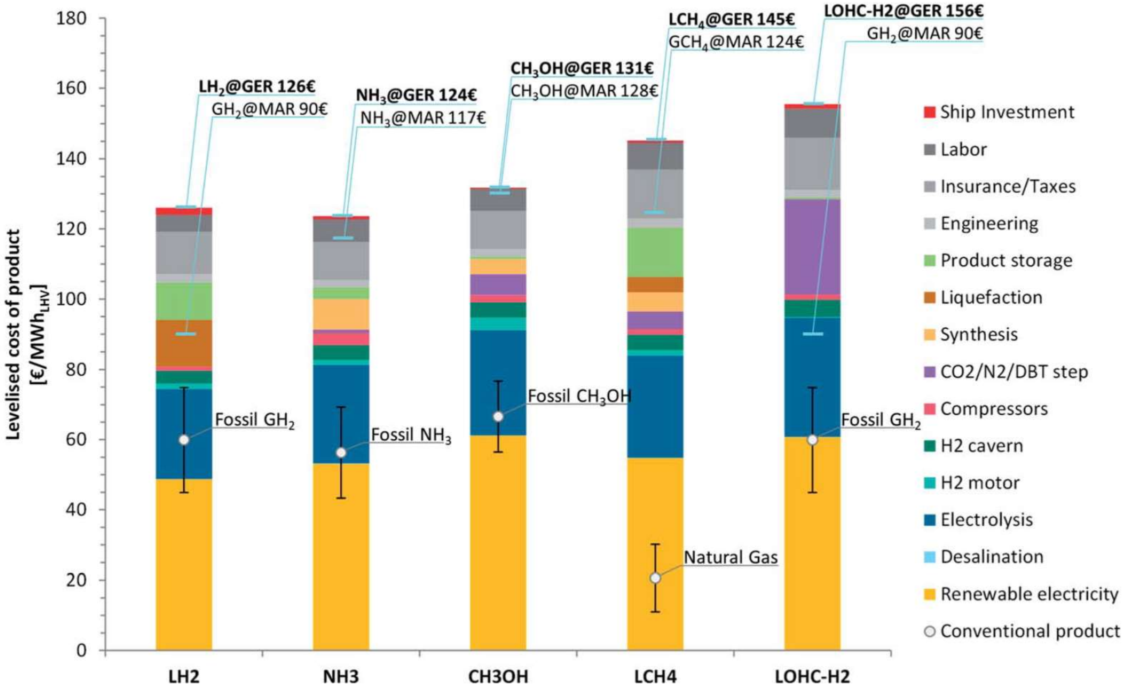

Figure 10.10: Cost of Power-to-X products ("@GER", incl. shipping Morocco-Germany) based on energy content (LHV). The product cost in Morocco ("@MAR") exclude the cost for shipping, product storage and liquefaction. Levelized cost for the conventional product indicated by including a respective maximum/minimum price spread based on available data (Hank *et al.*, 2020). LH$_2$: liquid hydrogen; GH$_2$: gaseous hydrogen; CH$_3$OH: methanol; LOHC: liquid organic hydrogen carrier.

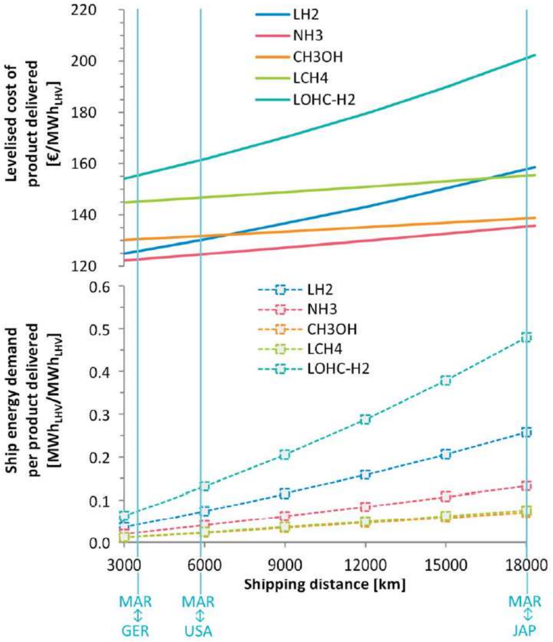

Figure 10.11: Top: levelized cost of PtX-product depending shipping distance. Bottom: MWh of fuel demand per MWh of product delivered at final destination (Hank *et al.*, 2020).

Similar hydrogen import costs (liquid hydrogen produced via electrolysis and imported from Northwest Africa to North-western European ports) were calculated by (Ueckerdt *et al.*, 2021), as shown in Figure 10.12. Substantial cost reductions until 2050 are expected, mainly due to reduced CAPEX for electrolysis and further decreasing costs of renewable electricity from large wind and solar farms.

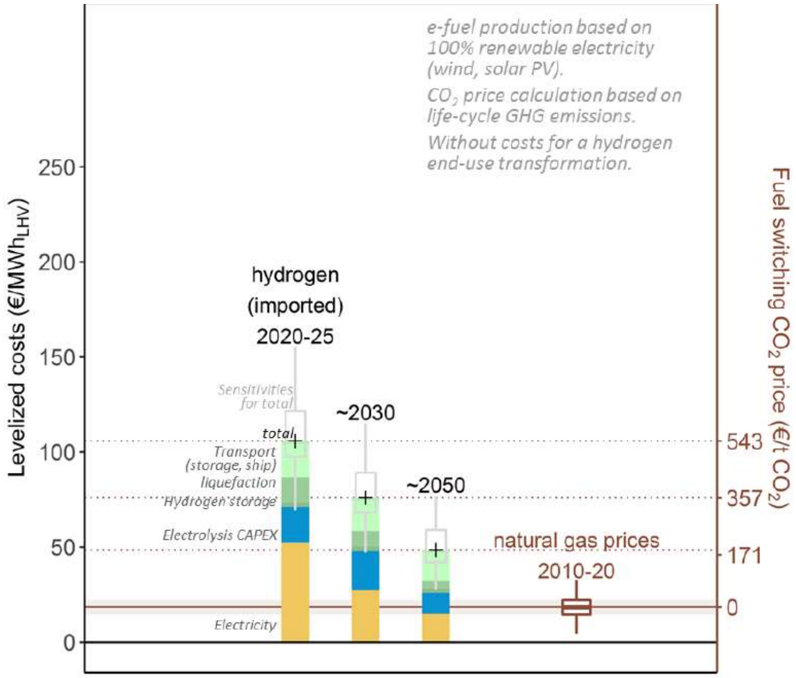

Figure 10.12: Levelized cost (and its components) and fuel switching CO_2 prices for liquefied hydrogen compared to natural gas (hydrogen shipped from Northwest Africa to North-western European ports for 2020-25, 2030 and 2050, in comparison to European whole-sale market natural gas prices for 2010-20 (Ueckerdt *et al.*, 2021).

(Kreidelmeyer *et al.*, 2020) performed an economic analysis of hydrogen and synfuels supply for Germany, comparing domestic production costs with costs of importing these energy carriers from the MENA region. Their analysis shows that hydrogen can be supplied at lower costs than synthetic hydrocarbons; results are ambiguous regarding the cost-competitiveness of domestic hydrogen production vs. import from the MENA region. While hydrogen supply costs based on imported hydrogen are estimated to be lower today, supply based on domestic generation is expected to be at a similar level as imports or even below in 2050 (Figure 10.13). In general, costs are substantially higher than those estimated by (Hank *et al.*, 2020; Ueckerdt *et al.*, 2021), which highlights the underlying basic uncertainties in such cost projections over decades.

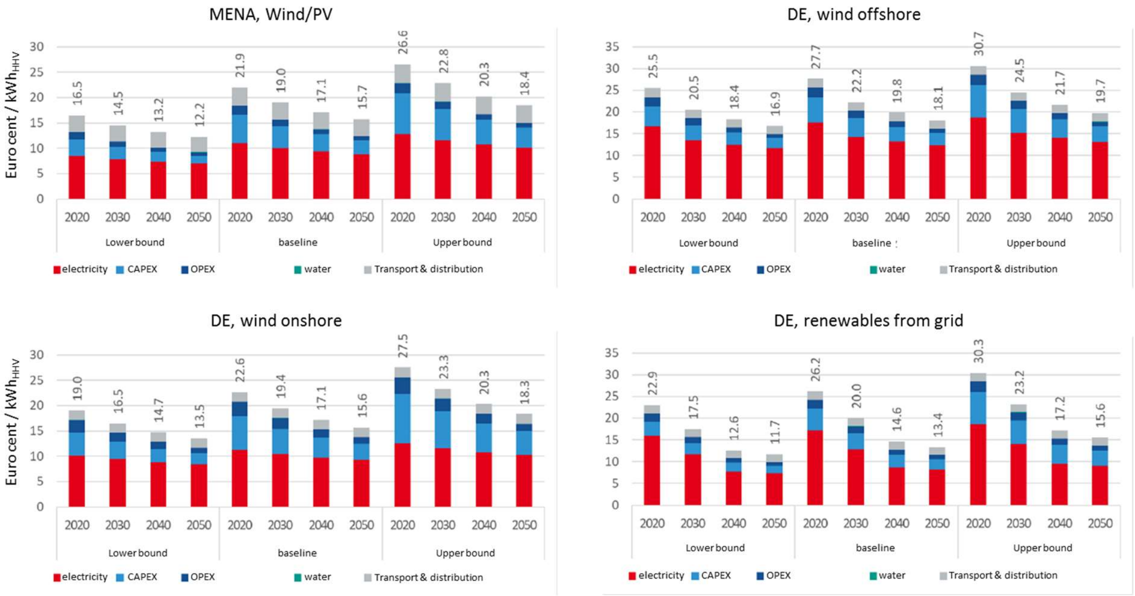

Figure 10.13: Hydrogen supply costs to end users in Germany (Kreidelmeyer *et al.*, 2020).

Another analysis on the economics of domestic hydrogen production vs. the hydrogen imports to selected Europan countries was recently published by the World Energy Council (World Energy Council, 2021). Figure 10.14 shows Germany as example – costs of domestically produced hydrogen vs. imported hydrogen, delivered to an industrial customer in 2030 (left panel) and 2050 (right panel). It shows that lower production costs in regions with access to low-cost resources are roughly compensated by hydrogen transport costs, resulting in similar cost ranges for the customer.

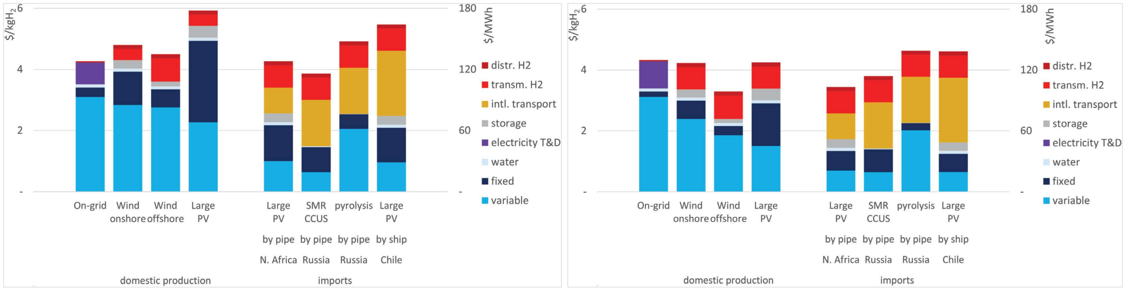

Figure 10.14: Costs of hydrogen delivered to a typical industrial customer in Germany from selected countries and technologies, 2030 (left) and 2050 (right) (World Energy Council, 2021).

The Fraunhofer Institute analyzed potential sites next to the ocean or inland water bodies for renewable electricity based hydrogen, hydrogen carriers, and synthetic hydrocarbon production worldwide from an economic perspective to evaluate potential import pathways to Germany (Pfennig, Bonin and Gerhardt, 2021). An interactive tool allows for exploring this work.[47] Figure 10.15 shows costs of liquid imported energy carriers from the MENA region in 2030, quantified for a high and a low-cost scenario.

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[47] https://devkopsys.de/ptx-atlas/ (9.11.2021).

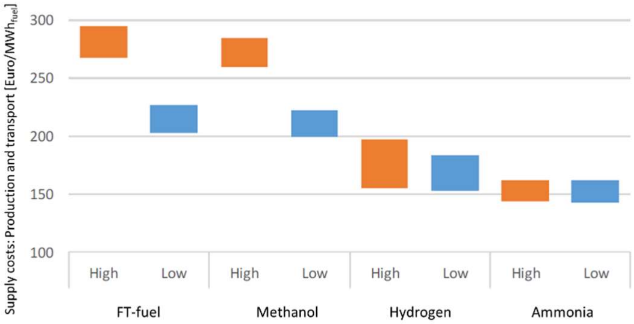

Figure 10.15: Costs of synthetic renewable electricity based energy carriers, imported from the MENA region to Germany in 2030. "High" and "low" indicate different cost scenarios. Adapted from (Pfennig, Bonin and Gerhardt, 2021). Costs for potentially required cracking of ammonia are not included here. FT: Fischer-Tropsch.

In general, the shorter the transport distance, the more cost-competitive is the import of hydrogen compared to synthetic hydrocarbons (Fischer-Tropsch fuels) (Figure 10.16).

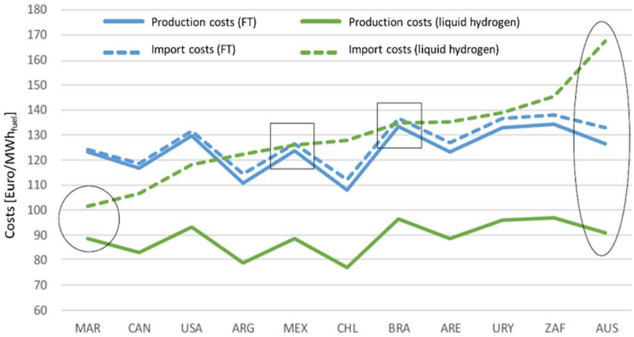

Figure 10.16: Production and import costs of Fischer-Tropsch (FT)-fuel and liquid hydrogen from different regions worldwide to Germany in 2050 (Pfennig, Bonin and Gerhardt, 2021).

Finally, an analysis performed by UNSW in Australia (Daiyan *et al.*, 2021) quantified costs of importing different low-carbon hydrogen energy carriers – produced in Australia – to Germany.

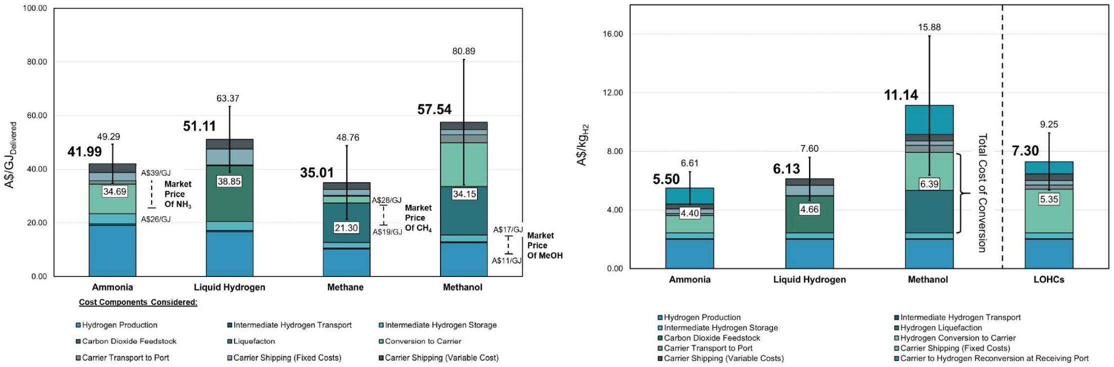

Figure 10.17: Indicative costs for shipping different hydrogen carriers from Australia to Germany in terms of Australian Dollars per GJ of energy delivered (left) and in terms of Australian Dollars per kg of hydrogen including reconversion (right). One Australian Dollar corresponds to about 0.75 US$. Reference year in the original source not provided, but likely to be 2040-2050, when the cost goel for green hydrogen production of 2 A$/kgH2 is assumed to be reached (Daiyan et al., 2021).

Comparing the costs of hydrogen imported to central Europe or Germany from these various literature sources with those of domestic hydrogen production in Switzerland (section 8.2.9) reveals two key insights:

- There are considerable variations in the cost estimates for imported energy carriers – hydrogen and electricity based hydrocarbons – already for today, but even more so regarding the future. These uncertainties are reflected by large cost ranges and due to different assumptions regarding costs of various components of hydrogen supply chains (and the underlying degree of optimism regarding future technology development), different supply routes, and forms of hydrogen supply. It is also likely that system boundaries for cost calculations differ to some extent, but studies are not always entirely transparent in this respect. Thus, comparing cost assessment results from different studies requires some caution.

- Costs of imported hydrogen today are estimated to be in a range of roughly 100-200 Euro/MWh$_{LHV}$ (Hank *et al.*, 2020; Kreidelmeyer *et al.*, 2020; Ueckerdt *et al.*, 2021), corresponding to about 3.5-7.5 CHF/kg. Cost reduction for imports to a range of 50-150 Euro/MWh$_{LHV}$ in 2050 are reported by these studies as well as (Daiyan *et al.*, 2021; Pfennig, Bonin and Gerhardt, 2021; World Energy Council, 2021), which corresponds to about 2-5.5 CHF/kg. Therefore, it seems that hydrogen imports from countries not too far away (like the MENA region) might be cheaper than domestic production in Switzerland. However, this first evidence must be confirmed by tailor-made analysis for specific hydrogen import options under Swiss-specific boundary conditions.

All these scenarios are based on the assumption that green hydrogen production can be scaled up quick enough to meet hydrogen demand, both on the European and the global level. Whether this is realistic, is far from certain, as a recent analysis (Odenweller *et al.*, 2022) shows. The authors conclude that “Despite initial exponential growth, green hydrogen likely supplies less than 1% of final energy until 2030 in the European Union and 2035 globally. By 2040, a breakthrough to higher shares is more likely, but large uncertainties prevail” (Odenweller *et al.*, 2022).

10.4.3 Energy efficiency and greenhouse gas emissions

Based on a screening LCA, which combines data from various literature sources and own calculations, life-cycle GHG emissions and energy efficiencies of various hydrogen production and supply chains to Switzerland were quantified. This screening LCA excludes some infrastructure related GHG emissions of hydrogen storage due to lack of data – however, these emissions are expected to be minor. Four different cases of hydrogen production and supply were distinguished:

A. Import of natural gas from Norway per pipeline; natural gas reforming with CO_2 capture in Switzerland; export of captured CO_2 to Norway for geologic storage per pipeline; regional hydrogen distribution to a user per pipeline in Switzerland.
B. Natural gas reforming with CCS in Norway; import of hydrogen from Norway per pipeline; regional hydrogen distribution to a user per pipeline in Switzerland.
C. Hydrogen production via grid-connected electrolysis using offshore wind power in the North Sea (Netherlands); import of hydrogen per pipeline; regional hydrogen distribution to a user per pipeline in Switzerland.
D. Hydrogen production via grid-connected electrolysis using offshore wind power on the coast of Morocco; hydrogen import per ship to Genova and further per pipeline; regional hydrogen distribution to a user per pipeline in Switzerland. Water for electrolysis is supplied via seawater desalination.

All those cases consider required hydrogen conversion steps, intermediate hydrogen storage, and associated energy demand, losses, and associated GHG emissions. Except of shipping of liquid hydrogen from Morocco to Genova, hydrogen is transported and stored in gaseous form. Three options for hydrogen transport per pipeline are evaluated, modeled according the information provided by (Cerniauskas *et al.*, 2020): using a) natural gas pipelines without modification, but reduced lifetime; b) natural gas pipelines with oxygen as corrosion inhibitator; c) dedicated, zinc-coated new hydrogen hydrogen pipelines.

For each considered supply chain, three cases were designed: a best (optimistic), a worst (pessimistic), and a base case. These differ in terms of hydrogen conversion, transport and storage losses, CO_2 capture rates for natural gas reforming, boil-off losses during liquefied hydrogen transport per ship, electricity transmission losses, etc. The analysis represents the implementation of these supply chains in year 2035.

Figure 10.18 shows life cycle GHG emissions per kg hydrogen ready to be used in Switzerland at a pressure of 700 bar; Figure 10.19 shows the energy efficiency of the entire supply chains. For case D, the electricity for hydrogen liquefaction is assumed to be supplied by the wind farm, which also feeds the electrolyzer. Results should be interpreted with some caution due to the simpilified character of the analysis.

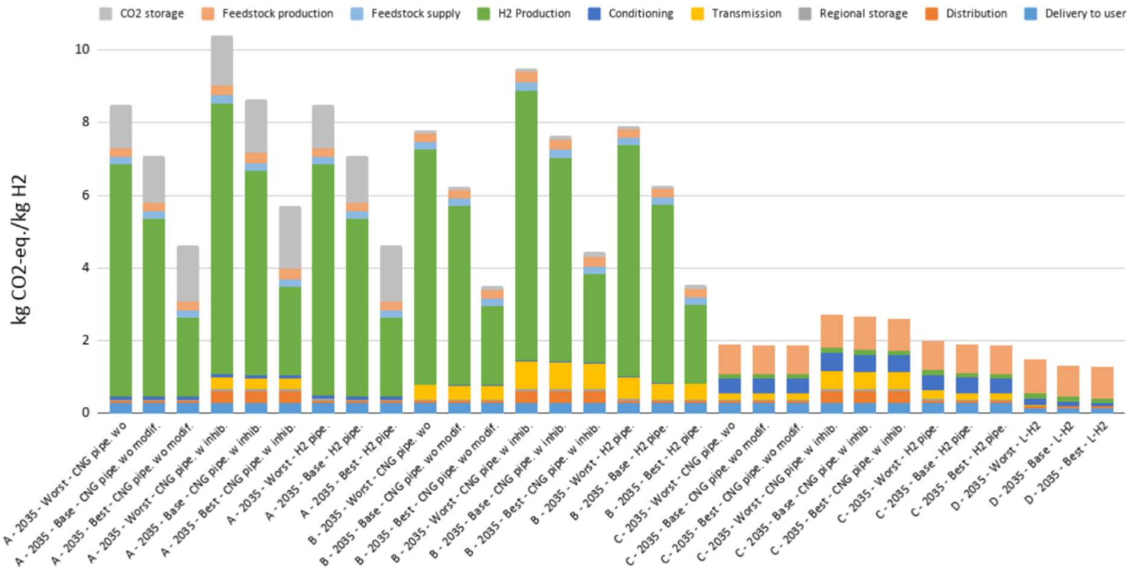

Figure 10.18: Life-cycle GHG emissions of hydrogen supply to users in Switzerland; different production and supply chains as described above; CO_2 capture rate for methane reforming between 45% (worst case) and 90% (best case).

GHG emissions of hydrogen from natural gas reforming with CCS mainly depend on the CO_2 capture rate at the production. Only with a 90% capture rate (possible with auto-thermal reforming (Antonini *et al.*, 2021a)), hydrogen from natural gas qualifies as "low-carbon hydrogen" and can almost compete with hydrogen from wind-powered electrolysis in terms of GHG emissions. Wind power, however, is – together with hydropower – the power generation technology which emits lowest life-cycle GHG emissions. Using photovoltaic power would increase the "feedstock production" contributions in cases C and D by a factor of two to three. The relative ranking of all natural gas based supply options is mostly determined by this CO_2 capture rate and other specifications of supply chains play a comparatively minor role. Comparing cases A and B shows that importing hydrogen from Norway directly instead of importing natural gas and exporting captured CO_2 causes slightly less GHG emissions. Comparing cases C and D shows that transporting hydrogen in liquid state per ship over a relatively short distance does not cause substantial GHG emissions. This shipping of liquid hydrogen may cause substantial emissions though, if the distance is longer, and if electricity for liquefaction is associated with substantial GHG emissions – in this calculation it is supplied by the wind farm which also feeds the electrolyzer.

Regarding energy efficiency, natural gas based supply exhibits lower losses – however, it must be taken into account that natural gas as feedstock is non-renewable, while wind power is renewable. Comparing cases A and B, i.e. natural gas or hydrogen import from Norway, shows almost identical results. Similar to GHG emissions, hydrogen transport in pipelines using corrosion inhibitors perform worse than the other options in terms of energy efficiency. Comparing cases C and D shows the non-negligible energy demand for hydrogen liquefaction. Overall, the energy efficiencies in the range of only 30%-60% reflect the fact that along such long supply chains with several intermediate steps of hydrogen conversion, conditioning, and storage, energy efficiencies are rather low.

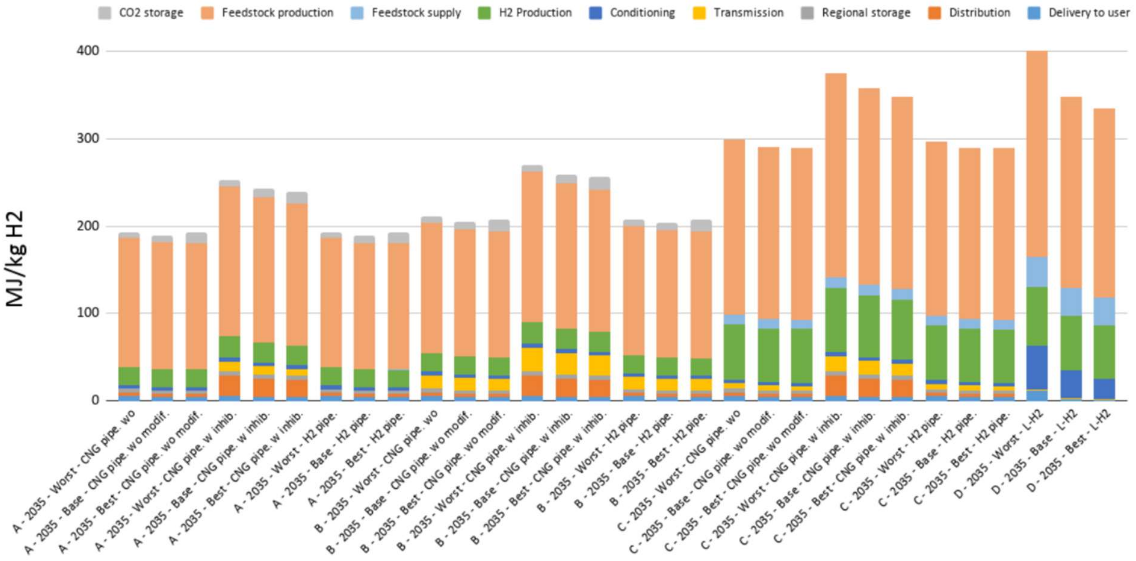

Figure 10.19: Energy efficiency of hydrogen supply to users in Switzerland; different production and supply chains as described above; "feedstock production" includes the energy embedded in the primary energy carrier used (natural gas or electricity). A result of 120 MJ/kg would indicate zero energy losses along the production and supply chain.

11 Hydrogen storage

Energy can be stored in the form of hydrogen. Being a versatile energy storage medium, hydrogen has significant potential for integration into the modernized, low-carbon energy system, despite of several challenges related to material properties, costs, and energy efficiency. Hydrogen can be used to store energy in large quantities for longer periods and to transport that energy over very long distances which makes hydrogen a major player for clean and flexible energy systems. Hydrogen is relevant as stationary energy storage, where it can be used for primary power in off-grid locations (using e.g. fuel cells), as well as serving as a reliable source of backup power for applications that cannot risk even short power outages, such as data and telecommunications centers. Hydrogen is especially advantageous for long-term storage of large amounts of energy – one metric ton of hydrogen contains 33 MWh of chemical energy – where only the energy storage portion of the system needs to be increased to store more energy (Wieliczko and Stetson, 2020).

11.1 Technologies

The choice of the storage option depends on the required storage capacity and duration, the roundtrip efficiency of the storage due to conversion and losses, the purpose and location of the storage (and use), safety issues, or local conditions such as making use of (waste) heat sources. Hydrogen may be used as energy carrier to take up surplus energy for use after a time shift, and it may be applied both to stationary and mobility applications.

Today, hydrogen is most commonly stored in compressed gas (high pressure vessels of varying size) or liquid form in tanks for small-scale mobile and stationary applications. Advanced materials-based storage technologies like adsorbents, metal hydrides and chemical carriers play a crucial role in bringing hydrogen to its full potential. The storage medium depends on various factors like the volume to be stored, the duration of storage, the required speed of discharge, and the geographic availability of different options. In general, however, geological storage is the best option for large-scale and long-term storage, while tanks are more suitable for short-term and small-scale storage (International Energy Agency, 2019).

Despite hydrogen storage technology has low round-trip efficiency and high equipment costs, it is currently the only low-carbon technology (besides – to some extent – pumped hydro storage) able to store over 100 GWh and operate over a timescale of weeks or even months (Staffell *et al.*, 2019). A general overview on hydrogen storage options is shown in Figure 9.1, which are detailed in Figure 11.1. We would like to point the reader to (Andersson and Grönkvist, 2019), which is a recommendable publication giving a comprehensive overview on large-scale hydrogen storage. Hydrogen storage methods can be generally categorized into physical storage, where hydrogen is stored on in gaseous or liquid form without involvement of physical or chemical bonding to other materials; or material-based storage where hydrogen is bound within other materials. Such bounding may be based on weak physical van der Waals based adsorption, or chemically based absorption to metal hydrides or chemical carriers.

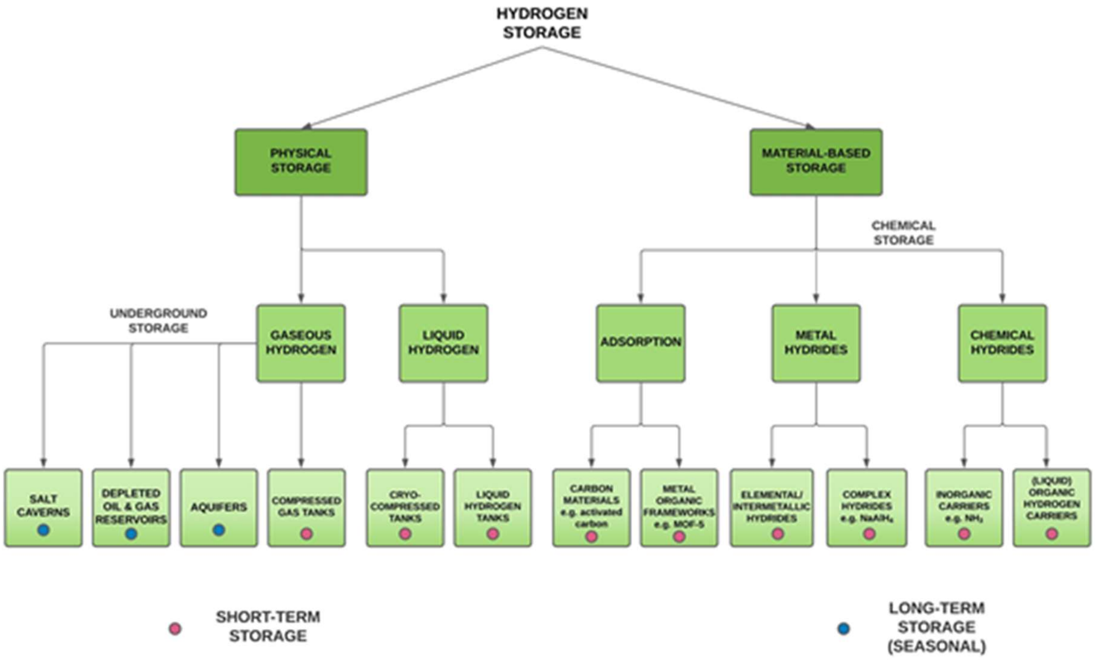

Figure 11.1: Overview on physical and materials-based hydrogen storage technologies.

Hydrogen storage may take place in underground caverns when large volumes and long-term storage are required. Suitable geological formations are salt and lined hard rock caverns (Gabrielli *et al.*, 2020; Guerra *et al.*, 2020; Sepulveda *et al.*, 2021), depleted oil and gas reservoirs, or buried underground pipes. Obviously, suitable geological conditions have to be present at a specific place so to be able to apply underground storage of hydrogen, which limits this storage option.

Physical storage may happen in compressed or liquid form for smaller volumes or shorter storage duration. Material-based storage is a broad category including both well-known conversions of hydrogen into e.g., ammonia, but also technologies in development such as various types of metal hydrides.

Hydrogen storage is challenging. Being the lightest molecule, hydrogen gas has a very low density: One kilogram of hydrogen gas occupies over 11 m^3 at room temperature and atmospheric pressure (Andersson and Grönkvist, 2019). To make the hydrogen storage economically feasible, its storage density must be increased, as described in section 9. Although hydrogen has high specific energy (by unit mass), its low energy density (by unit volume) is a challenge for compact, economical, and safe energy-dense storage. As a consequence, storage option choices will include the aspect of the energy density and the hydrogen content. Further challenges in the context of hydrogen storage are currently related to the need for complex thermal management systems, expensive catalysts, stability issues, speed of kinetics, operating pressures, energy densities, and safety.

Table 11.1 provides a qualitative overview on applications and technical readiness of various storage options.

Table 11.1: Qualitative overview on hydrogen storage options. "Small" capacity represents <1000kg, while "large" represents >1000kg.

Storage type	Hydrogen mode	Capacity	Temperature	Pressure	Duration	Deployment phase	Comment
Low pressure tanks	Gas	Small	Ambient	20-40 bar	Short-term	Established	Poor volumetric density.
Compressed H_2 tanks/ trailers	Compressed gas	Small	Ambient	100-700 bar	Short-term	Established	Simple & widely used, but low storage density
Liquid H_2 tanks	Liquid H_2	Large	-253°C	<10 bar	Short-term	Established	Relative boil-off losses inversely proportional to storage size.
	Ammonia	Large	15-50°C	200-350 bar	Short-term	Established	Dehydrogenation (and purification) needed before use; associated with high energy demand.
	LOHC	Large	Hydrogenation at 150-200°C Dehydrogenation at 250-320°C	10-50 bar	Short-term	Near operational	Dehydrogenation (and purification) needed before use.
Cryo-compressed tanks	Cryo-compressed H_2	Large	-253°C	<300 bar	Short-term, longer than liquid	In development	Less boil-offs, less energy use, higher flexibility than LH_2
Salt/Hard rock caverns	Compressed gas	Very large (>100 tonnes)	Ambient	<200 bar	Long-term (seasonal)	Established	3 salt caverns in use in UK. Well-insulated, negligible hydrogen losses.
Depleted oil and gas reservoirs	Compressed gas	Very large	Ambient	<200 bar	Long-term (seasonal)	Lab scale	(Un)wanted methanation possible
Aquifers	Compressed gas	Very large	Ambient	<200 bar	Long-term (seasonal)	Lab scale	
Metal Hydrides	Metal hydride	Large (theoretical potential), but rather high material costs => Small	150-285°C		Short-term	In development	Higher safety than LH_2. Storage at moderate T and P which increases safety.
MOF	MOF	Small	-196°C	25-95 bar	Short-term	In development	

11.1.1 Compressed gaseous storage

Compressed gas storage of hydrogen only requires a compressor and a pressure vessel, which makes it the simplest storage solution. Both spherical and cylindrical tanks are on the market for hydrogen storage. The low storage density, which depends on the storage pressure, is the main problem with compressed gas storage. Higher storage pressures result in higher capital and operating costs. Low-pressure spherical tanks typically operate at 15-20 bar and are made of steel. High-pressure storage vessels have maximum operating pressures of 200-300 bar. Such high pressure would require increased thickness of the steel containers, which would decrease the gravimetric density significantly. Thus, lighter storage tank materials such as carbon fiber reinforced composite tanks are used (Demirocak, 2017).

Stationary tube systems normally have pressures of between 200 and 350 bar and up to 700 bar in modern fuel cell vehicles (Klell, 2010; Rivard, Trudeau and Zaghib, 2019). Gaseous H_2 at 700 bar is generally regarded as the most viable storage system for on-board hydrogen storage in automotive applications (Reuß *et al.*, 2017; Rivard, Trudeau and Zaghib, 2019). High-pressure and low-pressure gas vessels have high investment costs and special requirements for the vessel material. The gaseous hydrogen storage depends on the high material permeability of hydrogen and their mechanical stability under extreme pressure. The steel tanks have very small stored hydrogen to weight ratio, and the hydrogen is stored at 200-300 bar. Composite fibers and aluminum liner tanks have higher ratio of stored hydrogen to weight and they are being used to store hydrogen at pressures up to 1000 bar (Khan *et al.*, 2019; Rivard, Trudeau and Zaghib, 2019). Pressure vessels are classified according to types (type I-IV), and these types differ by material, pressure, and gravimetric storage density, as discussed in (Rivard, Trudeau and Zaghib, 2019).

Table 11.2: Pressure vessel categorization (Abdalla *et al.*, 2018; Moradi and Groth, 2019; Rivard, Trudeau and Zaghib, 2019).

Type	Material	Typical pressure (bar)	Gravimetric density (wt %)
I	All-metal construction	200-500	1.0-1.7
II	Mostly metal, composite overwrap in the hoop direction	200	2.1
III	Metal liner, full composite overwrap	Up to 700	4.2
IV	All-composite construction	Up to 1000	5.7

11.1.2 (Compressed) liquid storage

Liquid hydrogen (LH2) offers the possibility of increasing the density up to 71 kg/m^3 (2.4 kWh/l) by cooling the hydrogen to a temperature below 21 K (Reuß *et al.*, 2017). Minimizing hydrogen losses from liquid boil-off is a major concern in liquid hydrogen storage (Ishimura and Fukuchi, 1991; Wieliczko and Stetson, 2020; Zou, 2020). According to (Ishimura and Fukuchi, 1991), boil-off losses can be avoided by performing ortho-to-para conversion of hydrogen during liquefaction and by using insulated cryogenic containers.

11.1.2.1 Liquid hydrogen storage

Most liquid hydrogen tanks are spherical and highly insulated, because it minimizes surface-to-volume ratio and reduces heat transfer or important problematic boil-off losses (Ishimura and Fukuchi, 1991; Andersson and Grönkvist, 2019; Wieliczko and Stetson, 2020). The latter limit the pressure within the vessel to a maximum of 10 bar. Sometimes cylindrical tanks are used because of their easier and cheaper construction and their volume-to-surface area ratio is almost the same as the spherical tanks. According to (Ishimura and Fukuchi, 1991), liquid hydrogen storage vessels at customer sites typically have a capacity of 110-5300 kg. NASA occupies the largest spherical tank in the world with a capacity of 228’000 kg of liquid hydrogen (Ishimura and Fukuchi, 1991; Wieliczko and Stetson, 2020). Hydrogen liquefaction plants normally have about 115’000 kg of storage onsite. Tanks with liquefied hydrogen have high discharge rates and efficiencies of around 99%, which makes them appropriate for smaller-scale applications where a local stock of fuel or feedstock needs to be readily available (International Energy Agency, 2019).

Cryogenic containers are designed to minimize conductive, convective, and radiant heat transfer from the outer container wall to the liquid. They have a double wall construction and the space between the walls is evacuated to nearly eliminate heat transfer from convection and conduction. Multiple layers (30-100) of reflective, low-emittance heat shielding are put between the inner and outer walls of the vessel to prevent radiant heat transfer from ambient. Some large storage vessels have an additional outer wall with the space filled with liquid nitrogen. This reduces heat transfer by lowering the temperature difference driving the heat transfer (Ishimura and Fukuchi, 1991; Demirocak, 2017).

Cryogenic tanks with a robust insulation at low pressure (<10 bar) can be used for liquid hydrogen storage, which allows the use of large bulk storage systems with high energy densities.

11.1.2.2 Cryo-compressed hydrogen

Additional compression of cryogenic (liquid) hydrogen requires special tanks capable of withstanding the high pressure. This makes them flexible enough to be "charged with liquid hydrogen, cryo-compressed hydrogen, or hydrogen in a two phase region" (Demirocak, 2017). This concept is enabled by the fact that liquid hydrogen is slightly compressible: at 21 K, the liquid density is 81 g/L at 240 bar compared to 70 g/L at 1 bar (Ahluwalia, Peng and Hua, 2016).

11.1.3 Underground storage

The storage capacity of underground reservoirs can be used to ensure large-scale energy storage, because geological formations have the potential to store large volumes of fluids with minimal impact to environment and society. Hydrocarbon industry has used underground formations for decades to store fluids for long-term storage. Underground hydrogen storage is useful for providing grid energy storage for intermittent energy sources like wind power, as well as providing fuel for electricity generation and for transport (Matos, Carneiro and Silva, 2019; Gabrielli *et al.*, 2020).

Seasonal storage has high storage capacities with a low number of charge cycles during the year. Over long residence times, seasonal storage system requires small expenses regarding the capacity and smaller losses. Various criteria and specifications need to be assessed before selecting the underground storage site, e.g., structural depth thickness, tightness, tectonic and seismicity issues, hydrogeological and geothermal issues, reservoir pressure, reservoir characteristics, porosity and permeability, geomechanical properties, and the suitable characteristics of the insulating roof rocks (Olabi *et al.*, 2020).

Salt caverns, depleted oil and gas reservoirs, and aquifers have been considered for large-scale and long-term underground hydrogen storage to attenuate supply disruptions or changing seasonal demand. Natural gas storage facilities could be converted to hydrogen stores one at a time as hydrogen use increases, reducing upfront costs. Even though underground geological storages have best potential for long-term and large-scale hydrogen storage, they are not very suitable for short-term and small-scale storage because of their geographic locations, large size and minimum pressure requirements of the site (International Energy Agency, 2019).

11.1.3.1 Salt Caverns

Salt caverns have been used for hydrogen storage by the chemical sector in the United Kingdom since the 1970s and the United States since the 1980s. The United States host the largest salt cavern hydrogen storage system currently in operation. It can store around 30 days of hydrogen output from a nearby steam methane reformer (between 10 and 20 thousand tonnes of H_2) to help manage the supply and demand for refining and chemicals. The United Kingdom has three salt caverns that can store 1 kt H_2, while a 3.5 kt H_2 storage demonstration project in a salt cavern is under preparation in Germany (planned for 2023) (International Energy Agency, 2019).

Salt caverns are considered to be the best option for storing hydrogen because salt is inert with respect to hydrogen and is extremely gas tight, since , the rock is almost impermeable to high pressure gases (Stolten and Grube, 2010; Gabrielli *et al.*, 2020). The risk of contamination of stored hydrogen in salt caverns is low, as the saline environment prevents the onset of biochemical reactions which could consume the hydrogen stored (Gabrielli *et al.*, 2020). High discharge rates can be obtained because of their potentially high pressures making them highly suitable for industrial and power sector applications. A higher depth of a cavern leads to more pressure and in turn more compressed gas. On the other hand, in a lower depth, lower amounts of cushion gas are needed which helps to reduce the cost of the operation.

11.1.3.2 Depleted Oil & Gas Reservoirs

Depleted oil and gas reservoirs are typically larger than salt caverns, but they are also more permeable and contain contaminants that need to be removed before the hydrogen could be used in e.g., fuel cells. Because of their well-identified geological structures, good tightness, and integrity of their caprock and pre-existence of the necessary surface and subsurface installations, the depleted oil and gas reservoirs are the most appropriate option for underground gas storage. Loss of hydrogen can take place due to the reactions with microorganisms, fluids and rocks present in the oil and gas reservoirs. Presence of residual oil can lead to chemical reaction and the conversion of hydrogen into e.g. methane which will reduce the purity of hydrogen.

11.1.3.3 Water Aquifers

Aquifers are porous and permeable media where their pore spaces are filled by fresh or saline water. However, a good reservoir characteristics of host rock and the presence of an impermeable layer to prevent transfer of the gas being stored are needed for hydrogen storage in deep aquifers (Tarkowski, 2019a). Water aquifers are the least mature of the three geological storage options, and there is mixed evidence for their suitability (although they were previously used for years to store town gas with 50-60% hydrogen) (International Energy Agency, 2019). Aquifers have not been investigated for commercial use with pure hydrogen so the exploration and development costs would be very high. To date, no pure hydrogen storage in aquifers is reported in the literature, but the storage projects of town gas with a composition of around 50% of hydrogen and 50% methane is reported in Europe such as Engelbostel and Bad Lauchstadt in Germany, Lobodice in the Czech Republic and Beynes in France (Zivar, Kumar and Foroozesh, 2020). Hydrogen storage in aquifers can be affected by the leakage along undetected faults, biochemical reactions, or reactions of hydrogen with minerals in the reservoir rock. More laboratory research and drilling of new wells is required to prevent the potential risk of higher operation costs.

11.1.4 Adsorption

While a variety of adsorbents for hydrogen storage (e.g., carbon materials, zeolites, polymers have been tested), MOFs which seem to be most promising. More research and testing is needed in order to manage the heat which is released during the exothermic formation of the bond between hydrogen and the adsorbent. Liquid nitrogen has been used for this purpose so far, but large amounts of it are needed to provide sufficient cooling (Andersson and Grönkvist, 2019). Improvements in the catalytic performance of the reaction will alleviate this problem. The class of metal organic framework materials includes in theory thousands of compounds with very different properties and potential for hydrogen storage applications. Commercial deployment has not yet been reached for any of these. The most important research needs include management of properties, stability, recyclability, and handling of the MOFs; as well as calculation of the involved cost and environmental impacts so to be able to compare them with other hydrogen storage methods (Ren *et al.*, 2015; Sun and Zhou, 2015; Ahmed *et al.*, 2019; Shet *et al.*, 2021).

11.1.5 Metal hydrides

Metal hydrides store hydrogen by chemically bonding the hydrogen to metal or metalloid elements and alloys. What makes hydrides unique is that some hydrides can absorb hydrogen at or below atmospheric pressure, then release the hydrogen at significantly higher pressures when heated. Depending on the alloy, hydrides have a wide range of operating temperatures and pressures

(Ishimura and Fukuchi, 1991). Hydrides store only about 2%-6% hydrogen by weight but have very high volumetric hydrogen storage densities, exceeding 100 g/L per unit volume of solid-state storage material (Ishimura and Fukuchi, 1991; Lototskyy *et al.*, 2019). Mostly earth metals like lanthanum, nickel, magnesium, and aluminum are used for metal-hydrides based hydrogen storage. The major drawback of the metal-hydride is its low mass absorption capacities (Khan *et al.*, 2019).

Elemental hydrides are formed via combination of metallic elements and hydrogen to a binary compound, e.g. magnesium hydride (MgH_2) or aluminium hydride (AlH_2). Intermetallic hydrides are formed by an alloy of a strongly and a weakly binding element each combined with the H_2. Unfortunately, material and processing cost of these elements are very high (Andersson and Grönkvist, 2019). The complex hydrides include again a variety of combinations of a complex anion with a metallic cation, with implications of performance, research state, challenges, and cost.

The heat of reaction for dehydrogenation, i.e. the release of hydrogen, can range from 9’300 kJ/kg to greater than 23’250 kJ/kg of hydrogen, and operating pressures can reach more than 100 bar (Ishimura and Fukuchi, 1991). Construction of the storage unit is a challenge for hydrides because of its wide temperature and pressure ranges. To allow rapid heat transfer for charging and discharging the hydride, the vessel containing the hydride must be pressurized and contain sufficient heat exchange area. In order to withstand numerous charge/discharge cycles, the metal hydride alloy must be structurally and thermally stable (Ishimura and Fukuchi, 1991). Some hydrides can also be poisoned by carbon dioxide, sulfur compounds, or water. Another challenge is that while hydrogen reacts with the metal lattice, the lattice changes its volume. This means that it expands during absorption and contracts again during desorption. This results in a volume change of up to 30-40% that depends on the material and the amount of absorbed hydrogen (Baetcke and Kaltschmitt, 2018).

11.1.6 Chemical hydrides

Chemical hydrides differ from metal hydrides particularly through the use of lighter elements and thus completely different properties. While the latter are mostly gaseous at ambient conditions, the chemical hydrides are present in liquid form. Further, the materials under research for this hydrogen storage are well-known and produced in large volumes already today, e.g. methanol, ammonia, or toluene. The class of liquid organic hydrogen carriers (LOHCs) is characterized through the fact that they are in liquid state in both hydrogenated and dehydrogenated form, while dehydrogenation of e.g. methanol will lead to gaseous products. Within the recent research project “HySTOC”[48] on hydrogen supply and transportation using LOHCs, a hydrogen value chain using LOHCs was established and tested in Finland for both transport and storage of hydrogen.

11.2 Costs

The main parameters in the calculation of hydrogen storage costs (including the conditioning step) are the following:

- Conditioning: Capital costs for infrastructure and materials (e.g., compressor, liquefaction unit, storage carrier materials such as hydrides, tanks); operating costs for conversion from energy use (electricity and/or heat). The efficiency of the compressor also affects the costs (the smaller, the lower the efficiency).
- Storage: Capital costs for storage vessels or cavern preparation, terminals; Operating costs for boil-off losses (liquid H_2), energy input for cooling/heating as well as pumping.

The operating costs are in general for all storage types driven by the electricity or heat use during the conversion step. Use of waste heat from exothermic processes, fuel cells, or nearby industrial processes may help to decrease these costs.

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[48] https://www.hystoc.eu (10..6.2021)

In general, compressed gaseous and liquefied hydrogen storage are economically attractive for smaller hydrogen volumes during a shorter storage duration. On the contrary, caverns are an economically attractive option for larger hydrogen volumes during a longer storage period. An overview of hydrogen storage costs and other important cost parameters is presented in Table 11.3. Specific explanation is provided in the following sub-sections.

Table 11.3: Overview table representing storage pressure levels, CAPEX, OPEX and lifetimes of the considered hydrogen storage mediums, based on (Le Duigou *et al.*, 2017; Reuß *et al.*, 2017; Derking, Togt and Keezer, 2019; Kumar, Alam and Dutta, 2019; Parra *et al.*, 2019; Runge *et al.*, 2019; Danish Energy Agency, 2020; Hurskainen and Ihonen, 2020).

Storage	Gaseous	Liquefied	Caverns	Metal hydrides	LOHC	Unit
Storage Pressure	15-700	~1	45-300	~10-60	2 – 70	bar
CAPEX	220-2200	~330	1-3	1400-3600 (tank plus hydride material)	No data	CHF/kg H_2 storage
OPEX	2%	2%	2%	No data	4%	Of CAPEX/year
Lifetime	20-25	20	30-50	25		years

11.2.1 Compressed and liquefied hydrogen storage

Compressed and liquefied hydrogen storage commonly use hydrogen storage tanks. This section discusses gaseous and liquefied hydrogen storage costs.

Hydrogen gas has low density compared to liquid hydrogen and is stored in various types of tanks and trailers at defined pressure levels. For small scale storage of highly pressurized gaseous hydrogen, so-called type IV storage tanks (see Table 11.2) applying a carbon/glass fibre composites construction are used. The carbon fibre layer is an important cost driver nowadays, contributing to 43% of the total tank costs according to (Amica, Arneodo Larochette and Gennari, 2020), with possibilities for optimisation when choosing an appropriate material. For bulk storage of gaseous hydrogen, metal tanks are used. Tank costs are shown to be in the range between 200-2000 CHF/kg H_2 (Parra *et al.*, 2019; Amica, Arneodo Larochette and Gennari, 2020). Tanks for gaseous hydrogen storage are cheaper than the equivalent tanks for liquid hydrogen storage due to higher insulation costs in case of liquid hydrogen (Jepsen *et al.*, 2012).

11.2.1.1 Compressed gaseous hydrogen storage

Pressurised gaseous hydrogen storage in tanks is attractive for a short hydrogen storage time (Derking, Togt and Keezer, 2019). Hydrogen storage in gas trailers is an attractive option with large quantities and short transportation distances, while hydrogen storage in gas cylinders is especially attractive for small quantities of hydrogen storage (IRENA, 2019). Several indications are given in the literature for CAPEX and OPEX. For example, (Parra *et al.*, 2019) identified a CAPEX for gaseous hydrogen storage from 220 CHF/kg H_2 (<100 bar) to 2200 CHF/kg H_2 (>500 bar), with an OPEX of 1.5 CHF/kg H_2. While for example other literature estimates 900 CHF/kg H_2 (700 bar) in combination with an electricity requirement of 6 kWh/kg H_2 (Derking, Togt and Keezer, 2019). (Rivard, Trudeau and Zaghib, 2019) report CAPEX for hydrogen pressure vessels of 80-90 CHF/kg H_2 for type I and type II vessels, and 600-700 CHF/kg H_2 for type III and type IV vessels (see Table 11.2).

The indicated cost range of gaseous hydrogen storage is large, and among other factors depends on the technical characteristics of the storage tank and compression needs to reach the required pressure level. For example, the costs differ significantly with working pressures and the materials used to produce the tanks, in order to ensure resistance to high hydrogen pressures, embrittlement and permeation (Danish Energy Agency, 2020).

11.2.1.2 Liquefied hydrogen storage

Compared to gaseous hydrogen storage, liquefied hydrogen storage is especially suitable for hydrogen storage during longer time periods (Derking, Togt and Keezer, 2019). However, liquefaction is required and corresponding drawbacks are high power requirements for liquefaction, vessel insulation, as well as hydrogen losses due to boil-off during no-use, which generates additional costs (Demirocak, 2017). (Derking, Togt and Keezer, 2019) indicated a CAPEX of 330 CHF/kg H_2 (1 bar) and an electricity requirement of 10-13 kWh/kg H_2. Liquefaction adds significantly to the overall costs of hydrogen and can be as high as 2.6-3.1 CHF/kg H_2, although is likely to be decreased to 1.6-1.9 CHF/kg H_2 in 2025 when considering technological improvements, such as a reduction of boil-off rates as well as improved insulation of tanks and compression (Bruce *et al.*, 2018).

11.2.2 Underground storage

Costs of storing hydrogen in existing salt caverns are mainly associated to compression as well as the injection of hydrogen to the storage site. Further, costs are also influenced by the roundtrip efficiency, and the specific stress and pressure limits of the salt cavern (Danish Energy Agency, 2020). (Zivar, Kumar and Foroozesh, 2020) in addition show a complete compilation of issues related to underground hydrogen storage, which might also influence the cost. This includes site selection, injection and withdrawal strategies, geological conditions, monitoring, leakage etc. While the largest cost driver of underground storage is the compressor machinery, such additional costs have to be considered. One of the major advantages of underground storage of large quantities of hydrogen is the lowest storage cost or most inexpensive (few hundred dollars or less) processes as compared to the other modes of storage (few thousand dollars or more) regardless of the purity of hydrogen (Taylor *et al.*, 1986).

In general, salt caverns are a cheap and mature (hydrogen) storage technology. However, the availability of salt caverns is geographically limited. The (Danish Energy Agency, 2020) indicated CAPEX of 111 CHF/kg H_2 for a salt cavern size of 150'000 MWh H_2 (=1250 kg H_2 LHV). A study of (Le Duigou *et al.*, 2017) determined cost potentials for salt caverns for years 2020 and 2050 in France. Results demonstrated that hydrogen storage in caverns is economically attractive with a renewable electricity penetration of more than 50%. Although the requirement of a significant investment needed for salt caverns (10 CHF/m^3), cost contributions for hydrogen storage remained lower than 5% (<0.4 CHF/kg H_2) of the total hydrogen supply chain costs (5.0-7.3 CHF/kg H_2) for all assessed cases. This figure corresponds well with the generic cost values of ~0.6 CHF/kg H_2 given in a report of the IEA (International Energy Agency, 2019) and 0.20 CHF/kg H_2 in (Bruce *et al.*, 2018). A study of (Reuß *et al.*, 2017) used a significant lower CAPEX of ~6 CHF/m^3 for a cavern of 500'000 m^3, considering a lifetime of 30 years.

According to (Lord, Kobos and Borns, 2014; Tarkowski, 2019b; Tarkowski, Uliasz-Misiak and Tarkowski, 2021), the cost of storing in the different underground storage types are very similar to each other when comparing to other storage options, being within a range of 1.23-2.77 CHF/kg H_2. Storage in depleted natural gas reservoirs seems to be cheaper than the equivalent depleted oil reservoirs. Hard rock caverns represent the most expensive solution. (Lord, Kobos and Borns, 2014) may serve as template for calculations with a detailed compilation of geologic site- and design-specific cost analysis assumptions which include cushion gas, geological site preparation, compressor, and pipelines and wells.

11.2.3 Adsorption - MOF

Metal Organic Framework materials for hydrogen storage are a broad class, as shown in previous chapters. They don't readily exist on the market and are currently not produced in large amounts, which makes any cost estimates difficult. (DeSantis *et al.*, 2017) have calculated the cost for synthesis of specific MOFs. However, their hydrogen storage capacity and further infrastructure, energy and materials requirements have not yet been combined to assess the resulting cost per hydrogen stored.

According to (Anastasopoulou *et al.*, 2021), increasing the gravimetric storage capacity will be necessary to get into a reasonable cost range.

11.2.4 Metal hydrides

Cost of metal hydrides are high nowadays, especially for the hydrogen storage applications (Abe *et al.*, 2019). Both the material with which the hydrogen reacts as well as the tanks suitable for storing the solid matrix contribute to the high costs; but both are expected to decrease based on learning curves and scaling up (Amica, Arneodo Larochette and Gennari, 2020). Cost estimates are hampered by the fact that suitable hydride materials are not necessarily available on the market today, but only synthetized in small amounts at lab scale. (Amica, Arneodo Larochette and Gennari, 2020) summarise existing cost estimates indicatimg a ratio of 4.5:1 between a specific reagent material ($Mg(NH_2)_2$) and the tank cost with the possibility to reduce this to around 2:1. This ratio may however be as low as 1:1 for another material ($NaAlH_4$), which proves that general conclusions shall not be drawn from specific hydride application cases. For the same material, calculations in (Amica, Arneodo Larochette and Gennari, 2020) even project ratios 0.4-0.7:1, i.e. higher tank costs. However, prices on the market for individual elements may fluctuate heavily with time, which increases the uncertainties in such cost calculations.

The tanks need to house the absorption material, heat transfer fluid, and the hydrogen. Eventually, additional (waste) heat has to be used for the dehydrogenation process. CAPEX for application in cars are projected to decrease to around 1100-2000 CHF/kg H_2 stored for the tank, plus 320-1600 CHF/kg H_2 for the storage materials (Amica, Arneodo Larochette and Gennari, 2020). (Jepsen *et al.*, 2012) found that metal hydride storage may in future come with a cost advantage compared to conventional high pressure (700 bar) or liquid storage systems due to simpler tank vessel structure and lower conditioning cost.

11.2.5 Chemical hydrides - LOHC

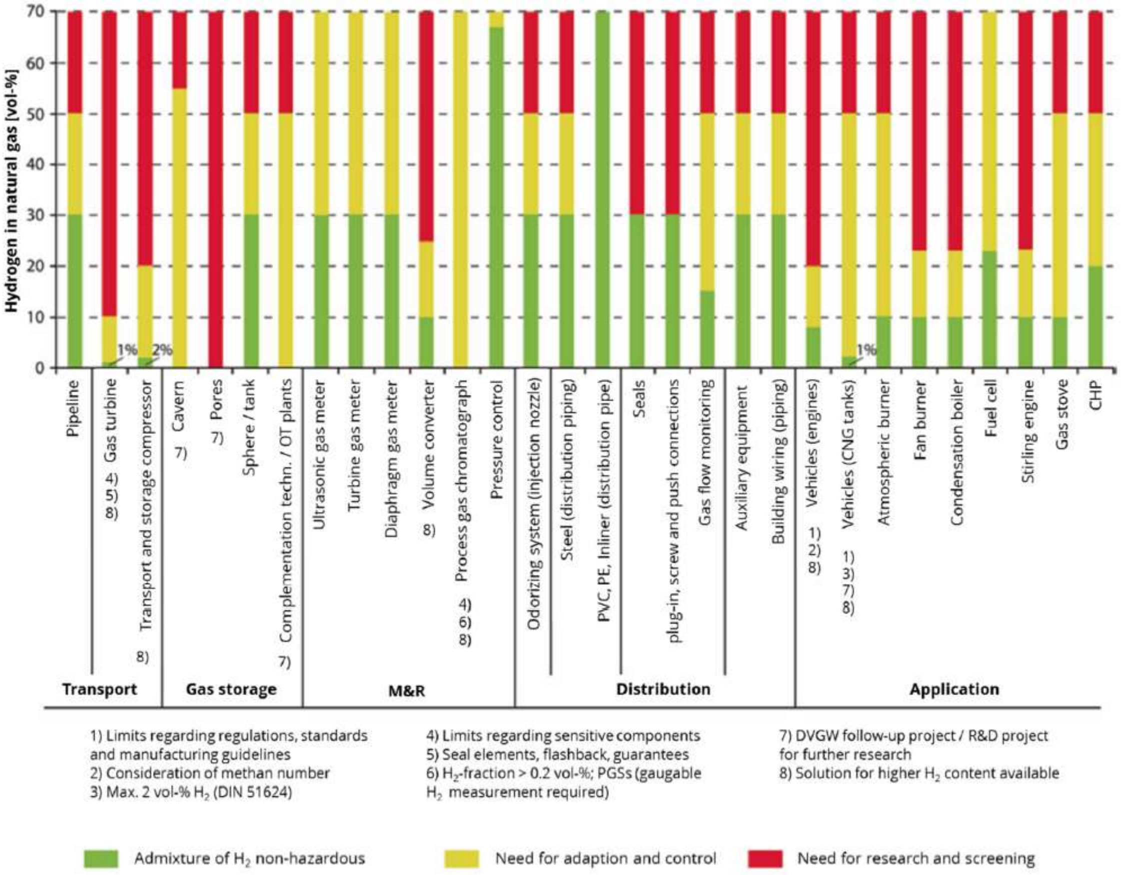
Costs for LOHC seem to be driven by the energy requirements for dehydrogenation, while the tank and other infrastructure or material costs play a minor role (Runge *et al.*, 2019). Again, the use of nearby surplus heat would have a significant effect on the costs, and accordingly, heat integration/sales from the exothermic hydrogenation step may be key for successful implementation of hydrogen storage and transport in LOHC (Hurskainen and Ihonen, 2020). In terms of materials, both toluene and chlorine which might become important carrier materials exhibit not scarcity on the markets. Dibenzyltoluene production would be well suited to react on a higher demand, which might have to happen as it is one of the most promising LOHC, and among the cheapest with 30-70 CHF/kg H_2 stored (Hurskainen and Ihonen, 2020; Andersson, 2021). Cost decreases are to be expected with upscaling due to lower CAPEX, maintenance and labour cost per kg hydrogen stored (HYSTOC, 2019a).

11.3 Environmental burdens

Similar to the environmental impacts shown for the transportation of hydrogen, the conditioning step(s) of hydrogen to prepare the storage are potentially the largest source of environmental impacts due to the related energy and materials use. This has already been discussed in chapter 10.3 on environmental impacts of hydrogen transport, where it was indicated that the presented case studies are heavily influenced by the choice of the energy source.

12 Hydrogen blending in the natural gas network

Hydrogen can be blended into the natural gas network to a certain extent. The mixtures of hydrogen and natural gas are sometimes called "H2NG blends". However, hydrogen tolerance levels substantially differ between certain natural gas transport, storage, and use technologies (Figure 12.1), evaluated for Germany.



1) Limits regarding regulations, standards and manufacturing guidelines
2) Consideration of methan number
3) Max. 2 vol-% H_2 (DIN 51624)
4) Limits regarding sensitive components
5) Seal elements, flashback, guarantees
6) H_2-fraction > 0.2 vol-%; PGSs (gaugable H_2 measurement required)
7) DVGW follow-up project / R&D project for further research
8) Solution for higher H_2 content available

Figure 12.1: Hydrogen tolerance levels for different components of the natural gas grid, storage and use technologies in Germany (Pieper, 2019).

Blending of hydrogen into the natural gas grid is limited by country-specific regulations, as visualized in Figure 12.2.

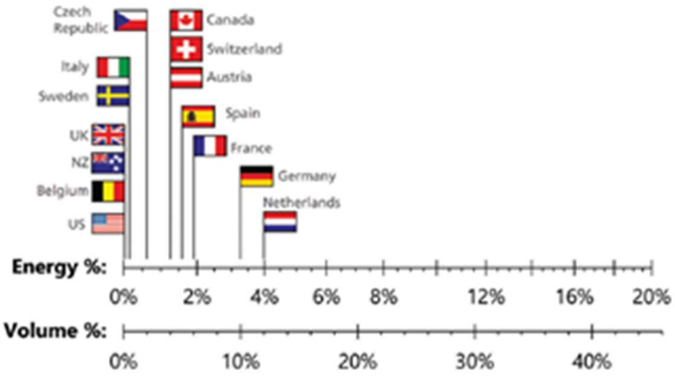


Figure 12.2: Limits on hydrogen blending into national natural gas grids (Staffell et al., 2019).

In some countries, the limits depend on circumstances as shown in Figure 12.3. In Germany, the general limit is at 2%. The higher limit of 10% applies only if there are no compressed natural gas (CNG) filling stations in the network. In Lithuania, higher limits are allowed for pressure greater than 16 bar. In Netherlands, the higher limit applies to high-caloric gas (IEA, 2020b).

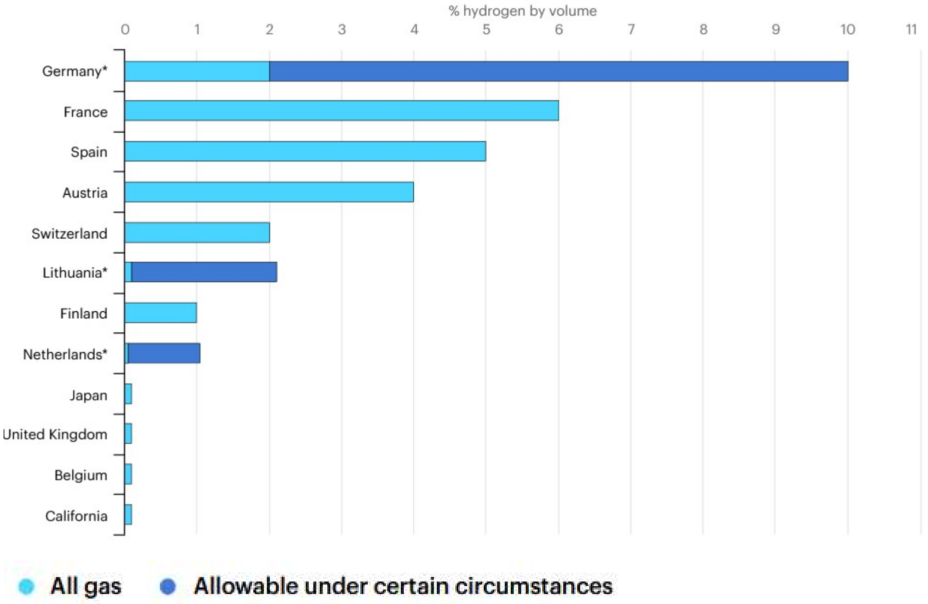


Figure 12.3: Limits on hydrogen blending in natural gas networks, last updated 4 March 2020. (IEA, 2020b).

Switzerland has already an extensive natural gas pipeline network covering the highly populated areas. The existing natural gas network in Switzerland is shown in Figure 12.4.

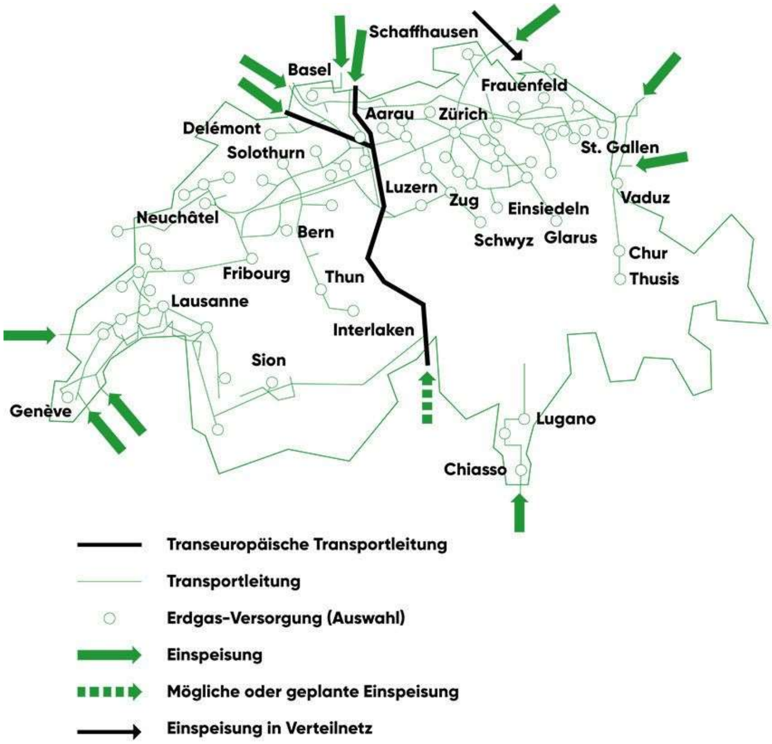


Figure 12.4: Main lines of the existing natural gas network in Switzerland (VSG, 2021).

The total length of the Swiss gas network is about 20’000 km as shown in Table 12.1. It is currently mainly used for fossil natural gas. The current annual natural gas consumption in Switzerland is about 38’000 GWh. Biogas in the Swiss gas network was about 401 GWh in year 2019 (VSG, 2020a).

The use of the natural gas pipelines by blending hydrogen could provide an option to transport hydrogen without the necessity to build a separate hydrogen pipeline network. This is not only interesting in view of the pipelines, but also in view of a combined storage of hydrogen and natural gas where space is limited.

Switzerland has only little storage capacity for natural gas, synthetic natural gas (SNG) or hydrogen. To a certain extent, the gas network itself can serve as storage. For example, the gas in the high-pressure network can be expanded from 70 bar to 50 bar, i.e. 20 bar can be used as buffer. It has been estimated that the Swiss high-pressure transport network can store about 28.35 GWh based on the lower heating value of 10.21 kWh/m^3 of natural gas (IET, 2017). The buffer capacity of the low-pressure distribution network is low (about 0.17 GWh). Together with the Swiss share in the transit network, the buffer in the gas network (3.8 Mio.Nm^3) is of the same order as the current capacity of the dedicated gas storages in Switzerland (4.8 Mio.Nm^3). Most of the current storage capacity is outside of Switzerland.

In summary, the current natural gas storage capacity inside Switzerland in the order of 100 GWh in terms of upper heating value is low compared to the storage capacity of electricity in hydro reservoirs in the order of 8’800 GWh (see chapter 16) (IET, 2017).

Table 12.1: Length of the Swiss gas pipeline network for natural gas and biogas (VSG, 2019), (VSG, 2020a).

Type	Length of gas network (km)	
	2018	2019
High-pressure transport network (> 5 bar)	2’243	2’271
Low-pressure distribution network (up tp 5 bar)	17’648	18’159
Total length	19’891	20’431

Table 12.2: Estimated current storage capacity for natural gas for Switzerland (energy based on lower heating value) (IET, 2017).

	Capacity (Mio. Nm3)	Energy (GWh)
Swiss gas network (buffer)	2.5	28.35
Swiss share in transit network (buffer)	1.3	14.4
Storages in Switzerland	4.8	48.7
Swiss share of storage in France	139	1510
Total	147.6	1601.45

The Swiss gas industry assumes that in 2050 the Swiss gas network will only contain climate-neutral gases i.e. biogas, hydrogen based on renewable energy, and synthetic natural gas ("2050 werden im Schweizer Gasnetz nur noch klimaneutrale Gase zirkulieren. Neben Biogas wird dies grüner Wasserstoff und daraus hergestelltes synthetisches Methan sein." (VSG, 2020b).

"Blending can support the initial development of larger-scale hydrogen production by offering a potentially stable demand for hydrogen that could form an important part of the case to invest in hydrogen. This could also potentially unlock future scenarios in which some systems convert to 100% hydrogen." (Deasley *et al.*, 2020).

Several projects have been started recently to investigate hydrogen blending in the natural gas network. For example, the US National Renewable Energy Laboratory (NREL) leads a collaborative research and development project known as “HyBlend” to address the technical barriers for H2NG blends in natural gas pipelines (NREL, 2020).

The “Hydrogen Materials Compatibility Consortium” (H-Mat) was launched in 2018 by the U.S. Department of Energy’s Hydrogen and Fuel Cell Technologies Office in the Office of Energy Efficiency and Renewable Energy (H-Mat, 2020). It focuses on understanding the effects of hydrogen on the performance of polymers and metals used in hydrogen infrastructure and storage.

The Swiss association of the gas industry started the project “Analyse der H2-Toleranz von Verteilnetzen” to investigate the hydrogen tolerance of the Swiss gas network (SVGW, 2019b).

Another example is the new THyGA project (Testing Hydrogen Admixtures for Gas Appliances) supported by the European Union (THyGA, 2021).

12.1 Technology

Hydrogen blending in the natural gas network is currently associated with safety issues like protection against fire and explosions due to a lack of generally accepted safety standards (SVGW, 2020).

A report for UK expects a limit of 20% hydrogen for safely blended natural gas (Deasley *et al.*, 2020). The report assumes that hydrogen blending with a 20% limit will be only a transitional option towards a low-carbon hydrogen system. Nevertheless, there are also arguments that a variety of storage options including hydrogen and carbons will be needed in future, for example for mobility, e.g. (Mertens, Belmans and Webber, 2020).

In Switzerland, many appliances are connected to the natural gas network like gas boilers for heating or combined heat and power (CHP) plants. The question is, how the transition to H2NG blends affects these end-user appliances.

Measurements have shown that the blending of natural gas with hydrogen has influence on the electric efficiency and heat recovery of ICE (internal combustion engine) CHP (combined heat and power) plants (Basso and Paiolo, 2016), (Basso *et al.*, 2015), (de Santoli, Lo Basso and Bruschi, 2013): “Up to 5% H_2 fraction the efficiency remains nearly unchanged compared to pure methane. With 8% H_2, variations on opposite sides due to fluid dynamic conditions within the combustion chamber and to fixed spark advance, were registered. In stoichiometric combustion, when 8% H_2 is added, the hydrogen enrichment has a positive effect on burning process … Regarding to Lambda=1.4, it has not registered an electrical efficiency increase. ” (de Santoli, Lo Basso and Bruschi, 2013), see Figure 12.5.

“The CHP performed the best, in terms of electrical efficiency, when it operated with H2NG@ 10% vol. and oxygen enrichment equal to 21.5 % vol.” (Basso and Paiolo, 2016).

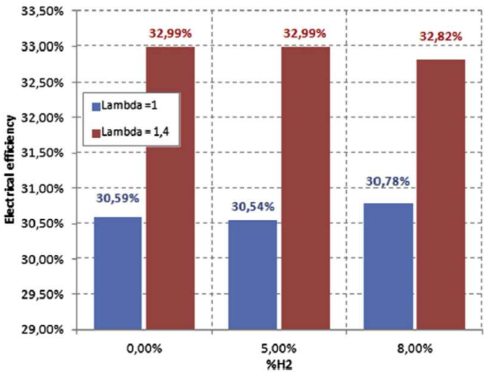


Figure 12.5: Measured electrical efficiency of CHP plant depending on H2NG blend (de Santoli, Lo Basso and Bruschi, 2013).

A study investigated the influence of H2NG blends on residential micro-CHP ICE plants with rated electrical power of 0.5-5 kW. The experimental campaign was carried out on a Single Cylinder ICE, fueled with NG (natural gas) and H2NG with 15% H_2. “In detail, energy performances were assessed at rated and partial loads. From data analysis, it emerged that the electrical efficiency increased up to 2.28%, at the expense of the heat recovery one, having added hydrogen.” (Basso *et al.*, 2015).

Solid oxide fuel cells (SOFC) are fuel-flexible and can tolerate some degree of impurities, such as ammonia and chlorides (USDOE, 2020). A study tested a SOFC as micro-CHP system with a gradual mix change from 0% to 99% hydrogen. The result was that the natural gas based systems have a higher electrical efficiency, but the introduction of hydrogen into the gas leads to a higher total efficiency of the combined heat and power system (Cinti, Bidini and Hemmes, 2019), see Figure 12.6.

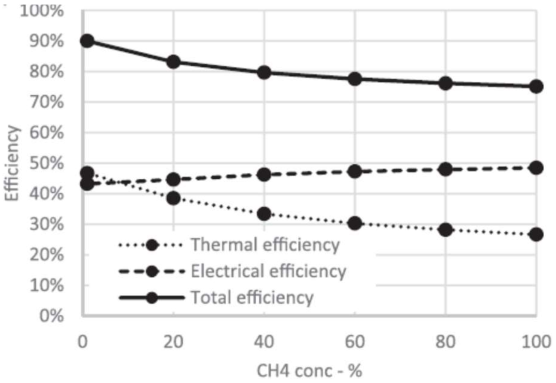


Figure 12.6: Electric, thermal and total efficiency of a solid oxide fuel cell (SOFC) used as micro-CHP with H_2/CH_4 mixtures (Cinti, Bidini and Hemmes, 2019).

According to (Deasley *et al.*, 2020), "The hydrogen content of blended gas will impact its Wobbe Index. The equipment of industrial users such as CCGTs is often tuned to function optimally in a given Wobbe Index range. Significant or rapid fluctuations in Wobbe Index can have a detrimental impact on the functioning of the equipment". "Local Wobbe specifications can prevent hydrogen injection because biomethane has already a low Wobbe index" (Altfeld and Pinchbeck, 2013).

"According to UNECE3 Regulation 110 for CNG vehicles, the H_2 content in CNG is limited to 2 vol-%, if the tank cylinders are manufactured from steel with an ultimate tensile strength exceeding 950 MPa. This limit stems from the risk of hydrogen embrittlement which is known to cause accelerated crack propagation in steel and is, therefore, a critical safety issue" (Altfeld and Pinchbeck, 2013).

Gas boilers for heating are currently an important part of the Swiss natural gas market. The company Buderus claims that 10% hydrogen are no problem for their gas boilers (Buderus, 2021). First natural gas boilers certified for 20% hydrogen are available on the market (Remeha, 2021). The 30-kW boiler ‚H2 Ready'-Heizkessel is intended for up to 20% hydrogen in the standard version and can be adjusted to 100% hydrogen (Bosch, 2020). It works similarly like a conventional condensing gas boiler.

It has been estimated that the leakage rate for hydrogen is about three times higher than that for natural gas for steel and ductile iron gas distribution systems (including seals and joints). For polyethylene (PE) pipes, the losses for a 20% H_2 blend were estimated to be about twice as high compared to pure natural gas (Melaina, Antonia and Penev, 2013). Nevertheless, "the calculation likely overestimates actual gas loss because the permeation coefficient taken from the literature is considered larger than those observed in experiments using pipe under actual operating pressures, especially at lower pressures" (Melaina, Antonia and Penev, 2013). "A calculation for the Dutch pipeline system, based upon experimentally derived permeation coefficients, predicts a gas leakage rate of 0.00005% with a 17% hydrogen blend" (Melaina, Antonia and Penev, 2013).

The use of conventional sulfur-based odorants to detect natural gas leakages may be not appropriate for high hydrogen content and may be replaced by alternative detection methods associated with additional costs (Gerboni, 2016).

The "Underground Sun Storage"[49] tested the storage of hydrogen in depleted natural gas reservoirs in Austria. The project showed that underground gas storage reservoirs can tolerate hydrogen content up to 10% (RAG, 2019).

The main findings of the project "Underground Sun Storage" were (RAG, 2018):

- Underground storage of renewable energy via hydrogen is possible
- Existing gas storage infrastructure has been successfully tested for the applicability of hydrogen
- There is no negative impact on the existing storage
- The integrity of porous gas storage is not compromised
    - No migration from the reservoir
    - No change in the storage rock
    - Microbial processes can be controlled
- Sustainable use of the existing infrastructure for the renewable energy future
- Synergies of storage and production of renewable gas

It is intended to test the storage in the underground depleted natural gas reservoirs also for 100% hydrogen.

Apart from the direct use of the H2NG blend, the mixture can also be converted. On the one hand, the H2NG blend can be used to convert hydrogen and CO_2 into methane. On the other hand, the H2NG blend can be used to obtain pure hydrogen (Panfilov, 2016).

The project "Underground Sun Conversion" found that conversion of hydrogen and carbon dioxide into methane in natural gas reservoirs through a microbiological process is possible. This conversion takes place in the porous rock at depths of more than 1'000 meters after CO_2 is added. "The gas taken from the reservoir may still contain residual unreacted hydrogen and carbon dioxide. In the course of the project, a membrane separation process is therefore being tested in order to reduce these gas components to a specification-compliant level." (RAG, 2018).

If pure hydrogen needs to be recovered from the H2NG blend, the gases need to be separated. Table 12.3 and Table 12.4 show the main components of natural gas in Switzerland. These compounds have to be removed if one wants to recover pure hydrogen from H2NG blend.

Some hydrogen applications can tolerate only low concentrations of impurities. Table 12.5 shows the limits of contaminants in hydrogen for the use in road vehicles with PEM (polymer electrolyte membrane) fuel cells (also known as proton-exchange membrane fuel cells (PEMFC)).

Table 12.6 shows a list of common hydrogen purification technologies with purity and recovery levels.

Several studies are investigating new membrane technologies for the separation of hydrogen from methane and other gases (Lu *et al.*, 2020), (Lei *et al.*, 2021), (Ibeh, Gardner and Ternan, 2007).

Table 12.3: Main components of natural gas distributed in Switzerland as of year 2018 (SVGW, 2019a).

			Mean value 2018	Range 2018	Recommended value for calculations
Methane	CH4	Vol-%	92.44	89.20 - 96.40	90.79
Other hydrocarbons	C2 - C6	Vol-%	5.43	3.45 - 6.52	5.69
Sulfur (as odorant)	S	mg/m3	7	5 - 11	8

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[49] https://www.underground-sun-storage.at/ (22.6.2021)

Table 12.4: Composition of natural gas in the high-pressure network in Switzerland after processing (Faist Emmenegger et al., 2007).

Compound	Unit	Natural gas Switzerland (high-pressure network)
Methane	kg/Nm3	0.68
Ethane	kg/Nm3	0.03
Propane	kg/Nm3	0.013
Butane	kg/Nm3	0.006
C5+	kg/Nm3	0.003
Carbon dioxide	kg/Nm3	0.011
Nitrogen	kg/Nm3	0.020
Sulfur:		
- without odorant	kg/Nm3	1.63E-6
- with odorant	kg/Nm3	8.4 E-6

Table 12.5: Maximum allowable limits of contaminants in hydrogen according to ISO FDIS 14687-2 (USDOE, 2016).

Characteristics (assay)	Type I, Type II
	Grade D
Hydrogen fuel index (minimum mole fraction) a	99.97%
Total non-hydrogen gases	300 µmol/mol
Maximum concentration of individual contaminants	
Water (H2O)	5 µmol/mol
Total hydrocarbons (Methane basis)	2 µmol/mol
Oxygen (O2)	5 µmol/mol
Helium (He)	300 µmol/mol
Total Nitrogen (N2) and Argon (Ar) b	100 µmol/mol
Carbon dioxide (CO2)	2 µmol/mol
Carbon monoxide (CO)	0.2 µmol/mol
Total sulfur compounds c (H2S basis)	0.004 µmol/mol
Formaldehyde (HCHO)	0.01 µmol/mol
Formic acid (HCOOH)	0.2 µmol/mol
Ammonia (NH3)	0.1 µmol/mol
Total halogenated compounds d (Halogenate ion basis)	0.05 µmol/mol
Maximum particulates concentration	1 mg/kg

Table 12.6: Comparison of Hydrogen Purification Techniques. Source: (Grashoff, Pilkington and Corti, 1983). (in table: 1: C. L. Newton, “Cryogenics” in: Kirk-Othmer Encyclopaedia of Chemical Technology, 7, 3rd Edn., 1978. 2: W. A. Bollinger,, D. L. MacLean and R. S. Narayan, Chem. Eng. Prog., 1982, 78, (10), 27. 3: L. J. Kaplan, Chem. Eng. (N.Y.), 1982, 89, (16), 34. 4: J. M. Sedlak,, J. F. Austin and A. B. LaConti, Int. J. Hydrogen Energy, 1981, 6, (1), 45. 5: Chem. Eng.(N.Y.), 1979, 86, (26), 90.)

Technique (Ref.)	Principle	Typical feed gas	Hydrogen output per cent		Scale of use	Comments
			Purity	Recovery		
Cryogenic Separation (1)	Partial condensation of gas mixtures at low temperatures	Petrochemical and refinery off-gases	90–98	95	Large scale	Prepurification step necessary to remove CO2, H2S and water
Polymer Membrane Diffusion (2)	Differential rate of diffusion of gases through a permeable membrane	Refinery off-gases and ammonia purge gas	92–98	>85	Small to large	He, CO2 and H2O may also permeate the membrane
Metal Hydride Separation (3)	Reversible reaction of hydrogen with metals to form hydrides	Ammonia purge gas	99	75–95	Small to medium	Hydrogen absorption poisoned by O2, N2, CO and S
Solid Polymer Electrolyte Cell (4)	Electrolytic passage of hydrogen ions across a solid polymer membrane	Purification of hydrogen produced by thermochemical cycles	99.8	95	Small	Sulphur-containing compounds poison the electro-catalysts
Pressure Swing Adsorption (5)	Selective adsorption of impurities from gas stream	Any hydrogen rich gas	99.999	70–85	Large	The recovery is relatively low as hydrogen is lost in the purging step
Catalytic Purification	Removal of oxygen by catalytic reaction with hydrogen	Hydrogen streams with oxygen impurity	99.999	Up to 99	Small to large	Usually used to upgrade electrolytic hydrogen. Organics, Pb-, Hg-, Cd- and S-compounds poison the catalyst. H2O produced
Palladium Membrane Diffusion	Selective diffusion of hydrogen through a palladium alloy membrane	Any hydrogen containing gas stream	≥99.9999	Up to 99	Small to medium	Sulphur-containing compounds and unsaturated hydrocarbon impair permeability

12.2 Costs

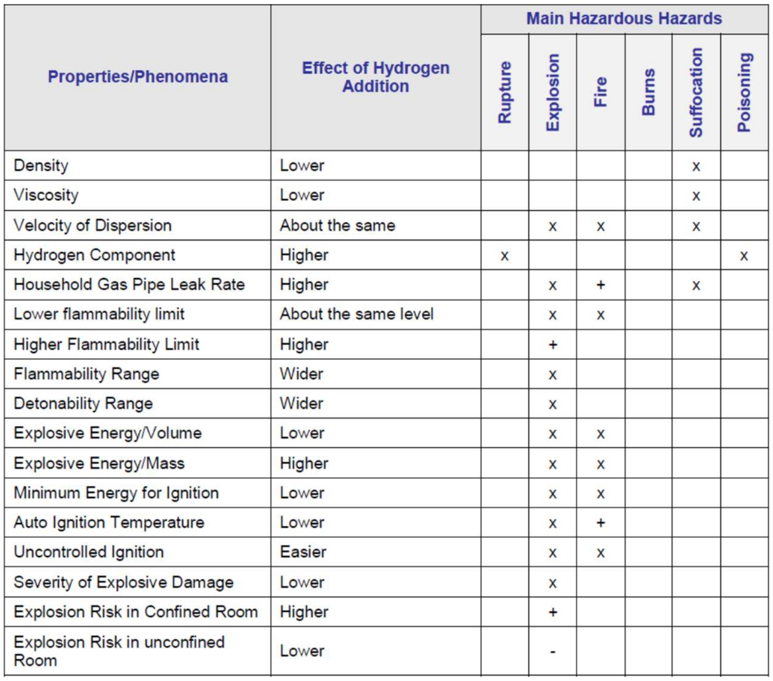
The association of the Swiss natural gas industry assumes that mixtures up to 30% hydrogen are associated only with little transformation costs for the gas infrastructure based on a study of the DBI (SVGW, 2019b). In order to investigate further the H_2 tolerance of the gas distribution network, the SVGW has organized the project “Analyse der H_2-Toleranz von Verteilnetzen” which started in 2020 (SVGW, 2019b).

Changes of fuel costs follow from the changes of efficiency, for example if the electricity output of a CHP plant should be kept constant, see efficiency results above e.g. Figure 12.5 and Figure 12.6.

Losses due to leakages in the gas pipeline systems are considered economically irrelevant (Melaina, Antonia and Penev, 2013).

Nevertheless, hydrogen blending in the natural gas network is associated with possible risks which have to be considered in the cost estimates. Important hazards are listed in Table 12.7.

Table 12.7: Effect of Hydrogen Addition in Natural Gas on Gas Properties and Hazards (Melaina, Antonia and Penev, 2013), (Polman et al., 2003).



Properties/Phenomena	Effect of Hydrogen Addition	Main Hazardous Hazards					
		Rupture	Explosion	Fire	Burns	Suffocation	Poisoning
Density	Lower					x	
Viscosity	Lower					x	
Velocity of Dispersion	About the same		x	x		x	
Hydrogen Component	Higher	x					x
Household Gas Pipe Leak Rate	Higher		x	+		x	
Lower flammability limit	About the same level		x	x			
Higher Flammability Limit	Higher		+				
Flammability Range	Wider		x				
Detonability Range	Wider		x				
Explosive Energy/Volume	Lower		x	x			
Explosive Energy/Mass	Higher		x	x			
Minimum Energy for Ignition	Lower		x	x			
Auto Ignition Temperature	Lower		x	+			
Uncontrolled Ignition	Easier		x	x			
Severity of Explosive Damage	Lower		x				
Explosion Risk in Confined Room	Higher		+				
Explosion Risk in unconfined Room	Lower		-				

Hydrogen blends will probably need additional leakage detection systems and more inspections compared to pure natural gas (Melaina, Antonia and Penev, 2013). It has been estimated that hydrogen blends in the natural gas network may lead to about 10% increase of costs for modifications to related to durability and integrity management (Florisson, 2010).

The separation of the gases needs energy and is associated with additional costs and environmental life cycle burdens in particular, if high purity of the gases (e.g. hydrogen 99.97%, see Table 12.5) is needed for specific applications.

Gas separation by pressure swing adsorption (PSA) can be economical in particular at pressure reduction stations. "For a 10% concentration and 80% recovery factor, the estimated cost of hydrogen extraction by PSA from a 300 psi[50] pipeline is \$3.3–\$8.3/kg hydrogen extracted, for a range of recovery rates of 1,000–100 kg/day. For a 20% concentration and 80% recovery factor, the extraction cost is \$2.0–\$7.4/kg hydrogen extracted, for the same range of recovery rates. However, if hydrogen is extracted at a pressure-reduction facility, the high cost of recompressing the natural gas to the original natural gas pipeline pressure can be avoided. The resulting estimated extraction cost for a 10% concentration and 80% recovery factor is \$0.3–\$1.3/kg… For a station with a pressure drop from 300 to 30 psi, we estimate an extraction cost ranging from \$0.3–\$1.3 per kg hydrogen for a 10% hydrogen blend" (Melaina, Antonia and Penev, 2013).

The costs of separation can be reduced by economies of scale. Figure 12.7 shows estimated costs for hydrogen separation with increasing recovery rate per day by PSA at about 20.7 bar pressure and recovery factor of 80%. The costs are about 61% capital costs, 9% energy costs, and 30% other costs at 100 kg/day from 10% H_2 (Melaina, Antonia and Penev, 2013).

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[50] 300 psi are about 20.7 bar.

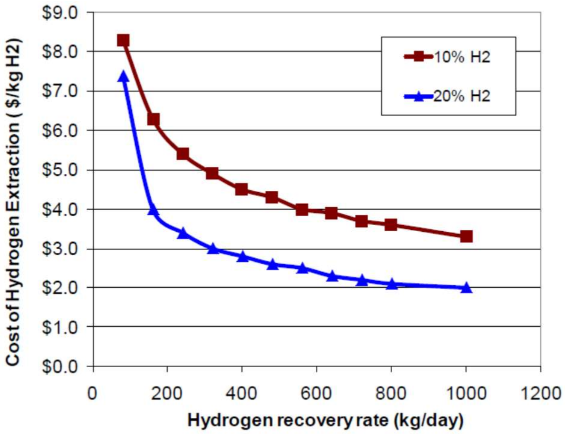

Figure 12.7: Estimated cost of hydrogen extraction by PSA unit from 300 psi (about 20.7 bar) natural gas distribution pipeline (assumed hydrogen recovery factor is 80%) (Melaina, Antonia and Penev, 2013).

Figure 12.8 shows estimated costs of hydrogen extraction by PSA at a pressure-reduction facility from about 20.7 bar to about 2.07 bar. Due to the pressure-reduction step, the costs are much lower than in the case of constant pressure shown above in Figure 12.7.

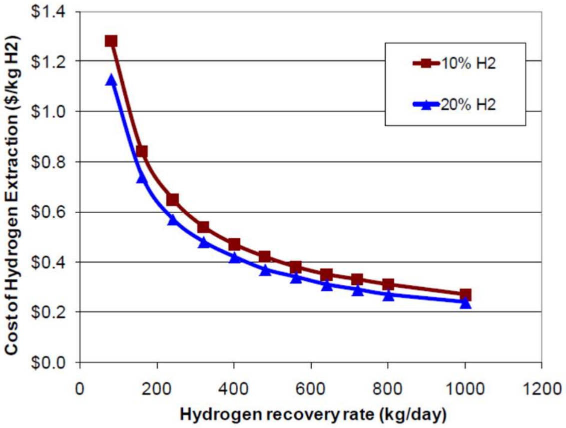

Figure 12.8: Estimated cost of hydrogen extraction by PSA unit at the pressure-reduction facility from 300 psi to 30 psi i.e. from about 20.7 bar to about 2.07 bar. Assumed hydrogen recovery factor is 80% (Melaina, Antonia and Penev, 2013).

12.3 Environmental burdens

Blending hydrogen in the natural gas network can possibly lead to a reduction of overall greenhouse gas emissions. It depends significantly on the life cycle burden of the hydrogen whether and to which extent the goal of GHG reduction by H2NG blends can be reached. If hydrogen is produced with a high GHG life cycle burden (e.g. by using fossil fuels), the effect can be even the opposite i.e. overall GHG emission may increase compared to natural gas. It has therefore to be checked that the hydrogen in the H2NG blend is produced in a sustainable low-carbon way. Environmental burdens due to the potentially required “upgrade” of the natural gas grid are unlikely to be substantial – quantitative evidence is however currently not available.

A study for three countries (UK, France, Netherlands) estimated that blending of hydrogen into the natural gas network may reduce CO_2 emissions with overall abatement costs including hydrogen production between 32$ and 43$ per ton avoided CO_2 (long-term costs of proceeding to 25% hydrogen). Without consideration of hydrogen production, the estimated abatement costs are 12$ to 23$ per ton avoided CO2 (Polman *et al.*, 2003).

Combustion of H2NG blends can have consequences on other emission factors like NO_x emissions compared to combustion of pure natural gas. A study tested an industrial low swirl burner with natural gas, methane, hydrogen-enriched natural gas and hydrogen as fuels. The study found that nitrogen oxide emissions increased significantly when hydrogen-enriched natural gas or pure hydrogen instead of natural gas were used as the fuel. The NO_x emissions are shown in Figure 12.9. By contrast, not only direct CO_2 emissions, but also direct CO emissions decreased (Cellek and Pınarbaşı, 2018).

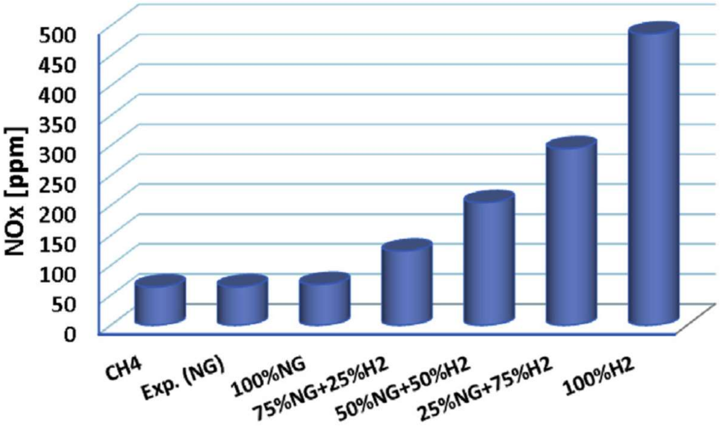

Figure 12.9: Nitrogen oxide emissions for H2NG blends, natural gas and hydrogen, of an industrial low swirl burner (Cellek and Pınarbaşı, 2018).

13 Conversion of hydrogen into synthetic natural gas (SNG)

“Synthetic Natural Gas” (SNG) is a term used for a gas mixture primarily consisting of methane (CH_4), which can directly substitute natural gas and thus be fed into the natural gas grid. In general, SNG can be produced through a variety of techniques, based on both renewable and non-renewable primary and secondary energy feedstock. Conventional methods of SNG production use non-renewable sources such as coal, while a more renewable method of SNG production harnesses biomass (Bolt, Dincer and Agelin-Chaab, 2020).

In addition to using such feedstock, SNG can also be generated via methanation of hydrogen and CO_2, and if hydrogen is generated via water electrolysis, this production pathway is referred to as “power-to-methane” (P2M). Such SNG production is gaining more and more importance, since it allows for so-called “sector coupling”, i.e. the indirect use of renewable electricity converted to SNG for example in mobility (as vehicle fuel) and industry (as feedstock or fuel). And it also represents an option to store electricity over long periods of time in case the SNG is re-electrified, which will become more and more relevant with the expansion of intermittent renewables such as photovoltaic and wind power (Blanco and Faaij, 2018; Kober *et al.*, 2019; Panos and Kober, 2020).

This section is dedicated to the “power-to-methane” pathway for SNG production. Worldwide, a substantial number of production units have recently become operational (Wulf, Linßen and Zapp, 2018; Thema, Bauer and Sterner, 2019). Currently, Europe can be considered as geographical hot-spot, as shown in Figure 13.1.

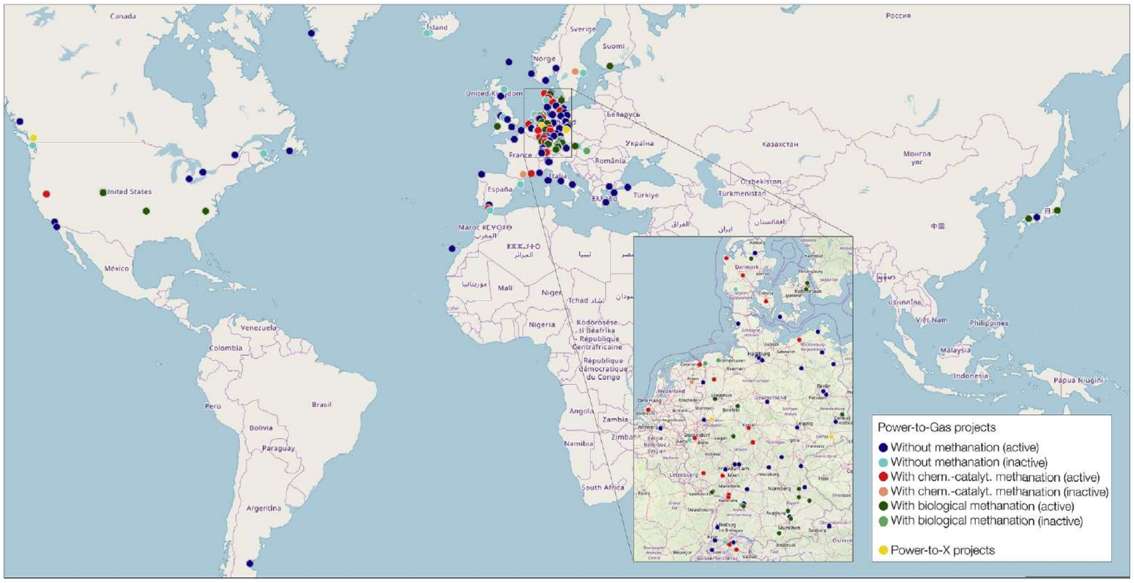

Figure 13.1: Locations of Power-to-gas facilities as of early 2019 (Thema, Bauer and Sterner, 2019).

Within Europe, most power-to-gas units are operated and planned in Germany. The German “Verein des Gas- und Wasserfaches” provides an interactive online map of power-to-gas units in Germany.[51] As of April 2021, it lists 36 units as operational and 23 in development. The majority of these units, however, is dedicated to hydrogen production only without subsequent methanation.

13.1 Technologies

Production of SNG via “power-to-methane” includes several processes, as visualized in Figure 13.2: Electrolysis (see section 8.1.1), separation/capture of CO_2, and methanation, in which CO_2 and hydrogen react and form SNG. The entire process chain also includes storage units and some gas

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[51] https://www.dvgw.de/themen/energiewende/power-to-gas/interaktive-power-to-gas-karte/ (11.4.2021).

cleaning/upgrading and compression steps. All processes require certain amounts of electricity input, electrolysis the major part of it. The methanation process is exothermal, i.e. it generates heat, which can be used in other processes.

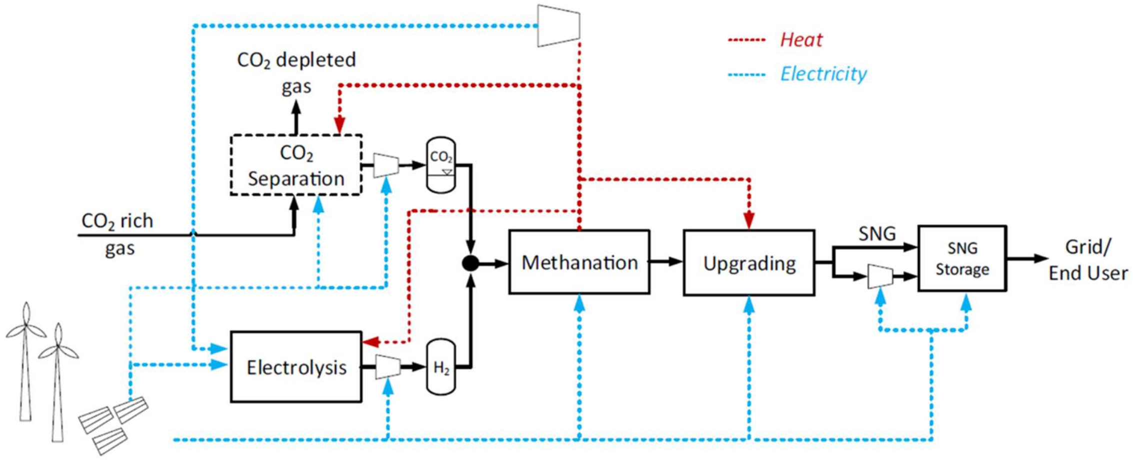

Figure 13.2: Conceptual scheme of SNG production via "power-to-methane" (Gorre, Ortloff and van Leeuwen, 2019). "CO_2 rich gas" can be the exhaust gas from the combustion of fossil fuels or biomass, but also be the atmosphere.

Conversion steps are associated with (waste) heat releases and if the energy in this heat is lost, the overall process chain efficiency is in the order of 55% (Figure 13.3). However, some of the "lost" energy might be available as usable waste heat (also depending on its temperature level) and optimal heat integration can improve the overall efficiency; this is mainly relevant for high-temperature SOEC electrolysis.

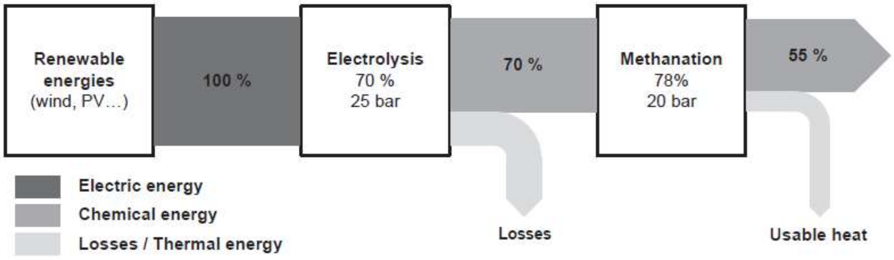

Figure 13.3: Overall process chain efficiency of SNG production (Götz et al., 2016). Figures represent average process performances.

13.1.1 Methanation

There are several concepts and technologies for methanation – regarding the conversion reactor, biological and catalytic methanation are distinguished (Figure 13.4). Biological methanation is a conversion process to generate methane from hydrogen and carbon dioxide using specialized microorganisms. The relevant metabolic processes are performed under anaerobic conditions and in an aqueous environment. Catalytic methanation corresponds to the Sabatier process, which produces methane and water from a reaction of hydrogen with carbon dioxide at elevated temperatures (optimally 300-400 °C) and pressures in the presence of a catalyst. Reactor designs, product yields, thermodynamics, operating conditions, and appropriate catalysts are extensively discussed in several recent review articles (Götz *et al.*, 2016; Rönsch *et al.*, 2016; Ghaib and Ben-Fares, 2018; Wulf, Linßen and Zapp, 2018; Thema, Bauer and Sterner, 2019; Bolt, Dincer and Agelin-Chaab, 2020).

While catalytic methanation has a long history and is ready to be deployed at scale, biological methanation is rather at the pilot and demonstration level (Götz *et al.*, 2016; Rönsch *et al.*, 2016; Thema, Bauer and Sterner, 2019). Today, fixed bed reactors represent the mainstream technology, mainly due to their simple and effective design (Bolt, Dincer and Agelin-Chaab, 2020). Nickel-based catalysts are the preferred option today due to their high selectivity and activity at comparatively low costs (Bolt, Dincer and Agelin-Chaab, 2020).

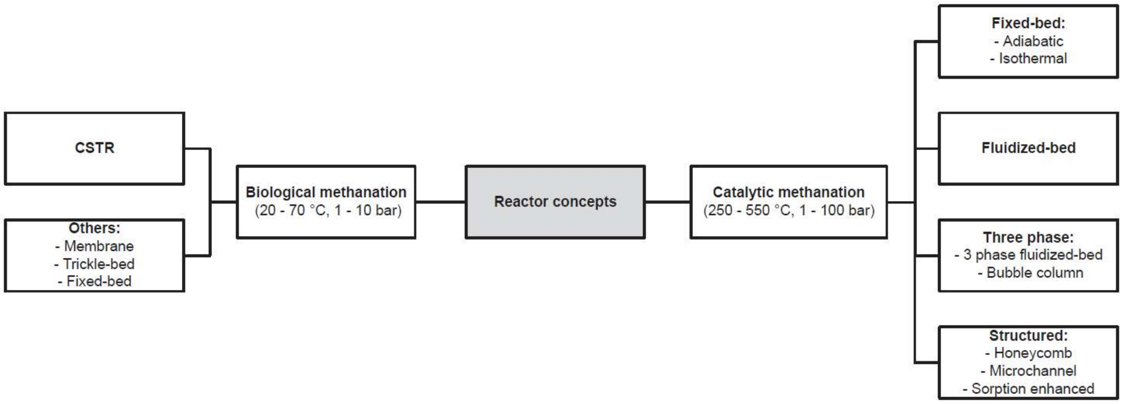

Figure 13.4: Reactor concepts for the production of SNG (Götz et al., 2016).

13.2 CO_2 sources

Potential CO_2 sources are industrial processes such as cement and steel making, coal and natural gas power plants, biomass and waste combustion and gasification, upgrading of biogas from anaerobic digestion processes as well as the atmosphere, from which the CO_2 can be extracted via direct air capture (DAC). High CO_2 concentration in exhaust streams from industry and power plants represents an advantage for separation; however, it often comes at the cost of gas impurities (e.g. Sulphur), which have to be removed before methanation due to poisonous effects on catalysts, which can have extremely low tolerance levels regarding trace elements in the feed gases (Götz *et al.*, 2016).

CO_2 concentration is one of the determining factors for the costs of CO_2 capture from different sources, which can vary within large ranges – Figure 13.5 provides an overview.

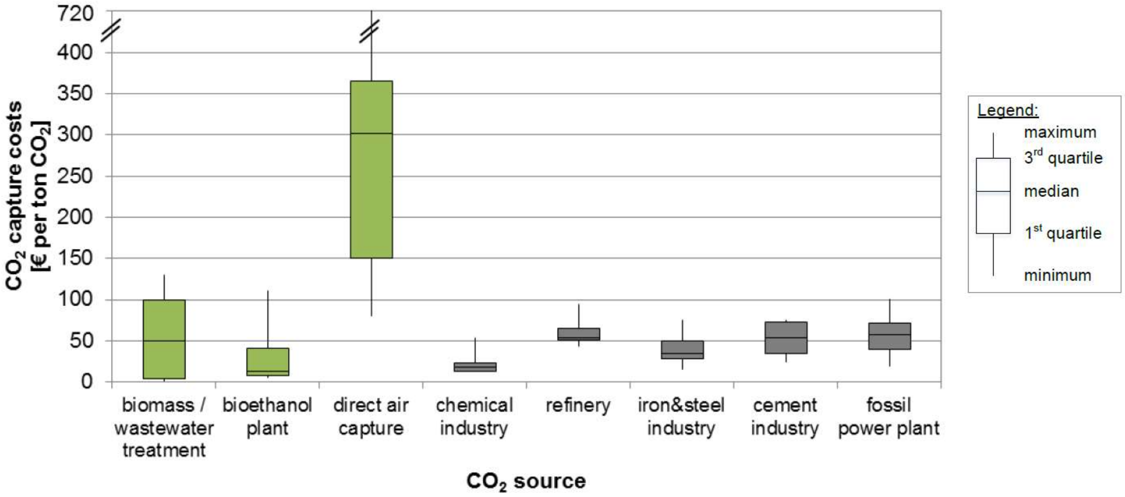

Figure 13.5: Costs for CO_2 capture (Leeuwen and Zauner, 2020). Green color reflects the potential to create closed carbon cycles with CO_2 from biogenic sources and the atmosphere. Large cost ranges for CO_2 from biomass and wastewater treatment (anaerobic digestion of biomass) and direct air capture (DAC) represent variability and uncertainty. Bioethanol produced from biogenic residues from ariculture. DAC costs indicated here can be regarded as rather low. Climeworks currently indicates CO_2 capture costs of around 600 $, with a long-term target of 100 $ per ton of CO_2[52].

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[52] https://www.nature.com/articles/d41586-018-05357-w (22.6.2021)

In Switzerland, main potential CO_2 sources besides the atmosphere are municipal solid waste incineration (MSWI) plants, wastewater treatment (WWT) plants, biogas upgrading facilities, potential large-scale wood combustion CHP units, and cement plants. A thorough analysis of potentially available CO_2 sources has recently been performed (Teske *et al.*, 2019) – available quantities of CO_2 from cement, MSWI and WWT plants are shown in Figure 13.6. Their overall annual CO_2 production amounts to about 7.1 Mt, which corresponds to an annual SNG production of 38 TWh (Teske *et al.*, 2019).

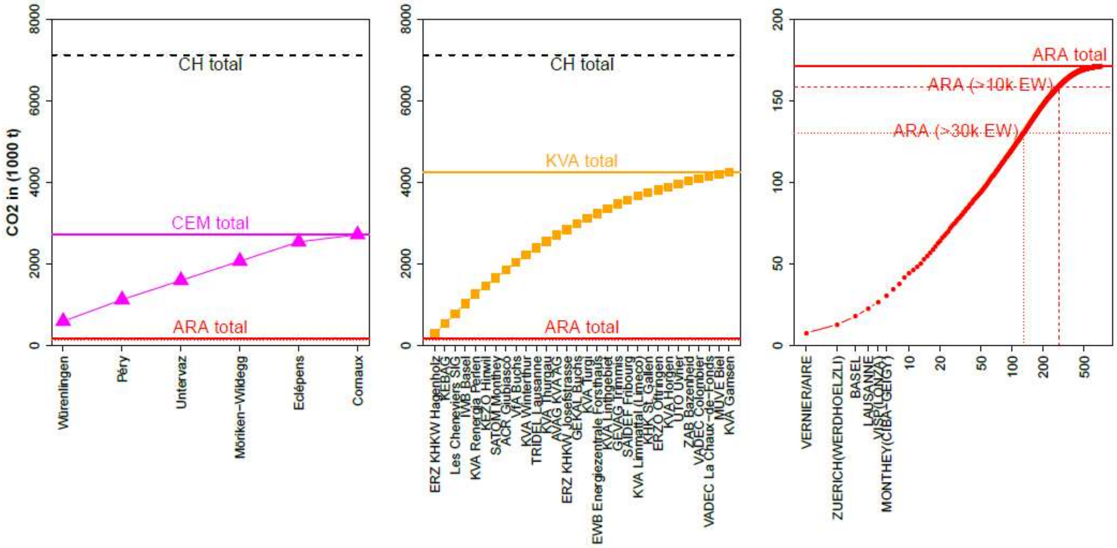


Figure 13.6: Cumulative amounts of CO_2 from main individual sources in Switzerland potentially to be used for SNG production (Teske *et al.*, 2019). ARA: wastewater treatment plant; CEM: cement plant; KVA: municipal waste incineration.

The geographical distribution of these sources (and the natural gas network) are shown in Figure 13.7.

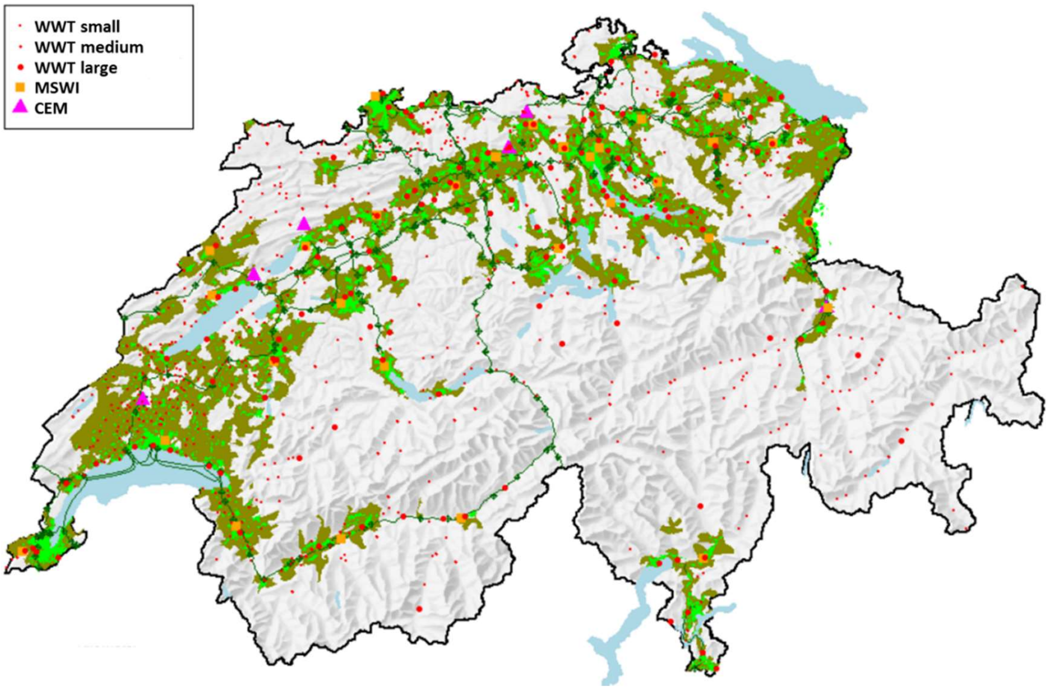


Figure 13.7: Geographical distribution of potential CO_2 sources for SNG production in Switzerland; reproduced based on (Teske *et al.*, 2019). CEM: cement plant; MSWI: municipal solid waste incineration; WWT: wastewater treatment.

13.3 Costs of SNG production

The economic viability of SNG production via power-to-methane processes is determined by a few key factors: hydrogen production costs (section 8.1.3), CAPEX of the methanation unit and its utilization factor, and CO_2 supply costs. Costs of hydrogen production via electrolysis are dominated by CAPEX for the electrolyser and its utilization factor as well as electricity costs. In a dynamic system with fluctuating electricity prices, cost optimization of SNG production is a complex exercise with a trade-off between minimizing electricity supply costs and maximizing utilization of the SNG production facilities. Integrating storage units for CO_2 and hydrogen can increase the economic viability of SNG production substantially (Gorre, Ortloff and van Leeuwen, 2019; Gorre *et al.*, 2020).

Due to the nature of its process design and the operational flexibility, levelized SNG production costs can vary within a broad range. There is a certain number of studies which quantify these levelized costs of SNG production, each of them with specific assumptions and input parameters. (Kober *et al.*, 2019) reviewed the available literature and synthesized SNG production costs, as shown in Figure 13.8 in comparison to levelized production costs for hydrogen, electricity from re-electrification of hydrogen, and power-to-liquid fuels. Current average levelized production cost of SNG are estimated to be in a range of 170–250 CHF/MWh_{th} and can be as low as 100 CHF/MWh_{th}. Large economies of scale can be expected, i.e. larger units can achieve substantially lower SNG production costs than small units (Parra *et al.*, 2017; Gorre, Ortloff and van Leeuwen, 2019).

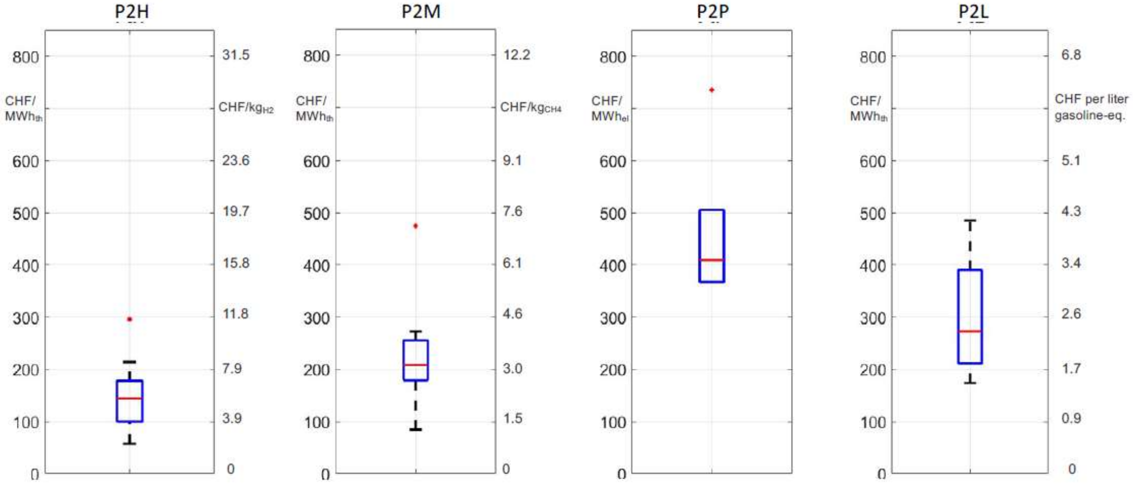
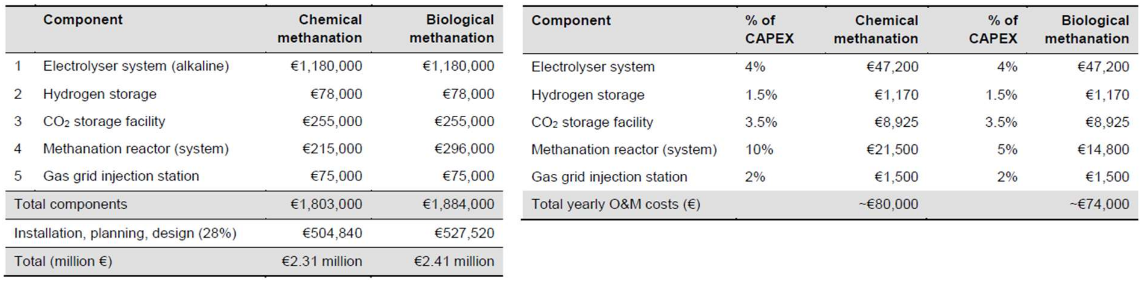


Figure 13.8: Distribution of the levelized cost for the various "power-to-X" routes based on current cost and performance data (Kober et al., 2019). The boxplots include the median (middle quartile inside the box), 25th and 75th percentiles. The whiskers extend to the most extreme data points not considering outliers, and the outliers are plotted individually using the '•' symbol. For routes producing gas, data are based on the HHV; for the P2L route, the unit "CHF per liter gasoline eq." represents an energy-related cost matrix with limited comparability to retail fuel prices, which entail a significant tax component. P2H: Power-to-hydrogen; P2M: Power-to-methane; P2P: Power-to-power (using fuel cells – section 14); P2L: Power-to-Liquids.

Specific and detailed cost estimates for a representative entire Power-to-methane unit based on recent experiences with demonstrator units as well as literature are provided by (Leeuwen and Zauner, 2020).



	Component	Chemical methanation	Biological methanation
1	Electrolyser system (alkaline)	€1,180,000	€1,180,000
2	Hydrogen storage	€78,000	€78,000
3	CO_2 storage facility	€255,000	€255,000
4	Methanation reactor (system)	€215,000	€296,000
5	Gas grid injection station	€75,000	€75,000
Total components		€1,803,000	€1,884,000
Installation, planning, design (28%)		€504,840	€527,520
Total (million €)		€2.31 million	€2.41 million

Component	% of CAPEX	Chemical methanation	% of CAPEX	Biological methanation
Electrolyser system	4%	€47,200	4%	€47,200
Hydrogen storage	1.5%	€1,170	1.5%	€1,170
CO_2 storage facility	3.5%	€8,925	3.5%	€8,925
Methanation reactor (system)	10%	€21,500	5%	€14,800
Gas grid injection station	2%	€1,500	2%	€1,500
Total yearly O&M costs (€)		~€80,000		~€74,000

Figure 13.9: CAPEX (left) and OPEX (right) of representative SNG production facilities, based on a 1 MW electrolyzer (Leeuwen and Zauner, 2020).

Based on these investment costs and electricity prices according to the German day-ahead market prices in 2016 (Figure 13.10), and assuming CO_2 costs of 50 €/t, levelized SNG production costs have been quantified (Figure 13.11). The average electricity costs on the German day-ahead market throughout the entire year 2016 amounted to about 30 €/MWh. In reality, electricity prices an SNG production unit has to pay are likely to be higher due to the addition of taxes and fees.

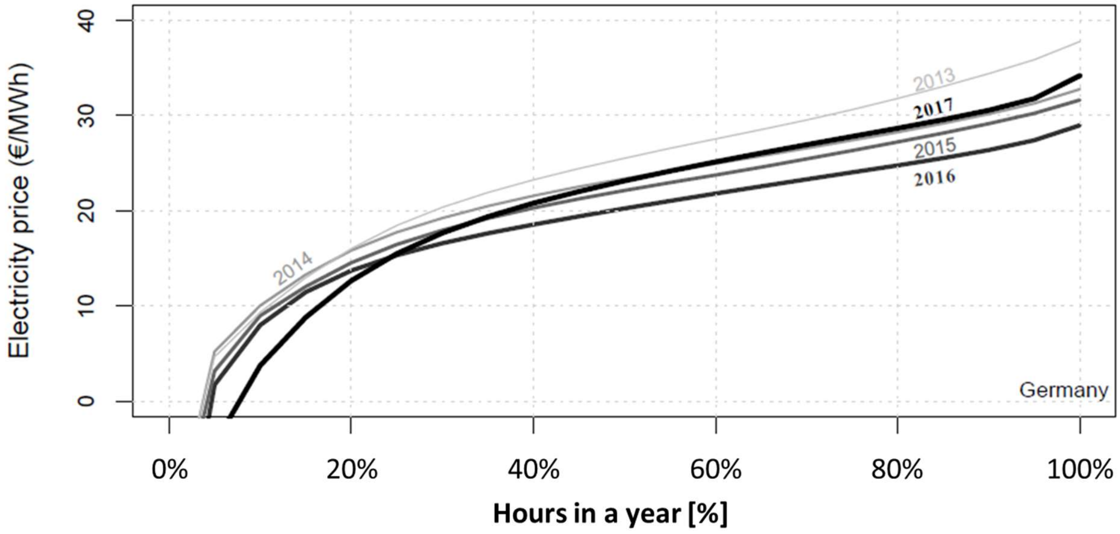


Figure 13.10: Average electricity prices in cheapest x% of the hours in Germany (Leeuwen and Zauner, 2020).

In this exemplary cost estimation, maximizing operational hours of the SNG production facility minimizes SNG production costs due to reduction of levelized CAPEX. The reduction of electricity costs at lower operating hours (operating only in periods with lowest electricity prices) does not compensate for the increase in levelized CAPEX. Depending on the specific electricity price profile throughout the year, this can however be different and operating the P2M facility less than possible can turn out to be economically optional. Thus, minimizing SNG production costs is a case-specific optimization, in which electricity price profiles, investment costs for electrolysis and methanation, and cost of capital play major roles. Installing storage tanks for hydrogen allowing for optimal sizing of electrolyser and methanation unit can turn out to reduce SNG production costs (Gorre, Ortloff and van Leeuwen, 2019; Gorre *et al.*, 2020).

Minimum SNG production costs amount to about 1.3 €/Nm^3 SNG, corresponding to about 12 Rp per kWh SNG or 120 CHF per MWh SNG. For comparison: average natural gas prices (including taxes, and including supply to the end user) in Switzerland in 2017-2020 have been in the order of about 4-10.5 Rp./kWh (depending on the amount of annual consumption).[53] Natural gas spot market prices

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[53] http://gaspreise.preisueberwacher.ch/web/index.asp?z=4 (22.6.2021)

in Europe, representing the product without costs associated with the supply to end users, have recently been in the order of 25-30 Euro per MWh (27-33 CHF/MWh) or in the order of 3 Rp/kWh.[54]

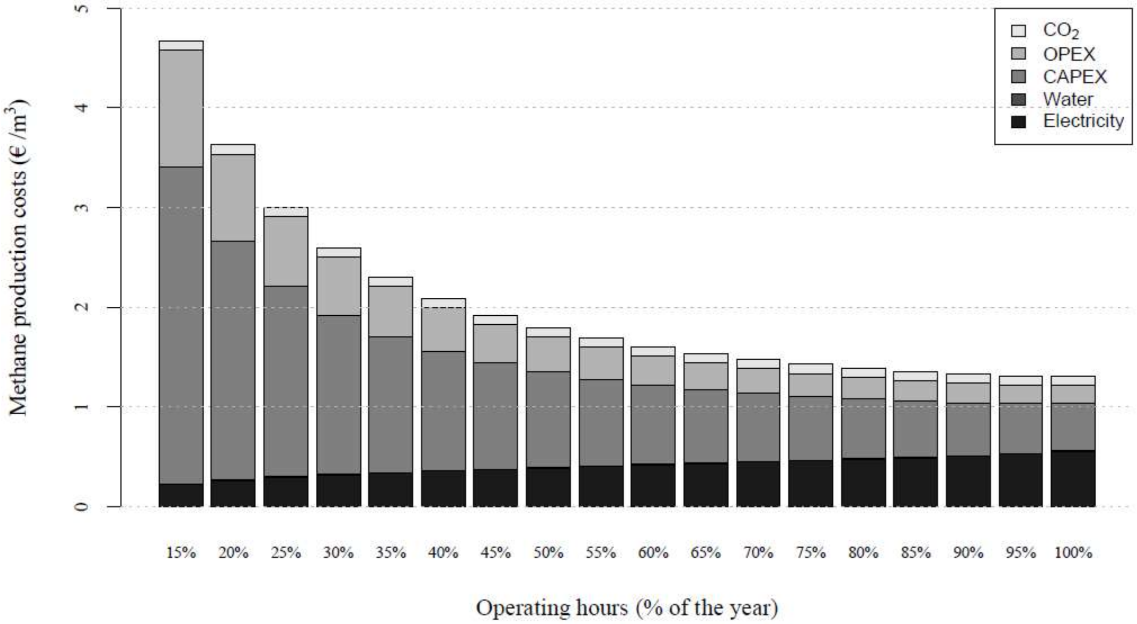

Figure 13.11: Levelized costs of methane production for an SNG production unit with catalytic methanation as a function of annual operating hours (Leeuwen and Zauner, 2020). Investment costs as reported in Figure 13.9. Assumed CO_2 costs: 50 €/t. Electricity prices according to time-dependent German day-ahead market prices in 2016. Project lifetime: 20 years; discount rate: 6%.

Future development of SNG production costs will mainly depend on future CAPEX of electrolysis and methanation units, CO_2 and electricity prices, and operation regimes (Gorre, Ortloff and van Leeuwen, 2019; Gorre *et al.*, 2020). Expected trends in CAPEX of electrolyzers and methanation reactors are similar; however, estimates for methanation are much more scarce that for electrolysis. Figure 13.12 shows CAPEX development until 2050 according to (Thema, Bauer and Sterner, 2019). While current CAPEX for biological methanation are substantially higher than those from catalytic methanation, both conversion technologies are expected to reach similar CAPEX levels in 2050.

Increase of efficiency of electrolysis and thus reduced electricity demand (section 8.1.1) will also contribute to cost reductions. However, these gains are expected to be minor compared to technology cost reductions (Schmidt, Gambhir, *et al.*, 2017).

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[54] https://www.powernext.com/spot-market-data (22.6.2021)

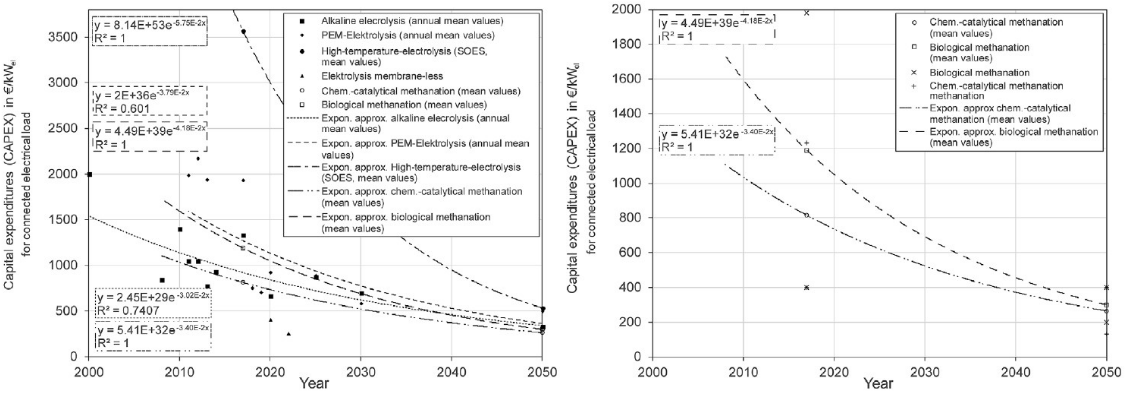

Figure 13.12: CAPEX as of today and projection until 2050 for biological and catalytic methanation in comparison to electrolysis (Thema, Bauer and Sterner, 2019). The right panel represents a zoon into methanation. All cost for methanation refer to the connected electrical power of an electrolyzer, but exclude electrolysis.

Future cost reductions of methanation has also been analyzed recently by (Böhm *et al.*, 2018), as shown in Figure 13.13. According to these projections, biological methanation will remain more expensive than catalytic methanation. These future investment costs are somewhat lower than those estimated in (Kreidelmeyer *et al.*, 2020), who use CAPEX for methanation of 665 €/kW$_{SNG}$ in 2020 declining to 481 €/kW$_{SNG}$ in 2050 in their calculations.

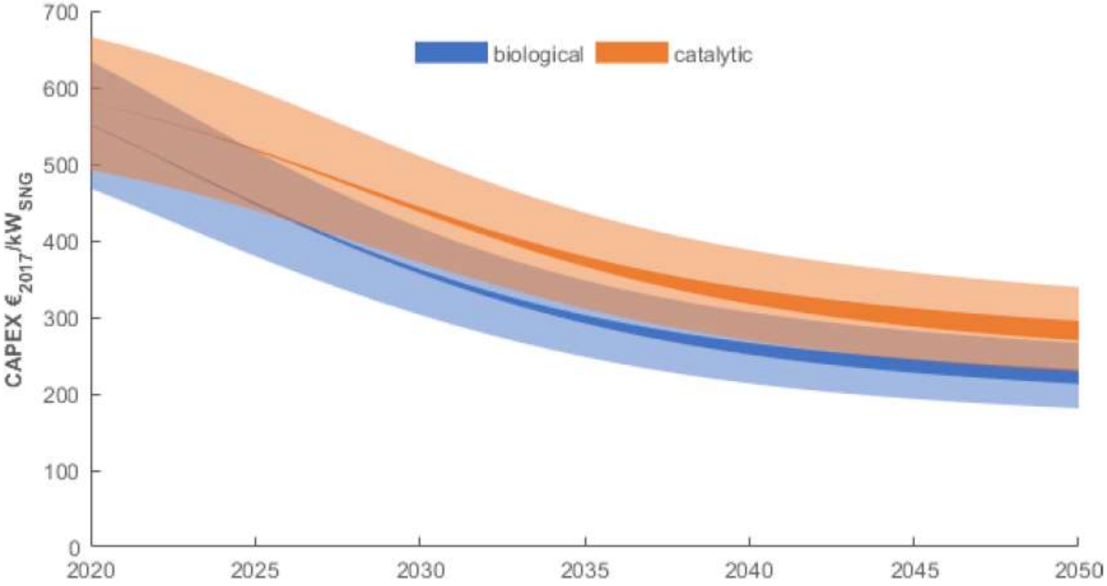

Figure 13.13: Expected cost developments for methanation systems (Böhm et al., 2018). Shaded areas represent variability of current CAPEX and the resulting uncertainties.

(Gorre, Ortloff and van Leeuwen, 2019) estimate future SNG production costs for different operation regimes and associated electricity costs (the higher the willingness to pay for electricity, the higher the number of operational hours per year) taking into account expected technology cost development until 2050 (Figure 13.14). Similar to (Leeuwen and Zauner, 2020), they find decreasing SNG production costs with increasing annual operational hours, but the optimum is not at full utilization over the entire year, which is due to the assumed electricity price distribution over the year. SNG production costs are estimated to be in a range of 80-150 €/MWh SNG in 2050, depending on capacity utilization and electricity prices.

(Kreidelmeyer *et al.*, 2020) also estimate current and future P2M costs, but only for production in MENA countries with high yields for wind and solar power for electrolysis. These estimates are in ranges of about 210-400 €/MWh$_{SNG}$ in 2020, 180-330 €/MWh$_{SNG}$ in 2030, and 150-270 €/MWh$_{SNG}$ in 2050; thus in the same order, but somewhat higher than those quantified by (Gorre, Ortloff and van Leeuwen, 2019).

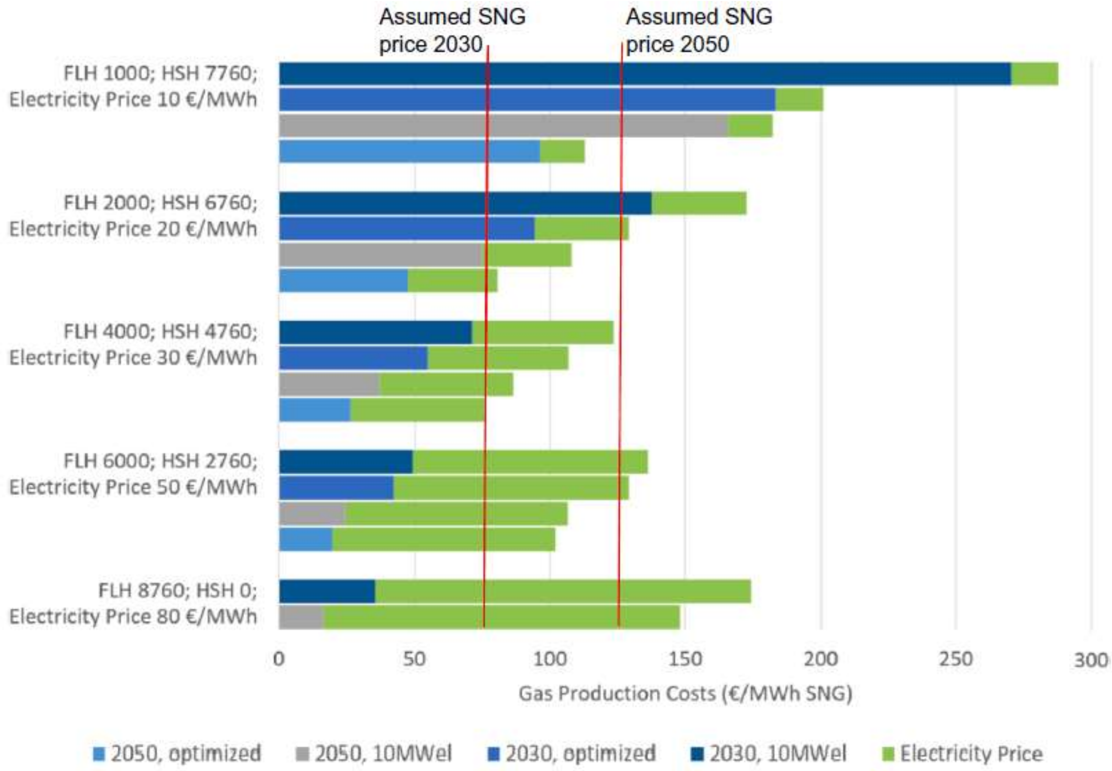

Figure 13.14: SNG production costs (€/MWh) for different full load hours (FLH) of the electrolyser and methanation subsystem. The FLH of the PtG system depend on the electricity price – the lower the electricity price (assuming a certain willingness to pay), the lower the FLH (Gorre, Ortloff and van Leeuwen, 2019). The "assumed SNG prices" in 2030 and 2050 indicate hypothetical market prices for "renewable" SNG and biomethane; the authors do not provide explanation why this price is supposed to increase substantially between 2030 and 2050. "Electricity price" refers to the part of the SNG production cost, which is due to purchasing electricity for electrolysis. Lowest SNG production costs are in this case achieved at 4000 FLH per year due to an optimum in levelized CAPEX and expenses for electricity. Higher amounts of FLH increase electricity costs disproportionally, while reducing FLH leads to an increase in levelized CAPEX which cannot be compensated by lower electricity expenses.

13.4 Environmental burdens

Greenhouse gas emissions associated with SNG production are – from a life-cycle perspective – determined by the GHG intensity of the electricity used for electrolysis, energy losses along the conversion chain, and the origin of CO_2 used for methanation (and, in case this CO_2 is of fossil or geogenic origin, the accounting procedure for CO_2 emissions from SNG use can be important) (Zhang *et al.*, 2017; Koj, Wulf and Zapp, 2019; Müller, Kätelhön, Bachmann, *et al.*, 2020; Müller, Kätelhön, Bringezu, *et al.*, 2020). GHG emissions related to infrastructure are negligible.

The GHG emissions of hydrogen production via electrolysis are almost a direct function of the GHG emissions associated with the electricity supply for the electrolysis and the electricity demand per unit of hydrogen (section 8.3). The origin of CO_2 is important, because it determines, whether SNG production and use can represent a closed carbon cycle (not adding additional greenhouse gases to the atmosphere), or whether it causes additional impacts on climate change. Only CO_2 from biomass and directly captured from the atmosphere allow for a closed carbon cycle, as visualized in Figure 13.15 (case a) for direct air capture of CO_2 and case c) for power generation from biomass). Using CO_2 from geogenic or fossil sources (cases b) and d) in Figure 13.15, respectively), can – from an overall system perspective – reduce GHG emissions by 50% at best, because the CO_2 captured at the point source will be later emitted by due to SNG use and is thus only delayed in time (Abanades *et al.*, 2017). On the contrary, burning SNG with CO_2 from biomass emits the same amount of CO_2 into the atmosphere, which has been either directly (direct air capture) or indirectly (via biomass growth) extracted from the atmosphere (relatively) short time before and therefore does not represent an additional impact on climate change.

If a product-specific carbon footprint for the SNG is required (e.g., for comparing the carbon footprint of SNG against natural gas), this overall system perspective is unfortunately inappropriate, because the reduction of CO_2 emissions as an effect of SNG production and use (compared to a system without SNG) has to be assigned to either the point source, where CO_2 is captured, or the SNG end-use, where the captured CO_2 is released (if the CO_2 is of fossil or geogenic origin). Assigning certain fractions to both is also possible. Current guidelines recommend the assign the reduction of CO_2 emissions to the SNG user, as long as CO_2 from fossil point sources is an unconstrained resource (Müller, Kätelhön, Bachmann, *et al.*, 2020; Müller, Kätelhön, Bringezu, *et al.*, 2020). However, this recommendation has to be challenged, since it is unclear why an emitter of CO_2, capturing and providing this CO_2 to SNG production, should still bear the responsibility for the CO_2 emissions physically taking place during SNG combustion and not any more at the original point source. Future regulation in this context must ensure that CO_2 emissions do not “disappear” in the accounting framework in the sense that both the CO_2 point source and the physical emitter (product end user) claim the emissions reduction entirely for themselves.

In any case, capturing CO_2 is always associated with energy demand and material requirements and both is causing additional GHG emissions. Energy demand depends to a large extent on the CO_2 concentration in the gas from which the CO_2 is captured. (Müller, Kätelhön, Bringezu, *et al.*, 2020) have quantified the GHG emissions associated with CO_2 capture from a wide range of available sources in industry and power generation in Europe, as shown in Figure 13.16 (also showing the amounts of CO_2 available today in Europe from each of these sources).

A recent analysis of the environmental performance of SNG produced in Iceland and used in Switzerland can serve as a showcase for LCA of SNG production (Zhang and Bauer, 2021). It shows that producing SNG in Iceland, with its ample potential for hydropower and CO_2 from geothermal power generation[55], and importing it to Switzerland, can represent an environmentally sound option in both the mobility and the residential sectors not tapping into the limited potential of renewable electricity in Switzerland. However, the currently given ambiguity regarding assigning CO_2 emissions of SNG use to either the SNG end-user or the point source where CO_2 is captured (assuming these CO_2 emissions would have happened anyway) represents a major uncertainty regarding the environmental performance of such SNG. The evaluation of different transport options for importing this SNG from Iceland to Switzerland revealed – in relative terms – large differences in terms of costs and GHG emissions. Due to the availability of low-cost electricity from hydropower in Iceland and the option of realizing large methanation facilities with high capacity factors, Iceland seems to be a cost-competitive location for SNG production for the Swiss market (H2 Energy, 2021).

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[55] CO_2 from geothermal sources is often referred to as “geogenic” carbon dioxide. In terms of accounting for GHG emissions, this is equivalent to fossil CO_2, since the geothermal energy production releases this carbon dioxide representing additional flows to the atmosphere. As opposed to biogenic CO_2, geogenic CO_2 cannot be considered to represent a “closed cycle” within appropriately short time frames.

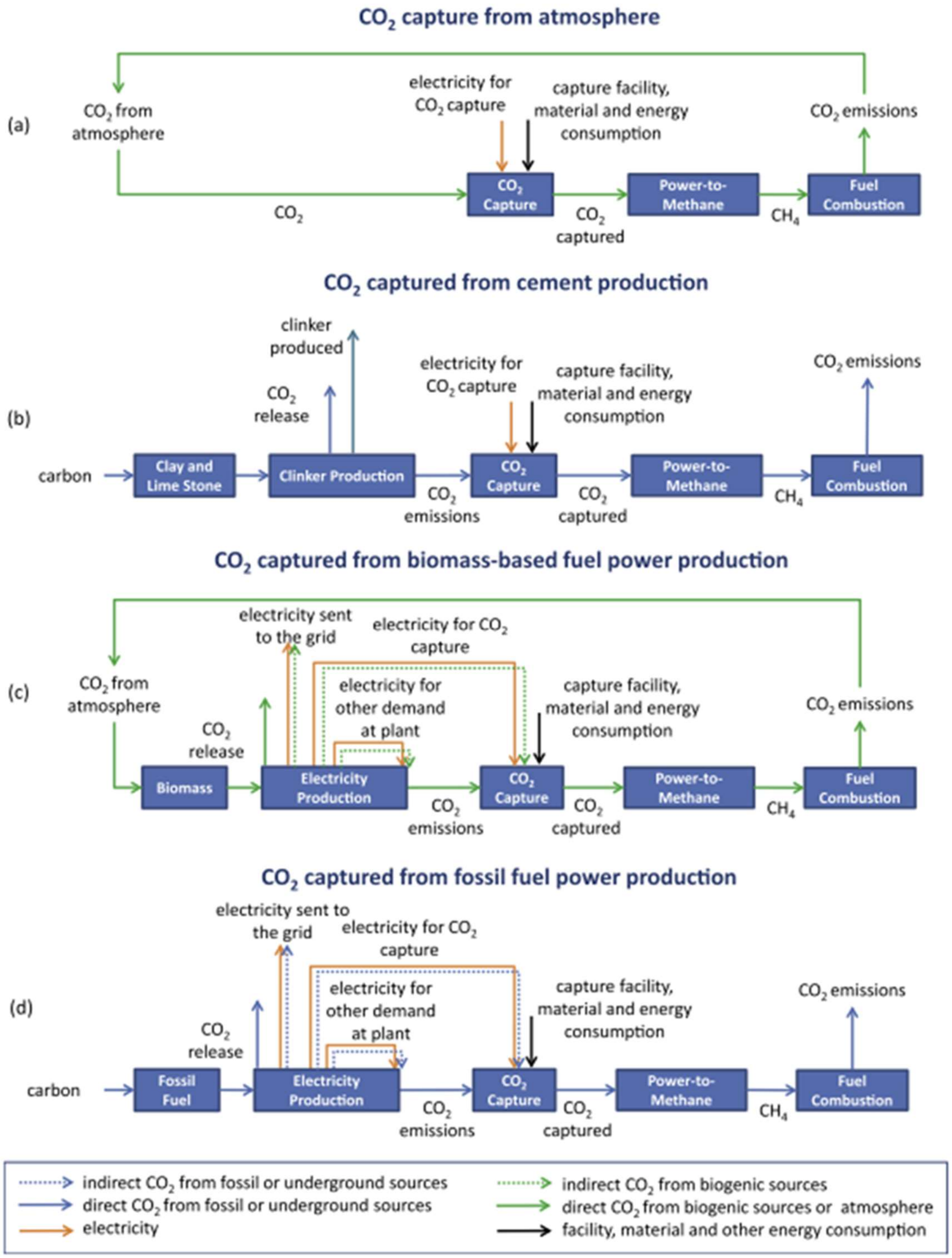

Figure 13.15: Carbon balance of different carbon dioxide sources for SNG production and utilization from a system perspective.

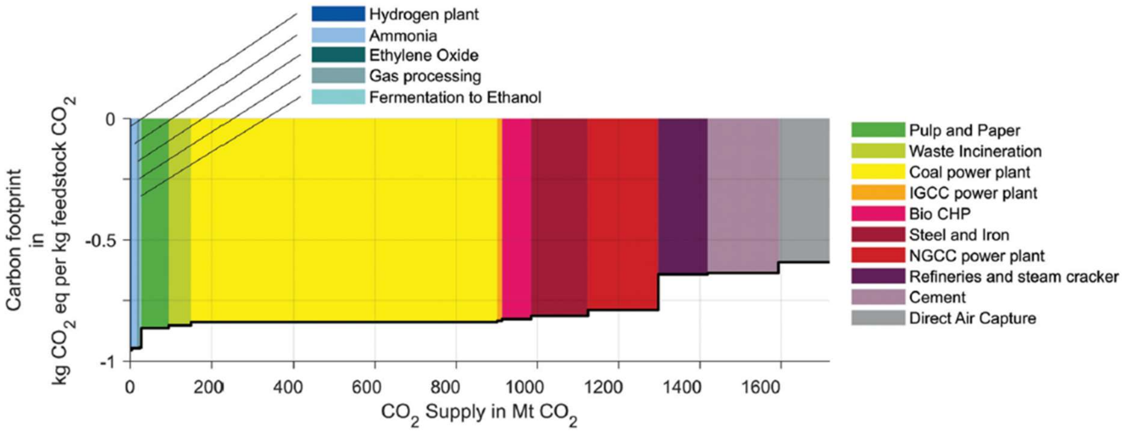

Figure 13.16: Life-cycle GHG emissions of capturing CO_2 from different point sources in Europe and the available amounts of CO_2 today (Müller, Kätelhön, Bringezu, et al., 2020). Here, capturing 1 kg CO_2 is assigned with a carbon footprint of minus 1 kg. Thus, the GHG emissions associated with the capture are equivalent to difference between minus 1 and the source-specific carbon footprint. The carbon footprint of direct air capture is quantified using the average European electricity mix for the capture process and therefore comparatively high.

14 Re-electrification of hydrogen via stationary fuel cells[56]

A fuel cell consists of two electrodes: the anode and cathode, with an electrolyte layer between the two electrodes. Hydrogen is consumed at the anode and oxygen is fed into the cathode, while the electrolyte ensures only the positive ions to flow from the anode to the cathode. Electrons flow simultaneously from the anode to the cathode in an external circuit, which generates electricity. The overall reaction results in water.

In this section, the focus will be on stationary fuel cells providing Combined Heat and Power (CHP) – e.g., for distributed energy generation. Fuel cell CHP systems can be useful in the context of the future Swiss electricity supply for example to replace centralized power plants (Bauer *et al.*, 2017). Fuel cell CHP systems convert chemical energy (*i.e.* hydrogen) into electrical energy (*i.e.* electricity), thermal energy and water (Kirubakaran, Jain and Nema, 2009; Pieper, 2019). The re-electrification of hydrogen adds a second energy conversion in the hydrogen supply chain: from hydrogen to electricity. Hence, this is less energy efficient than the generation of hydrogen and the subsequent (direct) consumption as such. The re-electrification of hydrogen can therefore also be perceived as an alternative for energy storage when coupled to an electrolyzer (Bruce *et al.*, 2018).

In general, stationary fuel cells have a high energy conversion efficiency and their low fuel costs make them an attractive option for future energy supply (Bauer *et al.*, 2017). Stationary fuel cells have additional advantages, such as resilience to disruptions of the electricity grid, a reduction of grid transmission losses, less overall reliance on the electricity grid and heating system, as well as an increase of the consumption of locally generated power (Wei *et al.*, 2016). Further, fuel cells can potentially reach near-zero GHG emissions and are well-known of their modularity and scalability (Kirubakaran, Jain and Nema, 2009). Stationary fuel cells are considered as a reliable and clean source for backup power, especially in cases where uninterrupted power is from crucial importance, as for example in hospitals and data centers (Wei *et al.*, 2016). On the other hand, stationary fuel cells are still more expensive than centralized power plants nowadays (Bauer *et al.*, 2017).

Stationary fuel cells and their fuel supply chain can re-use the natural gas infrastructure, and as such could reduce total costs and overall environmental impacts of distributed energy systems (Wei *et al.*, 2016). Fuel cell CHP systems are usually fueled by natural gas or biomass and therefore require a fuel processing unit – a reformer to convert hydrocarbons into hydrogen and CO_2 (Staffell and Green, 2013) - to generate hydrogen to be subsequently used in the fuel cell (Wei *et al.*, 2016). Alternatively, hydrogen can be directly fed into fuel cells – when hydrogen is for example readily available in a well-developed hydrogen supply chain - and therefore can be installed without a fuel processing unit. In the latter case, only water will be generated from the overall reaction, while natural gas as fuel source generates CO_2 in addition.

Different stationary fuel cell technologies exist on the fuel cell market nowadays. These fuel cell technologies differ in for example the type of electrolyte, start-up time, technological performance, as well as their technological readiness level (Kirubakaran, Jain and Nema, 2009; Pieper, 2019). Further, fuel cell technologies can be categorized into low and high temperature fuel cells (temperatures higher than 600°C) (Abdelkareem *et al.*, 2021). Fuel cells operating under low temperature conditions (<~250°C) need a catalyst to speed up the chemical reaction (Abdelkareem *et al.*, 2021). Platinum has been perceived as an ideal catalyst for low-temperature fuel cells, though generates significant economic and environmental impacts (Abdelkareem *et al.*, 2021). Specific fuel cell technologies are described in the next sections.

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[56] Purely hydrogen fired gas turbines are likely to represent an option for re-electrification in the future, but are out of scope of this report. For example General Electric aims at providing 100% H_2 fired gas turbines to the market by 2030 (https://www.euractiv.com/section/energy/news/ge-eyes-100-hydrogen-fuelled-power-plants-by-2030/, 22.6.2021), and Mitsubishi by 2027 (https://www.nature.com/articles/d42473-020-00545-7, 22.6.2021). TRL today is in the range of 6-7; technical challenges are associated with the high combustion temperature of hydrogen (Charnock *et al.*, 2019).

Table 14.1: Overview of fuel cell types, data is derived and combined from (Pieper, 2019), (Bruce et al., 2018), (Kirubakaran, Jain and Nema, 2009) and (Abdelkareem et al., 2021).

	Alkaline Fuel Cells (AFC)	Polymer Electrolyte Fuel Cells (PEFC)	Solid Oxide Fuel Cells (SOFC)	Phosporic Acid Fuel Cells (PAFC)	Molten Carbonate Fuel Cells (MCFC)
Electrolyte	Liquid solution of KOH	Solid polymer membrane (Nafion)	Yttria-stabilized zirconia (YSZ)	Phosphoric acid	Alkali carbonate melt
Catalyst	P or Ni Alloys	Pt	Ni- or Ni-based alloys	Pt	Ni- or Ni-based alloys
Operating temperature [°C]	20-90	60-80	700-1,000	200-250	600-700
Electrical efficiency Cell [%]	60-70	50-70	60-65	55	60-65
Electrical efficiency Stack/System [%]	62	30-50	55-60	40	55-60
Typical stack size [kW]	1-100	<1-100	1-2,000	5-400	300-3,000 (300kW modules)
Applications	Military space back-up power transportation	Backup power, portable power, distributed generation, transportation and specialty vehicles	Auxiliary power electric utility distributed generation	Distributed generation	Electric utility distributed generation
Advantages	Low temperature Quick start up Lower cost components	Low operating temperature Low noise High power density Quick start-up Small size	High efficiency Fuel flexibility Suitable for CHP	Increased tolerance to fuel impurities Suitable for CHP	High efficiency Fuel flexibility Suitable for CHP
Challenges	Sensitive to CO2 in fuel and air	Expensive catalyst Sensitive to impurities	High operating temperatures Corrosion Long start-up time Limited number of shutdowns	Expensive catalyst Long start-up time Sulphur sensitivity	High operating temperatures Low durability, susceptible to corrosion Long start-up time Low power density

14.1 Technologies

Table 14.1 provides an overview with key characteristics, applications, advantages and drawbacks per fuel cell technology. The considered fuel cell technologies are shortly described in the next sub-sections.

14.1.1 Alkaline Fuel Cells (AFCs)

Alkaline Fuel Cells (AFCs) use a liquid potassium hydroxide solution in their electrolyte. AFCs are already commercialized for several decades, and were initially used for the provision of energy during space travel missions as well as for military purposes (*e.g.* space shuttles), back-up power and transportation (Kirubakaran, Jain and Nema, 2009; Bruce *et al.*, 2018). The typical stack size of AFC is suitable for small scale applications - between 1kW to 100 kW - with an average electrical system efficiency around 62%. Advantages of AFCs are their operation under low temperature conditions (20-90°C), a quick start up time as well as comparably low stack costs. One drawback of AFCs is their sensitivity to CO_2 impurities, since this leads to slower reaction times and therefore it usually requires an additional process to remove CO_2 from the incoming air (Kirubakaran, Jain and Nema, 2009).

14.1.2 Polymer Electrolyte Fuel Cells (PEFCs)

Polymer Electrolyte Fuel Cells (PEFCs) utilize a solid polymer electrolyte, which is used to exchange ions between the two electrodes. PEFCs are particularly suitable for automotive vehicles due to their quick start-up time and high power density (Kirubakaran, Jain and Nema, 2009). Other applications are back-up and portable power, distributed energy generation as well as other transportation modes. The typical stack size of PEFC is rather small (<100 kW), and can therefore also be used in residential buildings (Kirubakaran, Jain and Nema, 2009). The operating temperatures of PEFCs are between 60°C to 80°C, and they have a comparably low electrical system conversion efficiency of 30-50%. Another drawback of PEFC is their high sensitivity to impurities of chemical substances, such as carbon monoxide, sulphur and ammonia (Staffell *et al.*, 2019). Advantages of PEFC are their low operating temperature, noise prevention, high power density, relatively small size and quick start-up time (Bruce *et al.*, 2018).

14.1.3 Solid Oxide Fuel Cells (SOFCs)

Solid Oxide Fuel Cells (SOFCs) use ceramic materials as electrolyte, such as yttria stabilized zirconia (Kirubakaran, Jain and Nema, 2009). The most common applications are distributed energy generation, the provision of energy to utilities and auxiliary power. SOFCs operate under high temperature conditions between 700°C to 1,000°C, and can achieve high electrical conversion efficiencies up to 65%. Typical stack sizes differ between 1 kW to 2 MW. Hence, advantages are their application for CHP plants as well as their fuel flexibility. Drawbacks of SOFC are mainly associated to their high operating temperatures, corrosion issues, and their rigid characteristics; such as long start-up times and the limited number of shutdowns of the stack (Bruce *et al.*, 2018).

14.1.4 Phosphoric Acid Fuel Cells (PAFCs)

Phosphoric Acid Fuel Cells (PAFCs) utilize phosphoric acid as electrolyte and operate under moderate temperatures between 200°C and 250°C. PAFCs applications are mainly operated in distributed energy generation, such as combined heat and power systems, with average stack sizes between 5 to 400 kW (Kirubakaran, Jain and Nema, 2009; Bruce *et al.*, 2018). Advantages of PAFCs are their suitability for CHP systems and their tolerance to fuel impurities, such as hydrocarbons (Kirubakaran, Jain and Nema, 2009). PAFCs use platinum as catalyst which is an expensive and critical material (Graedel *et al.*, 2015; Bruce *et al.*, 2018). Another drawback is the long start-up time of PAFC.

14.1.5 Molten Carbonate Fuel Cells (MCFCs)

Molten Carbonate Fuel Cells (MCFCs) use a molten carbonate electrolyte and operate under high temperatures between 600°C and 700°C, exhibiting a comparably high electrical conversion efficiency up to 60%. MCFCs do not require additional catalysts and separate reformers (Kirubakaran, Jain and Nema, 2009). Implemented stack sizes of MCFSs can be comparably large (up to 3 MW), and are therefore suitable for energy generation on an industrial scale, for example for CHPs (Bruce *et al.*, 2018). Drawbacks are associated to a slow start-up time, low power density, intolerance to Sulphur, corrosion (due to high operating temperatures) as well as a short lifespan of the stacks.

14.2 Literature review

A literature review has been conducted to collect literature which discusses performance indicators, costs and the environmental performance of stationary fuel cells. An overview has been provided in Table 14.2, which has been updated and is based on earlier work presented in (Bauer *et al.*, 2017). The next sub-sections present a short discussion on this literature.

Table 14.2: Literature review on costs, environment and performance for different fuel cell technologies, based on (Bauer *et al.*, 2017).

Study	**Cost**	**Environment**	**Performance**	**Fuel Cell Type Analyzed**				
				PEFC	MCFC	SOFC	PAFC	AFC
(Abdelkareem *et al.*, 2021)		x	x	x	x	x	x	x
(Ammermann *et al.*, 2015)	x	x	x	x	x	x		x
(Alkaner and Zhou, 2006)		x			x			
(Badwal *et al.*, 2015)				x		x		x
(Baratto and Diwekar, 2005)	x	x	x			x		
(Baratto, Diwekar and Manca, 2005)	x		x			x		
(Battelle Memorial Institute, 2016)	x		x	x				
(Cánovas, Zah and Gassó, 2013)		x				x		
(Chen, Chen and Lee, 2011)				x		x		
(Choudhury, Chandra and Arora, 2013)			x					
(Cox and Treyer, 2015)	x	x						x
(Dell, Moseley and Rand, 2014)			x	x	x	x	x	x
(Dincer and Zamfirescu, 2014)				x	x	x	x	x
(Dodds *et al.*, 2015)	x		x					
(Elmer *et al.*, 2015)	x		x	x		x		
(Gerboni *et al.*, 2008)	x	x		x	x	x		
('Status and outlook for the U.S. non-automotive fuel cell industry: Impacts of government policies and assessment of future opportunities', 2012)	x			x	x	x	x	
(Halliday *et al.*, 2005)	x	x		x		x	x	
(International Energy Agency, 2015)	x		x	x		x		
(Kannan *et al.*, 2007)	x	x		x				
(Kanuri and Motupally, 2013)			x				x	
(Karakoussis *et al.*, 2000)		x				x		
(Karakoussis *et al.*, 2001)		x				x		
(Kirubakaran, Jain and Nema, 2009)	x		x	x	x	x	x	x
(Lee *et al.*, 2015)		x				x		
(Shaner *et al.*, 2016)	x							
(Lin, Babbitt and Trabold, 2013)		x				x		
(Lunghi, Bove and Desideri, 2004)		x			x			
(Lunghi and Bove, 2003)		x			x			
(Mekhilef, Saidur and Safari, 2012)	x		x	x	x	x	x	x
(Monaco and Di Matteo, 2011)		x			x			
(Mori *et al.*, 2014)		x		x				
(Nease and Adams, 2015)		x				x		
(Notter *et al.*, 2015)		x		x				
(Osman and Ries, 2007)		x				x		
(Pade and Schröder, 2013)	x					x		
(Parra *et al.*, 2019)	x		x	x	x	x		
(Pehnt, 2001)		x		x				

Study	Cost	Environment	Performance	Fuel Cell Type Analyzed				
				PEFC	MCFC	SOFC	PAFC	AFC
(Raugei, Bargigli and Ulgiati, 2005)		x			x			
(Rivera-Tinoco, Schoots and Van Der Zwaan, 2012)	x					x		
(Sanghai, 2014)	x		x	x	x	x	x	
(Schoots, Kramer and van der Zwaan, 2010)	x			x			x	x
(Sharaf and Orhan, 2014)	x		x	x	x	x	x	x
(Squadrito *et al.*, 2014)	x		x	x	x	x	x	x
(Staffell and Green, 2009)	x			x				
(Staffell and Green, 2013)	x			x		x	x	
(Staffell and Ingram, 2010)		x						x
(Staffell, Ingram and Kendall, 2012)		x				x		
(Strazza *et al.*, 2010)		x				x		
(Strazza *et al.*, 2015)	x	x				x		
(Stropnik *et al.*, 2018)		x		x				
(Stropnik *et al.*, 2019)		x		x				
(van Rooijen, 2006)		x					x	
(Wilson *et al.*, 2013)		x						x
(Zucaro *et al.*, 2013)		x			x			

14.3 Costs

14.3.1 Literature

In general, comprehensive cost overviews – of fuel cell CHP systems - are relatively scarce nowadays. Further, especially older economic assessments are not representative for fuel cell costs nowadays, due to technological improvements. For these reasons, this section is not categorized in sub-sections determining costs for individual fuel cell technologies. Some economic studies relate to automotive fuels cells and not on stationary fuel cells as such. However, the costs of automotive fuel cell stacks – as low as 39-196 CHF/kW (Olabi, Wilberforce and Abdelkareem, 2021) - cannot be compared with stationary fuel cells stacks since their stack design and associated system components – such as the balance of system - differ significantly (Staffell and Green, 2013). For example, the power density of automotive fuel cell stacks are usually larger compared to fuel cell stacks developed for stationary applications (De Bruijn, 2005).

Stationary fuel cells are associated with high capital investment costs, and only a limited number of suppliers are currently active on the stationary fuel cell market (Sanghai, 2014; Dodds *et al.*, 2015). Economies of scale reduces investments costs and therefore cost assessments usually differ between stack and system volume sizes (Dodds *et al.*, 2015; Wei *et al.*, 2016). In general, the cumulative production volume of stationary fuel cells is one of the most important driver for cost reductions of fuel cell suppliers (Ammermann *et al.*, 2015). Further, stationary fuel cell costs are also highly influenced by the application of the fuel cell (Ammermann *et al.*, 2015). In general, fuel cell costs can be reduced by increasing the stack lifetime, the power density, reducing expensive catalysts (such as platinum) as well as reducing the emissions of contaminants in order to reduce the requirement of expensive contaminant removal systems (Remick and Wheeler, 2010).

Fuel cell CHP systems can be categorized into use cases and market segments - as has been done in a (Ammermann *et al.*, 2015) and (Parra *et al.*, 2019): Micro-CHP (family dwellings), Mini-CHP (apartment buildings), CHP-commercial (>50 kW_{el}), Prime power (industrial application 1 MW_{el}), CHP-natural gas (industrial application ~1.4 MW_{el}) and CHP-biogas (industrial application ~0.4 MW_{el}). An important cost component are the installation costs, which can have a share up to 20% of the total CAPEX (Parra *et al.*, 2019). However, the costs presented in the previous studies include a reformer to generate hydrogen from hydrocarbons, while this report is focused on hydrogen production, storage and the possible re-electrification of hydrogen without the consumption of hydrocarbons.

A comprehensive cost assessment is difficult herein, since fuel cell costs differ between fuel cell systems (*e.g.* differentiating between fuel cells only and domestic fuel cell CHP systems), purchase volumes and suppliers. Hence, a large cost variability has been found between fuel cell technologies within literature, which can also be explained by the difference cost indication approaches between academic theories and real commercial fuel cell costs (Staffell and Green, 2013). Due to these reasons, we consider fuel cell costs as still highly uncertain nowadays.

Future projections of fuel cells usually consider costs improvements. Learning rates apply the cumulative production of (fuel cell) technologies and its associated cost improvements during the coming decades. (Staffell and Green, 2013) found an average learning rate of 16% for fuel cell technologies, while EneFarm - the largest producer of PEFC systems - indicated learning rates between 19-21% (Staffell and Green, 2013). A recent work of (Schmidt, Hawkes, *et al.*, 2017) found a learning rate of 18% for residential fuel cells. To put this into perspective: batteries are for example associated with learning rates between 4-30%, with a learning rate of 12% for residential lithium-ion batteries (Schmidt, Hawkes, *et al.*, 2017). Therefore, significant cost improvements can be expected for fuel cell technologies in the coming decades.

14.3.2 Fuel cell performance and cost parameters

Earlier research – conducted by colleagues at PSI (Bauer *et al.*, 2019) – presented a comprehensive overview of cost and technological parameters regarding stationary fuel cell CHP systems, though based on natural gas fueled CHP systems including a reformer to generate hydrogen from methane or biomethane.

As mentioned, this work focuses on hydrogen potentials, and hydrogen could also be fed directly into the stationary fuel cells. This avoids the installation of a reformer for these system lay-outs, which could reduce costs and environmental impacts. Two state-of-the art system lay-outs are included for comparison, to produce hydrogen using methane and biomethane with the integration of a reformer. The latter energy sources – especially methane – can be economically attractive in the coming years or decades to enhance the transition to the utilization of cleaner energy sources in stationary fuel cell CHP systems, *i.e.* 'green' hydrogen. However, note that environmental impacts from hydrogen production from methane are significantly higher compared to electrolysis based 'green' hydrogen (Antonini *et al.*, 2020a).

Four different system lay-outs are considered in this stationary fuel cell CHP system assessment, with the categorization based on the fuel source used for hydrogen production.

(1) *Methane*: using natural gas in a reformer to generate hydrogen to be fed into the fuel cell.
(2) *Biomethane*: using biomethane in a reformer to generate hydrogen to be fed into the fuel cell.
(3) *Electrolysis (grid) based hydrogen:* using hydrogen – obtained from a hydrogen supply chain where hydrogen is generated with water electrolysis using grid electricity – directly fed into the fuel cell. Hence, no reformer is needed.
(4) *Electrolysis (solar PV) based hydrogen*: using hydrogen – obtained from a hydrogen supply chain where hydrogen is generated with water electrolysis using solar PV electricity – directly fed into the fuel cell. Hence, no reformer is needed.

Small modifications are made for CHP systems with and without a reformer regarding economic and technological parameters. However, CAPEX data for hydrogen driven fuel cells are difficult to find and are therefore associated with large uncertainties. The reformer costs are indicated as 250 CHF/kW$_e$, which is based on economic and technological data from the Swiss Times Energy System (STEM) model (Panos *et al.*, 2021). Capital expenditures of CHP systems without a reformer are reduced with the latter cost figure. This assumption can be considered as conservative, since expert judgement at PSI identified a possible CAPEX reduction up to 50% for smaller sized (1 kW) hydrogen driven fuel cells without a reformer[57]. Furthermore, the electrical efficiency of fuel cell systems without a reformer are assumed to increase by 2%, to compensate for the missing reformer stage (Ramachandran Kannan and Turton, 2014). The total stationary fuel cell CHP system efficiency is assumed to stay the same. And finally, the fixed operational expenditures are reduced by 7 CHF/kW$_e$/year (Ramachandran Kannan and Turton, 2014).

For the sake of simplicity, environmental impacts – generated from fuel cell production – are not adapted to compensate for a difference between system layouts with and without a reformer. In general, environmental impacts of fuel cells are mainly driven by the impacts generated during the production of hydrogen as well as the operation phase, and therefore this (minor) difference in the production is expected to have a negligible influence on the overall environmental results.

All parameters, costs and indicators are presented in Table 14.3 for stationary fuel cell CHP systems with a reformer from year 2020 up to year 2050 for different fuel cells technologies (PEFC, SOFC, MCFC and PAFC) as well as two sizes in terms of electrical capacity: 1 kW electrical capacity is representative for residential households, while 300 kW is representative for larger buildings or several apartments/buildings, although can be scaled up to megawatt sizes. Table 14.4 shows the economic and technological parameters of stationary fuel cell CHP systems without a reformer. These cost and performance parameters of both tables are used for the economic and environmental assessment for the Swiss situation.

Three procedures are used to present the economic and environmental performance. First, the overall results are presented per kWh electricity produced by the fuel cell; all costs or GHG emissions are allocated to electricity consumption. Second, an allocation on exergy has been applied. Third, the overall results are presented considering an economic and/or environmental credit for heat – *i.e.* system expansion in environmental LCA – to show the difference in overall costs and GHG-emissions between procedures needed to consider multi-functional product outputs.

14.3.3 Fuel cell costs

14.3.3.1 Methane and biomethane as hydrogen fuel (reformer)

The costs for stationary fuel cell CHP systems using methane and biomethane are presented – per kWh electricity produced – in Figure 14.1 and Figure 14.2, respectively. Currently, the price range of electricity production – considering a heat credit – is large between 0.2 CHF/kWh and 0.61 CHF/kWh for methane, and 0.3 CHF/kWh and 0.7 CHF/kWh for biomethane in year 2020. In general, electricity costs from methane are lower compared to biomethane, mainly due to lower costs of methane as energy source. Further, larger stationary fuel cells such as SOFC and MCFC exhibit lower costs per kWh, mainly depending on the maturity of the technology as well as economies of scale and higher (electrical) conversion efficiencies.

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[57] Personal information by Felix Büchi, Head of the Laboratory for Electrochemistry, March 2021.

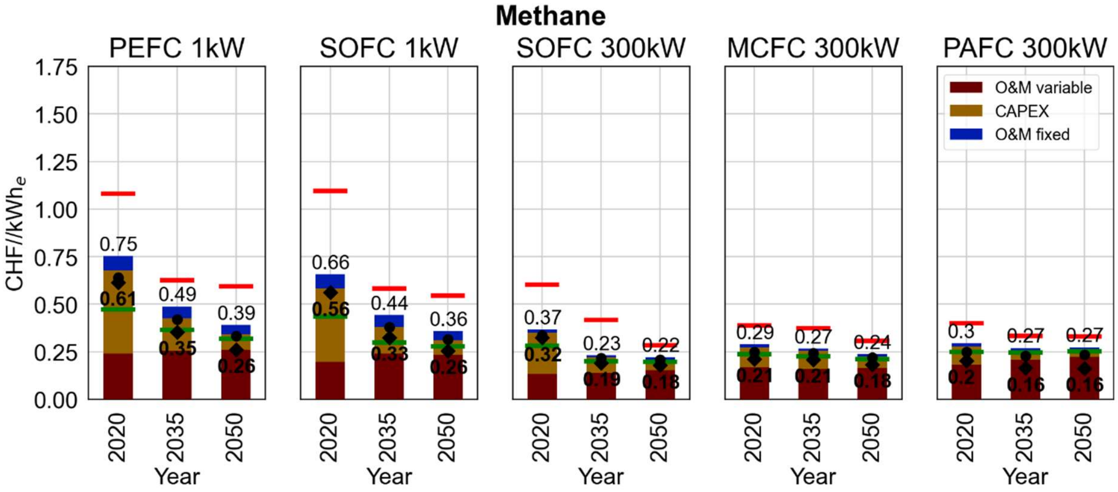

Figure 14.1: Stationary fuel cell CHP systems costs using methane as fuel to produce hydrogen for 2020, 2035 and 2050. Costs are categorized in O&M variable costs (e.g. costs for the fuel), fixed O&M (e.g. maintenance) and annualized CAPEX. Maximum and minimum costs are indicated with red and green lines in the figures (without considering a heat credit for heat or allocation)(without considering a heat credit for heat or allocation). The 'black circle' symbol represents the total costs applying an allocation based on exergy. The 'diamond' symbol - and its associated value in bold - represent the total costs applying a heat credit. Lastly, total GHG emissions – without applying allocation on exergy or system expansion - are indicated above the bars. Figures are consistent with the ones provided by (Bauer *et al.*, 2019).

Table 14.3: Stationary fuel cell CHP systems performance parameters and indicators *with* a reformer, table is obtained from earlier work of (Bauer et al., 2019). Costs are representative for European fuel cell installations. Annual load hours are indicated as 4000 hours for each fuel cell technology.

			PEFC			SOFC			SOFC			MCFC			PAFC		
			Cons.	Base	Opt.	Cons.	Base	Opt.	Cons.	Base	Opt.	Cons.	Base	Opt.	Cons.	Base	Opt.
Electrical Capacity	kW		1	1	1	1	1	1	300	300	300	300	300	300	300	300	300
Electrical Efficiency	LHV	2020	32%	36%	39%	35%	44%	48%	52%	55%	58%	41%	44%	47%	37%	40%	43%
		2035	39%	42%	45%	42%	45%	60%	60%	63%	66%	52%	55%	58%	39%	42%	45%
		2050	42%	45%	50%	47%	50%	60%	62%	65%	68%	57%	60%	63%	42%	45%	48%
CHP Efficiency	LHV	2020	85%	88%	95%	85%	88%	95%	75%	85%	92%	75%	85%	92%	75%	85%	92%
		2035	85%	89%	95%	85%	89%	95%	78%	88%	93%	78%	88%	93%	78%	88%	93%
		2050	85%	90%	95%	85%	90%	95%	80%	90%	95%	80%	90%	95%	80%	90%	95%
Heat Temperature	°C	2020	50	60	80	80	80	80	80	80	500	80	80	500	80	80	120
		2035	60	70	80	80	80	80	80	80	200	80	80	200	80	80	120
		2050	70	80	80	80	80	80	80	80	200	80	80	200	80	80	120
System Lifetime	years	2020	11	13	20	11	15	20	11	15	20	10	13	16	18	23	29
		2035	13	15	23	14	20	26	14	20	26	11	15	20	19	28	30
		2050	14	20	26	16	23	29	16	23	29	14	20	26	23	30	30
Stack Lifetime	thousand hours	2020	45	50	80	42	60	78	42	60	78	40	50	65	63	90	117
		2035	50	60	90	56	80	104	56	80	104	42	60	78	77	110	120
		2050	56	80	104	63	90	117	63	90	117	56	80	104	91	120	120
Capital Costs	CHF/kW$_{el}$	2020	24000	16000	10000	24000	16000	10000	14000	9000	7000	5700	3800	3040	7500	5000	4000
		2035	10000	7000	4000	10000	7000	4000	10000	4000	3200	6000	4000	3200	4500	3000	2400
		2050	10000	4000	2000	10000	4000	2000	4500	3000	2400	4500	3000	2400	4000	2500	2000
Fixed O&M Costs	CHF/kW$_{el}$	2020	400	300	200	400	300	200	100	70	45	100	70	45	100	70	45
		2035	300	250	200	300	250	200	70	45	45	70	45	45	70	45	45
		2050	250	200	200	250	200	200	70	45	45	70	45	45	70	45	45

Table 14.4: Stationary fuel cell CHP systems performance parameters and indicators *without* a reformer (i.e. direct use of hydrogen), table is adapted from Table 14.3. Costs are representative for European fuel cell installations. Annual load hours are indicated as 4000 hours for each fuel cell technology. Values are associated with considerable uncertainties, since accessible literature and data on fuel cells directly using hydrogen are scarce.

			PEFC			SOFC			SOFC			MCFC			PAFC		
			Cons.	**Base**	**Opt.**	**Cons.**	**Base**	**Opt.**	**Cons.**	**Base**	**Opt.**	**Cons.**	**Base**	**Opt.**	**Cons.**	**Base**	**Opt.**
Electrical Capacity	kW		1	1	1	1	1	1	300	300	300	300	300	300	300	300	300
Electrical Efficiency	LHV	2020	34%	38%	41%	37%	46%	50%	54%	57%	60%	43%	46%	49%	39%	42%	45%
		2035	41%	44%	47%	44%	47%	62%	62%	65%	68%	54%	57%	60%	41%	44%	47%
		2050	44%	47%	52%	49%	52%	62%	64%	67%	70%	59%	62%	65%	44%	47%	50%
CHP Efficiency	LHV	2020	85%	88%	95%	85%	88%	95%	75%	85%	92%	75%	85%	92%	75%	85%	92%
		2035	85%	89%	95%	85%	89%	95%	78%	88%	93%	78%	88%	93%	78%	88%	93%
		2050	85%	90%	95%	85%	90%	95%	80%	90%	95%	80%	90%	95%	80%	90%	95%
Heat Temperature	°C	2020	50	60	80	80	80	80	80	80	500	80	80	500	80	80	120
		2035	60	70	80	80	80	80	80	80	200	80	80	200	80	80	120
		2050	70	80	80	80	80	80	80	80	200	80	80	200	80	80	120
System Lifetime	years	2020	11	13	20	11	15	20	11	15	20	10	13	16	18	23	29
		2035	13	15	23	14	20	26	14	20	26	11	15	20	19	28	30
		2050	14	20	26	16	23	29	16	23	29	14	20	26	23	30	30
Stack Lifetime	thousand hours	2020	45	50	80	42	60	78	42	60	78	40	50	65	63	90	117
		2035	50	60	90	56	80	104	56	80	104	42	60	78	77	110	120
		2050	56	80	104	63	90	117	63	90	117	56	80	104	91	120	120
Capital Costs	CHF/kW$_{el}$	2020	23750	15750	9750	23750	15750	9750	13750	8750	6750	5450	3550	2790	7250	4750	3750
		2035	9750	6750	3750	9750	6750	3750	9750	3750	2950	5750	3750	2950	4250	2750	2150
		2050	9750	3750	1750	9750	3750	1750	4250	2750	2150	4250	2750	2150	3750	2250	1750
Fixed O&M Costs	CHF/kW$_{el}$	2020	393	293	193	393	293	193	93	63	38	93	63	38	93	63	38
		2035	293	243	193	293	243	193	63	38	38	63	38	38	63	38	38
		2050	243	193	193	243	193	193	63	38	38	63	38	38	63	38	38

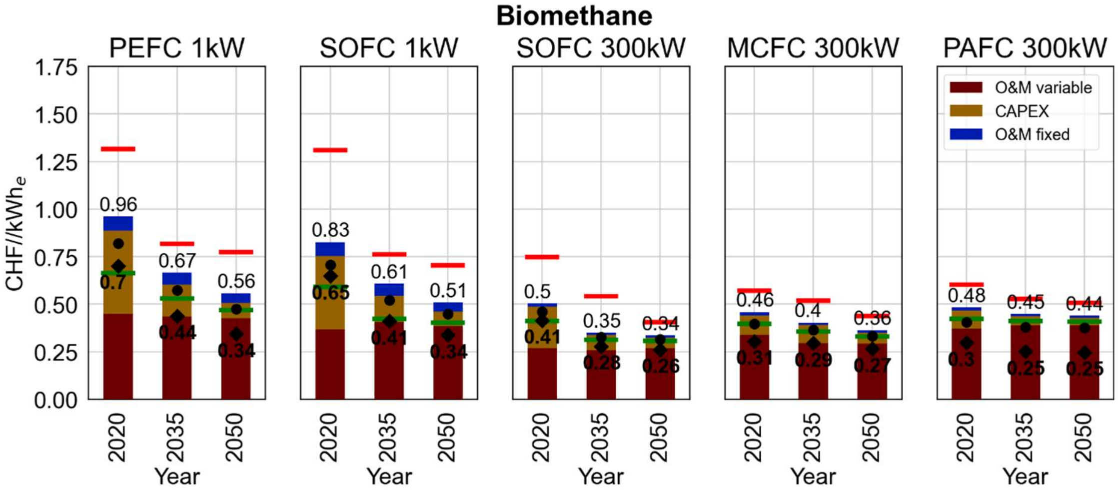

Figure 14.2: Stationary fuel cell CHP systems costs using biomethane fuel to produce hydrogen for 2020, 2035 and 2050. Costs are categorized in O&M variable costs (e.g. costs for the fuel), fixed O&M (e.g. maintenance) and annualized CAPEX. Maximum and minimum costs are indicated with red and green lines in the figures (without considering a heat credit for heat or allocation). The 'black circle' symbol represents the total costs applying an allocation based on exergy. The 'diamond' symbol - and its associated value in bold - represent the total costs applying a heat credit. Lastly, total GHG emissions – without applying allocation on exergy or system expansion – are indicated above the bars.

14.3.3.2 Electrolysis for hydrogen production (fuel cells without a reformer)

Figure 14.3 demonstrates stationary fuel cell CHP systems costs based on water electrolysis using Swiss grid electricity, see Section 8.2.9.1 for specific hydrogen cost calculations for Switzerland. Currently, fuel cells using water electrolysis – generated by grid electricity – exhibit higher costs than both methane and biomethane, although a strong future cost reduction can be expected, mainly due to higher energy conversion efficiencies and the cost reduction of hydrogen production supply chain, see Section 8.2.9.1.

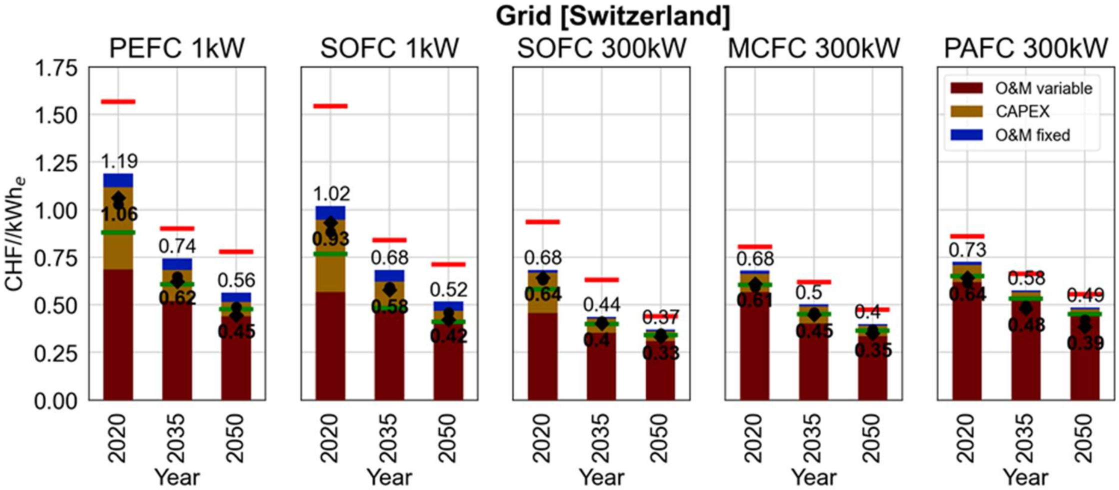

Figure 14.3: Stationary fuel cell CHP systems costs using hydrogen generated by water electrolysis using grid electricity (0.15 CHF/kWh), to produce hydrogen for 2020, 2035 and 2050 (using 8.7 CHF/kg H_2, 7.6 CHF/kg H_2 and 6.8 CHF/kg H_2, respectively). Costs are categorized in O&M variable costs (e.g. costs for the fuel), fixed O&M (e.g. maintenance) and annualized CAPEX. Maximum and minimum costs are indicated with red and green lines in the figures (without considering a heat credit for heat or allocation). The 'black circle' symbol represents the total costs applying an allocation based on exergy. The 'diamond' symbol - and its associated value in bold - represent the total costs applying a heat credit. Lastly, total GHG emissions – without applying allocation on exergy or system expansion – are indicated above the bars.

Electricity generation of stationary fuel cell CHP systems – driven by (green) water electrolysis – is presented in Figure 14.4. Solar PV water electrolysis becomes nearly cost-competitive with methane driven stationary fuel cells in 2050 (0.24-0.32 CHF/kWh$_e$ and 0.16-0.26 CHF/kWh$_e$ for PV driven hydrogen and methane, respectively, when applying a heat credit), due to expected cost reductions for fuel cells as well as a cost reduction in the hydrogen production supply chain, see Section 8.2.9.1.

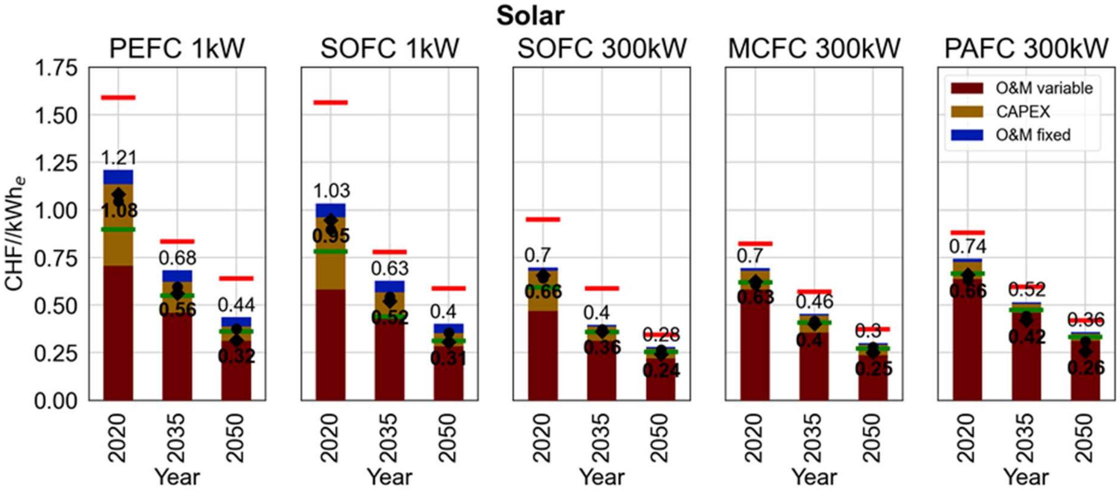

Figure 14.4: Stationary fuel cell CHP system costs using hydrogen generated from solar PV electrolysis to produce hydrogen for 2020, 2035 and 2050 (using 8.9 CHF/kg H_2, 6.7 CHF/kg H_2 and 4.9 CHF/kg H_2, respectively). Costs are categorized in O&M variable costs (e.g. costs for the fuel), fixed O&M (e.g. maintenance) and annualized CAPEX. Maximum and minimum costs are indicated with red and green lines in the figures (without considering a heat credit for heat or allocation). The 'black circle' symbol represents the total costs applying an allocation based on exergy. The 'diamond' symbol - and its associated value in bold - represent the total costs applying a heat credit. Lastly, total GHG emissions – without applying allocation on exergy or system expansion – are indicated above the bars.

14.4 Environmental burdens

Different functional units can be used to compare fuel cells on their environmental burdens. First, fuel cells can be compared on environmental burdens generated from the production of the fuel cell stack only, for example per kW fuel cell stack capacity. Alternatively, the environmental burdens from the production of the fuel cells tack, the Balance of Plant as well as the integration of a CHP unit can be integrated in the environmental assessment. In both cases, only the production phase is included and fuel cells are compared without the inclusion of operational parameters.

Alternatively, a more common functional unit for comparison is per kWh of electricity generated by the fuel cell (Abdelkareem *et al.*, 2021). In this case, all environmental burdens during the life-cycle are quantified, and can be used to compare different fuel cell technologies. In this section, we compare fuel cells per kWh of electricity generated, to include the entire life-cycle of fuel cells. As explained in 14.3.2, three procedures are used to consider multi-functional product outputs generated by stationary fuel cell CHP systems: heat and electricity. First, available literature is shortly discussed. A comprehensive overview of available literature on stationary fuel cells has been provided in Table 14.2.

14.4.1 Literature

It turns out that environmental burdens of the deployment of fuel cells are mainly generated from the fuel source used for hydrogen, which is fed into the fuel cell (Abdelkareem *et al.*, 2021). Fuel cells can achieve very low GHG emissions when fueled with 'green' hydrogen, *i.e.* with the generation of hydrogen with wind and/or solar power during water electrolysis. On the other hand, GHG emissions of fuel cell systems can be high when hydrogen is produced with for example coal gasification

(Abdelkareem *et al.*, 2021). More detailed environmental burdens are provided in the next sub-sections, categorized per fuel cell technology, specified for the Swiss situations.

Environmental burdens - associated to the production of fuel cell stacks - turned out to have the lowest environmental impact for PEFC, followed by PAFC, AFC and SOFC, respectively (Staffell and Ingram, 2010). General improvements - applicable for all fuel cell technologies - are associated to a switch to a renewable hydrogen source, the avoidance of a reformer (related to a switch to electrolysis based hydrogen), the improvement of the efficiency and power density of the fuel cell, increase the lifetime of the fuel cell system as well as an increased recycling rate of manufacturing materials (especially the recycling of catalysts).

14.4.2 GHG emissions of fuel cells applicable to Switzerland

14.4.2.1 Methane and biomethane

GHG emissions generated by stationary fuel cell CHP systems during the life-cycle - operated by methane and biomethane - are presented in Figure 14.5 and Figure 14.6, respectively. Stationary fuel cells operating on methane fuel exhibit higher GHG emissions during operation, while fuel cells running on biomethane are assumed to avoid GHG emissions during operation, since these GHG emissions are assumed to be CO_2-neutral (*i.e.* assuming that forests take up and store CO_2). Further, SOFCs – and larger fuel cell systems - turn out to have lower life-cycle GHG emissions due to comparably high energy conversion efficiency factors. Future improvements are expected for all fuel cell systems, mainly due to higher conversion efficiencies and longer stack and system lifetimes.

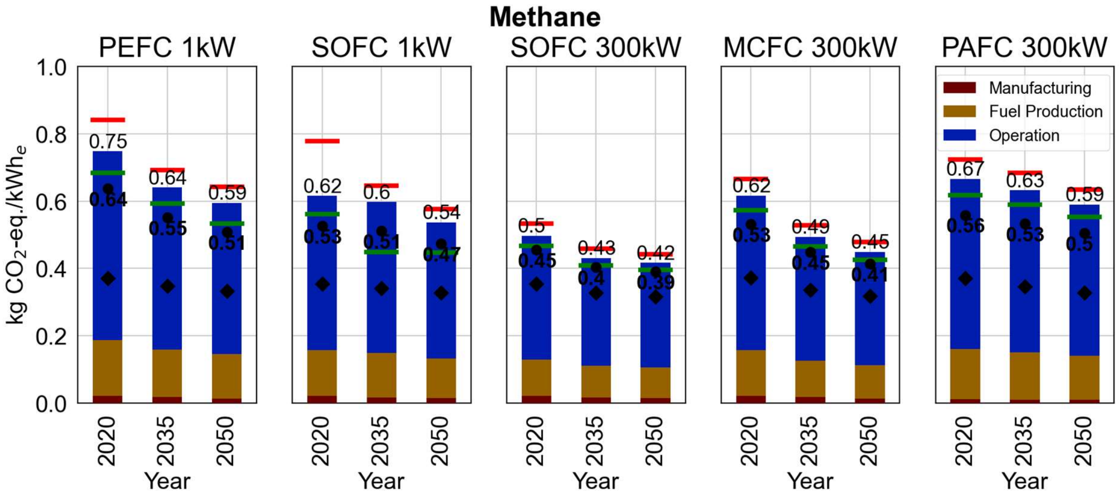

Figure 14.5: Life-cycle GHG emissions generated from stationary fuel cell CHP systems using methane as fuel (to produce hydrogen) for 2020, 2035 and 2050. Burdens are entirely allocated to electricity consumption, presented per kilowatt-hour of electricity produced. GHG-emission contributions are categorized in fuel cell manufacturing, fuel production (methane) and operation. Maximum and minimum GHG emissions are indicated with red and green lines in the figures (without considering a heat credit for heat or allocation). The 'black circle' symbol - and its associated value in bold - represent the total GHG emissions applying an allocation based on exergy. The 'diamond' symbol represents the total GHG emissions applying a heat credit. Lastly, total GHG emissions – without applying allocation on exergy or system expansion – are indicated above the bars.

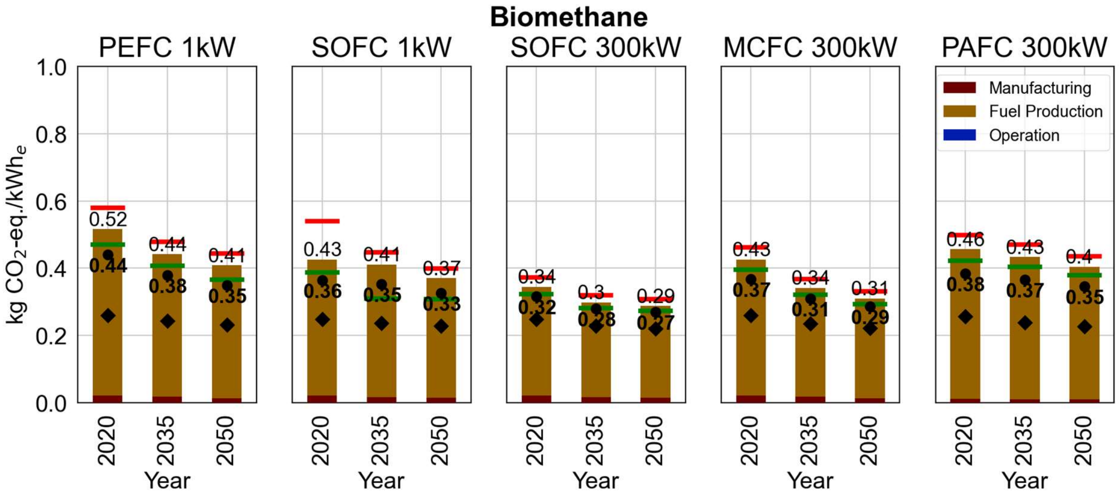

Figure 14.6: Life-cycle GHG emissions generated from stationary fuel cell CHP systems using biomethane as fuel (to produce hydrogen) for 2020, 2035 and 2050. Burdens are entirely allocated to electricity consumption, presented per kilowatt-hour of electricity produced. GHG-emission contributions are categorized in fuel cell manufacturing, fuel production (biomethane) and operation. Maximum and minimum GHG emissions are indicated with red and green lines in the figures (without considering a heat credit for heat or allocation). The 'black circle' symbol - and its associated value in bold - represent the total GHG emissions applying an allocation based on exergy. The 'diamond' symbol represents the total GHG emissions applying a heat credit. Lastly, total GHG emissions – without applying allocation on exergy or system expansion – are indicated above the bars.

14.4.2.2 Electrolysis based hydrogen

Figure 14.7 demonstrates life-cycle GHG-emissions for stationary fuel cell CHP systems operating on hydrogen generated by water electrolysis using Swiss grid electricity. Currently, life-cycle GHG emissions for fuel cells using water electrolysis – generated by grid electricity – turn out to have lower GHG-emissions than methane and also slightly lower GHG emissions than biomethane, mainly due to the low GHG intensity of Swiss grid electricity (~0.10 kg CO_2-eq./kWh).

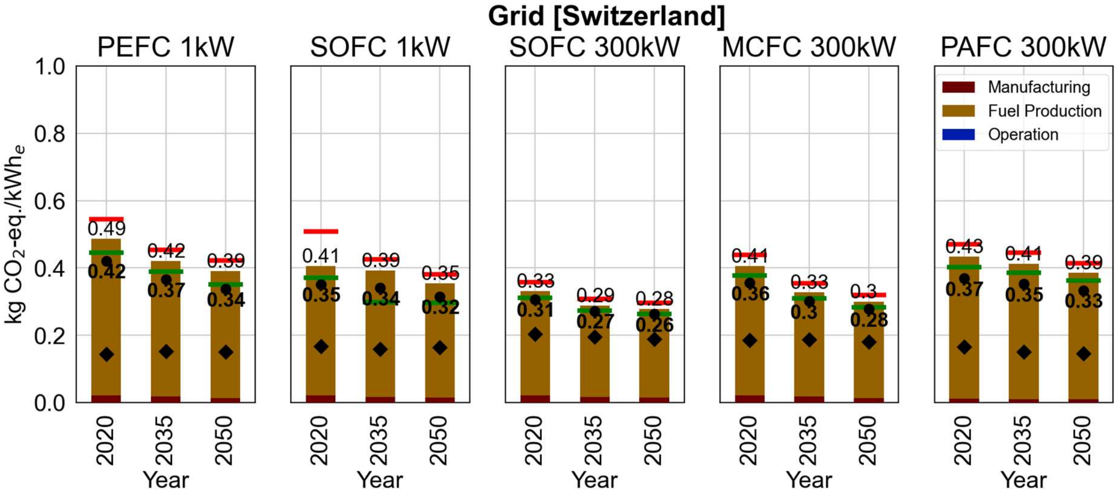

Figure 14.7: Life-cycle GHG emissions generated from stationary fuel cell CHP systems operating on hydrogen generated by grid electricity as fuel for water electrolysis for 2020, 2035 and 2050 (using 0.177 kg CO_2-eq./kWh hydrogen (Antonini *et al.*, 2020a)**). Burdens are entirely allocated to electricity consumption, presented per kilowatt-hour of electricity produced. GHG-emission contributions are categorized in fuel cell manufacturing, fuel production and operation. Maximum and minimum GHG emissions are indicated with red and green lines in the figures (without considering a heat credit for heat or allocation). The 'black circle' symbol - and its associated value in bold - represent the total GHG emissions applying an allocation based on exergy. The 'diamond' symbol represents the total GHG emissions applying a heat credit. Lastly, total GHG emissions – without applying allocation on exergy or system expansion – are indicated above the bars.**

Figure 14.8 shows that solar PV water electrolysis exhibits the lowest life-cycle GHG emissions – considering an allocation on exergy - as low as 0.23-0.32 kg CO_2-eq./kWh electricity in year 2020 - of all considered fuel cell system lay-outs, mainly as a result of comparably low GHG emissions in the fuel production phase of hydrogen. Note that GHG emissions from PV electricity are comparably high for Switzerland - due to older PV datasets for electricity in the ecoinvent 3.6 database – and therefore the results can be perceived as conservative.

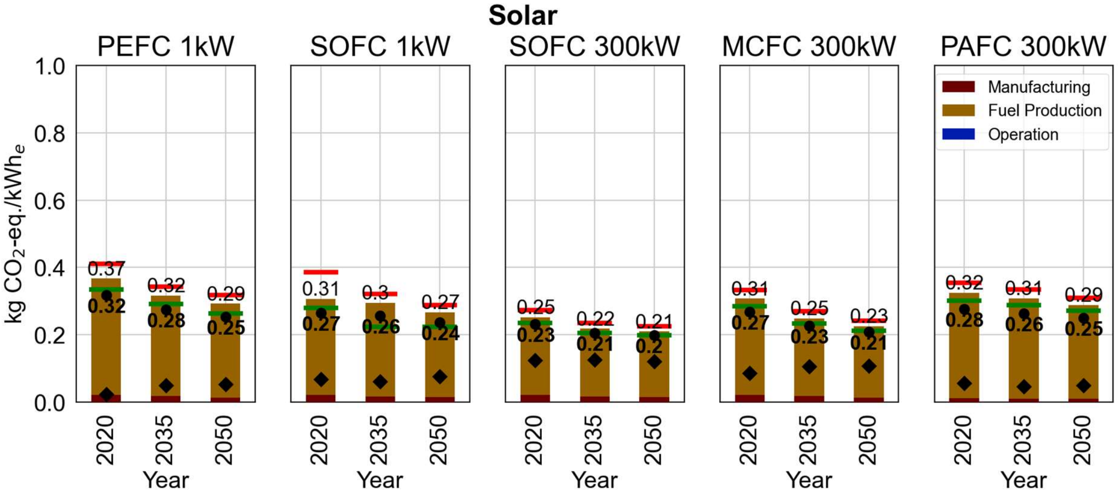

Figure 14.8: Life-cycle GHG emissions generated from stationary fuel cell CHP systems operating on hydrogen generated by solar PV electricity as fuel in water electrolysis for 2020, 2035 and 2050 (using 0.131 kg CO_2-eq./kWh hydrogen (Antonini *et al.*, 2020a)**). Burdens are entirely allocated to electricity consumption, presented per kilowatt-hour of electricity produced. GHG-emission contributions are categorized in fuel cell manufacturing, fuel production and operation. Maximum and minimum GHG emissions are indicated with red and green lines in the figures (without considering a heat credit for heat or allocation). The 'black circle' symbol - and its associated value in bold - represent the total GHG emissions applying an allocation based on exergy. The 'diamond' symbol represents the total GHG emissions applying a heat credit. Lastly, total GHG emissions – without applying allocation on exergy or system expansion – are indicated above the bars.**

Finally, an overview of environmental burdens considering additional environmental impact categories is provided in an earlier work of (Bauer *et al.*, 2017), although these are specified for stationary fuel cell CHP systems using a reformer and natural gas as fuel. For simplicity, this environmental assessment only focuses on GHG emissions. Future assessments should apply a more sophisticated and holistic environmental analysis, for example by considering additional environmental impact categories, such as resource utilization, land use, human toxicity and water consumption.

14.5 Data summary for fuel cells

Table 14.5: demonstrates a comprehensive overview of electricity generation costs (with a credit for heat) and total GHG emissions (with an allocation on exergy) of stationary fuel cell CHP systems.

Table 14.5: Overview for stationary fuel cell CHP systems running on hydrogen and (bio)methane; hydrogen produced with water electrolysis, applicable for the Swiss situation using the average scenario per kilowatt-hour of electricity produced. A heat credit has been applied for costs and an allocation on exergy has been applied for environmental burdens[60]. The range is presented for the specific fuel cell technology, energy source used to generate hydrogen and the corresponding year.

		Technology	Energy source	2020	2035	2050
Electricity generation costs[58,59]	Rp./kWh electricity	MCFC 300 kW	Biomethane	25-43	26-43	24-36
			Hydrogen using grid power	54-74	40-58	32-43
			Methane	17-32	17-32	16-26
			Hydrogen using solar PV power	56-76	36-53	23-33
		PAFC 300 kW	Biomethane	25-43	24-35	24-33
			Hydrogen using grid power	57-78	45-57	36-47
			Methane	16-31	15-24	15-23
			Hydrogen using solar PV power	59-80	39-51	24-33
		PEFC 1 kW	Biomethane	41-102	31-58	28-55
			Hydrogen using grid power	75-142	48-77	37-66
			Methane	33-92	23-48	20-46
			Hydrogen using solar PV power	77-145	43-71	25-52
		SOFC 1 kW	Biomethane	41-105	31-55	28-53
			Hydrogen using grid power	68-142	42-73	34-62
			Methane	34-96	23-46	20-44
			Hydrogen using solar PV power	70-144	38-67	24-49
		SOFC 300 kW	Biomethane	32-67	25-49	24-35
			Hydrogen using grid power	54-90	37-61	31-41
			Methane	24-57	16-39	16-25
			Hydrogen using solar PV power	55-92	33-56	22-32
GHG emissions[60]	g CO_2-eq./kWh electricity	MCFC 300 kW	Biomethane	250-400	260-340	250-310
			Hydrogen using grid power	240-390	260-330	240-300
			Methane	360-580	380-490	360-450
			Hydrogen using solar PV power	180-300	190-250	180-230
		PAFC 300 kW	Biomethane	330-420	320-400	300-380

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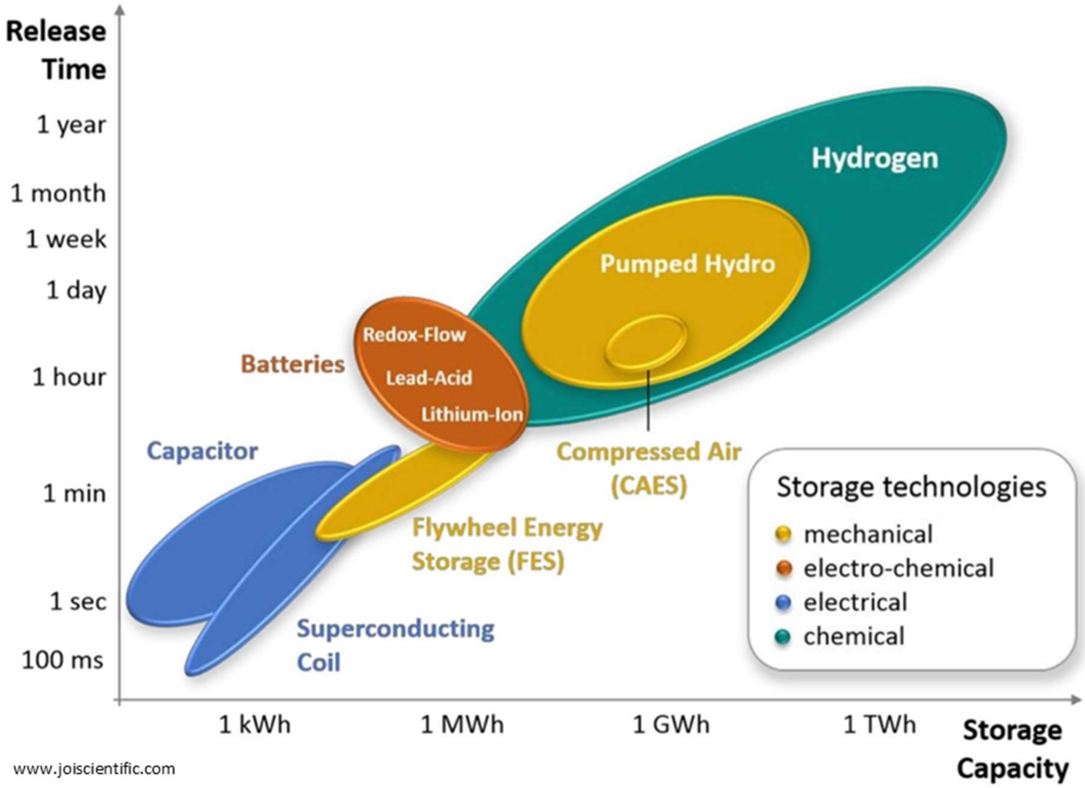
[58] Applying a heat credit for the substitution of methane. The main purpose of stationary fuel cells in Switzerland is expected to be heat supply, therefore only electricity generation costs with heat credits are provided.

[59] An additional heat premium of 0.075 CHF/kWh has been considered for biomethane (Bauer *et al.*, 2019).

[60] Environmental burdens are allocated according to exergy; quantified per kilowatt-hour of electricity produced. Applying system expansion (substituting methane) could lead to negative GHG-emissions, due to very low GHG emissions of green electrolysis (in this case PV based). The application of system expansion in some situations could therefore lead to confusion, since these negative GHG-emissions do not represent GHG removals from the atmosphere (Terlouw, Bauer, *et al.*, 2021), therefore the results from the application of system expansion are not presented in this table as such.

	Technology	Energy source	2020	2035	2050
		Hydrogen using grid power	320-410	310-390	300-360
		Methane	480-620	460-580	440-550
		Hydrogen using solar PV power	240-310	230-290	220-270
	PEFC 1 kW	Biomethane	380-500	340-420	320-390
		Hydrogen using grid power	360-480	330-400	310-370
		Methane	550-730	500-610	460-560
		Hydrogen using solar PV power	270-360	250-300	230-280
	SOFC 1 kW	Biomethane	330-430	280-380	280-350
		Hydrogen using grid power	320-420	270-370	270-340
		Methane	480-630	410-550	410-510
		Hydrogen using solar PV power	240-320	210-280	200-260
	SOFC 300 kW	Biomethane	240-350	240-300	240-290
		Hydrogen using grid power	230-340	240-300	230-280
		Methane	340-500	350-440	340-420
		Hydrogen using solar PV power	180-260	180-220	170-220

Electricity Storage



15 Batteries

15.1 Technologies

Rechargeable batteries store electrical energy in the form of chemical energy, which is released in electrochemical reactions. Batteries are built in different sizes, with energy capacities ranging from a few W up to several MW. Different types of batteries are currently used in stationary energy storage applications, including lithium-ion batteries (LIBs), lead-acid batteries, and vanadium redox flow batteries (VRFBs) (Aneke and Wang, 2016), (T. S. Schmidt *et al.*, 2019).

15.1.1 Lithium-Ion

LIB cells consist of an anode and a cathode, which are separated by an electronically insulating separator. The anode usually consists of graphite, while lithium iron phosphate (LFP) or a transition metal oxide, such or lithium nickel manganese cobalt oxide (NMC), is used for the cathode. During discharge, lithium ions move from the anode to the cathode through the separator. This ionic flux constitutes an electric current, which is compensated by the release of electrons by the anode, resulting in an electric current between the anode and cathode in an external electric circuit. In rechargeable batteries, these processes are reversible, which allows the battery to be recharged by applying an external power source. Figure 15.1 shows the schematic of a LIB cell (Schneider, 2021).

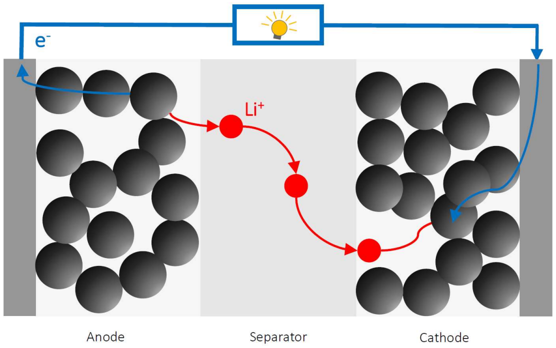


Figure 15.1: Schematic of a LIB cell. During discharge, lithium ions and electrons are transferred from the anode to the cathode side. During charge, the processes are reversed (Schneider, 2021).

A LIB storage system is composed of the battery itself (multiple battery cells assembled into battery packs) and auxiliary components including an energy managements system, thermal management system, and cooling system. In addition, battery systems used for stationary energy storage usually require a power electronics system that consists of multiple AC/DC inverter and voltage transformer units. Figure 15.2 shows the schematic of a grid-connected stationary battery system (Schneider, 2021).

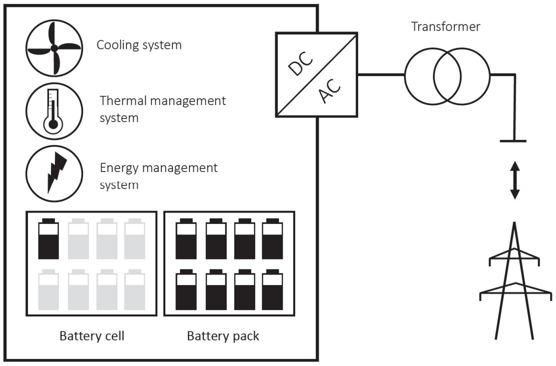


Figure 15.2: Grid-connected stationary battery system (Schneider, 2021).

15.1.2 Lead-acid

The lead-acid battery is the oldest rechargeable battery for both household and commercial applications. Despite its low investment costs, the potential of lead-acid batteries for stationary energy storage is limited due to the development of alternative batteries (e.g., LIBs) with longer cycle and calendar lifetimes, higher energy efficiencies, and higher energy density. Lead-acid batteries consist of a cathode made of lead dioxide and an anode made of metallic lead (T. S. Schmidt *et al.*, 2019), (Aneke and Wang, 2016).

15.1.3 Vanadium redox flow batteries

VRFBs are another type of rechargeable batteries. The principle of energy storage is based on electrochemical reactions of two redox couples contained in the anolyte (V^{2+}/V^{3+} redox couple) and catholyte (V^{4+}/V^{5+} redox couple). During discharge, the following reactions take place:

$$V^{2+} \rightarrow V^{3+} + e^{-} \qquad (anolyte)$$
$$VO_2{}^{+} + 2H^{+} + e^{-} \rightarrow VO^{2+} + H_2O \qquad (catholyte)$$

During discharge, the direction of the electrochemical reactions is reversed. Figure 15.3 shows the schematic of a VRFB (Clemente and Costa-Castelló, 2020).

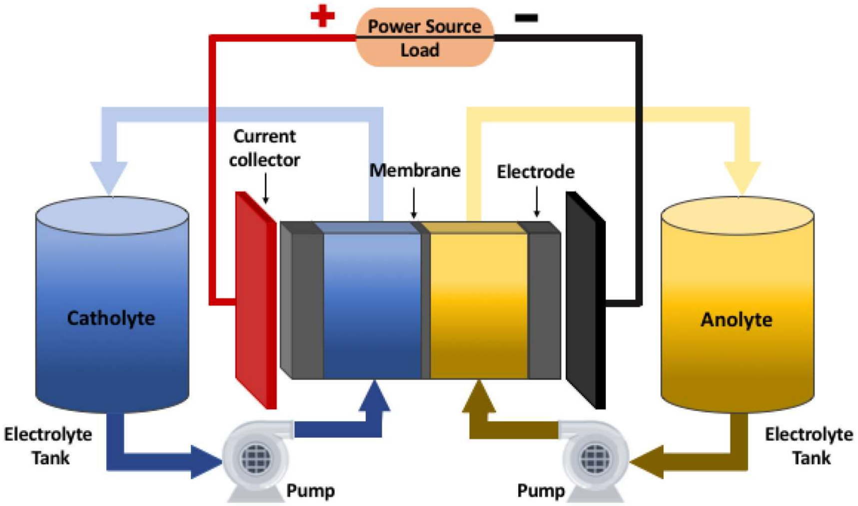


Figure 15.3: Schematic of a VRFB consisting of two electrolytes that each contain a redox couple. Figure from Ref. (Clemente and Costa-Castelló, 2020).

An advantage of VRFBs over LIBs and lead-acid batteries is that the energy and power capacities can be scaled independently. The energy capacity of VRFBs is related to the amount of electrolyte stored in the system, whereas the power capacity is related to the behavior of the redox couples and the size of the electrodes. The separation of energy and power capacities increases the flexibility of VRFBs for stationary energy storage. A drawback of VRFBs is their relatively low roundtrip energy efficiency of ca. 60-70%, which leads to comparatively high energy losses during charging and discharging (Lourenssen *et al.*, 2019)(T. S. Schmidt *et al.*, 2019). Technology options, their current status and future persepctives are extensively discussed in (Sánchez-Díez *et al.*, 2021).

15.1.4 Emerging Technologies

Due to rising concerns related to the future availability of lithium raw materials, battery researchers are currently exploring alternative technologies, such as organic electrode materials (Esser *et al.*, 2021), Na-ion batteries (Schneider *et al.*, 2019; Hasa *et al.*, 2021), Mg-ion batteries (Dominko *et al.*, 2020), and Al-ion batteries (Elia *et al.*, 2021). While these technologies can potentially offer cost and environmental benefits due to the high abundance of the raw materials, they are generally not expected to become competitive with LIBs in terms of energy density and also costs (Vaalma *et al.*, 2018; Peters, Cruz and Weil, 2019; Schneider *et al.*, 2019). This is in contrast to emerging lithium-based technologies, such as solid-state LIBs with metallic lithium for the anode (instead of graphite), lithium-sulfur batteries, and lithium-air batteries, which promise significantly higher energy densities than today´s LIBs (Walter, Kovalenko and Kravchyk, 2020), (Schneider, 2021).

15.2 Battery cells: state-of-the-art and further development

LIBs are expected to remain one of the dominating storage technologies in the electricity sector. (Beuse, Steffen and Schmidt, 2020) In order to further increase the energy density of LIBs and reduce their costs, the following technological developments are anticipated for LIB anode and cathode materials:

Anode: The specific charge (i.e., number of charge carriers per unit weight, Ah/kg) of the anode material can be increased by using graphite/silicon composites instead of pure graphite. This will increase the energy density of LIB cells.

Cathode: Further improvement is expected by increasing the nickel content in today´s NMC based cathode materials (e.g., by replacing $LiNi_{0.333}Mn_{0.333}Co_{0.333}O_2$ by $LiNi_{0.8}Mn_{0.1}Co_{0.1}O_2$). The replacement of parts of the cobalt by nickel reduces the overall amounts of cobalt required for the manufacturing of LIB cells, which would be beneficial both in terms of costs and due to concerns related to the mining of cobalt raw materials. Another advantage of nickel-rich NMC cathodes is that they offer higher energy densities. A challenge related to these materials is that they currently still suffer from stability and safety issues.

In addition to the above development targets for the anode and cathode materials, the energy density of LIBs can be further increased by improving the design of the battery cells and reducing the amount of electrochemically inactive cell parts. These improvements will also reduce the costs of LIB cells. (Armand *et al.*, 2020)

Table 15.1 provides an overview of key performance indicators for LIB research and development efforts in the mid- and long-term future. (Armand *et al.*, 2020)

Table 15.1: Key performance indicators for LIBs today and in the year 2030 and 2050. Remarks: (a) The energy density depends strongly on whether the focus in on energy or power density, as well as on the cycle life required. (b) The values shown for the cycle lifetime refer to average values. The cycle lifetime is strongly affected by the cycling conditions (e.g., depth of discharge, charge/discharge rate) and cell chemistry. Table adapted from Ref. (Armand et al., 2020).

	Current (2020)	**2030**	**2050**
Gravimetric energy density (Wh/kg)	90-180 (pack level) 160-260 (cell level)	190-230 (pack level) 275-320 (cell level)	> 250 (pack level) > 350 (cell level)
Volumetric energy density (Wh/L)	250-400 (pack level) 450-730 (cell level)	450-550 (pack level) 750-900 (cell level)	> 600 (pack level) > 1,000 (cell level)
Typical gravimetric power density (W/kg) (continuous discharge from 100% - 20% state of charge)	340-500 (cell level)	800-1,100 (cell level)	> 1,200 (cell level)
Typical volumetric power density (W/L) (continuous discharge from 100% - 20% state of charge)	ca. 1,000 (cell level)	ca. 2,000 (cell level)	> 3,000 (cell level)
Cycle lifetime (stationary energy storage, until 80% remaining capacity)	ca. 5,000 cycles	ca. 10,000 cycles	> 10,000 cycles
Calendar lifetime (until 80% remaining capacity)	ca. 10 years	10-15 years	15-20 years
Costs (CHF/kWh)	67-111 (cell level) 100-156 (pack level)	44-67 (cell level) 72-122 (pack level)	< 56 (cell level) 44-77 (pack level)

15.3 Battery systems: state-of-the-art and further development

15.3.1 Current battery system costs

Table 15.2 and Table 15.3 provide an overview of key performance indicators for battery systems, distinguishing between costs that scale mainly with the energy capacity (CHF/kWh) and power capacity (CHF/kW) of the battery system. The energy specific costs include mainly the battery pack costs, while the power specific costs include the costs of the cooling system, thermal management system, energy management system, AC/DC power inverters, and transformers. The total costs of a battery system are the sum of the energy and power specific costs. The parameter ranges (minimum value, maximum value, and most likely value) were collected by Schmidt et al. (representing year 2017) (T. S. Schmidt *et al.*, 2019) from various literature sources and manufacturer data sheets. It should be noted that the LIB pack costs in Table 15.2 and Table 15.3 are somewhat higher than the more "optimistic" values in Table 15.1 (100-156 CHF/kWh). These differences can be ascribed to the fact that the costs in Table 15.1 are representative of industry cost targets for battery packs manufactured in large-scale battery manufacturing facilities, whereas the costs Table 15.2 and Table 15.3 correspond to the actual costs of battery packs.[61]

Table 15.2 and Table 15.3 show performance indicators for the following battery technologies:

- NMC LIB (graphite anode, lithium nickel manganese cobalt oxide cathode),
- LFP LIB (graphite anode, lithium iron phosphate cathode),
- NCA LIB (graphite anode, lithium nickel cobalt aluminum oxide cathode),
- LTO LIB (lithium titanium oxide anode, lithium nickel cobalt aluminum oxide cathode)
- Lead-acid battery,
- VRFB (vanadium redox flow battery).

Table 15.2 and Table 15.3 distinguish between the costs for large-scale (MWh) and small-scale (kWh) stationary battery systems, which small-scale systems being more expensive per kWh of energy capacity.

Compared to LIBs with graphite-based anodes (i.e., NMC LIB, LFP LIB, and NCA LIB), LIBs with LTO anodes offer higher cycle stability and hence longer cycle lifetime. These benefits, however, come at the expense of lower energy densities und thus higher battery pack costs per kWh (T. S. Schmidt *et al.*, 2019).

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[61] Note that the lithium-ion battery-pack cost is for packs deployed in electricity-sector applications (typically 50% above the reported cost for automotive packs) (Beuse2020).

Table 15.2: Key performance indicators for stationary battery systems (I). Table adapted from (T. S. Schmidt *et al.*, 2019).

Technology	Small/large scale	Parameter description	min value	max value	most likely
NMC LIB	Large scale	Battery pack costs (CHF/kWh)	278	467	372
	Large scale	Power specific costs (CHF/kW)	270	431	351
	Large scale	O&M cost (CHF/kW p.a.)			10
	Small scale	Battery pack costs (CHF/kWh)	278	467	372
	Small scale	Power specific costs (CHF/kW)	1653	3204	2430
	Small scale	O&M cost (CHF/kW p.a.)			0
	-	Calendar lifetime (# years)	5	20	12
	-	Cycle lifetime (# cycles)	2'555	8'000	4'996
	-	Depth of discharge			93%
	-	Roundtrip Efficiency	87%	92%	89%
	-	Capacity at end of life			80%
LFP LIB	Large scale	Battery pack costs (CHF/kWh)	382	642	512
	Large scale	Power specific costs (CHF/kW)	270	431	351
	Large scale	O&M cost (CHF/kW p.a.)			10
	Small scale	Battery pack costs (CHF/kWh)	382	642	512
	Small scale	Power specific costs (CHF/kW)	1549	3029	2290
	Small scale	O&M cost (CHF/kW p.a.)			0
	-	Calendar lifetime (# years)	5	20	12
	-	Cycle lifetime (# cycles)	2'000	10'000	6'529
	-	Depth of discharge			93%
	-	Roundtrip Efficiency	84%	89%	87%
	-	Capacity at end of life			80%
NCA LIB	Large scale	Battery pack costs (CHF/kWh)	233	391	312
	Large scale	Power specific costs (CHF/kW)	270	431	351
	Large scale	O&M cost (CHF/kW p.a.)			10
	Small scale	Battery pack costs (CHF/kWh)	233	391	312
	Small scale	Power specific costs (CHF/kW)	1698	3280	2490
	Small scale	O&M cost (CHF/kW p.a.)			0
	-	Calendar lifetime (# years)	5	20	12
	-	Cycle lifetime (# cycles)	1'278	4'000	2'498
	-	Depth of discharge			93%
	-	Roundtrip Efficiency	87%	92%	89%
	-	Capacity at end of life			80%

Table 15.3: Key performance indicators for stationary battery systems (II). Table adapted from (T. S. Schmidt *et al.*, 2019).

Technology	Small/large scale	Parameter description	min value	max value	most likely
LTO LIB	Large scale	Battery pack costs (CHF/kWh)	889	1111	1000
	Large scale	Power specific costs (CHF/kW)	270	431	351
	Large scale	O&M cost (CHF/kW p.a.)			10
	Small scale	Battery pack costs (CHF/kWh)	889	1111	1000
	Small scale	Power specific costs (CHF/kW)	1042	2560	1802
	Small scale	O&M cost (CHF/kW p.a.)			0
	-	Calendar lifetime (# years)	20	25	23
	-	Cycle lifetime (# cycles)	5'000	20'000	15'000
	-	Depth of discharge#			100%
	-	Roundtrip Efficiency	88%	95%	91%
	-	Capacity at end of life			80%
Lead-acid battery	Large scale	Battery pack costs (CHF/kWh)	117	526	292
	Large scale	Power specific costs (CHF/kW)	270	431	351
	Large scale	O&M cost (CHF/kW p.a.)			10
	Small scale	Battery pack costs (CHF/kWh)	117	526	292
	Small scale	Power specific costs (CHF/kW)	1034	1550	1270
	Small scale	O&M cost (CHF/kW p.a.)			0
	-	Calendar lifetime (# years)	3	15	9
	-	Cycle lifetime (# cycles)	250	2'500	1'500
	-	Depth of discharge			55%
	-	Roundtrip Efficiency	73%	78%	75%
	-	Capacity at end of life			80%
VRFB	Large scale	Battery pack costs (CHF/kWh)	349	602	476
	Large scale	Power specific costs (CHF/kW)	1182	1182	1182
	Large scale	O&M cost (CHF/kW p.a.)			48
	Small scale	Battery pack costs (CHF/kWh)	523	903	713
	Small scale	Power specific costs (CHF/kW)	1773	1773	1773
	Small scale	O&M cost (CHF/kW p.a.)			48
	-	Calendar lifetime (# years)	13	25	19
	-	Cycle lifetime (# cycles)	12'000	14'000	13'000
	-	Depth of discharge			100%
	-	Roundtrip Efficiency	64%	68%	66%
	-	Capacity at end of life			80%

Batteries are subject to comparatively fast costs reductions due to technological improvements and economies of scale. Therefore, earlier projected battery costs provided in Table 15.2 and Table 15.3 (representing year 2017) can be considered as conservative estimates from today's perspective, especially for lithium-ion batteries (Beuse, Steffen and Schmidt, 2020). For this reason, the costs of lithium-ion batteries are adapted considering experience rates and cumulative deployment capacities presented in (Beuse, Steffen and Schmidt, 2020). The latter reference uses the same technological and economic data as provided in (T. S. Schmidt *et al.*, 2019) and therefore can be updated in an accurate way. The power unit and energy unit turned out to have independent learning rates (T. S. Schmidt *et al.*, 2019), and therefore a cost distinction between these two battery components has been made.

Figure 15.4 demonstrates the cost reduction of the energy storage unit for both stationary batteries and batteries used in electric vehicles. As indicated, stationary battery energy units generally have 50% higher costs per unit of energy storage capacity compared to batteries in electricity vehicles, although both benefit from learning in the stationary battery and battery electric vehicle industry (Beuse, Steffen and Schmidt, 2020). Battery costs for the energy unit are indicated as 200 CHF/kWh and 136 CHF/kWh in year 2020 for stationary and electricity vehicle battery applications, respectively. This corresponds to stationary battery energy storage costs presented in literature, for example 150-200 CHF/kWh in (Elshurafa, 2020) and 171 CHF/kWh (year 2019) in (Comello and Reichelstein, 2019).

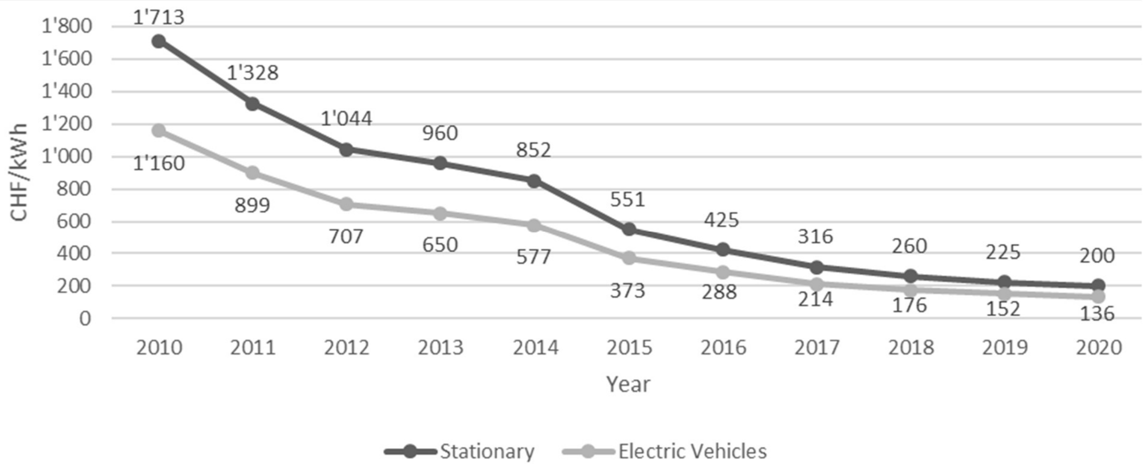


Figure 15.4: Costs per kWh energy storage capacity of stationary batteries as well as batteries for electric vehicles; based on expected cumulative deployments and data obtained from (Beuse, Steffen and Schmidt, 2020). A learning rate of 20.8% has been applied (Beuse, Steffen and Schmidt, 2020).

The power unit can be categorized in Front of The Meter (FTM) and Behind of The Meter (BTM) solutions. FTM refers to large containerized solutions and BTM to (residential) solutions behind the meter (Beuse, Steffen and Schmidt, 2020). Both power solutions differ in learning rates and cumulative deployment capacities (Beuse, Steffen and Schmidt, 2020). Cumulative deployment capacities are available until year 2017, therefore a trend line is fitted and used to estimate deployment capacities for power units to be used for FTM and BTM applications until 2020, see Figure 15.5.

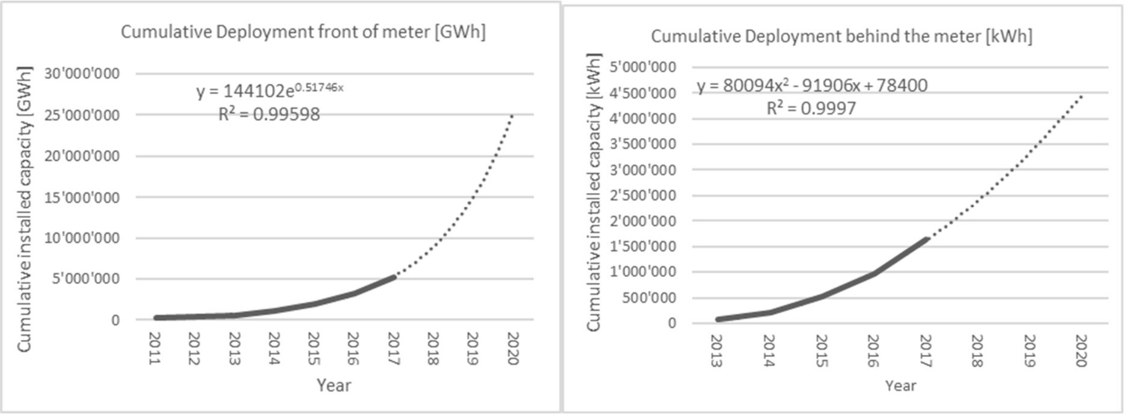


Figure 15.5: Cumulative deployments and fitted trend lines for front of the meter (left) and behind of the meter solutions (right).

Figure 15.6 illustrate the cost development of the power unit for FTM and BTM, respectively. The costs of the power unit of BTM (residential) solutions (1595 CHF/kW) are significantly higher compared to larger containerized FTM power units (159 CHF/kW) in year 2020. The costs of the power unit for BTM (residential) solutions is conservative compared to scientific literature, (Comello and Reichelstein, 2019) indicated for example 970 CHF/kW for a residential battery power unit.

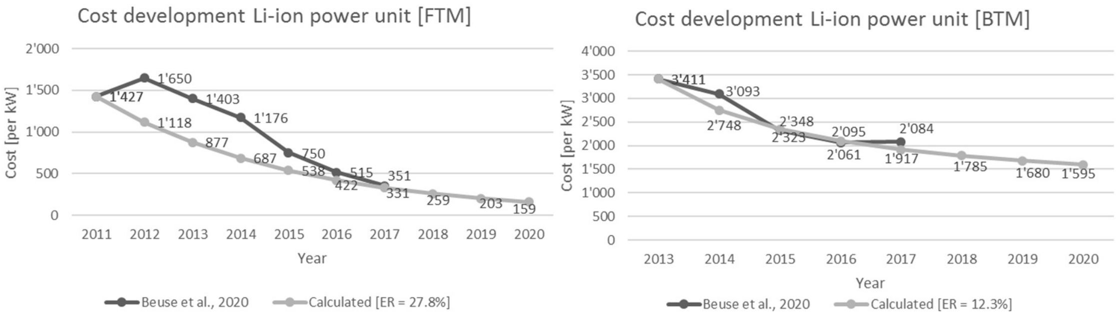


Figure 15.6: Battery costs for the power unit, applicable for front of the meter solutions (utility, left) and behind the meter (residential, right) solutions.

Table 15.4 shows an updated factsheet applicable for lithium-ion batteries operated in 2020. Significant cost improvements and technological improvements are indicated compared to initial data presented in Table 15.2 and Table 15.3.

Table 15.4: Update of lithium-ion battery costs and technological parameters for year 2020 based on trend lines and literature.

Technology	Small/large scale	Parameter description	Value	Source
Lithium-ion battery (2020)	Large scale	Battery pack costs (CHF/kWh)	200	Figure 15.4
	Large scale	Power specific costs (CHF/kW)	159	Figure 15.6
	Large scale	O&M cost (CHF/kW p.a.)	10	(T. S. Schmidt *et al.*, 2019)
	Small scale	Battery pack costs (CHF/kWh)	200	Figure 15.4
	Small scale	Power specific costs (CHF/kW)	1595	Figure 15.6
	Small scale	O&M cost (CHF/kW p.a.)	0	(T. S. Schmidt *et al.*, 2019)
	-	Calendar lifetime (# years)	13.3	(Beuse, Steffen and Schmidt, 2020)
	-	Cycle lifetime (# cycles)	5386	(Beuse, Steffen and Schmidt, 2020)
	-	Depth of discharge#	93%	(Beuse, Steffen and Schmidt, 2020)
	-	Roundtrip Efficiency	91%	(Beuse, Steffen and Schmidt, 2020)
	-	Capacity at end of life	80%	(T. S. Schmidt *et al.*, 2019)

15.3.2 Cost projections for lithium-ion battery systems

Figure 15.7 shows normalized cost trajectories with low, mid, and high projections for the years 2020 to 2050. The cost projections were performed by Cole et al. (year 2020), employing a literature-based approach, in which projections rely on the low, median, and highest values from 19 different literature sources. The normalized costs are shown for 4-hour battery systems, i.e., for battery systems with an energy-to-power ratio of 4 MWh/MW. By 2030, costs are reduced by 63%, 47%, and 26% in the low, mid, and high cases, respectively. By 2050, the costs are reduced by 78%, 60%, and 44%, respectively. The mid and low projections have steep initial slopes, indicating that the majority of the publications see larger cost reductions in the near-term that then slow over time (Cole *et al.*, 2020).

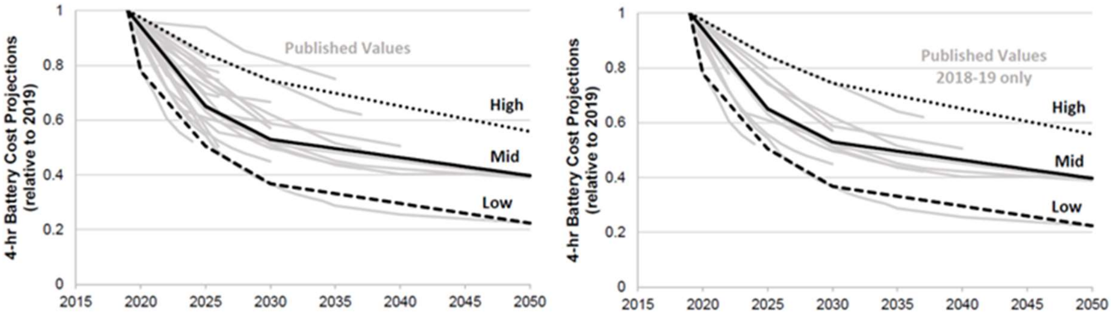


Figure 15.7: Battery cost projections for 4-hour LIB systems, with values relative to 2019. The high, mid, and low cost projections established based on multiple publications are shown in bold. The upper figure shows the full range of cost projections (considering projections published between 2017 and 2019), while the lower figure shows only those cost projections published after 2017 (Cole et al., 2020).

The most recent and comprehensive analysis of cost development of battery cells in the past with extrapolations into the future has been performed by MIT (Ziegler and Trancik, 2020). Their analyses shows that extrapolating past cost trends into the future results in large variations of potential future battery cell costs as shown in Figure 15.8. The simple projections, which are intended to examine the differences in the underlying data, suggest a nearly 20 year range for when prices might cross a 75 USD per kWh threshold and a nearly 30 year range for reaching 20 USD per kWh.

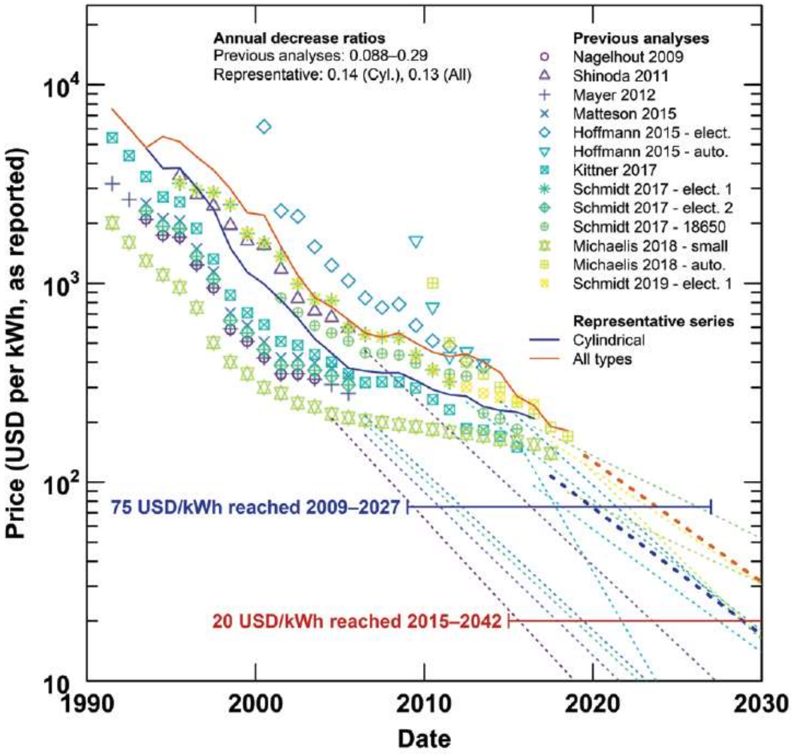


Figure 15.8: Reported lithium-ion cell price series and projections based on simple extrapolation (Ziegler and Trancik, 2020).

Figure 15.9 shows our projections of future battery (FTM) cost developments at utility scale for the energy unit as well as the power unit based on the projections of (Cole et al., 2020) – learning rates applied are within the range provided by (Ziegler and Trancik, 2020). This figure shows that the costs could be reduced to approximately 45-110 CHF/kWh and 35-90 CHF/kW in 2050 for the energy unit and power unit, respectively.

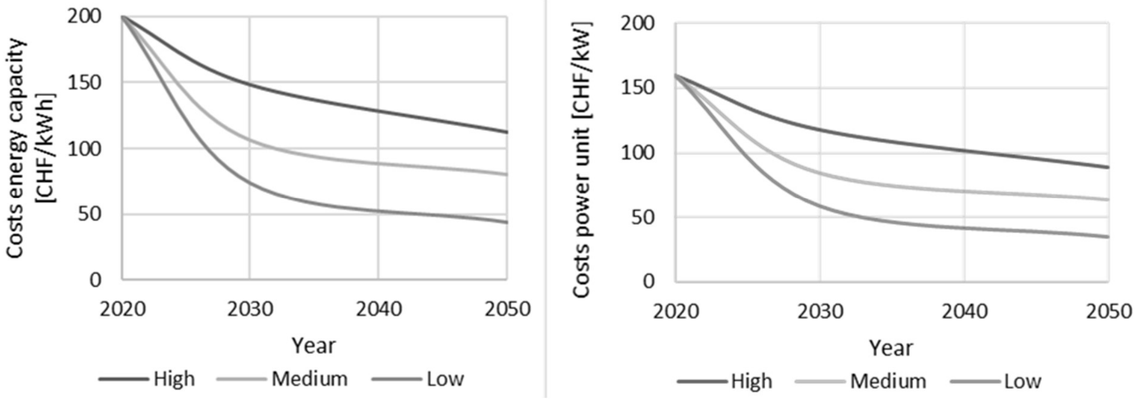
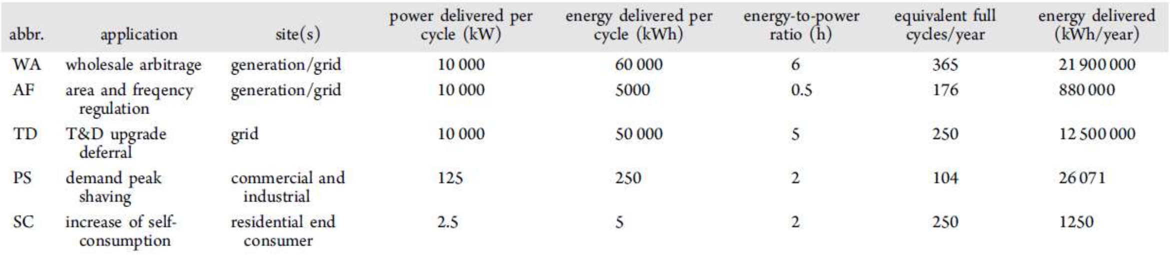


Figure 15.9: Estimation of battery costs for the energy unit (left) and power unit (right) for battery systems (FTM) with an energy-to-power ratio of 4 MWh/MW.

15.4 Environmental burdens

Life-cycle environmental burdens of residential and utility battery systems have been comprehensively assessed in (T. S. Schmidt *et al.*, 2019). Six different battery technologies were assessed on GHG-emissions, considering four lithium-ion battery systems: Lithium Iron Phosphate/graphite (LFP), Lithium Nickel Cobalt Aluminium Oxide/graphite (NCA), NCA/Lithium Titanate Oxide (LTO) and Lithium Nickel Manganese Cobalt Oxide/graphite (NMC). Further, the Valve Regulated Lead Acid (VRLA) battery and the Vanadium Redox Flow Battery (VRFB) were included in their analysis; based on the same battery technology data as presented in Table 15.2 and Table 15.3. The results were presented for three countries on five different battery applications, the characteristics of these battery applications are described in Figure 15.10.



abbr.	application	site(s)	power delivered per cycle (kW)	energy delivered per cycle (kWh)	energy-to-power ratio (h)	equivalent full cycles/year	energy delivered (kWh/year)
WA	wholesale arbitrage	generation/grid	10 000	60 000	6	365	21 900 000
AF	area and freqency regulation	generation/grid	10 000	5000	0.5	176	880 000
TD	T&D upgrade deferral	grid	10 000	50 000	5	250	12 500 000
PS	demand peak shaving	commercial and industrial	125	250	2	104	26 071
SC	increase of self-consumption	residential end consumer	2.5	5	2	250	1250

Figure 15.10: Five battery applications considered in (T. S. Schmidt et al., 2019), figure is reproduced from a table presented in (T. S. Schmidt et al., 2019).

Figure 15.11 shows that lithium-ion batteries exhibit lowest GHG-emissions in most battery applications (*e.g.* 0.06-0.30 kg CO_2-eq. for delivering 1 kWh of stored electricity in Switzerland), mainly due to their high roundtrip efficiency and long battery lifetime compared to the VRLA battery (low roundtrip efficiency and low battery lifetime) and the VRFB (low roundtrip efficiency). Minor differences regarding GHG emissions are found between lithium-ion batteries due to similar costs and technological parameters. Differences on GHG emissions between countries can be mainly explained by the different GHG emissions of the national electricity grid (which was assumed to be stored in this analysis), which are the highest in Poland (coal based electricity) and the lowest for Switzerland for the three countries assessed.

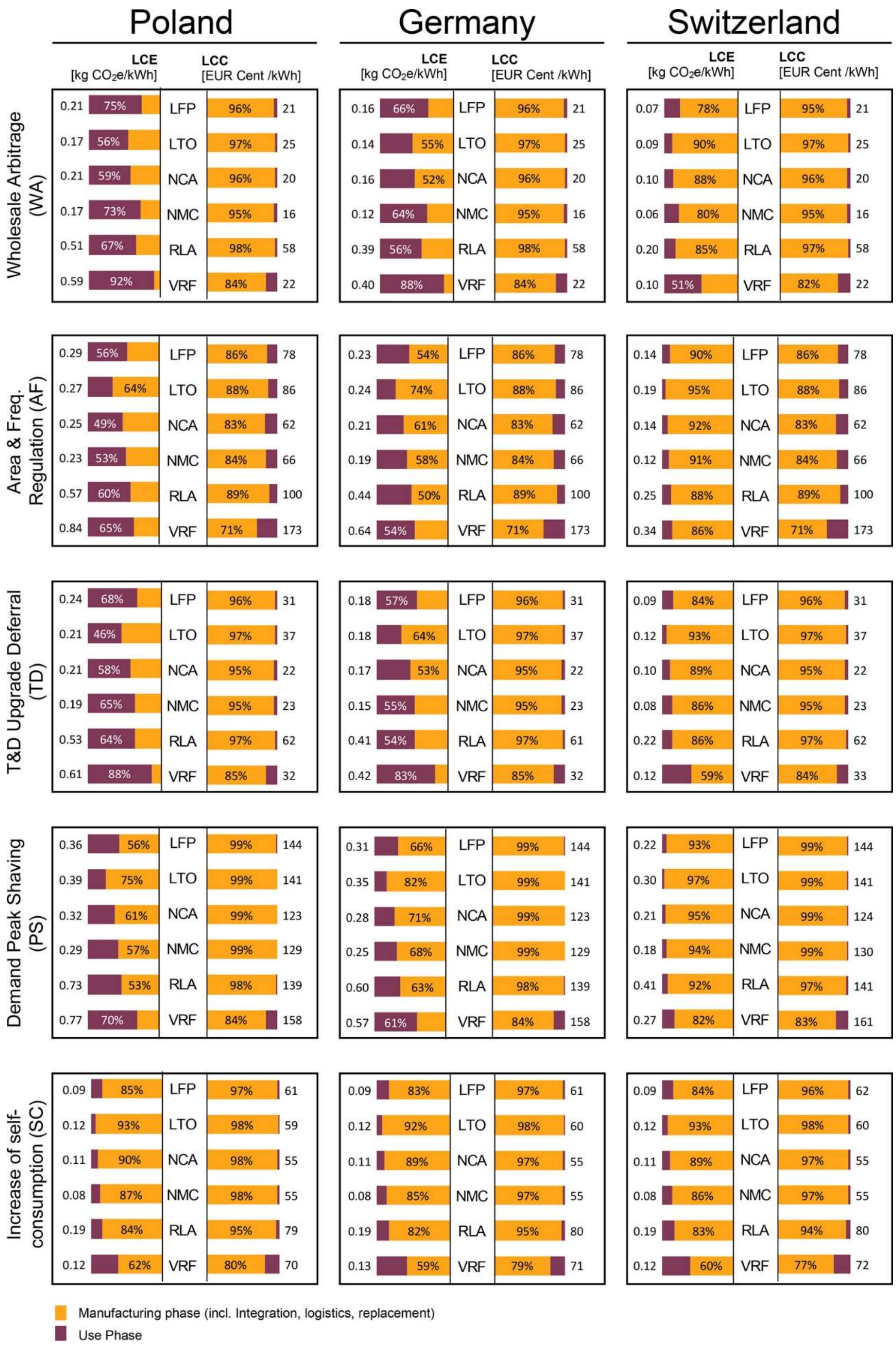


Figure 15.11: Life-cycle costs (LCC) and GHG-emissions (LCE) for six battery technologies, five battery applications and three countries; figure is reproduced from (T. S. Schmidt *et al.*, 2019). Further, a contribution analysis of battery costs and GHG emissions is presented, to indicate GHG emissions attributed to the manufacturing phase and operation phase of battery systems.

GHG emissions of the operation phase become more important for battery technologies with low roundtrip efficiencies – such as the VRLA battery – since more electricity is lost during a battery cycle. On the contrary, GHG emissions from the operation phase become less influential with low carbon electricity, high roundtrip efficiencies and with battery applications exhibiting low energy throughputs (for example demand peak shaving). The contribution of the manufacturing phase can be as high as 90% in these situations.

Figure 15.12 demonstrates that GHG emissions generated during manufacturing of lithium-ion batteries are mainly driven by the energy consumption (for manufacturing) and electrode materials requirements. Lithium-ion batteries exhibit lowest GHG emissions during the manufacturing phase, with lowest GHG emissions for NMC batteries in general. The VRLA battery exhibited generally the highest GHG emissions, mainly due to its low volumetric density, necessary battery replacements (as a result of its low battery lifetime) as well as high GHG emissions generated for the module housing, pack housing and the container system.

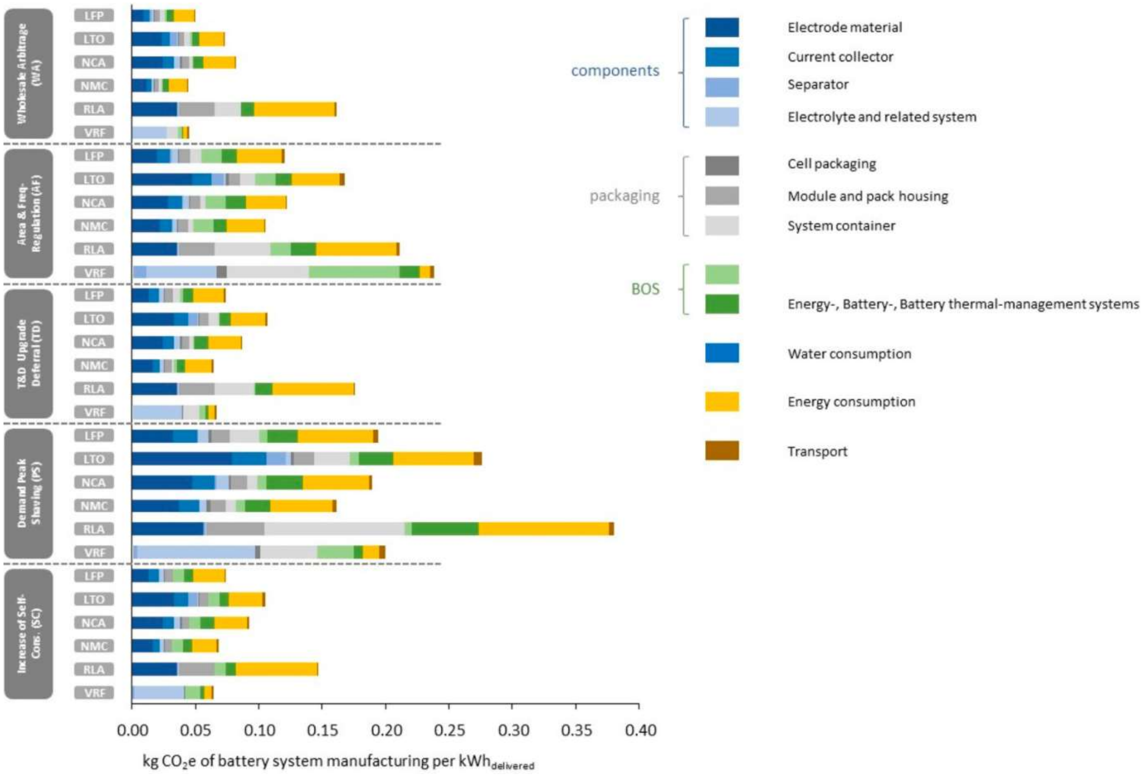


Figure 15.12: Contribution analysis of GHG emissions associated with manufacturing of delivering 1 kWh of stored electricity; for six battery technologies and five battery applications. Figure is reproduced from (T. S. Schmidt *et al.*, 2019).

The same battery portfolio has been assessed in (Terlouw *et al.*, 2019), to determine the metal criticality of home-based battery systems. Metal criticality evaluates the scarcity and risks associated to metal supply (Terlouw *et al.*, 2019). The characterization factors for metal criticality were generated considering 13 metals using three metal criticality methodologies; (Graedel *et al.*, 2012), (NSTC, 2016) and (European Commission, 2014). The results are presented in Figure 15.13 per kWh of electricity delivered (per cycle), including necessary battery replacements of battery packs during the system lifetime.

Similar conclusions as regarding GHG emissions are generated for the assessment of metal criticality in home-based battery systems; the VRLA battery performs worst, and lithium-ion batteries generally perform best with a slightly better performance for the LFP Battery. The VRFB shows promising potential, though associated with a high uncertainties regarding (metal) inventory. Further, the battery lifetime turns out to be a key factor in metal criticality assessments. In addition, higher specific energy density, low metal-intensive batteries, the low utilization of critical metals as well as recycling rates are identified as crucial parameters to minimize the metal critically of home-based battery systems.

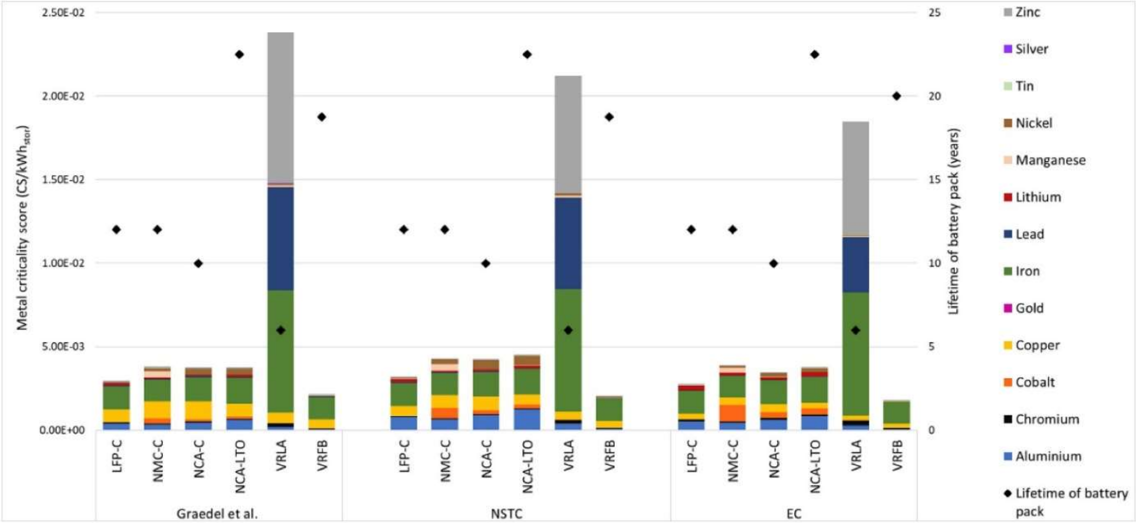


Figure 15.13: Metal criticality analysis for six battery technologies considering three metal criticality methodologies; figure is reproduced from (Terlouw et al., 2019).

In terms of material criticality and regarding supply risks, sodium-ion as well as cobalt-free lithium-ion battery cells caon offer advantages compared to the currently most often used lithium ion cell containing cobalt. However, technology performance of these alternative technologies has to be improved to become competitive (Vaalma *et al.*, 2018; Schneider *et al.*, 2019; Sharma and Manthiram, 2020).

15.4.1 Future GHG emissions of stationary battery electricity storage

Figure 15.14 shows current and future life-cycle GHG emissions of battery production of home-based battery systems considering three lithium-ion battery cathode chemistries: LFP, NCA and NMC (graphite is used for the anodes). The life cycle inventories used are based on those established by (T. S. Schmidt *et al.*, 2019); however, energy consumption for battery cell manufacturing has been updated according to (Cox *et al.*, 2020) in order to reflect latest developments in this respect. Latest research confirms that life-cycle GHG emissions of battery production (NMC-C and NCA-C chemistries) today are at about 100 kg $CO_{2\text{-eq.}}$ per kWh storage capacity; NMC_{111} and NMC_{811} chemistries exhibit very similar production related GHG emissions (Crenna *et al.*, 2021).

For the prospective LCA, two future scenarios – based on the integrated assessment model Remind (Luderer *et al.*, 2015) – are included, namely a business as usual scenario (RCP 6.0 W/m^2) and a more ambitious future scenario to achieve the 2°C target of the Paris Agreement (RCP 2.6 W/m^2). The results are generated using the premise open-source Python package updating all available industrial sectors in the ecoinvent background database (premise version 0.3.6)[62].

Current GHG emissions – generated from the production of batteries for home based applications – are similar for all three battery chemistries, with slightly lower GHG emissions for the LFP battery. The biggest contributors to GHG emissions of battery production are the cathode production and energy requirements to produce the battery cells, respectively. Further, future GHG emissions are expected to be reduced significantly for all three battery chemistries, although this reduction is also largely driven by the development of the total energy sector, such as the electricity, steel and cement sectors.

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[62] https://github.com/romainsacchi/premise (5.5.2021)

For example, the business as usual scenario (RCP 6.0 W/m^2) exhibits significant higher GHG emissions in 2050 (between 63-67 kg CO_2-eq. per kWh energy storage capacity) compared to the more ambitious climate scenario (RCP 2.6 W/m^2), which results in significant lower GHG emissions between 47-52 kg CO_2-eq. per kWh energy storage capacity. Again, slightly lower future GHG emissions – of battery production for home-based applications – are obtained from the LFP battery, followed by the NCA and NMC battery, respectively. This figure also shows that future GHG emissions can be reduced by about 50% in the 2°C target scenario (RCP 2.6 W/m^2) in 2050, compared to 2020.

This quantification of life-cycle GHG emissions of producing future batteries has been performed using constant specific energy (i.e. kWh storage capacity per kg battery) of all three batteries. Therefore, the results are likely to represent a kind of pessimistic perspective, since specific energies of batteries have increased continuously in the past, as shown in Figure 15.15. However, up to now, this development has been driven mostly by automotive and consumer electronic applications and for these, saving weight and volume is key in product improvement. That is less so for stationary battery applications, where cost reduction is way more important than increasing specific energy.

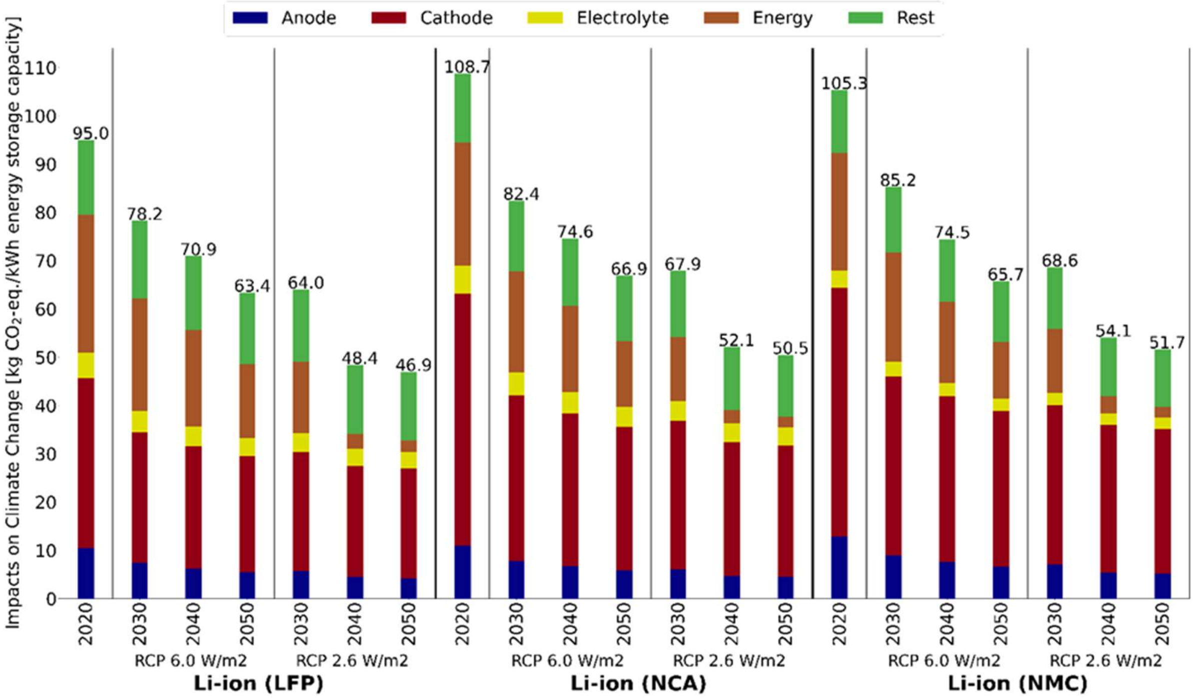

Figure 15.14: Contribution analysis of current and future GHG emissions of battery production for home-based stationary applications considering three battery chemistries: LFP, NCA and NMC. Total GHG emissions are presented above the individual bars. The IPCC 2013 Climate Change GWP 100a LCIA method has been used.

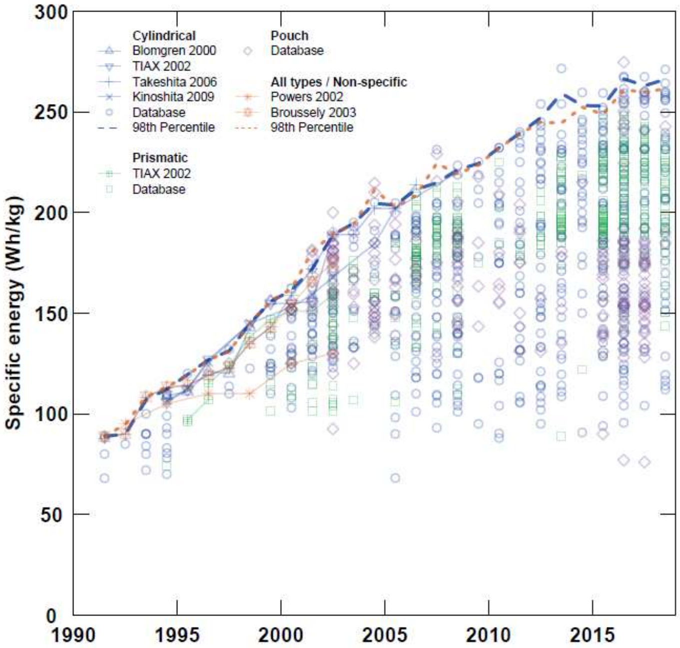

Figure 15.15: Lithium-ion battery cell specific energy over time (Ziegler and Trancik, 2020).

The environmental performance of (stationary) batteries can in general be improved by recycling and design of closed-loop material flows in which materials (especially metals) from old batteries are recovered and used for the production of new batteries. Such recycling pathways do not yet represent established commercial processes in industry and have therefore not been considered in LCA (Pellow *et al.*, 2020).

Designing batteries without cobalt is recommended by (Sharma and Manthiram, 2020) to improve the sustainability (in a broader sense including socially problematic impacts) of stationary batteries. Further, they recommend that the N-methylpyrrolidone (NMP) solvent should be eliminated to reduce energy demand and harmful emissions. Toxicity could be reduced by using low toxicity electrolyte salts and non-toxic binders. Iron and manganese-based cathodes are less toxic, less energy-intensive alternatives to cobalt and nickel-based cathodes. Lastly, to preserve habitat, sodium should be used over lithium for grid storage and cellulose separators over polyethylene separators for all applications (Sharma and Manthiram, 2020).

16 Pumped hydro electricity storage (PHES)

As of 31st of December 2020 there were 677 hydropower plants with a capacity of 300 kW or above in Switzerland in operation with an expected annual power generation of 36’567 GWh – 48.7% of that by run-of-river power plants, 47% by storage power plants, and 4.3% by pumped storage power plants (PSPP) (“Pumpspeicherkraftwerke”) (SFOE, 2021b). In addition to these three plant types, there are circulating power plants (CPP) (“Umwälzkraftwerke”). While circulating power plants exclusively use water pumped and stored for electricity generation, pumped storage hydro power plants use a combination of pumped water and natural inflow into reservoir lakes. Expected annual generation of pumped storage power plants refers to the use of natural water inflows only (SFOE, 2021a).

According to the Swiss hydropower statistics, there are currently 20 PSPP and CPP in operation with a cumulative generation capacity of 3109 MW and an expected annual generation of 1516 GWh (without circulating operation, “Umwälzbetrieb”); installed pump capacity amounts to 3164 MW. Two – with a generation capacity of 1020 MW, an expected annual generation of 153 GWh, and an installed pump capacity of 960 MW – are categorized as “under construction” (SFOE, 2021a). The usable total volume (for power generation) of reservoir lakes currently amounts to about 3800 Mio. m^3, which corresponds to an annual electricity generation of 8800 GWh (Felix, Müller-Hagmann and Boes, 2020).

This differentiation between PSPP and CPP is hardly present in the international literature. Therefore, both types are aggregated under the term “Pumped hydro electricity storage (PHES)” in the following. Within the European Union, PHES currently represents the vast majority of installed electricity storage capacity with a share of more than 90% (Andrey *et al.*, 2020).

16.1 Technology

PHES store energy in the form of gravitational potential energy of water, pumped from a lower elevation reservoir to a higher elevation. Electricity is generated when the water flows back into the lower lake through turbines.

Roundtrip electric efficiency is usually in a range of 70-80% (some references refer to a range of 65-85%) and plant lifetime can be assumed to be in the order of about 80 years (60-150 years) (with shorter periods for certain components) (Bauer *et al.*, 2007; Deane, Ó Gallachóir and McKeogh, 2010; Oliveira *et al.*, 2015; Rehman, Al-Hadhrami and Alam, 2015; Immendoerfer *et al.*, 2017; Rahman *et al.*, 2020; Vilanova, Flores and Balestieri, 2020; VSE, 2020; wikipedia, 2021).

16.2 Costs

Investment costs for the two most recent large scale PHES projects in Switzerland have been reported as 2.1 Billion CHF for Linth Limmern and 2 Billion CHF for Nant de Drance (VSE, 2020). Linth Limmern represents the addition of an underground PSPP connecting two existing reservoir lakes and increasing the installed turbine power from 520 MW to 1520 MW. Commercial operation started in 2017. A turbine capacity of 900 MW was installed in Nant de Drance for an expected annual generation of 2.5 TWh, connecting two existing lakes. Full operation is expected for 2021 (Nant de Drance SA, 2020). Specific CAPEX amount to 2’100 CHF/kW and 2’200 CHF/kW for Linth Limmern and Nant de Drance, respectively.

CAPEX for PHES are, however, very location-specific and often dominated by construction work; they also crucially depend on whether a new dam has to be constructed, an existing dam can be increased in height, or whether existing reservoirs can be used as they are adding only waterways, turbines and generators. (Andrey *et al.*, 2020) report CAPEX of 500-1500 €/kW and 19 €/kWh (storage capacity) on average (with a maximum of 90 €/kWh) for European countries.

Table 16.1 shows an overview of reported costs (and other key parameters for economic assessment) with ranges indicated by the individual studies.

Table 16.1: Overview of PHES costs and other key parameters for economic assessment as reported by different studies (Deane, Ó Gallachóir and McKeogh, 2010; Rehman, Al-Hadhrami and Alam, 2015; Andrey et al., 2020; Rahman et al., 2020; Vilanova, Flores and Balestieri, 2020; VSE, 2020). n.a.: not available.

Source	CAPEX [CHF per kW]	CAPEX, [per $kWh_{storage}$]	OPEX []	Efficiency [%]	Lifetime [a]
(Andrey et al., 2020)[63]	1350 CHF (550-1650 CHF)	19 €	1.2% of CAPEX	81	60
(Rahman et al., 2020)	403-4644 CHF	5-136 US$	2-10 US$/kWa	65-80	n.a.
(Vilanova, Flores and Balestieri, 2020)	2000-4300 CHF	5-100 US$	4.6 €/(kWa) 0.22 €/MWh	65-85	30-70
(Deane, Ó Gallachóir and McKeogh, 2010)	560-2400 CHF	n.a.	n.a.	70-75	50-100
Linth Limmern	2100 CHF	n.a.	n.a.	82.6 (Pöyry Energy AG, 2008)	n.a.
Nant de Drance	2200 CHF	n.a.	n.a.	>80 [64]	n.a.

16.3 Environmental burdens

Pumped hydro electricity storage can include two types of environmental burdens: a) disturbance of local ecosystems due to land flooded by reservoir lakes, and b) "life-cycle" burdens related to material and energy supply chains linked to construction, operation, and disposal of power plants. The latter also include direct GHG emissions from reservoir lakes due to decomposition of organic matter in those lakes – which can be high in areas with high temperatures and substantial amounts of biomass present in the flooded areas, but not in Switzerland. Impacts on local ecosystems are site-specific and out of scope of this analysis. Life-cycle burdens are also site-specific, but less so.

Life cycle assessments of PHES are rare, but the few available recent studies agree on the main conclusion that the burdens of storing electricity with PHES mainly depend on the electricity losses in storage cycles and therefore the burdens associated with the stored electricity (with exceptions for few impact categories) (Oliveira *et al.*, 2015; Wernet *et al.*, 2016; Abdon *et al.*, 2017; Immendoerfer *et al.*, 2017). High cycle efficiencies are therefore important to ensure an environmentally sound storage of electricity. However, the lower the burdens of the stored electricity, the more important construction related burdens become in relative terms.

Regarding life-cycle GHG emissions, the contribution form construction and end-of-life of PHES plants amounts to only few grams of CO_{2eq}/kWh stored electricity over the entire lifetime of PHES plants (Oliveira *et al.*, 2015; Wernet *et al.*, 2016; Abdon *et al.*, 2017; Immendoerfer *et al.*, 2017). In tropical regions, however, additional operational GHG emissions from decomposition of biomass in reservoir lakes can be substantial (Hertwich, 2013; Scherer and Pfister, 2016).

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[63] Figures valid for 2030 and 2050.

[64] https://www.alpiq.com/de/alpiq-gruppe/medien/medienmitteilungen/media-release-detail/meilenstein-fuer-neues-pumpspeicherkraftwerk-nant-de-drance-im-unterwallis (11.4.2021).

17 (Advanced adiabatic) Compressed air energy storage

Electricity can be used to operate a compressor and store ambient air at high pressure levels. When required, the compressed air can be expanded and drive a turbine which generates electricity. This is the concept of Compressed Air Energy Storage (CAES). During air compression, heat is generated. Compression to a pressure level of 100 bar would result in a temperature of around 1000°C, which poses a challenge for any air storage unit, and therefore the air needs to be cooled down. This thermal energy can be released to the atmosphere; it that case, however, it is missing when the air is expanded and thus cools down to temperatures which would lead to icing of the turbine. To prevent this icing, the expanding air needs to be heated up. Traditional CAES technology uses natural gas burners for this purpose. Burning natural gas, however, reduces overall energy efficiency to about 50% and generates GHG emissions. Two of these “traditional” CAES systems have become operational in the past – one in 1978 in Huntorf (Germany), and one in 1991 in McIntosh (USA) (Olympios *et al.*, 2021).

Advanced Adiabatic CAES avoids natural gas combustion for heat supply by storing the thermal energy released during air compression in appropriate storage media, and using this thermal energy to heat up the expanding air during discharge of the storage unit. Such AA-CAES units do not release GHG emissions and achieve substantial higher energy efficiencies than CAES (SCCER Heat and Electricity Storage, 2020). Thus, only AA-CAES seems to be compatible with climate and energy policy and this report focuses on the AA-CAES concept.

AA-CAES is still in the pilot and demonstration phase (TRL 6) and no commercial plant is operating worldwide. One installation is currently being planned, with operation scheduled to start in 2025 (Andrey *et al.*, 2020).

17.1 Technology

The AA-CAES concepts, which have been investigated over the last few years for potential application in Switzerland (Barbato *et al.*, 2019; Haselbacher *et al.*, 2019; SCCER Heat and Electricity Storage, 2020), represent two system configurations in which charge and discharge (i.e. air compression and expansion) are divided into low and high pressure stages. After each compressor there is a storage cavity with a Thermal Energy Storage (TES) unit. The maximum pressure in the second storage cavity is approximately 100 bar in both configurations. These configurations differ in terms of pressure and therefore also temperature after the first compression stage:

- In the first configuration, the air is compressed to 33 bar and 580°C in the first stage by the low-pressure compressor. In the second stage, i.e. the high-pressure compressor, the air is compressed from 33 bar to 100 bar.
- In the second configuration, the air in the low-pressure compressor is compressed to only 10 bar and 320°C. In the high-pressure compressor, the air is then compressed from 10 bar to 100 bar.

The advantages of the second configuration are 1) that the lower temperatures allow for using existing industrial compressors and turbines for the first stage of air compression, and 2) that this lower pressure after the first compression stage allows for shorter response times, i.e. the storage unit is more flexible in terms of ramp-up and -down. Both system configurations exhibit a nominal discharge capacity of 100 MW and an energy storage capacity of 500 MWh. This means that the second storage cavity must have a volume of around 177’000 m^3, corresponding to a cube with an edge length of about 56 m. Using existing caverns from the Swiss army no longer in use has been investigated, but these are too small and required extensions do not offer economic benefits compared to new constructions. Drilling new caverns is not supposed to represent a major challenge, since corresponding know-how is available, e.g. from tunnel construction for railway lines.

Key component for an AA-CAES unit is the thermal energy storage, with constant energy release, low costs and low energy losses as key requirements. A combination of one sensible and one latent TES turned out to fulfill the operational requirements in the best way. The sensible TES consists of a concrete basin filled with gravel, while the latent TES is more complex: steel tubes containing an alloy of aluminum, copper, and silicon. This alloy melts at a temperature of 525°C and takes up thermal energy, which is released when changing to solid state. This change to solid state while releasing thermal energy happens at a constant temperature level, which stabilizes the air temperature during discharge. Splitting up the entire TES into smaller units comes with the advantages of higher structural flexibility and also flexibility regarding regulation of the air stream to ensure a constant discharge load and stable electricity generation by the turbine.

Both experiments and test sites as well as process simulation suggest that an AA-CAES unit such as the one investigated would reach energy efficiencies (electricity-to storage-to electricity) of 65-75%. System lifetime is estimated to be 60 years.

Further technology-related research must address the long-term stability and airtightness of the underground air storage caverns as well as the ability to provide constant power outputs.

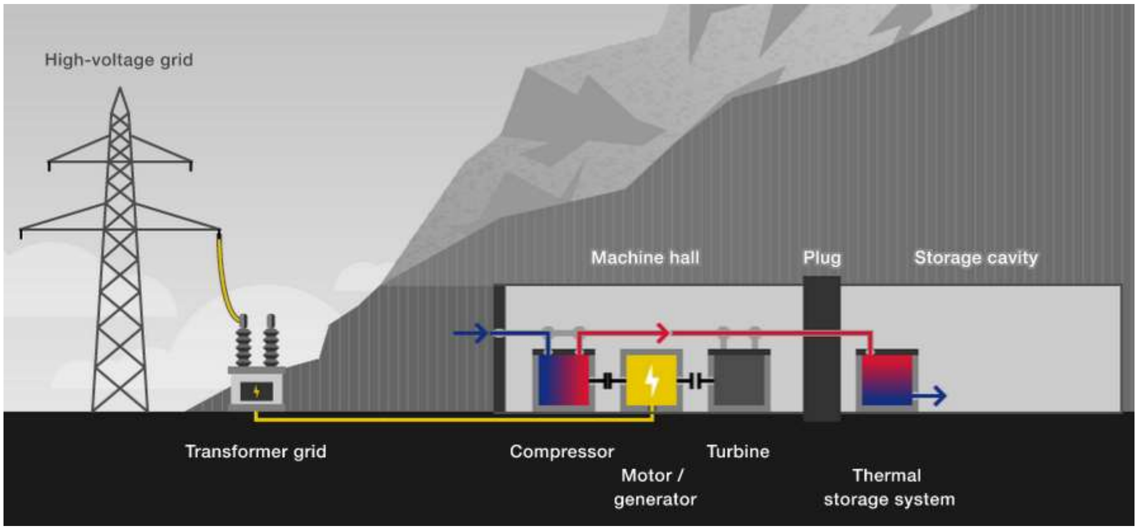

Figure 17.1: Schematic diagram of an AA-CAES system with a storage cavity in the rock. Blue and red indicate low (e.g., around 20°C) and high temperatures, with "high temperatures" between 320°C and 580°C depending on the system design. The blue and red arrows show the flow direction of the air during the charging phase. During the discharge phase, the air flows are reversed (Haselbacher et al., 2019).

17.2 Costs

Since AA-CAES is still at the prototype demonstration stage (TRL 6), cost data are associated with considerable uncertainties.

CAPEX for a 100 MW/500 MWh AA-CAES plant in Switzerland are estimated to amount to about 110 million CHF, which corresponds to 200-300 CHF per kWh of installed storage capacity. Annual operating costs amount to approximately 2.5% of the CAPEX (Haselbacher *et al.*, 2019). Figure 17.2 shows the breakdown of CAPEX into specific components. Construction work, including the construction of the access tunnel, the storage cavities, the closure plug and the sealing mechanism, accounts for more than half. Turbomachinery accounts for 32%, and the TES for 6%. Comparison of these investment costs with other electricity storage technologies must take into account the system lifetime of 60 years.

A profitable operation of such an AA-CAES system on the Swiss market for secondary reserve power might be possible assuming optimal part load behaviour of the system, but needs to be further investigated. One obstacle hampering cost-effective operation is the AA-CAES, as other electricity storage units except of pumped hydro storage, are considered as electricity consumers and thus have to pay grid fees.

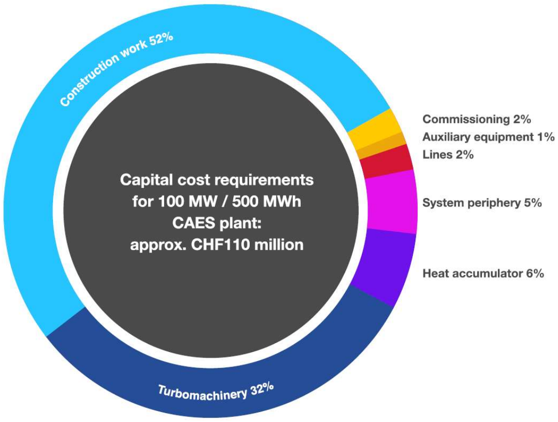

Figure 17.2: AA-CAES CAPEX – Relative shares of various components in the capital costs of an AA-CAES plant with an output of 100 MW and an energy storage capacity of 500 MWh. Costs for electrical components such as motors and generators are included under "System periphery" (Haselbacher et al., 2019).

Investment costs (CAPEX) of 580 million € with annual OPEX of 19.6 million € (3.4% of CAPEX) have been estimated for the planned unit in the UK with a power of 540 MW and an energy storage capacity of 2.5 GWh, corresponding to around 250 CHF/kWh.[65]

Economic assessments of AA-CAES are rare. An analysis for China reports total investment of AA-CAES system with a discharge power of 10 MW and a capacity of 80 MWh of around 11 million CHF, corresponding to ca. 140 CHF/kWh (Andrey *et al.*, 2020). Since construction work in China is expected to be considerably cheaper than in Switzerland, the costs per kWh storage capacity seem to be consistent. A recent review of thermo-mechanical energy storage technologies provides cost ranges for adiabatic CAES of 20-220 US$/kWh and 970-1200 US$/kW (Olympios *et al.*, 2021).

Future cost developments for AA-CAES is hard to estimate, since current cost estimates would have to be verified building a large-scale plant and operating it for some years. However, the breakdown of the CAPEX suggests limited cost reduction potential, since construction work as such would hardly profit from learning and the same holds somewhat true for the turbomachinery, which represents existing technology. A conservative, but not unrealistic assumption would be to keep AA-CAES costs constant when extrapolating into the future.

17.3 Environmental burdens

Life Cycle Assessment (LCA) of AA-CAES shows a comparatively good environmental performance for storage of clean electricity, similar to the one of pumped hydro storage (Figure 17.3). Advantages of AA-CAES are the lack of major construction related interventions above ground and associated land use – neither storage dams, nor reservoir lakes are required – and the rather simple technology, which does not rely on scarce metals. However, compared to PHS and batteries, storage efficiency is lower. Thus, in order to contribute to a reduction of GHG emissions in an effective way, stored electricity should be associated with low GHG emissions.

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[65] https://tyndp.entsoe.eu/tyndp2018/projects/storage_projects/1022 (5.1.2021)

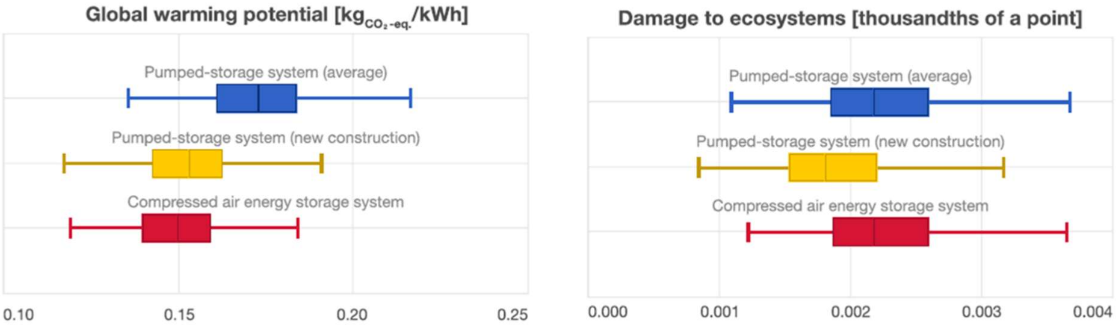

Figure 17.3: LCA-based environmental burdens due to electricity storage with AA-CAES compared to PHS (per kWh of discharged electricity). Left: life-cycle GHG emissions; right: damage to ecosystems, quantified according to the ReCiPe method (Haselbacher et al., 2019). Swiss electricity supply mix is used for charging storage units. Ranges shown represent uncertainties and potential location-specific differences.

18 Other electricity storage technologies

There are other technologies for electricity storage besides those covered by the previous sections 15 to 17. For example, several concepts for gravity-based electricity storage are being developed by a few companies such as Gravitricity, Energy Vault, and Gravity Power (O'Grady, 2021). However, since they are all still at an early stage of development, reliable performance data are not available and therefore, these technologies have not been addressed within this analysis. Future work should however include such novel concepts, since they are technically relatively simple and first cost estimates are promising (O'Grady, 2021).

19 References

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Appendix

20 Photovoltaic electricity generation: update on potential and costs

20.1 Introduction

Renewable electricity produced from solar photovoltaics (PV) plays an important role in the current global energy transition. By the end of 2019, a total of 620 GW_p of solar PV systems were installed worldwide, with an annual installed capacity of 115 GW_p – an increase of 12% in comparison with 2018 (International Energy Agency (IEA), 2019). Reviewing some of the major projections published in worldwide in 2014/2015, the path that the world is currently on in terms of global cumulative PV installed capacity is among the most optimistic projections back then (Figure 20.1).

The installation of Solar PV systems has grown rapidly and it currently generates electricity that contributes to 3% of the global electricity generation (International Energy Agency (IEA), 2019), while in some countries such as Germany, this share in 2019 was already at 8% (Fraunhofer Institute for Solar Energy Systems, 2020). Meanwhile, the sector has developed rapidly in the last decade due to this scaling effect. According to the a recent report from International Renewable Energy Agency (IRENA), a 82% drop in global average levelized cost of electricity (LCOE) has been observed for electricity produced from utility-scale solar PV system between 2010 and 2019 (International Renewable Energy Agency (IRENA), 2021).

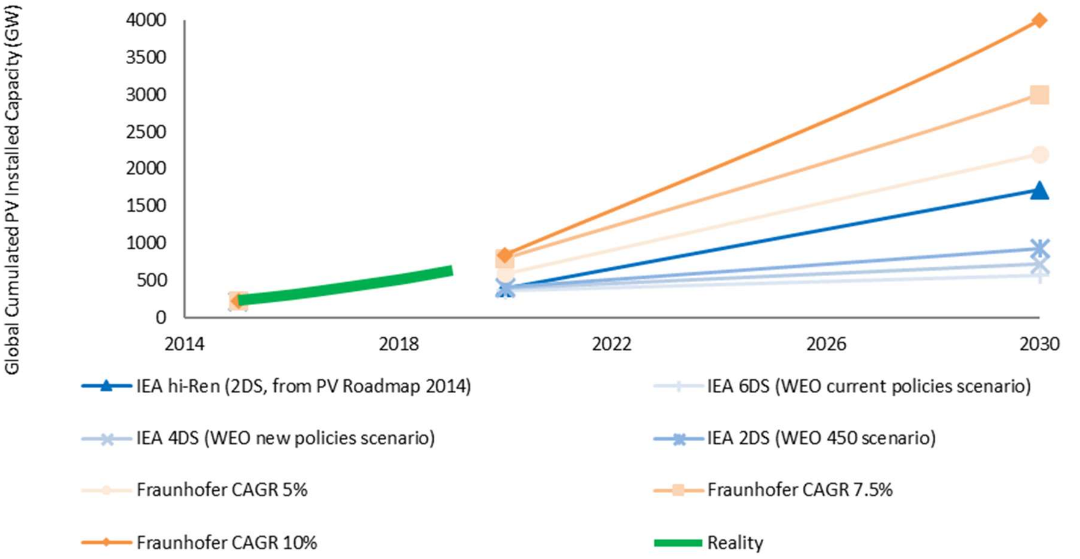

Figure 20.1: Global cumulated PV installed capacity: reality (Statista, 2020) vs. projections by scenarios from IEA, WEO, Fraunhofer in 2014/2015 (Bauer et al., 2017)

A strong growth has been observed in Switzerland. In 2020, 2’973 MW_p (DC) of installed PV systems has generated 2’599 GWh of electricity, which corresponds to about 4% of the current national electricity consumption (Kaufmann, 2021).

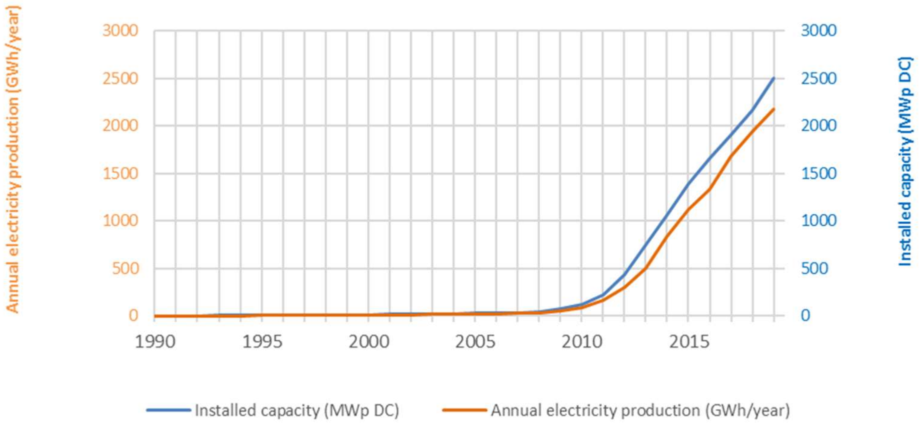

Figure 20.2: Cumulated installed capacity and annual electricity generation of solar PV systems in Switzerland, 1990-2019 (Kaufmann, 2021)

Solar PV is expected to play a key role in the national energy transition. In the Swiss energy perspectives published in 2013, solar PV is expected to supply up to 6 to 11 TWh of electricity by year 2050 depending on the selected scenario (Bundesamt für Energie (BFE), 2013). In the latest update of the energy perspectives, a more ambitious goal of reaching climate neutrality by 2050 is set, hence the projected amount of electricity generation from solar PV has increased to 34 TWh/a, which corresponds to 40% of the current total national electricity production (Swiss Federal Office of Energy, 2020).

20.2 Annual Generation Potential

The annual generation potential from solar PV has been analyzed by various parties. Using data from “Sonnendach.ch”, the Swiss Federal Office of Energy estimated up to 50 TWh per year of electricity generation from rooftop building PV systems (BAPV), and 17 TWh from façade installations on buildings (SFOE, 2019). This BAPV potential, however, seems to be a relatively rough estimation (e.g., applying a generic factor of 70% of rooftop area available for PV modules), not taking into account some specific factors in real implementation that may further reduce the generation potential from solar PV. When more factors such as temporal variation of solar irradiation, roof geometry and superstructures, as well as correlation between PV module efficiency and temperature are considered, BAPV systems are estimated to generate up to 24 (+/- 9) TWh per year according to another recent study (Walch *et al.*, 2020). Comparing the estimates from (SFOE, 2019) and (Walch *et al.*, 2020) reveals that the higher annual generation potential quantified by SFOE is mainly due to higher figures for total available area on roofs (439 km^2 vs. 267 km^2) and the percentage of total roof surface that is suitable for installing PV (71.6% vs. 56.4%) used in the quantifications, while both estimates are based on very similar annual tilted irradiation and system efficiencies (Walch *et al.*, 2020).

When the generation from solar PV contributes a significant share of the Swiss total generation, grid infrastructure and storage might be a factor limiting growth that has to be taken into account to provide a realistic potential estimate. Another recent study (Gupta, Sossan and Paolone, 2021) has considered this aspect and reached an estimate of 33 TWh a year for rooftop installations.

However, recent analysis suggests to use not only roofs of existing buildings, but to exploit the PV potentials in mountain areas (Kahl, Dujardin and Lehning, 2019; Dujardin, Kahl and Lehning, 2021). This could partially shift the summer generation peak to winter and increase annual yields in general, since higher altitude, reflections from snow cover, and lower temperatures both increase PV yields. Within this report, such installations are not further discussed, since associated cost estimates are largely missing. (Dujardin, Kahl and Lehning, 2021) provide an estimate of the available area for PV installations in mountain areas based on a GIS analysis and accounting for accessibility and potential issues regarding social acceptance by defining several “exclusion criteria” for land surface on which PV modules are unlikely to be installed (e.g., at elevations above 2700 meters). This analysis results in approximately 150 km^2 useable area on roofs (very similar to the estimate of (Walch *et al.*, 2020)) and around 450 km^2 on open ground. Based on this estimate, ground-mounted PV installations could exhibit an annual generation more than three times higher than the one of roof-top installations.

20.3 Current costs in Switzerland (BAPV)

When considering the cost of solar PV, a common perception is the dramatic drop of costs in recent years, which is often associated with the low price of electricity (e.g. 4-6 Euro cents/kWh) for grid-connected MW-scale PV plants (Fraunhofer Institute for Solar Energy Systems, 2020) with power purchase agreement (PPA) in e.g. Germany. In countries like the US, 40% of utility-scale solar PV systems have already reached lower costs than the cheapest fossil fuel alternative (International Renewable Energy Agency (IRENA), 2021). In Germany, there has been unsubsidized PV projects based on PPA (Diermann, 2020), and similar trend has been observed in China. However different from these countries, where PV systems of more than 1 MW$_p$ play a major role of driving the growth (U.S. Energy Information Administration, 2019), in 2019, only 43% of the installed capacity in Switzerland is contributed by systems of more than 100 kW$_p$ (Hostettler, 2019), whereas in Germany, this has reached 51%, with possibly a much higher share of systems of more than 500 kWp (Figure 20.3).

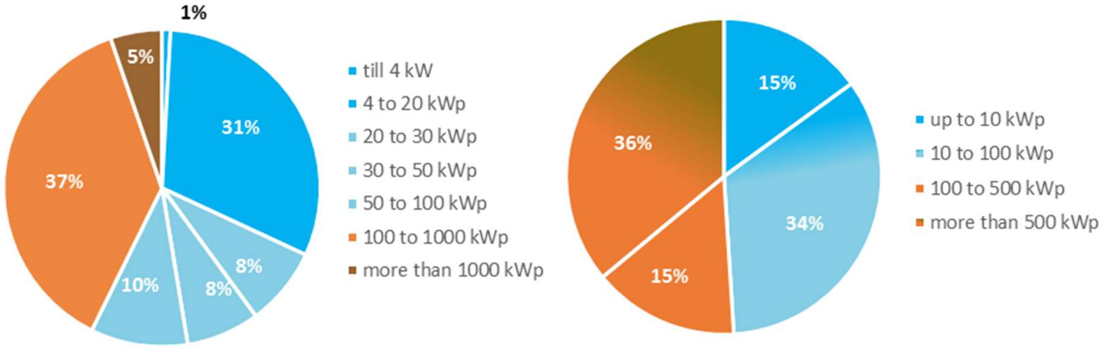

Figure 20.3: Share of installed capacity by system size in Switzerland[66] (left) (Hostettler, 2019) and Germany (right) (Fraunhofer Institute for Solar Energy Systems, 2020)[67] in 2019.

In terms of the number of installed systems, systems of more than 100 kWp only contribute to 3% of all the installed systems, while systems with a size from 4 to 30 kW$_p$ contribute to 89% of the installed systems (Hostettler, 2019). This indicates that 43% of contribution in the overall installed capacity is contributed by very limited number of large-scale systems, and the growth of solar PV in Switzerland has been mostly dominated by small-scale applications such as for single family house, which usually has an installed capacity of less than 10 kW$_p$ (Fraunhofer Institute for Solar Energy Systems, 2020).

Since the size of a PV system is closely related to its investment cost (Fraunhofer Institute for Solar Energy Systems, 2020), and the installed systems in Switzerland have been mostly focused on small- (e.g. for single- and multi-family house) rather than utility-scale applications, it is crucial to differentiate the PV cost development in Switzerland from other countries, while keeping a close monitoring on it. Based on the capital investment costs from 772 BAPV systems offers in Switzerland in 2020 (Swiss Federal Office of Energy, 2021), Figure 20.4 shows that most of the systems are concentrated on a size of less than 30 kW$_p$.

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[66] Only grid-connected systems are included, as the total installed capacity of island-systems is insignificant, of less than 0.1%.

[67] Due to different categorization of size ranges in the available data, the breakdown by size between Switzerland and Germany are not directly comparable, but the color codes are adjusted for easier association.

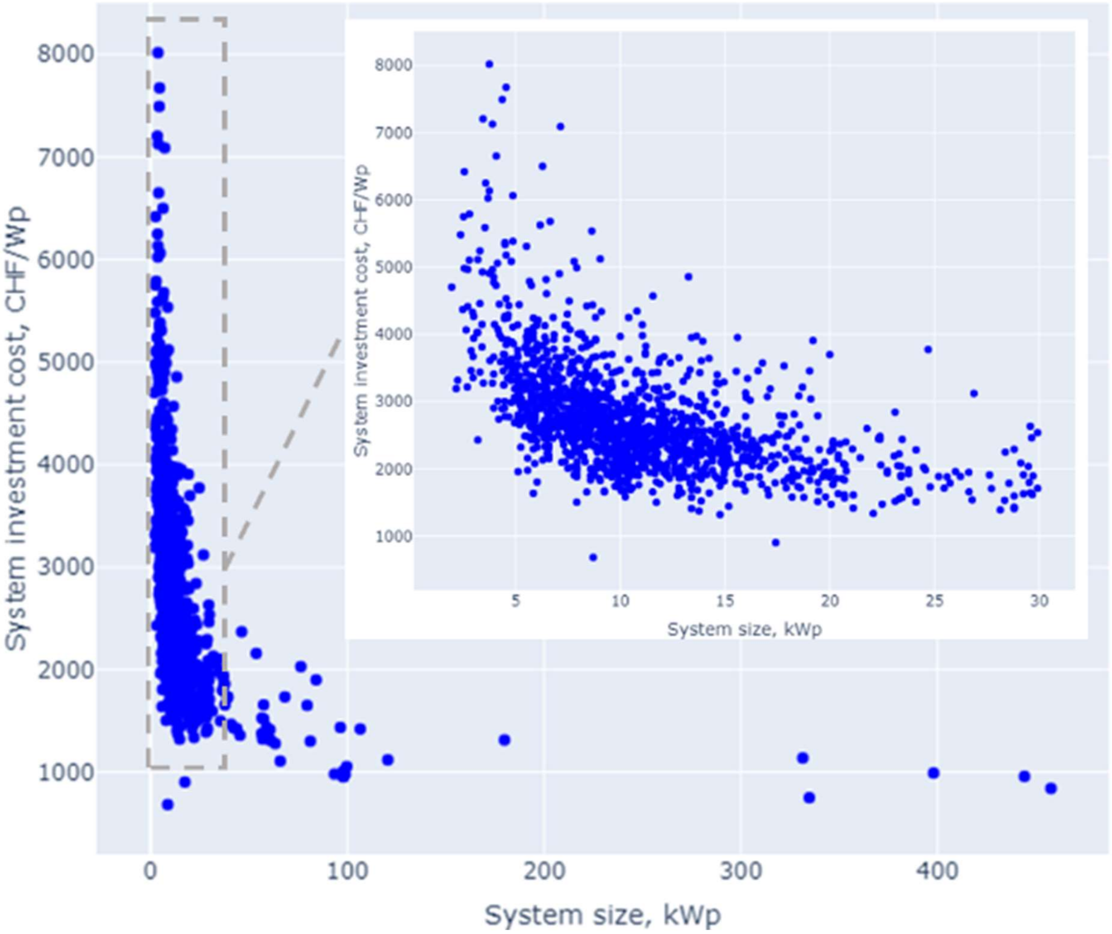

Figure 20.4: BAPV system investment cost offers in Switzerland, 2020 (Swiss Federal Office of Energy, 2021).

Figure 20.5 shows that the system investment costs by size range based on the BAPV systems offers from 2015 to 2021 (until Jan 2021; whenever 2021 is referred to hereafter, it stands for until Jan 2021). For systems less than 20 kW_p, a clear decreasing trend of median system investment costs can be observed from 2015 to 2020, while the higher range of costs for systems less than 10 kW_p has increased a bit in 2020 (and 2021), likely due to the impact of shortage in material supply due to the pandemic. The decreasing trend is less obvious for systems of larger size. It also shows that the smaller the system size is, the more pronounced the cost decrease is throughout the years. Interestingly, more outliers can be seen in more recent years than previously for system size from 6 to 10 kW_p (a common range of system size that is installed in single family houses). Since the data sampled from these offers are mostly for small-scale systems of less than 100 kW_p, system investment costs used in this analysis for larger systems are based (Sauter and Jacqmin, 2020) (Table 20.1).

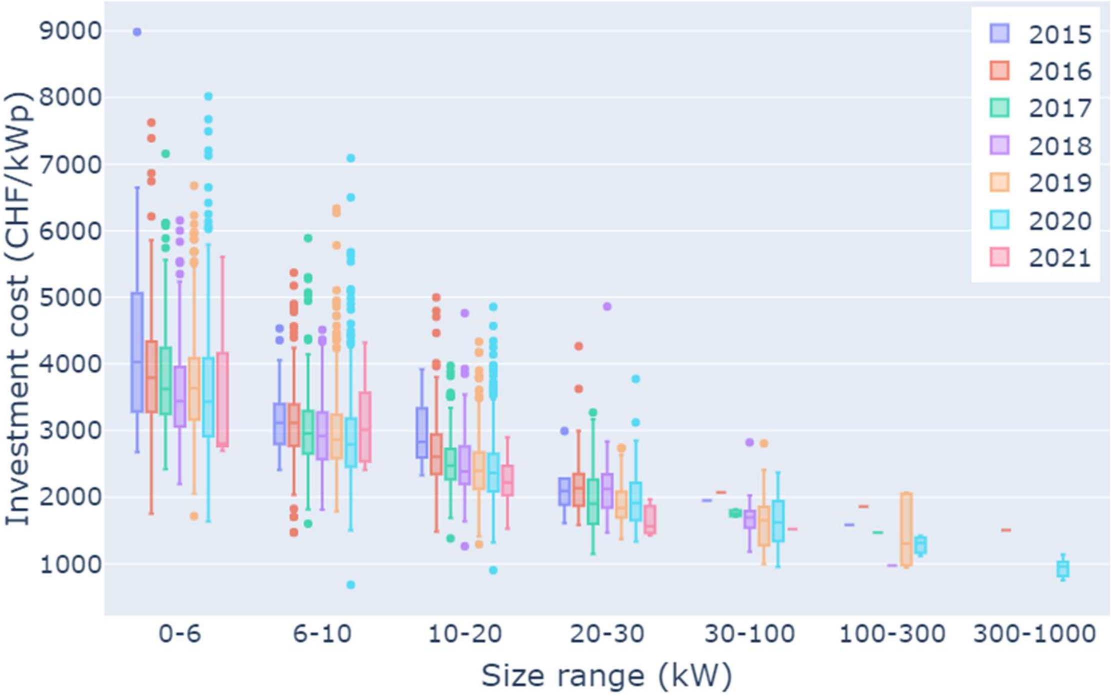

Figure 20.5: Distribution box plot[68] for selected BAPV system investment costs by system size in Switzerland from 2015 to January 2021 (Swiss Federal Office of Energy, 2021).

A more detailed breakdown of these system investment costs by their different installed regions in Switzerland is shown in Figure 20.6, in which reference points from the German-speaking region are the majority. It can be seen that the systems with a size of more than 100 kW$_p$ are all from the German-speaking region, and the German-speaking region has the highest system investment cost, followed by the French- and Italian-speaking regions. The German-speaking region has also more outlier reference points than the other two regions. For the differences and number of outliers throughout the years as well as between regions, more detailed investigation is required and worth better understanding.

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[68] Definition of box plot: https://en.wikipedia.org/wiki/Box_plot

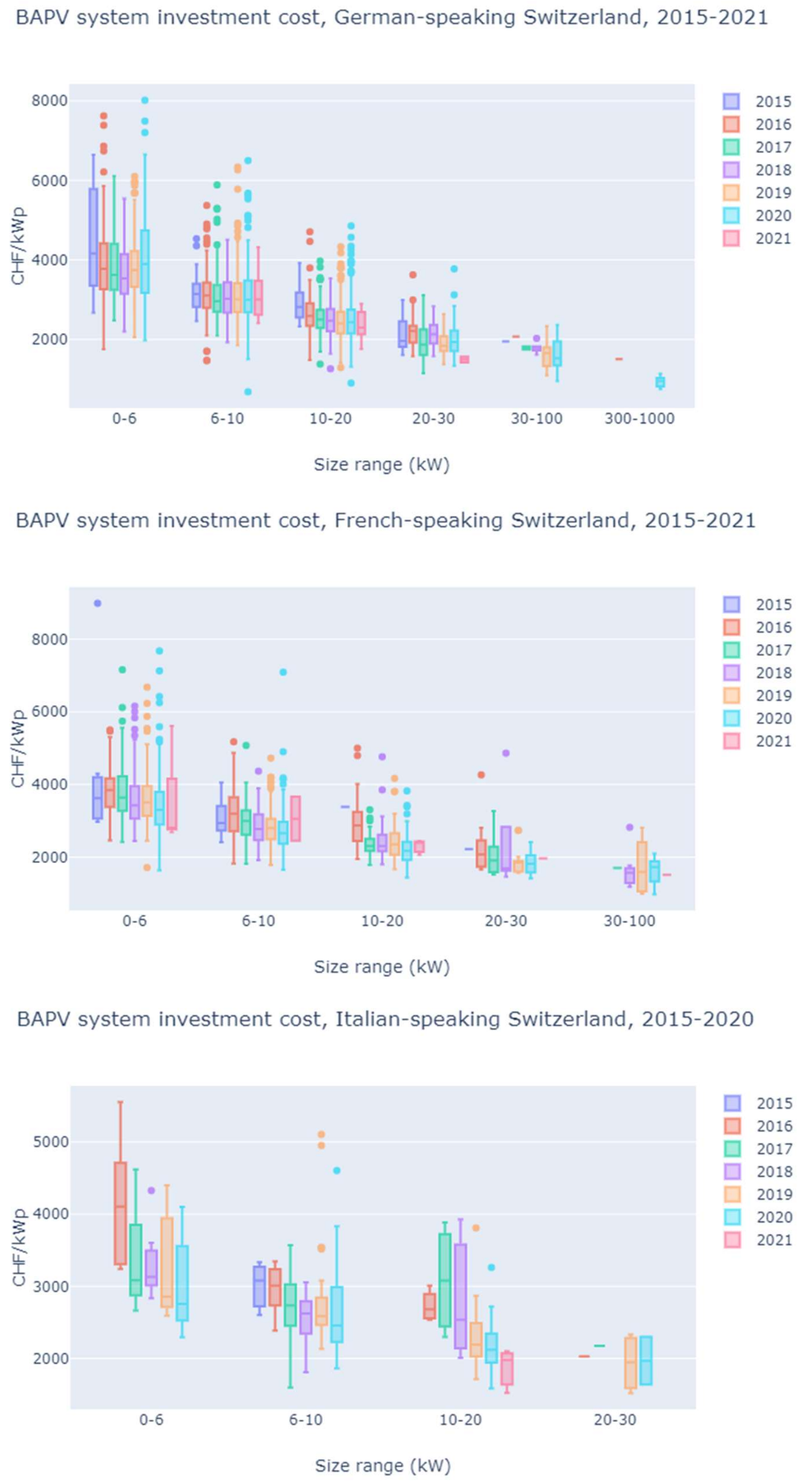

Figure 20.6: Distribution box plot[69] for selected BAPV system investment costs by system size for the German- (501 data points), French- (223 data points) and Italian-Speaking (48 data points) part of Switzerland from 2015 to 2021 (Swiss Federal Office of Energy, 2021).

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[69] Definition of box plot: https://en.wikipedia.org/wiki/Box_plot

In comparison with the system capital investment costs for small-scale rooftop PV systems (i.e. systems up to 10 kW_p) in Germany of about 1600-1850 EUR/kW_p in 2019 to 2020 (PV magazine Deutschland, 2019) (Solaranlagen-Portal, 2020), the median system investment costs in Switzerland from 2020 to 2021 (about 3100 CHF/kW_p) are around 63% higher than in Germany, while the minimum system capital costs in both countries are on a comparable level at around 1500-1630 CHF/kW_p. Capital investment cost for systems of a size from 10-100 kW_p is around 1950 CHF per kW_p in Switzerland from 2020 to 2021, which is about double the average cost of PV system ranging from 10-100 kW_p in Germany in 2019 (1050 EUR/kW_p) (Simon Philipps and Warmuth, 2020). Capital investment cost for systems from 300 kW_p to 1 MW_p is around 1000 CHF/kW_p in Switzerland from 2020 to 2021 (Swiss Federal Office of Energy, 2021). For systems with a size from 10-100 kW_p, the percentage of module cost is 45% in Germany (Fraunhofer Institute for Solar Energy Systems, 2020), while this is slightly less than 30% in Switzerland.

In general, the system capital investment costs for small-scale PV systems in Switzerland remains to be high in comparison with the costs in Germany. Given the above cost breakdown by components, it shows both the costs for modules and other costs in Switzerland are higher, but the latter contributes even more to the cost difference, which is possibly due to the higher profit margin, administrative and labor costs in Switzerland. To facilitate further increased deployment of PV systems in the future, it is worthy to systematically look into the cause behind these higher costs and formulate policy to reduce them.

Annual O&M cost has further decreased and according to a latest study in 2018 (Toggweiler, 2018): 3 Rp. per kWh of electricity produced for system of less than 100 kW_p, and 2 Rp/kWh for systems above 1 MW_p, including both the replacement of inverter and BOS components. Other key assumptions for the calculation of current LCOE in Switzerland are listed in Table 20.1.

The LCOE for different sizes of BAPV systems are shown below: median LCOE in Figure 20.7 and their distribution based on single offers in Figure 20.8. Since the interest rate for PV systems – especially for small systems (e.g., PV system installed for single family house)[70] – might be lower than the one applied for other power generation technologies[71], two sets of results are provided here for both interest rates (5% and 2%). The LCOE ranges (without considering outliers for the small capacities) from 7-26 Rp/kWh with interest of 5%, or 6-19 Rp/kWh with interest of 2%.

Given the remuneration of mostly less than 10 Rp/kWh when PV generation is fed into the grid[72], as well as the grid electricity price of mostly more than 15 Rp/kWh (e.g., for single family house with about 7500 kWh of consumption per year, category H5)[73], for small-scale applications (capacities below 10 kW_p), two conclusions can be drawn: first, the LCOE from PV is still most often more expensive than grid supply (note here the tax reduction is not taken into account because sustainable long-term of PV rollout need to be subsidy-free); second, self-consumption should be highly encouraged, as once PV system is installed and electricity is generated, it is economically more beneficial to consume it as much as possible to meet electricity demand of the owner, avoiding buying electricity from the grid rather than selling it to the grid.

Table 20.1: Overview of key parameters for current LCOE calculation.[74]

Data (general reference)	Key assumptions used in calculating current LCOE (specific reference)
Current system investment cost (Swiss Federal Office of Energy, 2021) (Sauter and Jacqmin, 2020)	Systems up to 100 kW_p: system capital costs data provided by SFOE in April 2021 (median value based on offers in 2020 and Jan 2021) (Swiss Federal Office of Energy, 2021) • 0-6 kW_p: 3430 CHF/kW_p

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[70] For example, Helion provides solar PV system with 2.9% of interest rate: https://www.helion.ch/solaranlage/solaranlage-finanzierung/

[71] An interest rate of 5% is used as baseline for all other technologies in this report.

[72] https://www.vese.ch/pvtarif/

[73] https://www.strompreis.elcom.admin.ch/Map/ShowSwissMap.aspx: for year 2020, category H5, total price for standard product.

[74] Assumption with no reference provided indicates own-assumptions of the authors.

<table>
<tr><td></td><td>• 6-10 kW$_p$: 2790 CHF/kW$_p$
• 10-20 kW$_p$: 2360 CHF/kW$_p$
• 20-30 kW$_p$: 1910 CHF/kW$_p$
• 30-100 kW$_p$: 1590 CHF/kW$_p$

System capital costs for PV installations with capacities above 100 kW$_p$ are based on (Sauter and Jacqmin, 2020):
• 100-300 kW$_p$: 1283 CHF/kW$_p$
• 300-1000 kW$_p$: 1060 CHF/kW$_p$
• More than 1000 kW$_p$: 780 CHF/kW$_p$</td></tr>
<tr><td>Percentage breakdown of current system investment cost by module, inverter, BOS (structure), administration, planning and construction site protection costs (Sauter and Jacqmin, 2020)</td><td><table>
<tr><th>kW$_p$</th><th>0-6,
6-10</th><th>10-20,
20-30</th><th>30-100</th><th>100-300</th><th>300-1000,
>1000</th></tr>
<tr><td>Module</td><td>19%</td><td>25%</td><td>30%</td><td>32%</td><td>34%</td></tr>
<tr><td>Inverter</td><td>11%</td><td>9%</td><td>8%</td><td>8%</td><td>9%</td></tr>
<tr><td>BOS (structure)</td><td>10%</td><td>12%</td><td>12%</td><td>10%</td><td>8%</td></tr>
<tr><td>Administration, planning and construction site protection</td><td>17%</td><td>14%</td><td>11%</td><td>13%</td><td>11%</td></tr>
<tr><td>Other</td><td>43%</td><td>40%</td><td>39%</td><td>36%</td><td>38%</td></tr>
</table></td></tr>
<tr><td>Annual O&M cost (Bauer *et al.*, 2019)</td><td>Based on (Toggweiler, 2018), including replacement cost:
• small systems (<=100 kWp): 3 Rp/kWh
• large system (> 100 kWp): 2 Rp/kWh for</td></tr>
<tr><td>Decommissioning cost (Bauer *et al.*, 2017) (Simon Philipps and Warmuth, 2020)</td><td>• Cost for decommissioning labor: 50% of labor cost in system capital investment
• Cost for disposal is assumed to equal to the residual value of the entire system (providing the system at the end-of-life as a valuable waste is sufficient to finance its decommissioning).</td></tr>
<tr><td>Other key assumptions</td><td>• Annual avg. yield: 1013 kWh/kW$_p$ (Vontobel, Nordmann and Lingel, 2016)
• Performance ratio: 80% (Vontobel et al. 2018)
• Area required per kW$_p$ installation: 6 m^2/kW$_p$ (suggested by SFOE, Oct 2018)
• Average module efficiency: 17% (Simon Philipps and Warmuth, 2020)[75]
• Average annual solar irradiance: in order to match the yield above: 1267 kWh/m^2/year of annual solar irradiance has to be assumed (reference: Mittelland: 1100 kWh/m^2/year; Swiss Alps: 1400-1600 kWh/m^2/year)
• Annual electricity production degradation rate: 0.15% (Wirth, 2021)
• Average inverter efficiency: 98%
• Lifetime: 30 years
• Interest rate: 5% & 2%</td></tr>
</table>

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[75] Although according to (Wirth, 2021), the efficiency of new silicon-based PV modules on the German market today is about 20%, to be consistent with the assumption used in (Walch *et al.*, 2020), which is referred to in the analysis in section 20.5, the module efficiency is assumed to be 17%. This figure therefore represents a conservative assumption, which, however, does not have an impact on the calculated LCOE.

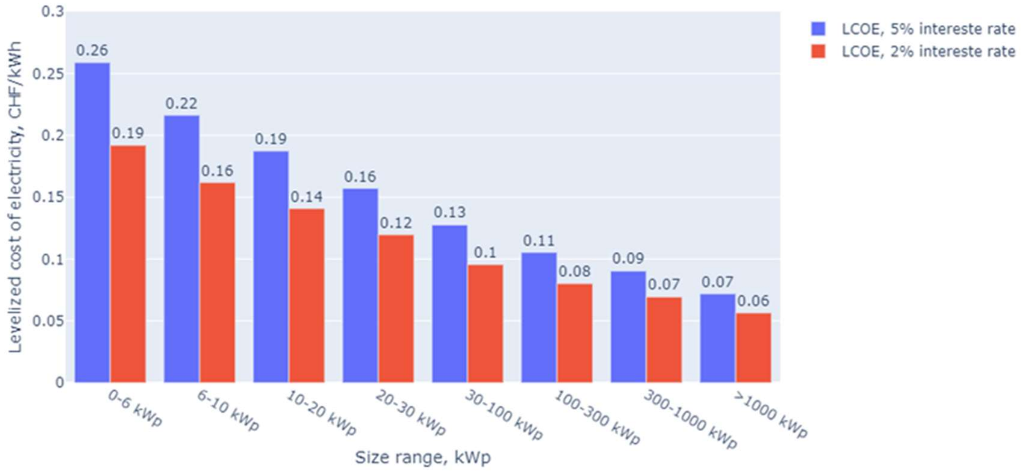

Figure 20.7: Median LCOE for rooftop PV systems by various size range in 2020 (and January 2021) considering two different interest rates, based on assumptions listed in Table 20.1.

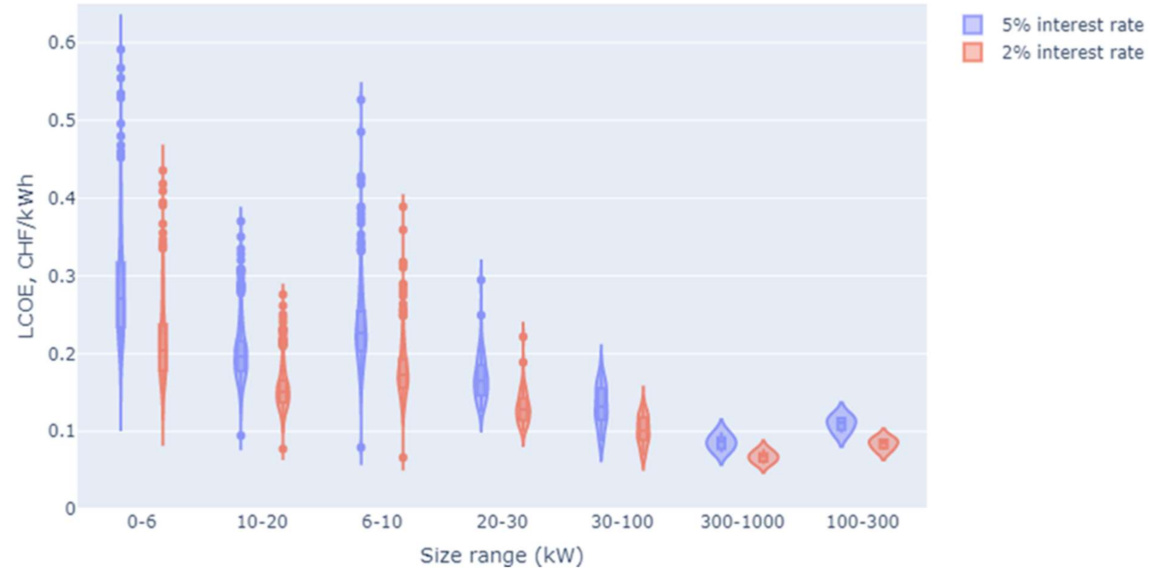

Figure 20.8: LCOE distribution for rooftop PV systems by various size ranges in 2020 (and January 2021) considering two different interest rates, based on assumptions in Table 20.1.

20.4 Future costs in Switzerland (BAPV)

Base on cost development by component either due to learning or future efficiency improvement, future LCOE for the BAPV systems were projected in 2017 and are shown in Figure 20.9 (Bauer *et al.*, 2017). It shows that in 2050, depending on the system size, LCOE can reach 4-16 Rp/kWh, which is quite cost competitive given the current standard electricity tariff of 12-24 Rp/kWh for commercial and industrial customers, and 17-28 Rp/kWh for households in Switzerland[76], as well as the likely increase of electricity prices in the future (Panos and Densing, 2019). A closer investigation on the driven factor for future LCOE reduction shows essential role of module price for all system sizes, despite its steadily decreasing percentage contribution in the overall system capital investment cost (Bauer *et al.*, 2017).

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[76] Electricity tariff in Switzerland by region: https://www.strompreis.elcom.admin.ch/Map/ShowSwissMap.aspx (accessed in Sep 2020)

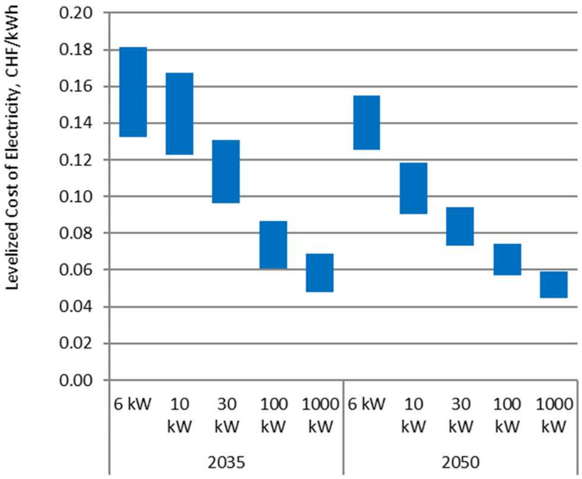

Figure 20.9: Range of future LCOE for electricity generated from PV systems in Switzerland, 2035-2050 (Bauer *et al.*, 2017) (5% interest rate).

20.5 Annual electricity production potential vs. levelized cost of electricity (LCOE)

Based on the data for all individual rooftops for the entire Switzerland[77] and the new estimates for PV module costs, efficiencies and other parameters, associations can be made between LCOE and electricity generation potential, to better understand the realistic potential that could be possibility achieved in the future (Bauer *et al.*, 2019). In this previous analysis, estimates based on 100% and 70% availability of rooftop areas were made in order to take into account the potential obstacle structure on roofs that may reduce the generation potential. The approach applied, however, is subjective to high uncertainties, as potential competing use of rooftops (e.g., for solar thermal heat collectors, area occupied by super-structure such as chimneys, etc.) is not taken into account. A recent new study by Walch an colleagues (Walch *et al.*, 2020) was published, which addresses some of these limitations, thus the analysis carried out in (Bauer *et al.*, 2019) has been improved by taking more realistic estimates of available roof area and annual electricity generation potential from (Walch *et al.*, 2020). This new evaluation is limited to rooftop installations only – installations on facades are not considered due to lack of precise information.

Figure 20.10 and Figure 20.11 show the potentials vs. LCOE considering current system capital investment costs in 2020 and January 2021 as well as current PV performance data[78] (as updated in this analysis) and improved estimates for rooftop areas from (Walch *et al.*, 2020). In addition to applying more realistic available area and annual electricity generation potential as the basis for LCOE and potential estimates, another improvement compared to the previous analysis is the additional consideration of roofs grouped by building (i.e., by “SB_UUID” in (Swisstopo Federal Office of Topography, 2019)). Not considering this aspect (i.e., separate individual roofs (as in the raw data in the Sonnendach) as opposed to one large roof for the same building) resulted in overestimates of LCOE for some buildings before.

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[77] www.sonnendach.ch

[78] See Table 20.1. Considering the latest information according to (Wirth, 2021) regarding PV module efficiency and associated area required per kW_p,, the figures used for the present estiamtes (17% and $6m^2/kW_p$) represent conservative assumptions. With a continuous expansion of PV installations over the coming years, these will profit from cost reductions and improved performance – thus, the LCOE vs. generation potential curves will shift towards up left, as discussed in (Bauer *et al.*, 2019).

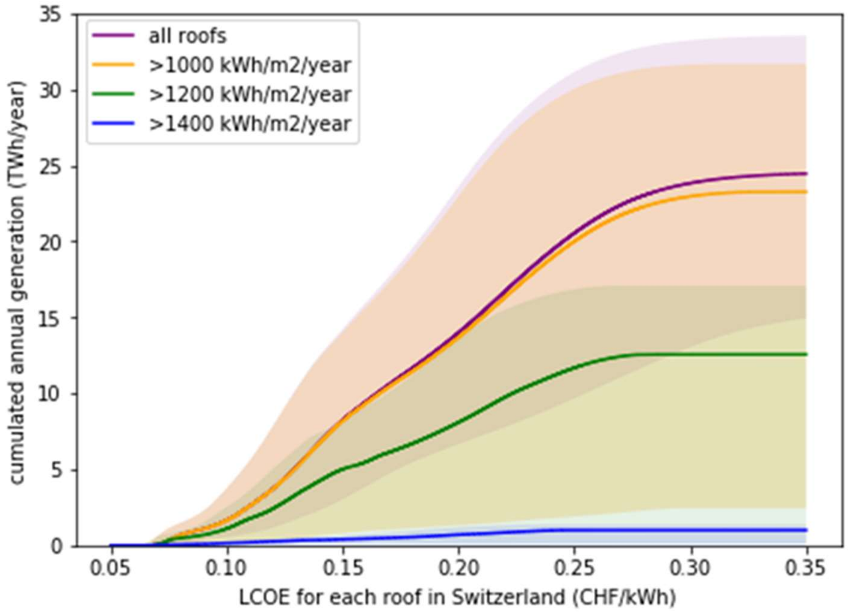

Figure 20.10: Annual electricity generation potential calculated by PSI vs. LCOE for all roofs and tilted solar irradiance (considering shading effect) of more than 1000, 1200 and 1400 kWh/m²/year, based on system capital investment costs in 2020 and January 2021 (Table 20.1) and improved estimates for available rooftop area and annual electricity generation potential from (Walch *et al.*, 2020), considering uncertainties of annual generation potential and available area: average (average; average + standard deviation; average - standard deviation[79], which corresponds to an annual generation potential of 24±9 TWh of annual electricity generation in the entire Switzerland).

It shows that the curve greatly flattens when LCOE is more than 25 Rp/kWh, indicating the majority of this potential could be achieved with a LCOE of less than this. The lowest LCOE is about 6 Rp/kWh on the largest roofs, which is comparable with the current electricity tariff and the feed-in tariff[80] (mostly from 6-8 Rp/kWh, with very few municipalities providing up to 12-15 Rp/kWh or less than 6 Rp/kWh) in Switzerland. Given the electricity tariff in Switzerland from 17 to 25 Rp/kWh[81], this shows that self-consumption should be prioritized over the feed-in to the grid in order to improve the economic attractiveness of the installed systems. With increasing demand for grid flexibility in the future to accommodate more renewable electricity, the charge dedicated to grid service in the electricity tariff are very likely to increase in the future (Panos and Densing, 2019), as it has been observed in Germany in the past decade[82]. This will make the self-consumption of PV even more economically attractive in the future. When uncertainty of annual generation potential, area and tilted solar radiation are not considered (Figure 20.11, solid line, all roofs), more than 90% of the generation potential comes from the roofs which have tilted solar radiation of more than 1000 kWh/m²/year (comparing the orange and purple line, Figure 20.10), while the potential for roofs with more than 1400 kWh/m²/year of tilted solar radiation is negligible and the amount of its potential is already realized today. This means that the deployment of rooftop solar PV systems should not only be limited to the roofs with high solar irradiance. When standard deviation for these parameters are considered (shaded areas, Figure 20.10 and Figure 20.11), the solar radiation exhibits very high uncertainty, with the higher-bound potential for all roofs (without considering façade installations) matching roughly with the projection for solar PV potential of 34 TWh/year in the latest climate-neutral Swiss energy perspective scenario (Kirchner *et al.*, 2020). The lower-bound potentials for roofs with a specific solar irradiance level exhibit very

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[79] When average value – standard deviation is considered, about 0.3% of buildings' area and/or annual generation are negative. These buildings are excluded.

[80] Interactive map of grid feed-in tariff for PV systems with more than 10 KVA capacity: https://www.vese.ch/pvtarif/#MapTitle

[81] Total price of electricity tariff in Switzerland in 2020 https://www.strompreis.elcom.admin.ch/Map/ShowSwissMap.aspx?CatID=4&CantonBez=GL&View=0&Period=2021&ProdID=10

[82] Electricity prices for households in Germany: https://www.statista.com/statistics/418078/electricity-prices-for-households-in-germany/

high uncertainties. Since the lower-bound potentials are estimated with the worst-case assumptions combined, it is very unlikely that these potentials will reflect the reality. Instead, they serve as the most conservative estimates for lower-bound potential.

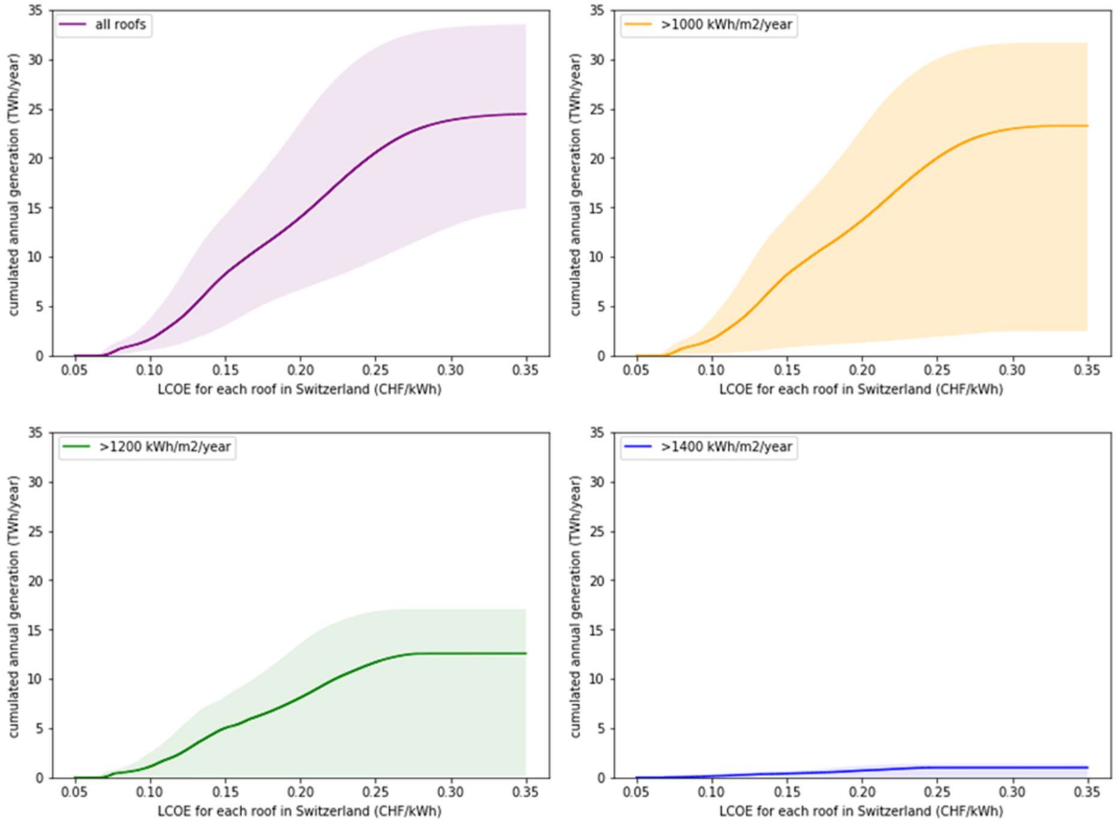

Figure 20.11: Annual electricity generation potential calculated by PSI vs. LCOE for all roofs and tilted solar irradiance (considering shading effect) of more than 1000, 1200 and 1400 kWh/m^2/year, based on system capital investment costs in 2020 and January 2021 (Table 20.1) and improved estimates for available rooftop area and annual electricity generation potential from (Walch *et al.*, 2020), considering uncertainties of annual generation potential and available area: average (average; average + standard deviation; average - standard deviation[83], which corresponds to an annual generation potential of 24±9 TWh of annual electricity generation in the entire Switzerland).

There are also some limitations of the estimated costs shown in Figure 20.10 and Figure 20.11. First, the estimated costs do not include any grid infrastructure investments or flexibility measures or storage units in order to ensure stability of the overall electricity supply system, which is required with substantially higher amount of decentralized PV systems installed (Haegel *et al.*, 2019). On the other hand, it might be not economically viable to always expand the grid capacity to accommodate all the decentralized PV generation all the time. Depending on the local constraints (e.g., economically viable power capacity addition, voltage level) of the network, it might be necessary to curtail the PV generation at peak hours sometimes. In addition, any potential social concerns (e.g., level of acceptance due to local aesthetics) and restrictions are not considered. Addressing such aspects will require the use of energy or electricity system models capturing more systemic issues, which has recently been performed by (Panos *et al.*, 2021).

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[83] When average value – standard deviation is considered, about 0.3% of buildings' area and/or annual generation are negative. These buildings are excluded.

21 Data sheets for further technologies

For the sake of completeness in the context of PSI's technology assessment and monitoring activities for SFOE, this section contains data sheets of electricity generation technologies, which have been only partially (solar photovoltaic and wind power) or not (hydropower, geothermal, fossil and nuclear power, and others) updated within the scope of this analysis. These data sheets are based on or equivalent to those presented in previous reports (Bauer *et al.*, 2017, 2019), in which more detailed background information is available. These data sheets summarize key figures regarding costs, electricity generation potentials, and life-cycle based greenhouse gas emissions. Current updates regarding wind power are based on inputs from SFOE, which have cross-checked using recent literature on current and future wind power costs and past and future technology development (Ren *et al.*, 2017; Williams *et al.*, 2017; Zerrahn, 2017; Ram *et al.*, 2018; Jansen *et al.*, 2020; Johnston *et al.*, 2020; Soares-Ramos *et al.*, 2020; Stehly, Beiter and Duffy, 2020; Beiter *et al.*, 2021). Figures for biomass based, geothermal, nuclear, wave and tidal, and concentrated solar power are likely to be partially outdated, but can still be used as reference values, especially when it comes to prospective long-term estimates (i.e. towards 2050).

21.1 Wind power

Technology: Horizontal axis wind turbines (HAWT) are dominating the world market. Kinetic energy from moving air is harvested and turned into electrical due to rotation of blades. Today's wind turbines can exploit wind speeds of 3-34 m/s. n.a.: not addressed.

Wind power			**Current** [10]	**2025**[12]	**2035**	**2050**
Turbine Capacity	Onshore		2-6 MW		>20 MW expected	
	Offshore		4-15 MW			
Capacity factor (cf)[1]	Switzerland		19-22%	19-41%	26-46%	29-47%
	Onshore, Germany		34%	n.a.		
	Onshore, world		36%			
	Offshore		up to 55%			
Lifetime[12]			25		30	30
Potential	TWh/a	Switzerland	around 9 (of which 6 in winter)[13]			
	TWh/a	Europe[6]	580-630		2030: 604-988	No data available
CAPEX[2]	CHF/kW	Switzerland	2000-3000	1750 -2200	1540-1940	1490-1870
		Europe, onshore	1590	1400	1160	1000
OPEX[2]	Rp./kWh	Switzerland	3.5-5.5	3.5	3	3
		World	0.6-2			
Electricity generation costs[2,3]	Rp./kWh	Switzerland	12-17	ca. 7-13	ca. 5-9	ca. 5-8.5
		Europe, onshore	4-5.5		ca. 3-4	ca. 2-3
		Europe, offshore[7]	9-16		5-12	5-10
GHG emissions[4,5,11]	g CO_2-eq./kWh	Switzerland	5-30	5-30		
		Europe, onshore[8]	5-25	5-25		
		Europe, offshore[9]	5-20	5-20		

[1] Annual "full load hours" divided by 8760 h. Annual full load hours are calculated as the time of the year, which a turbine would operate at its rated capacity in order to generate the annual electricity output. Current capacity factors for world average and Germany according to (International Renewable Energy Agency (IRENA), 2021). While the global weighted-average capacity factors have improved from 27% to 36% from 2010 to 2020, further improvements are still expected due to technological improvements at the level of the wind turbine (better utilization of low wind speed) as well as wind speed forecasting and improved placement of wind turbines.

Capacity factors of current projects in Switzerland are based on former technologies and represent the upper range (19-22%). Figures for 2025 are based on production of turbines available on the market ranging from an Enercon E103 to a Vestas V155 at average wind speeds of 5 m/s and 7 m/s, respectively (15% losses included), resulting in capacity factors of up to 41%.

[2] CAPEX constitute the investment costs. The estimated current costs are ranging from 2000-3000 CHF/kW and average reference cost for projects under preparation and to be implemented in the coming years are evaluated based on a reference study (SFOE, 2020) amounting to 2000 CHF/kW). This costs takes into accout the historical long project development time in Switzerland, which is expected to improve provided recent decisions of the federal court. A lower end value of 1750 CHF/kW and an upper end around 2200 CHF/kW can hence be considered. Average European figure is drawn from (International Energy Agency (IEA), 2021) (1445 euro/kW). Continuous decrease in investments costs expected and quantified according to (Wiser *et al.*, 2021). Decrease of 12% used for Switzerland and Europe in 2035 and 15% for 2050 based on values of 2025. Cost reductions for Europe according to the median scenario quantified in (Wiser *et al.*, 2021).

OPEX consist of operating and maintenance costs. They also include redistribution of revenues to stakeholders such as municipalities. The current values for Switzerland are estimated at 3.5-5.5 Rp/kWh; (SFOE, 2020) established the operating costs for projects under development to be implemented in the comng years from 3-4.5 Rp./kWh depending on the location in the country (from Plateau to the Alps). An average value can be set at 3.5 Rp./kWh, but is expected to decrease with the increasing number of wind parks. Three Rp/kWh have been used for 2035 and 2050. For an international comparison, (International Energy Agency (IEA), 2021) reports for onshore wind average (all-in) O&M costs between USD 0.006/kWh and USD 0.02/kWh.

Generation costs for Switzerland correspond to the Levelised Cost of Energy based on investment, operation & maintenance and other costs, and a discount rate of 5%. The range is defined by the range in CAPEX and in the annual yield. At sites with very favorable/unfavorable wind conditions, figures can be outside of the ranges provided here. Values for Europe are extracted from (windeurope, 2021). The expected decrease in LCOE at European level (30% by 2035 and 45% by 2050) are partially reflected in the decrease in Switzerland. LCOE for current projects, which do not benefit from latest technologies, are based on current capacity factors.

[3] Future cost estimates represent rough estimates based on scarce literature and recent trends in cost development, not taking into account potential substantial changes in commodity prices.

[4] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided reflect potential variability of performance due to site-specific conditions and turbine technology. For comparison: the current Swiss electricity consumption mix (incl. imports) has a GHG intensity of about 100-150 g $CO_{2eq.}$/kWh.

[5] Environmental impacts are not expected to change substantially. A decrease would mainly be due to better exploitation of the wind resource. An increase would mainly be due to reduced availability of good sites.

[6] Based on the available data, differentiation between future onshore and offshore generation is not possible.

[7] Intervals estimated according to EU-specific literature sources in Figure 7.5 in (Bauer *et al.*, 2019); 1.15 CHF/€.

[8] Estimated using capacity factors of 0.15-0.35.

[9] Based on the ecoinvent database, v3.3, "allocation – cut-off by classification". Estimated with cf of 0.30-0.55.

[10] "Current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants (theoretically) built in 2021 – planning procedures for such turbines in Switzerland would have started several years ago due to long permission periods and therefore, such projects could not profit from recent technology development resulting in LCOE reductions only for turbines installed from 2025 on.

[11] Lifetimes are taken from (Wiser and Bolinger, 2019). Most wind project developers, sponsors and long-term owners have increased project-life assumptions over time, from a typical term of ~20 years in the early 2000s to ~25 years by the mid-2010s and ~30 years more recently. Current assumptions range from 25 to 40 years, with an average of 29.6 years (Wiser and Bolinger, 2019).

[12] Cost figures presented for 2025 in Switzerland are based on costs that can be achieved with faster project development procedures and with technologies existing on the market today.

[13] These figures represent the upper limit of what could be implemented by 2050. The ecological potential in Switzerland is estimated at around 29.5 TWh/a according to the latest study (Meyer *et al.*, 2022). Generating these almost 30 TWh per year would require more than 4400 wind turbines to be installed. Generation durng winter time ("Winterhalbjahr") is estimated to amount to 55% of the annual generation, i.e. 16.2 TWh.

21.2 Photovoltaic power

Technology: Photovoltaic modules directly convert solar irradiance into electricity. Roof-top PV installations are most common in Switzerland. PV technology can be categorized as follows:

- 1st generation: crystalline Silicon cells (single-c Si and multi-c Si); on the market today
- 2nd generation: thin-film technologies – CdTe, amorphous Si, CIGS; on the market today
- 3rd generation: concentrating PV, dye-sensitized PV and organic PV; in research and development

Technology development focuses on increase of efficiencies and reduction of manufacturing costs.

Photovoltaics			**New power plants**		
			2020	**2035**	**2050**
Potential	Roof-top	TWh/a	2.2 (2019)	24 (+/-9)[10] (22-54)[8]	
	Facades	TWh/a		5.6[7] 17[9]	
Key technical parameters[1]	Solar irradiation	(kWh/m^2/a)	Switzerland (average of installed modules today): 1267		
	Efficiency	Module (%)	17-19	20-27	24-27
		Inverter (%)	98		
	Area per kW_p installed PV module capacity (m^2/kW_p)		6	3.8-5.0	
	Performance ratio (%)		80		
	Swiss average annual yield[2] (kWh/kW_p/a)		1013		
	Lifetime of modules (a)		30	35	35
Costs[1]	System capital costs[3] (CHF/kW_p)	6 kW	3430 (0-6kW)	1679-2382	1572-2045
		10 kW	2790 (6-10kW)	1529-2168	1034-1475
		30 kW	1910 (20-30kW)	1132-1608	774-1107
		100 kW	1280-1590 (30-300kW)	591-940	534-814
		1000 kW	780-1060 (>300kW)	503-800	455-693
	Electricity generation costs[4] (Rp./kWh)	6 kW	26 (0-6kW)	13-18	13-16
		10 kW	22 (6-10kW)	12-17	9-12
		30 kW	16 (20-30kW)	10-13	7-9
		100 kW	12 (30-300kW)	6-9	6-7
		1000 kW	8 (>300kW)	5-7	4-6
Life-cycle GHG emissions[1,5,6]	(g CO_2eq/ kWh)	multi-c Si	35-66	21-55	7-45
		single-c Si	56-104	33-88	11-71
		thin-film CdTe	23-42	15-36	8-30
		ribbon-Si	n.a.	n.a.	n.a.
		a-Si	n.a.	n.a.	n.a.
		thin-film CIS	n.a.	n.a.	n.a.

[1] All data provided here refer to building-attached or -integrated PV. Large open-ground PV installations have not been addressed since from the current perspective social and political constraints are likely in Switzerland.

[2] Assumed in this study based on the average yield for PV plants in Switzerland in (Vontobel, Nordmann and Lingel, 2016) and used as reference value for cost and LCA calculations.

[3] Including PV module, balance of system, inverter, labor and other costs. Ranges provided for future costs according to (Bauer *et al.*, 2019).

[4] Calculation includes system capital costs as well as costs for decommissioning, operation and maintenance (including replacement of inverter and balance of system during the lifetime). Ranges today are based on the ranges of investment costs. Ranges provided for future costs reflect optimistic and pessimistic cost reduction rates, based on the current best estimates. Calculated with the current average, annual PV yield and an interest rate of 5% - LCOE using 2% are provided in Figure 20.7).

[5] Greenhouse gas emissions are used as key indicator for the environmental performance; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided here reflect potential variability of annual yields in Switzerland (850-1500 kWh/kW$_p$/a). For comparison: the current Swiss electricity consumption mix (incl. imports) has a GHG intensity of about 100-150 g CO$_{2eq.}$/kWh.

[6] Current reference values are calculated with a yield of 1013 kWh/kW$_p$/a. No estimates for future ribbon-Si, a-Si and thin-film CIS modules available. Ranges for emissions of future technologies reflect both variability of assumptions concerning future technology development and variability of site-dependent annual PV yields in Switzerland (850-1500 kWh/kW$_p$/a).

[7] Sustainable generation potential using to the current Swiss building stock according to (Remund 2017). This sustainable potential is supposed to correspond to “exploitable” potentials as quantified in this report and as discussed in (Bauer et al. 2017). Due to higher module efficiency, less area per installed capacity will be needed in the future. This effect is not taken into account here and therefore, depending on the time buildings will be equipped with PV modules, potential generation will increase by up to 20%.

[8] This electricity generation range represents the technical potential for an LCOE range of 10-15 Rp./kWh (using cost data for year 2035) as a result of the cost vs. potential calculations, discussed and presented in section 10.3 in (Bauer *et al.*, 2019). To which extent this potential can be exploited is unknown.

[9] This is the latest estimate according to SFOE[84] based on the recently available data regarding available facades on existing buildings in Switzerland[85]. Electricity generation costs for this potential have not been quantified. To which extent this potential can be exploited is unknown.

[10] According to (Walch *et al.*, 2020). Other estimates indicate potentials of up to 50 TWh/a.

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[84] https://www.bfe.admin.ch/bfe/de/home/news-und-medien/medienmitteilungen/mm-test.msg-id-74641.html

[85] https://www.uvek-gis.admin.ch/BFE/sonnenfassade/

21.3 Large hydropower (LHP)

Source: (Bauer *et al.*, 2019).

Technology: Hydropower plants generate power by converting kinetic or potential energy of water into electricity. Power plants with capacities above 10 MW average gross capacity are categorized as "large" in Switzerland. Depending on the way water is used, hydropower plants can be categorized as:

- Storage power plants: Water is dammed up with a dam in a reservoir, fed via a pressure pipe to a turbine and turbined there.
- Run-of-river power plants: The water flows directly from the river to a turbine or is dammed with a dam and then led via a discharge channel/pressure line to a turbine further downstream (discharge power station).
- Pumped storage power plants: supplying peak power by moving water between reservoirs at different elevations using pumps.

LHP plants represent mature technology. Turbine efficiencies are not expected to increase substantially in the future.

LHP		New power plants: current[1]		2020	2035	2050
Potential[2] (expected average, renewable production)	TWh/a		31.9[10]	~32.0	33.6-34.8	33.6-34.8[11]
					32.5-34.2	32.5-33.6[11]
Investment costs[3]	CHF/kW		3'500 (2'000-10'000)	2'000-10'000	2'000-10'000	2'000-10'000
Electricity generation costs[4,5]	Rp./kWh	Run-of-river[8]	7-30	7-30	7-30	7-30
		Storage[9]				
GHG emissions[6,7]	g CO_2eq. per kWh	Run-of-river	5-10	~5-10	~5-10	~5-10
		Storage	5-15	~5-15	~5-15	~5-15

[1] "current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today; current potential refers to current annual average expected renewable electricity production as of 1.1.2019 (expected production minus consumption of pumps; actual production varies from year to year depending on rainfall, climate, etc.).

[2] According to (SFOE 2019). Expansion and its speed beyond 2020 will predominantly depend on the economic boundary condition and social acceptance of new LHP. Around 700 million CHF in investment contributions will be available by 2030 for the expansion of Switzerland's large hydroelectric power plants. New constructions and renovations/extensions of existing power plants are supposed to contribute about equally to increasing generation. For 2035 and 2050, the upper row represents the technical potential without considering new legislation ("Gewässerschutzgesetz"); the lower row takes into account reduction of LHP generation of 1'170 GWh/a (overall reduction: 1'300 GWh/a; 90% assigned to LHP, 10% to small hydropower in proportion to current generation) due to effects of new legislation.

[3] Available data do not allow for differentiation between storage and run-of-river power plants. 3'500 CHF/kW represents a generation weighted average of potential additional LHP generation (new constructions and extensions of existing plants) excluding projects focusing on modification of hydropeaking.

[4] Generation costs include investment, operation & maintenance and other costs. Ranges provided represent variability due to site-specific aspects. Details concerning data used and sensitivities can be found in the report.

[5] Assuming that the economically more attractive power plant sites would be exploited first, electricity generation costs from new plants would increase from the lower range of the interval provided for today to the higher range in 2050. In total, additional 1.6 TWh/a (not considering the effect of new legislation ("Gewässerschutzgesetz")) can be generated with production costs below 15 Rp./kWh.

[6] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided are supposed to reflect potential variability of performance due to site-specific conditions. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 100-150 g CO_2-eq./kWh.

[7] Environmental burdens are assumed to stay constant in the future, since LCA burdens of LHP are comparatively minor and technology development with substantial impact on LCA results of LHP is unlikely.

[8] LCOE of currently operating plants with partially amortized investments: 5-6 (2-10) Rp./kWh.

[9] LCOE of currently operating plants with partially amortized investments: 6 (3-9) Rp./kWh.

[10] 35.9 TWh/a average, renewable expected generation as of 1.1.2019 reduced by 4 TWh/a generated by small hydro according to the small hydro statistics from Swiss Small Hydro.

[11] As climate change progresses, glaciers will shrink, creating glacial lakes that may be used for hydropower. The SFOE (SFOE 2019) estimates this additional potential at around 700 GWh/a; however, whether and to which extent this generation potential can be realized, is highly uncertain and therefore, this amount is not included in the figures.

21.4 Small hydropower (SHP)

Source: (Bauer *et al.*, 2019).

Technology: Hydropower plants generate power by converting kinetic or potential energy of water into electricity. Power plants with capacities below 10 MW are categorized as "small" in Switzerland. Power plants with capacities below 300 kW are often referred to as "mini hydropower" plants. SHP plants can also be integrated in existing infrastructure, such as drinking water pipes. Depending on the way the water is used, SHP plants can be categorized as:

- Storage power plants: including a dam and a storage reservoir lake
- Run-of-river power plants: without a dam; the hydrological regime remains unchanged

Small hydropower plants represent mature technology. Current turbine efficiencies are not expected to increase substantially in the future. However, current research aims at providing new and more efficient solutions for medium head and low-head respectively low-runoff applications in order to make more sites exploitable.

SHP		**New power plants: current[1]**		**2020**	**2035**	**2050**
Potential[2]	TWh/a		4.0	4.0	~4.0-4.4	~4.0-4.4
Investment costs[3]	CHF/kW	Diversion/ Run-of-river	6'160 (5'200-13'700)	~6'160	~7'150	~7'400
		Drinking water	11'150 (9'600-25'100)	~11'150	~13'000	~13'400
Electricity generation costs[4,5]	Rp./kWh	Diversion/ Run-of-river	12-28	~12-28	~14-33	~14-34
		Drinking water	17-42	~17-42	~20-49	~20-50
GHG emissions[6,7]	g CO_2eq./kWh	Diversion/ Run-of-river	~5-10	~5-10	~5-10	~5-10
		Drinking water	~2-5	~2-5	~2-5	~2-5

[1] "current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today; current potential refers to current expected, annual renewable electricity production as of 1.1.2019 (actual production varies from year to year depending on rainfall, climate, etc.).

[2] The range for future potentials reflects the variety of estimates in literature (SFOE 2019). The SFOE estimates additional potential of 110-550 GWh/a (other sources slightly more or less). These numbers are supposed to be reduced by ~130 GWh/a as an effect of new legislation ("Gewässerschutzgesetz"). Actual implementation of new SHP plants will depend on future funding schemes.

[3] Estimates for current investment costs are based on SHP data in the "KEV-list" (cost-covering feed-in remuneration). The analyzed sample of new SHP constructions covers 1049 SHP projects. Future investment costs are supposed to increase due to exhaustion of favorable SHP sites and tightening of environmental regulations.

[4] Generation costs include investment, operation & maintenance and other costs. Electricity generation costs of SHP strongly depend on site-specific boundary conditions and have to be evaluated on a case-by-case basis.

[5] Assuming that the economically more attractive sites would be exploited first, future electricity generation costs would increase from the lower range of the interval provided in 2020 to the higher range in 2050.

[6] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided reflect potential variability of performance due to site-specific conditions and variations in power plant lifetime. For comparison: the current Swiss electricity consumption mix (incl. imports) has a GHG intensity of about 100-150 g CO_2eq./kWh.

[7] Environmental burdens are assumed to stay about constant in the future, since burdens of SHP are minor and major technology development with substantial impact on the environmental performance of SHP is unlikely.

21.5 Natural gas combined cycle and CHP plants

Source: (Bauer *et al.*, 2019).

Technology: Natural gas can be used in large Combined Cycle (NGCC) power plants as well as smaller, decentralized combined heat and power (CHP) generation units. Plant sizes range from 1 kW$_{el}$ to the order of GW$_{el}$. “Carbon Capture, Utilization and Storage” (CCUS) for large natural gas power plants is currently a field of R&D. Technologies for CO_2 capture are mature; future development aims at increasing efficiencies and further reduction of combustion-related emissions of air pollutants.

Electricity from natural gas		**New power plants**			
		Current[4]	**2020**	**2035**	**2050**
Potential	TWh/a	1.6	n.a.[5]		
Electricity generation costs[1] (with heat credits for CHP) (Rp./kWh$_{el}$)	NGCC	9.7 (9.2 - 10.6)	9.6 (9.1 - 10.5)	11.1 (10.6 – 11.8)	12.6 (12.0 - 13.4)
	NGCC post	11.4 (10.3 - 13.1)	11.3 (10.3 - 12.9)	12.5 (11.5 - 13.9)	13.7 (12.7 - 15.1)
	NGCC pre	11.5 (10.6 - 13.2)	11.2 (10.3 - 12.8)	12.3 (11.5 - 13.8)	13.4 (12.6 - 14.9)
	CHP 1kW$_{el}$	71.7 (50.0 - 114.3)	70.3 (49.2 - 111.9)	67.2 (47.5 - 106.2)	66.0 (47.2 - 103.7)
	CHP 10kW$_{el}$	29.4 (22.0 - 45.0)	29.2 (21.8 - 45.2)	29.6 (22.7 - 45.0)	30.5 (23.8 - 45.8)
	CHP 100kW$_{el}$	20.0 (14.6 - 25.6)	20.1 (14.1 - 26.3)	21.8 (15.5 - 28.0)	23.6 (16.9 - 29.9)
	CHP 1000kW$_{el}$	15.6 (13.2 - 18.3)	15.7 (13.2 - 18.8)	17.3 (14.8 - 20.4)	19.1 (16.4 - 22.3)
Electricity generation costs[1] (without heat credits) (Rp./kWh$_{el}$)	CHP 1kW$_{el}$	93.5 (72.0 - 130.8)	91.4 (71.4 - 128.6)	90.7 (72.3 - 124.8)	91.7 (74.2 - 124.0)
	CHP 10kW$_{el}$	48.2 (39.7 - 62.2)	48.1 (39.8 - 62.3)	50.7 (42.7 - 64.1)	53.5 (45.6 - 66.7)
	CHP 100kW$_{el}$	29.6 (26.1 - 34.4)	29.7 (26.3 - 34.4)	32.2 (28.7 - 36.8)	34.9 (31.3 - 39.5)
	CHP 1000kW$_{el}$	20.8 (19.0 - 23.1)	20.9 (19.1 - 23.1)	22.7 (20.9 - 25.0)	25.0 (23.1 - 27.3)
Fuel costs: natural gas (CHF/kWh)	According to Table 11.2 in (Bauer *et al.*, 2019).				
	consumer categories	consumption [MWh/a]			
	II-V	<500	0.0863	0.1027	0.1171
	VI	>500	0.0767	0.0913	0.1040
	VII	>1'163	0.0735	0.0875	0.0997
	VIII	>11'630	0.0657	0.0782	0.0892
	IX	>116'300	0.0520	0.0619	0.0705
	X	>250'000	0.0443	0.0528	0.0601
Life cycle GHG emissions[2,3] (gCO_2-eq/kWh$_{el}$)	NGCC	393 (387 - 400)	380 (374 - 386)	365 (359 - 371)	357 (346 - 363)
	NGCC post	104 (94 - 114)	99 (90 - 109)	90 (81 - 103)	83 (75 - 100)
	NGCC pre	97 (81 - 120)	91 (76 - 112)	86 (72 - 107)	83 (70 - 103)
	CHP 1kW$_{el}$	643 (611 - 677)	636 (605 - 670)	618 (589 - 648)	606 (578 - 635)
	CHP 10kW$_{el}$	611 (583 - 633)	605 (575 - 632)	586 (558 - 613)	575 (546 - 601)
	CHP 100kW$_{el}$	506 (476 - 529)	500 (464 - 530)	482 (448 - 511)	474 (441 - 503)
	CHP 1000kW$_{el}$	481 (459 - 500)	473 (450 - 498)	452 (429 - 476)	445 (423 - 468)

[1] Calculations include capital, decommissioning, operation & maintenance costs as well as costs associated with direct CO_2 emissions for NGCC plants. Ranges reflect optimistic and pessimistic technology specification and development, respectively, as well as future cost reduction rates.

[2] GHG emissions are used as key indicator for environmental performance; further indicators can be found in (Bauer *et al.*, 2017). Indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. Ranges reflect optimistic and pessimistic technology specification and development. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 100-150 g $CO_{2eq.}$/kWh.

[3] GHG emissions of CHP units are calculated applying exergy allocation for combined heat and power generation.

[4] “Current” refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants in 2018.

[5] Electricity generation (and import) is technically only limited by fuel/electricity import capacities; however, limited by economic, environmental and social constraints in reality. A thorough analysis of CHP potentials has not been performed, since such units are currently not economically viable options and space heating demand will considerably change in the coming years.

NGCC: Natural gas combined cycle; NGCC post: Natural gas combined cycle, CO_2 capture post-combustion; NGCC pre: Natural gas combined cycle, CO_2 capture pre-combustion; CHP 1kW$_{el}$: Natural gas piston engine combined heat and power plant 1 kW$_{el}$; CHP 10kW$_{el}$: NG piston engine combined heat and power plant 10 kW$_{el}$; CHP 100kW$_{el}$: NG piston engine combined heat and power plant 100 kW$_{el}$; CHP 1000kW$_{el}$: NG piston engine combined heat and power plant 1000 kW$_{el}$.

21.6 Fuel cells (using natural gas as fuel)

Source: (Bauer *et al.*, 2019).

Technology: Fuel cells electrochemically convert natural gas into heat and electricity. Systems operating on hydrogen are assumed to be equipped with a fuel reformer to generate hydrogen on site. Installations are extremely scalable from <1 kW to hundreds of kilowatts. Operation is very flexible, with high part load efficiency; start up times range from minutes to hours, depending on fuel cell type.

Some fuel cell types have been made commercially available, though most projects are still dependent on funding support for demonstration projects. Significant improvements to capital costs, system lifetimes and efficiencies are expected for the future.

Fuel cells			**New power plants: current[1]**	**2020**	**2035**	**2050**
Potential[2]	TWh/a		<0.01	~1.2	~6.1	~7.9
Electricity generation costs[3,4] (with heat credits)	Rp./kWh	PEFC 1 kW_{el}	79 (49 - 104)	33 - 92	23 - 48	21 - 46
		SOFC 1 kW_{el}	81 (57 - 109)	35 - 99	23 - 48	20 - 45
		SOFC 300 kW_{el}	42 (29 - 63)	24 - 57	16 - 39	16 - 25
		MCFC 300 kW_{el}	25 (19 - 34)	17 - 32	17 - 32	16 - 26
		PAFC 300 kW_{el}	25 (19 - 35)	16 - 31	15 - 24	15 - 23
Fuel costs: natural gas and biomathane[9]	CHF/kWh	According to Table 11.2 in (Bauer *et al.*, 2019).				
		Consumer cat.	Demand [MWh/a]			
		II-V	<500	0.0863	0.1027	0.1171
		VI	>500	0.0767	0.0913	0.1040
		VII	>1'163	0.0735	0.0875	0.0997
		VIII	>11'630	0.0657	0.0782	0.0892
		IX	>116'300	0.0520	0.0619	0.0705
		X	>250'000	0.0443	0.0528	0.0601
GHG emissions[5,6,8]	g CO_2-eq./ kWh	PEFC 1 kW_{el}	730 (620 - 850)	550 - 730	490 - 610	450 - 560
		SOFC 1 kW_{el}	560 (500 - 770)	490 - 650	480 - 560	440 - 520
		SOFC 300 kW_{el}	490 (360 - 540)	340 - 500	350 - 440	340 - 420
		MCFC 300 kW_{el}	560 (370 - 610)	360 - 580	380 - 490	360 - 450
		PAFC 300 kW_{el}	590 (500 - 650)	480 - 620	460 - 580	440 - 550
GHG emissions[5,7,8]	g CO_2-eq./ kWh	PEFC 1 kW_{el}	390 (350 - 430)	310 - 410	300 - 380	300 - 370
		SOFC 1 kW_{el}	410 (350 - 520)	320 - 480	310 - 420	300 - 390
		SOFC 300 kW_{el}	390 (330 - 460)	310 - 420	300 - 380	290 - 370
		MCFC 300 kW_{el}	410 (340 - 490)	320 - 450	310 - 400	290 - 370
		PAFC 300 kW_{el}	410 (340 - 500)	320 - 460	310 - 420	300 - 400

[1] Refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new fuel cells to be built today (reference year 2018).

[2] Potential is technically unlimited; this estimation is based on replacement of fossil fueled domestic heating.

[3] Generation costs include investment, operation and maintenance and fossil natural gas as fuel. Ranges provided here represent variability in assumptions concerning e.g. efficiency, investment cost, lifetime, etc. Details concerning data used and sensitivities can be found in (Bauer *et al.*, 2019). Since the main purpose of stationary fuel cells in Switzerland would be heat supply, only electricity generation costs with heat credits are provided in this fact sheet.

[4] Results shown for fossil natural gas as a fuel source. If biomethane is used, costs increase by 8-14 Rp./kWh.

[5] GHG emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in (Bauer *et al.*, 2017). All indicators are quantified using Life Cycle Assessment (LCA) methodology and represent the complete fuel cycle/energy chain. The ranges provided here reflect potential variability of performance parameters such as efficiency and lifetime. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 100-150 g $CO_{2eq.}$/kWh. Since only rounded numbers are provided here, small changes in LCOE (in red) due to slightly changed efficiencies for some technologies are not reflected in changes in GHG emissions.

[6] Emissions allocated between heat & electricity based on exergy. Results shown for electricity production.

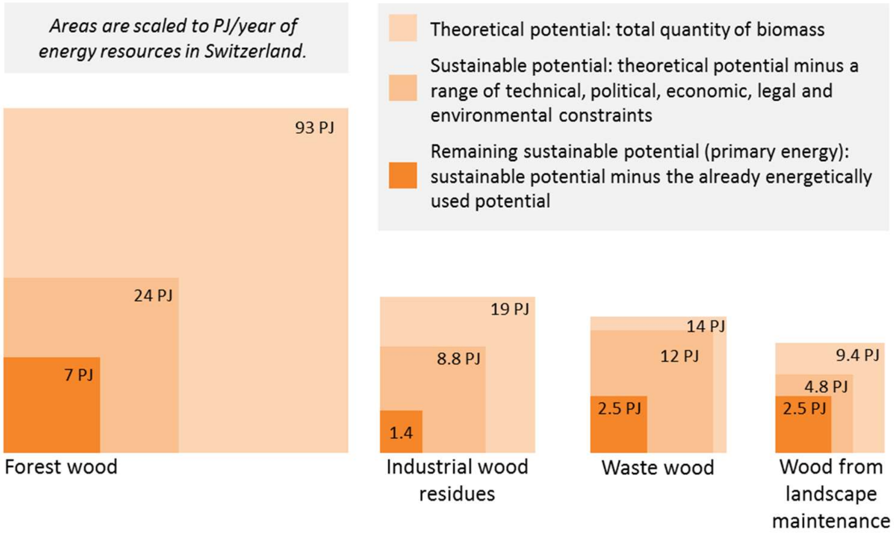
[7] GHG emissions based on system expansion, which means that the GHG emissions associated with the equivalent heat produced by a modern condensing natural gas boiler have been subtracted from the total.

[8] GHG emissions with biomethane as fuel decrease by 32-34%.

[9] Natural gas prices for Swiss residential and industry, respectively, and a premium of 75 CHF/MWh for biomethane.

21.7 Woody biomass

Source: (Bauer *et al.*, 2017).



Potentials of domestic Swiss woody biomass resources.[86]

Technology: Woody biomass consists of forest wood, industrial wood residues, waste wood, and wood from landscape maintenance. Only a certain portion of these resources are currently recoverable – legally and economically – for energetic use in Switzerland. These resources can be converted to electricity either by combustion or gasification pathways. Combustion is followed by a combined heat and power system (CHP) to produce electricity and heat. Gasification is followed by any technology that can take gaseous fuel as an input (internal combustion engine, turbine or fuel cells). The following conversion technology types can be distinguished based on the classification used by BFE in the Swiss Renewable Energy Statistics:

- **Automatic wood combustion CHP:** Combustion of clean wood chips and logs for CHP use starting at 50 kW_{fuel}.
- **Combustion of wood and organic wastes:** Industrial-scale combustion of waste woods and organic wastes, which can be used for energetic uses.
- **KVA – waste incineration**: Large installations with the primary purpose of incinerating wastes.
- **Wood gasification CHP**: CHP unit based on the gasification of wood, instead of its combustion.

Autom. wood combustion CHP in Felben-Wellhausen (TG)
© Schmid

Combustion of wood & organic wastes, Spiez (BE)
© Eicher + Pauli

KVA,
Basel (BS)
© IWB

Wood gasifier,
Stans (NW)
© Korporation Stans

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[86] The sustainable potential of forest wood shown here is the quantity using a price threshold without subsidies of 5.9 Rp./kWh. If considering subsidies to the feedstock costs, a larger potential would result.

Gasification technologies are not yet as widely used as combustion technologies. Combustion approaches have higher technological maturity, but most biomass combustion systems in Switzerland still produce heat only. Upgrading these installations to CHP units and utilizing currently unused feedstock represent the two largest potentials for added electricity generation from woody biomass.

Woody biomass		**New power plants**			
		Current	**2020**	**2035**	**2050**
Electricity generation potential[1] [GWh/a]	Autom. wood CHP[2]	126	126-225	126-614	126-1142
	Combustion of wood & organic wastes[3]	70	70	70	70
	KVA[4] – waste incineration[5]	1065	1065-1072	1065-1105	1065-1262
Electricity generation costs[6] [Rp./kWh_{el}] *(in italics without heat credits)*[7]	Autom. wood combustion	18-36 *(35-71)*	18-37 *(35-73)*	18-41 *(35-80)*	18-45 *(35-87)*
	Combustion of wood & organic wastes		18-36 *(35-71)*	18-36 *(35-71)*	18-36 *(35-71)*
	Wood gasification[8] CHP[2]	18-31 *(25-44)*	18-32 *(25-44)*	17-33 *(24-47)*	16-35 *(23-49)*
	KVA[4] – waste incineration	2.5-16[9] *(2.6-17)*	2.5-16 *(2.5-16)*	2.4-15 *(2.5-16)*	2.3-15 *(2.5-16)*
GHG emissions[10,11] [g CO_2eq/kWh]	Combustion and gasification	~10-120	~10-120	~10-100	~10-100 (minus ~1300)[12]

[1] The possible range of future potential is large, because these are still relatively new technologies. The lower end of the future potential range refers to today's electricity production. The upper end of the future potential range assumes a gradual increase in the use of technically and economically recoverable biomass resources, until 100% of this feedstock is utilized in 2050. It also assumes an increase in the efficiency of technologies by greater use of gasification for the use of the additional feedstock. A more conservative scenario is also considered in the report.

[2] CHP: Combined heat and power (Wärme-Kraft-Kopplung, WKK).

[3] This category does not increase in the future, because it is assumed that feedstock should be directed to the "Autom. wood CHP" category instead, as it has a significantly higher electrical efficiency.

[4] KVA: Kehrichtverbrennungsanlage (waste incineration plant).

[5] This category is also listed in the non-woody biomass factsheet. It should only be counted once making a total.

[6] Predictions in costs of electricity production are done by starting from today's costs. The cost structure of each technology (contribution from capital costs, fuel, O&M, etc.) is analyzed based on selected case studies, and assumptions are made about the outlook for each of these categories. Increases in these costs are due to predicted increases in the price of wood as a feedstock as more wood becomes utilized for energy uses.

[7] Costs are also estimated without heat credits. Capital costs, O&M costs are not otherwise changed; heat credits are only removed. However, in reality wood-based electricity systems depend heavily on heat sales, so it is strongly recommended to use the costs *with* heat credits.

[8] Gasification & combustion are combined in the "Autom. wood CHP" category for potentials but not for costs.

[9] The low end of the KVA cost range refers to "standard" KVA incinerating municipal waste. The high end refers to specialized units which burn more wood than waste, for example the KVA/Holzkraftwerk in Basel.

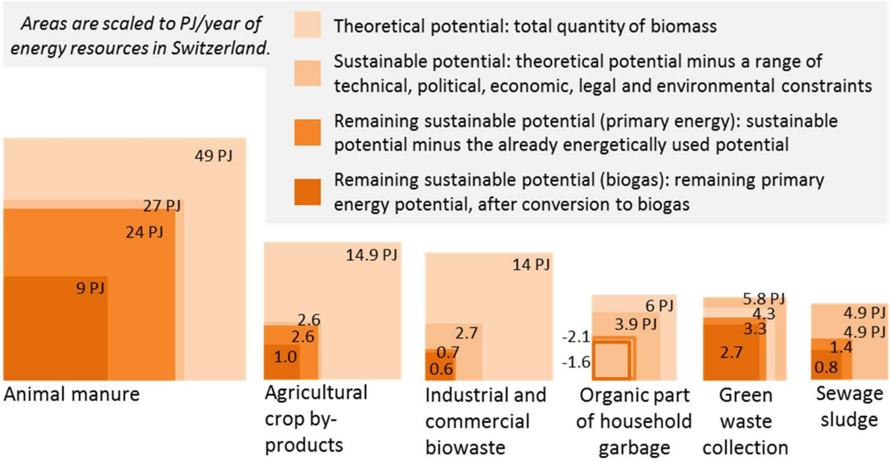
[10] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies and are quantified using LCA and thus represent the complete fuel cycle/energy chain. Further environmental indicators are discussed in the report. The ranges provided are based on literature and are supposed to reflect variability in terms of technology, fuel supply, etc. Due to lack of data, these ranges are not Swiss-specific and can only be provided on an aggregated level. Swiss-specific results for some selected technologies are provided in the report. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 100-150 g CO_2eq./kWh.

[11] Decreasing emissions for 2035 and 2050 reflect expected increase in efficiency of electricity generation.

[12] Negative GHG emissions are possible with Carbon Capture and Storage (CCS).

21.8 Non-woody biomass

Source: (Bauer *et al.*, 2017).



Potentials[87] of domestic Swiss non-woody biomass resources.

Technology: Non-woody biomass consists of several feedstocks of varying liquid content, including organic parts of household waste, industrial and commercial bio-waste, agricultural crop by-products, green waste, animal manure, and sewage sludge. Feedstocks with high liquid content (sewage sludge, manure, etc.) are first processed through an anaerobic digester. The resulting biogas can be used to generate electricity and heat in an engine, turbine, or fuel cell. Feedstocks with lower liquid content can be combusted to drive a steam or organic Rankine (ORC) cycle. Gasification of waste feedstocks is also technically feasible. One commercial waste gasifier exists today in Lahti, Finland. The following conversion technology types can be distinguished based on the classification used by SFOE in the Swiss Renewable Energy Statistics:

- **KVA – waste incineration:** Large installations with the primary purpose of incinerating wastes.
- **Municipal WWTP:** Biogas produced by anaerobic digestion of municipal sewage sludge.
- **Industrial WWTP:** Biogas produced as a result of required pre-purification of effluents in some industries, especially in the processing of fruits and vegetables.
- **Industrial biogas:** Production of biogas from green waste, food waste, slaughter waste, etc. from municipal, commercial and industrial sources.
- **Agricultural biogas**: Production of biogas on farms from manure and co-substrates.

**KVA,
Basel (BS)
© IWB**

**Municipal WWTP
Morgental (SG)
© morgenthal.ch**

**Industrial WWTP
Rickenbach (LU)
© Gefu Produktions**

**Industrial biogas
KBA Hard, Beringen
(SH) © abfall-sh.ch**

**Agricultural biogas
Düdingen (FR)
© ZHAW**

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[87] The organic part of the household garbage is expected to decrease in future, as more green waste is separated at source. This is the reason for the negative value of the remaining potential for organic part of household garbage.

Anaerobic digestion is a relatively mature technology at large scales (e.g., wastewater treatment plants) but not yet at smaller scales. Manure represents the largest currently unused biomass potential in Switzerland, but it is distributed at many small farms. Small scale systems are still heavily supported by feed-in tariffs (KEV) and will need to reduce capital costs to become economical. Electrical efficiency for waste incineration is expected to improve as steam parameters become optimized (previously, the focus was only on waste destruction, not electricity).

Non-woody biomass		**New power plants**			
		Current	**2020**	**2035**	**2050**
Potential[1] [GWh/a]	KVA[2] – waste incineration[3]	1065	1065 – 1072	1065 – 1105	1065 – 1262
	Municipal WWTP[4]	119	119 – 129	119 – 170	119 – 225
	Industrial WWTP[4,5]	84	84 – 149	84 – 381	84 – 668
	Industrial biogas[5]				
	Agricultural biogas	100	100 – 232	100 – 718	100 – 1342
Electricity generation costs[6] [Rp./kWh$_{el}$] *(in italics without heat credits)*[7]	KVA[2] – waste incineration	2.5 – 16[9] *(2.6-17)*	2.5 – 16 *(2.5-16)*	2.4 – 15 *(2.5-16)*	2.3 – 15 *(2.4-16)*
	Municipal WWTP[4]	4 – 22 *(4-22)*[8]	4 – 22 *(4-22)*[8]	4 – 22 *(4-22)*[8]	4 – 22 *(4-22)*[8]
	Industrial WWTP[4]				
	Industrial biogas	20 – 49 *(23-55)*	20 – 49 *(22-55)*	18 – 50 *(20-56)*	16 – 51 *(18-57)*
	Agricultural biogas				
GHG emissions[10,11] [g CO$_2$eq/kWh]	Agricultural biogas	150-450	150-450	no data	no data

[1] The lower end of the future potential range refers to today's electricity production. The upper end of the future potential range assumes a gradual increase in the use of technically and economically recoverable biomass resources, until 100% of this feedstock is utilized in 2050. It also assumes a gradual increase in the efficiency of technologies by greater use of fuel cells as biogas-to-electricity converters. A more conservative scenario, which assumes that technology does not improve even though more feedstock is used, is also considered in the report.

[2] KVA: Kehrichtverbrennungsanlage (waste incineration plant).

[3] This category is also listed in the woody biomass factsheet. It should only be counted once if making a total.

[4] WWTP: Wastewater treatment plant (Abwasserreinigungsanlage, ARA).

[5] These categories are combined in the future generation prediction because they utilize similar feedstocks.

[6] Predictions in costs of electricity production are done by starting from today's costs. The cost structure of each technology (contribution from capital costs, fuel, O&M, etc.) is analyzed based on selected case studies, and assumptions are made about the outlook for each of these categories. WWTP costs are not expected to change because the technology is assumed to be mature.

[7] Costs are also estimated without heat credits. Capital costs, O&M costs are not otherwise changed; heat credits are only removed. However, in reality some systems rely heavily on heat sales, so it is strongly recommended to use the costs *with* heat credits.

[8] It is assumed that the majority of heat produced at WWTPs is used on site and therefore no significant income results from heat sales.

[9] The low end of the KVA cost range refers to "standard" KVA incinerating municipal waste. The high end refers to specialized units which burn more wood than waste, for example the KVA/Holzkraftwerk in Basel.

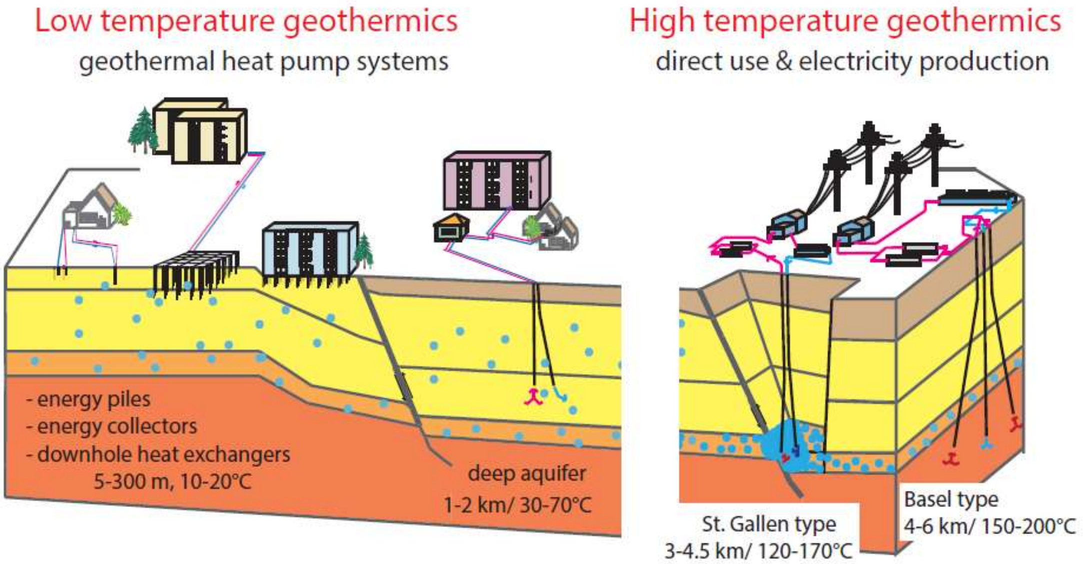
[10] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies and are quantified using LCA and thus represent the complete fuel cycle/energy chain. Further environmental indicators are discussed in the report. Consistent and recent LCA results for non-woody biomass conversion are scarce – uncertainties and ranges are large. The ranges provided are rough estimates for agricultural, small-scale manure gasification and CHP generation. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 100-150 g CO$_2$eq./kWh.

[11] Life cycle GHG emissions are dominated by potential "leakage" of methane during anaerobic digestion of feedstock. No substantial changes can be expected until 2020. High-quality estimates for 2035 and 2050 are not available.

21.9 Deep geothermal power

Source: (Bauer *et al.*, 2017).

Technology: Deep geothermal electricity generation. In general, depths of wells are larger than 400m and underground temperatures are above 120°C. In Switzerland, due to lack of shallow geothermal resources, well depths will be most likely around 4-6 km.



Technologies can be categorized based on the way thermal energy resources are used:

- Flash steam, dry steam, back pressure plants: Such plants globally exist and are feasible at suited locations with hot water or steam reservoirs (not in Switzerland).
- Hydrothermal (HT) plants: HT plants are globally operated. The potential of these plants is limited as they require high underground temperatures (>100°C), water-bearing geological formations and structures, and adequate generation of hot water in these formations.
- Enhanced Geothermal Systems (EGS): EGS plants are envisioned to generate electricity in Switzerland in the future. Currently, EGS plants are not operated at commercial scale. The potential of EGS plants is high, as they do not depend on local conditions as much as the other deep geothermal plant types. EGS plants are more dependent on technical issues such as the drilling and a successful stimulation phase. By drilling two or more deep wells and connecting them, cold water can be injected to high-temperature rock formations, warm up there and then be pumped up through one or two other well(s) back to the surface. The hot water will drive a generator with or without an organic working fluid in a binary cycle.

Power plant (net) capacities are mainly determined by the temperature gradient, well depth, and reservoir impedance, i.e. are mostly site- and less time-dependent. Model reference cases for Switzerland result in capacities of ca. 1.5-3 MW_{el}, good cases (conditions are average or above expectations) reach 3-5.5 MW_{el}, and very beneficial conditions result in plants with up to 10 MW_{el} per well triplet. Well fields with several triplets may be built at such optimal locations.

Deep geothermal power - EGS		**New power plants**			
		Current	**2020**	**2035**	**2050**
Potential[1]	TWh/a	No deep geothermal power generation in Switzerland	n.a.	n.a.[9]	~4.5
GHG emissions[2,3,4,5]	g CO_2-eq./kWh		27 - 84		
Investment costs					
Well	Million CHF/well			18 - 30	15
Fracturing	Million CHF/well			3.3	3.3
Power generation plant	CHF/kW_{el}			4000	3500
Electricity generation costs[3,4,6,7] (without heat credits)	Rp./kWh			16 - 58	13 - 47 (~10)
Electricity generation costs[3,4,8] (with heat credits)	Rp./kWh			-3 - 33	-4 - 27

[1] The Swiss energy strategy aimed at 4-5 TWh/a in 2050. The number provided here for 2050 represents a long-term potential in line with this target, which can only be realized, if current geological, technical, legal, social and economic barriers can be overcome.

[2] Greenhouse gas emissions are used as key indicator for the environmental performance; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided here reflect potential variability due to site-specific conditions. For comparison: the current Swiss electricity consumption mix (incl. imports) has a GHG intensity of about 100-150 g CO_2-eq./kWh.

[3] Figures provided here are results of a Swiss-specific coupled economic/environmental EGS model considering variability of geothermal conditions (temperature gradient, flow rates, etc.). The ranges in GHG emissions and LCOE provided here are supposed to reflect this variability.

[4] Both the LCOE and the environmental impacts are very location-specific, mainly depending on geological conditions. Therefore, only a rough estimate for the potential development over time can be provided.

[5] Emissions are completely allocated to electricity, since it's uncertain whether the by-product heat can be used.

[6] LCOE are provided first without heat credits, since EGS plants are likely to be located in relatively remote areas without large heat consumers.

[7] Very favorable geological conditions could result in LCOE of about 10 Rp./kWh.

[8] Revenues from heat sales can substantially improve the economic performance of EGS (even lead to negative LCOE).

[9] Still not seen as available on a large scale.

21.10 Wave and tidal power

Source: (Bauer *et al.*, 2017).

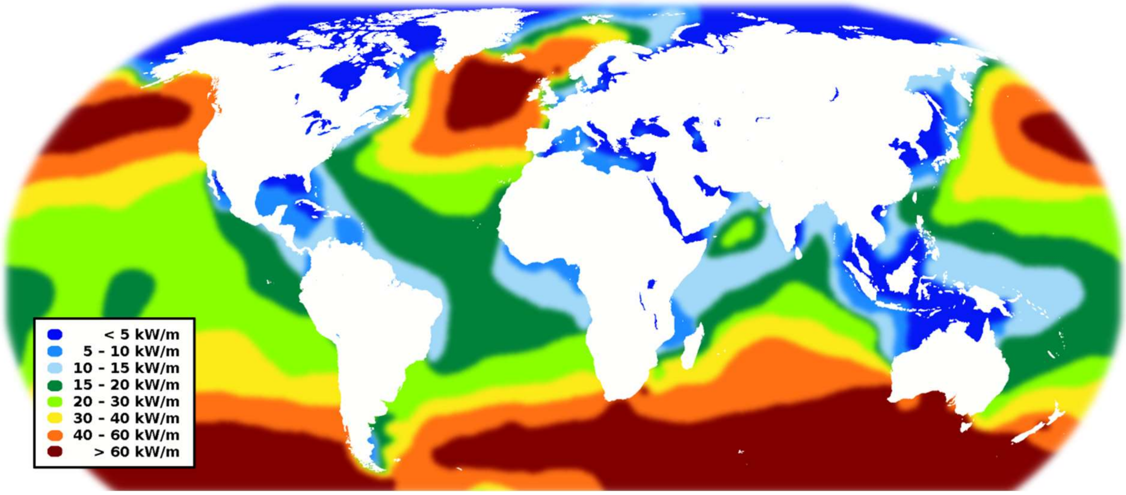
Technology: Wave power is the transport of energy by ocean waves driven by the wind, and the capture of that energy to do useful work, for example, electricity generation. Machines able to exploit wave power are known as wave energy converters (WEC). Tidal power converts the energy obtained from tides into electricity. Wave power technologies can be divided into two broad categories, **onshore** and **offshore**.

Wave power technologies. From the left to the right: Pelamis; SINN; Wave roller; Atlantis turbine; Wave dragon.

Wave and tidal power generation are still in their adolescence, with a relatively small number of demonstration scale installations scattered around the globe. Future developments are likely to focus on offshore designs due to larger energy density, less restricted siting and no visual disturbance.

Resource: Locations with the most potential for wave power include the western seaboard of Europe, the northern coast of the UK, and the Pacific coastlines of North and South America, Southern Africa, Australia, and New Zealand. The north and south temperate zones have the best sites for capturing wave power. The prevailing westerlies in these zones blow strongest in winter.

Wave energy for Switzerland would have to be imported, most likely from the Atlantic coast of Spain, Portugal or France.



World wave energy resource map; wave energy density in kW/m around the globe.

Wave and tidal power			**New power plants**			
			Current[1]	**2020**	**2035**	**2050**
Potential[2]	TWh/a	offshore	n.a.	30	30	30
		onshore	n.a.	10-15	10-15	10-15
Investment costs[3]	CHF/kW	offshore & onshore	4000-9500	3000-7000	2100-5000	1900-3500
Electricity generation costs[3,4,5]	Rp./kWh	offshore & onshore	~38 (23-80)	~30 (14-42)	~17 (9-24)	~11 (8-19)
Import costs[6]	Rp./kWh	~1000 km	n.a.	~0.5	~0.5	~0.5
GHG emissions[7,8]	g CO_2-eq./kWh	wave power	15-105			
		tidal power	15-70			

[1] "Current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today.

[2] Generation at the Southern European and French Atlantic coast with subsequent transmission to Switzerland.

[3] Available data do not allow for differentiation between onshore and offshore technologies.

[4] Generation costs include investment, operation and maintenance costs. Details concerning data used can be found in the report.

[5] Ranges provided are based on literature and reflect variations in site characteristics, technology and uncertainties in future developments.

[6] Costs for long-distance electricity transmission from the Atlantic coast to Switzerland.

[7] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided here reflect different technologies. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 100-150 g $CO_{2eq.}$/kWh.

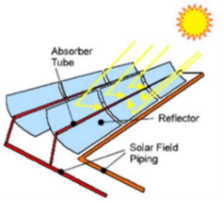
[8] The ranges provided reflect a range of different current wave and tidal power concepts; more differentiated estimates concerning future development of LCA results are not possible given the technological maturity and due to limitations of available literature.

21.11 Solar thermal power generation (Concentrated solar power CSP)

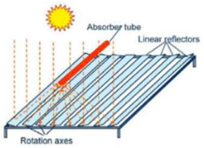
Source: (Bauer *et al.*, 2017).

Technology: CSP technologies produce electricity by concentrating direct solar irradiance to heat a liquid, solid or gas that is then used in a downstream process for electricity generation. Linear focusing systems with heat transfer fluid temperatures of up to about 550°C and point focusing systems allowing for higher temperatures and efficiencies are available. CSP plants are usually installed at locations with direct normal irradiation DNI >2000 kWh/m^2/a (i.e. not in Switzerland) at latitudes of <35-40° and can integrate thermal storage for peaking, intermediate and base load generation (less than one hour up to 15 hours of generation from stored energy). Electricity from CSP plants in the Mediterranean area could be imported to Switzerland. This can be accomplished with minor losses (3%/1000 km) via High Voltage DC (HVDC) power lines.

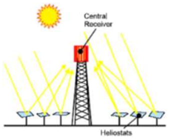
The following four CSP technologies can be distinguished:



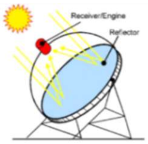
- Parabolic trough (PTC): Long parabolic troughs track the sun on one axis, concentrate the solar rays on linear receiver tubes isolated in an evacuated glass envelope, heat a transfer fluid, and then transfer this heat to a conventional steam cycle.



- Linear Fresnel reflector (LFR): Work similar to PTC and approximate the parabolic shape of trough systems, but use long rows of flat or slightly curved mirrors to reflect the sun's rays onto a downward-facing linear, fixed receiver.



- Central receiver or "Power tower" (CRS): A large number of mirrors ("solar field") is used to concentrate solar rays in a central receiver. Heat generated there is used to operate a conventional steam cycle.



- Parabolic dish (PDC): The concentrated sunlight is used to operate single heat-to-electricity engines (Stirling motors or micro-turbines) at the focal points of curved reflectors. Limited possibilities for integration of heat storage.

Few commercial CSP plants operate today, mainly in Spain and the USA. Largest plants today with capacities of up to 750 MW are installed in the USA. PTC and CRS, the two CSP technologies predominantly installed in recent years, can be considered as most mature and reliable in operation. PDC have almost disappeared from the commercial energy landscape, due to comparatively high costs and more difficult integration of heat storage. There is still a significant potential for technological improvement as well as for cost reduction due to mass production and larger scales. Further CSP development mainly aiming at cost reductions will still require substantial private and governmental R&D and market incentives. Learning rates are estimated as approximately 10%. Electricity imports from the Mediterranean area require the construction of additional transmission lines, either point-to-point HVDC transmission or connection to an extended future European grid.

Concentrated Solar Power, CSP			**New power plants**			
			Current[1]	**2020**	**2035**	**2050**
Potential	TWh/a	Worldwide	~25[2]	31-466	n.a.	222-9’348
		EUMENA[3]	n.a.	<99	<660	<1358
		MENA[4]	n.a.	<69	<490	<1150
Performance	Full load hours per year	(Switzerland)	n.a.	(1250)	(1375)	n.a.
		Spain[5] (incl. TES; max. 6400)	~5000	~5500	~5500	~5500
		Algeria[6] (incl. TES; max. 8000)	~5500	~6000	~6000	~6000
Annual solar-to-electricity efficiency	%	PTC (including storage)	13-15	n.a.	~19	~19
		LFR (<10min storage)	9-13	n.a.	~12	~12
		CRS (including storage)	14-18	n.a.	~18	~18
		PDC (no storage)	22-24	n.a.	n.a.	n.a.
Investment costs[7]	CHF/kW	PTC (without storage)	3’100-8’000	3’100-8’000	3’000-5’900	2’000-5’900
		PTC (0.5-8h storage)	3’400-12’800			
		CRS (0.5->8h storage)	3’400-12’800			
		LFR (0.5-4h storage)	3’400-6’700			
Electricity generation costs[8,9]	Rp./kWh	Without storage	16-33	n.a.	n.a.	n.a.
		With storage (4-15h)	14-28	6-23	7-11	6-9
Import costs[10]	Rp./kWh		n.a.	n.a.	~2	~2
GHG emissions[11]	g CO_2-eq./ kWh	Parabolic trough	13-55	13-55	5-44	5-36
		Central receiver system	9-42	9-42	5-25	5-21
		Parabolic dish	5-60	5-60	3-36	3-30

[1] “Current” refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today.

[2] Rough estimate based on installed capacities.

[3] Europe, Middle East and North Africa. Only small fractions would probably be available for Swiss supply.

[4] Middle East and North Africa. Only small fractions would probably be available for Swiss supply.

[5] DNI 2000 kWh/m2/a; TES=Thermal Energy Storage. Rough estimate; actual performance in practice depends on dimensioning of solar field and TES (and other factors, see report).

[6] DNI 2500 kWh/m2/a; TES=Thermal Energy Storage. Rough estimate; actual performance in practice depends on the layout of the solar field and TES (and other factors, see report).

[7] Available data do not allow for differentiation between specific CSP technologies in the future.

[8] Generation costs include investment, operation and maintenance and fossil natural gas as fuel. Ranges provided here represent variability in literature. Details concerning data used can be found in the report.

[9] Literature data do not allow for estimation of CSP technology specific LCOE.

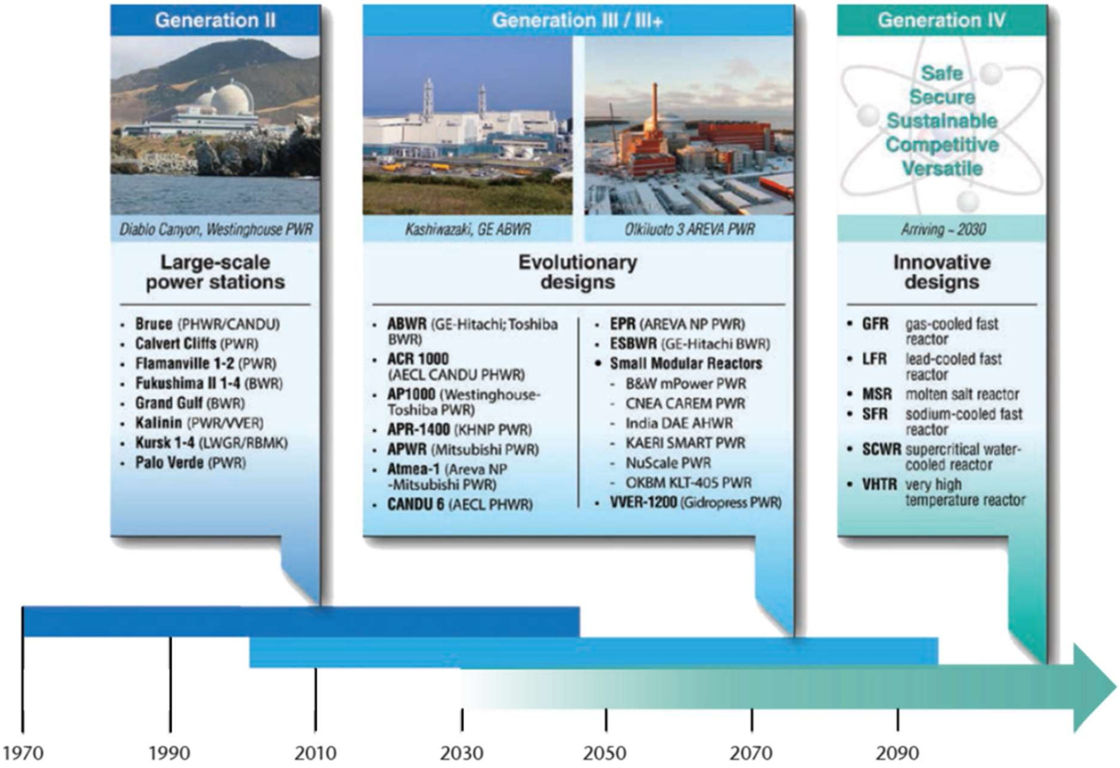
[10] Costs for long-distance electricity transmission from MENA countries to Switzerland.

[11] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided here reflect potential variability of performance parameters. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 100-150 g CO_2-eq./kWh.

21.12 Nuclear power

Source: (Bauer *et al.*, 2017).

Technology: Nuclear power is based on the fission of U-235 atoms in fuel that has generally been enriched from the natural level of 0.7%, producing fission fragments and enough neutrons to sustain a chain reaction. Beyond these fundamentals, there is a very broad range of possible choices: different fuel cycles (feedstock, enrichment, oxide vs. metal), whether the neutrons should be moderated (slowed down) from fast to thermal spectra, the material used as a moderator (light or heavy water, graphite, etc.), the coolant used to generate steam (water, molten metal or gas), and the overall reactor configuration. The dominant reactor designs have been based on uranium oxide enriched to 3-5%, using light water as a moderator for thermal neutrons (Light Water Reactors; LWR), and generating steam by either direct boiling (Boiling Water Reactors; BWR) or using pressurized steam generators (Pressurized Water Reactors; PWR). The figure below shows the successive generations of reactor designs and the many variations, driven by the goals of economic generation and increased safety.



Successive generations of nuclear power technologies.

The presently dominant LWR technology can be considered relatively mature, but the pressure to increase safety and remain cost-competitive is driving evolutionary designs (Generation 3+). This includes a recent trend to small modular reactors (SMR) with a wider design range that it is hoped can trade the benefits of standardized, factory construction for economies of scale. Actual cost estimates are few and uncertain. Although some designs are potentially low in cost, most estimates of overnight costs (capital costs without interest) are not far from current designs, and the barriers of factory investment and first unit costs and orders are significant. Beyond this, a broader spectrum of Generation 4 designs are intended on a case-by-case basis to achieve more inherent safety, improved proliferation resistance, reduced volumes of long-lived radioactive wastes, and better resource sustainability (higher temperatures to increase efficiency and thermal applications).

A broad range of current and future reactor designs can also be fuelled with thorium. Unlike U-235, thorium is not fissile, but rather fertile (like U-238), so the thorium is converted (or bred) to U-233 inside the reactor, and the fuel cycle must be initially driven by another fissile fuel or a neutron accelerator. Thorium is more abundant, can produce less high level waste, and is somewhat more proliferation resistant than present nuclear fuels. However, the breeding ratio limits the rate of fleet expansion, and there are still technical and economic uncertainties.

Resource: The availability of uranium is not the dominant limiting factor in future nuclear generation. The use of present reasonably assured reserves in current reactor designs could conceivably limit a growing reactor fleet in the next century, but alternate fuel cycles, reactor designs, enrichment methods, and backstop fuel resources (e.g., uranium from seawater) all mean that the limits on reactor construction are more likely to be determined by cost competitiveness, and societal choices balancing the environment (climate change), safety and proliferation.

Nuclear power		**Currently operating plants in CH**	**“New plants”[1]** (hypothetical new, Gen III/III+)	**2035** (SMR[6])	**2050** (Gen IV)
Electricity generation potential[2]	TWh/a	not applicable			
Investment costs[3]	CHF/kW	1’300-6’000	4’000-7’000	3’000-9’000	not analyzed
Electricity generation costs[4]	Rp./kWh	4-6 [7]	7.5 (5.1 - 12.5)	7.4 (5.1 - 12.2)	not analyzed
GHG emissions[5]	g CO_2-eq./kWh	10-20	10-20	5-40	

[1] “Current” refers to power plants decided to be built today. Construction of new nuclear power plants in Switzerland is no longer allowed, since the Swiss population agreed to the energy strategy 2050 on May 25, 2017.

[2] As explained above, the energy resource (uranium or thorium) is not the limiting factor, but rather economic constraints and the societal choice to implement this technology.

[3] Overnight Capital Costs. The cost range for the presently operating Swiss plants includes the costs of major upgrades since start of operation (KKL and KKG). The capital cost provided for “current” represents the cost of present designs (Gen III/III+, e.g. the EPR) to be built in Switzerland. The capital cost given for the 2035 time period represents the possible range of capital costs for small modular reactors (SMR), but the Gen III/III+ price in the previous column would also be valid for 2035. Although the midrange cost value for the small modular reactor is only slightly higher than for the Gen III/III+, the considerably broader price range reflects a broader range of designs, potential savings and technical uncertainty. Based on the available information, Gen IV costs for 2050 are still too uncertain to indicate a cost range.

[4] Generation costs include investment, operation, maintenance as well as dismantling and waste disposal costs. For “current” and 2035 the cost range is based on sensitivity analysis varying single cost factors individually from 50% to 200%. Details concerning the data used can be found in the nuclear technology chapter. Gen III/III+ and SMR cost ranges reflect the base value, lower bound and upper bound of the single variable sensitivity analysis. Although the base SMR investment cost is higher, it is assumed to be built in only two years, and the lower interest cost means that the average cost is slightly lower.

[5] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the nuclear technology chapter. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided here reflect the variability concerning a range of assumptions in inventory data. Due to limited data availability, values for 2035 and 2050 represent only rough estimates and Gen IV reactors have not been analyzed due to lack of data. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 100-150 g CO_2-eq./kWh.

[6] Small modular reactors.

[7] For average generation costs of the current Swiss nuclear power plants, capital costs are largely amortized, and the generation cost is taken from annual reports of KKL and KKG.