Perspectives of Power-to-X technologies in Switzerland

Supplementary Report to the White Paper

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1 Motivation and Scope

Ambitions to mitigate climate change, increase the pressure to reduce greenhouse gas (GHG) emissions across all sectors of the economy, with significant implications for the energy landscape as well as other emissions sources. Switzerland has committed to reducing its annual direct emissions of GHG by 50% by 2030 compared to 1990. A major share of this reduction shall be achieved domestically while some emissions can be based on measures abroad through the use of international credits [1]. The Swiss government has also formulated the long-term goal to reduce GHG emissions in 2050 by 70-85% compared to 1990 levels (including measures abroad), and to achieve climate neutrality after 2050 [2]. Today, domestic GHG emissions in Switzerland originate by about 60% from energy conversion in the transport and building sectors, and by 40 % from other sources including industry. Carbondioxide (CO_2) is the major GHG that is emitted with the transport sector being the sector with largest contribution (Figure 1). Given this distribution of GHG emissions, particularly CO_2 emissions in the demand sectors attributable to energy conversion and industrial production processes need to be avoided to achieve the climate goals. As of 2017, the Swiss electricity sector is already almost CO_2-free as electricity is mainly generated from hydropower (60%), nuclear (32%) renewable and non-renewable combustible energy (5%) and other renewable energy (4%) [3]. Future pathways for the developments of the Swiss energy sector are framed by the Swiss Energy Strategy 2050, which aims at discontinuing energy supply from nuclear power plants in Switzerland, and promoting renewable energy and energy efficiency [4].

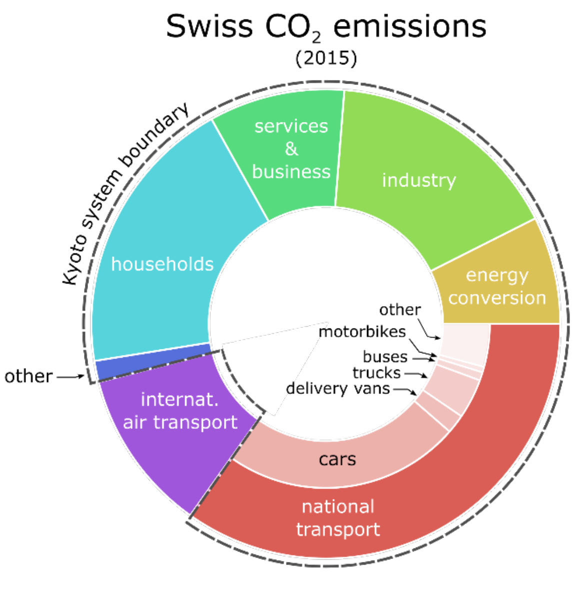

Figure 1: CO_2 emissions in Switzerland in 2015 split in different sectors [5]

The transformation of the Swiss energy economy calls for the deployment of new low-carbon energy solutions while maintaining the high level of energy supply reliability, which in particular applies to the electricity sector. One option to provide low-carbon energy services is an increased electrification of energy demand services while using low-carbon generation sources. Against the background of a growing share of variable renewable energy sources in the electricity mix, such as wind and solar energy, the challenges of temporal and spatial balancing of supply and demand is expected to increase in future. Temporal balancing arises due to the inevitable mismatch between renewable electricity production and demand as a consequence of day/night cycles, weather effects and seasonal differences, while spatial balancing is resulting from differences between the locations of electricity production and consumption.

A future Swiss energy supply substantially relying on large shares of intermittent electricity generation (mainly photovoltaics and wind power) will need sufficient flexibility options. These must allow for shifting energy between day and night as well as from summer to winter: roof-top PV installations, which exhibit the largest potential for new renewable electricity generation in Switzerland by far, show a distinct seasonal peak in summer and daily peak at noon. These peaks in electricity generation – if not to be curtailed – must either be stored and re-used as electricity at times without sufficient generation, or transformed into other energy carriers such as gases and liquids, which can be used as e.g. transport or heating fuels. In addition to the flexible power plants operated in Switzerland already today, i.e. dam hydro plants and pump storage power plants, increasing the system's flexibility and installing of further flexible power plants and storages becomes inevitable at very high shares of wind and solar PV electricity production in order to operate the electricity system cost-efficiently and to ensure the system's secure operation [6]–[8][9]. A related aspect concerning flexibility options is their location in the system, which, preferably, is close to the Solar-PV generation sites which are often embedded in the consumption centres.

There are multiple technologies and measures to avoid CO_2 emissions and to increase the energy system's flexibility with Power-to-X (P2X) technologies representing one possible option of the technology portfolio [9]. As defined in this White Paper, the terminology "P2X" refers to a class of technologies that use an electro-chemical process to convert electricity into a gaseous or liquid energy carrier or chemical product (and vice versa), and which may include energy storage. As such, P2X technology not only offers the possibility of enhanced sector coupling between the power sector and energy demand sectors but also to provide short and long-term supply and demand balancing.

The objective of the White Paper its supplementary report is to collect the major existing P2X knowledge and to provide a synthesis and evaluation for the Swiss energy market. With the aim to derive a technical, economic and environmental assessment of P2X in the energy system, the gas market, the mobility sector and the electricity market are specifically investigated. Where possible, the White Paper also provides information on applications of P2X technologies in production industries. P2X technology stands for a cluster of technologies which use electricity and other inputs in order to produce other secondary energy carriers. Hence, P2X comprises multiple conversion pathways and energy carriers. In this White Paper we focus on the conversion to hydrogen as well as further gaseous and liquid energy carriers, such as methane, methanol, OME and FT-diesel, as well as the re-electrification where appropriate. For industrial P2X applications further energy carriers/conversion pathways might be included (depending on available information). Since this White Paper focusses on P2X technologies based on chemical conversion processes, technologies for the conversion of electricity with the purpose to produce heat as target product is not in the scope of this White Paper.

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2 Power-to-X technology overview: technology features, economics and environmental aspects

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The term "Power-to-X (P2X)" refers to a set of technologies, which can be used for converting electricity into gaseous and liquid energy carriers by electrolysis of water – which generates hydrogen and oxygen – and subsequent conversion of hydrogen into hydrocarbons such as synthetic methane and methanol. This chapter focuses on the current and future technical and economic characteristics of various conversion technologies and P2X pathways, with key details given in Table 1. We outline below the key conversion processes across all P2X pathways, starting by electrolysis of water, which is the common process to all routes which results in hydrogen generation:

First step: Electrolysis of water: $2\ H_2O \rightarrow 2\ H_2 + O_2$

There are various possible second steps to convert hydrogen into a hydrocarbon, requiring a carbon source, e.g. the input of CO_2 from a biogas plant:

Methanation of CO_2 and hydrogen: $CO_2 + 4\ H_2 \leftrightarrow CH_4 + 2\ H_2O$ or

Methanation of CO and hydrogen: $CO + 3\ H_2 \leftrightarrow CH_4 + H_2O$

Methanol synthesis: $CO_2 + 3\ H_2 \leftrightarrow CH_3OH + H_2O$

Synthesis of liquid fuels via Fischer-Tropsch process: $CO_2 + H_2 \rightarrow CO + H_2O$; $CO + H_2 \rightarrow C_xH_yOH + H_2O$

The third step refers to product upgrading/conversion and conditioning for further usage, and may require gas separation/cleaning, compression and pre-cooling.

P2X pathway	Conversion steps	Carbon atoms	Inputs	Technology	Outputs
Hydrogen (H2)	1(+3)	0	Electricity, water, heat, (in case of SOEC)	Electrolyser, hydrogen storage	Hydrogen, oxygen, heat
Synthetic methane (CH4)	1+2+3	1	Electricity, water, CO_2	Electrolyser, methanation reactor	Methane, oxygen, heat
Synthetic methanol (CH3OH)	1+2+3	1	Electricity, water, CO_2	Electrolyser, methanol synthesis reactor	Methanol, oxygen, heat
Synthetic liquids (CxHyOH)	1+2+3	variable	Electricity, water, (heat), CO_2	Electrolyser, Fischer-Tropsch reactor	Liquid hydro-carbon fuels, oxygen, heat
Ammonia (NH3)	1+2+3	0	Electricity, water, nitrogen (N_2)	Electrolyser, Ammonia synthesis reactor	Ammonia, oxygen, heat

Table 1: Technology overview of various P2X pathways including main technologies and their major in-/outputs

Technology options

The following technology options are considered across the various P2X routes:

- Electrolyser: alkaline, Polymer electrolyte membrane (PEM) and solid oxide (SO)
- Hydrogen storage: compressed gas[1]
- Methanation reactor: thermochemical reactor and biological reactor
- Fischer-Tropsch synthesis: thermochemical reactor; CO is generated from CO_2 via inverse water gas shift
- Methane storage: Synthetic methane can be stored in the natural gas grid or in dedicated storage tanks (above ground or underground)
- Synthetic liquid storage: synthetic liquids can be stored in tanks as other liquid fuels such as gasoline

Applications

The various P2X pathways presented in Table 1 can produce various products such as hydrogen, methane and liquid synthetic fuels, which also can be used for various purposes. Some key applications of the main P2X outputs are fuels for engines, electricity and heat production with fuel cells and turbines, transport fuels, but also as feedstock in chemical and industrial processes. They can also be stored, partially using the existing storage infrastructure (e.g., the natural gas grid for methane) and therefore facilitate the integration of intermittent renewable power generation as well as the further integration of the energy system. An important angle to consider is that the main outputs for each P2X pathway, namely hydrogen, methane, methanol and synthetic liquids require various levels of integration within the current energy system. The most extreme case is hydrogen, for which an alternative economy was firstly postulated. This is not the case anymore and there is now an agreement that hydrogen would only complement the existing electricity and gas infrastructure. However, various technical challenges emerge from, for example, the injection (and mixture) of hydrogen into the natural gas network [10], [11]. In this regard, methane, methanol and other synthetics fuels are more flexible, e.g., easy to be stored and/or related infrastrucutre is on place.

2.1 Techno-economic Perspective

This section gives the current and future techno-economic characteristics of key technologies involved in the various P2X pathways. At the end, we link technologies with specific P2X pathways in order to estimate the total cost of production, namely the levelized cost. The list of key parameters, including relevant uncertainty ranges when possible, discussed in this section, is given below:

- Technical: efficiency, lifetime, degradation, dynamic response, flexibility, reliability, technology readiness level (some indicators may be assessed on qualitative terms) (make use of CEDA and other on-going projects).
- Economic: capital expenditures (CAPEX) and operational expenditures (OPEX); and levelized cost (LCOX) as techno-economic indicator.

We do not include profitability indicators such as the net present value (NPV) and internal rate of return (IRR), since they rely on revenue streams, for which future values are subject to future market

[1] Considering that space is not a dominant constraint in P2X systems, we limit the scope of hydrogen storage to only compressed gas. Therefore, we exclude other promising options such as liquefied hydrogen or metal hydrides, and also technologies for applications where there is weight or a space constraint, due to their still early development; lacking maturity results in substantially higher cost.

conditions and therefore very uncertain. We also compare with the final cost of conventional production routes which rely on fossil fuels. Our data are mainly based on values reported by the previous literature, mainly from studies targeting countries in Europe. We take the year 2015 as benchmark for the current status of the technology, while projections for the year 2020 and 2030 are based on a review of the literature on e.g., learning curves and expert elicitations. The final cost trajectories will be strongly affected by research and development (R&D) efforts and final production volumes [9].

2.1.1 Electrolysis

Capital expenditure (CAPEX)

Table 2 gives the CAPEX for various electrolyser technologies including the stack (namely the various cells which produce hydrogen), the electronics and balance of plant (BoP). CAPEX data are representative for electrolyser systems with a capacity between 1 MW^{2}_{el} and 10 MW_{el} which corresponds to the scale of the deployment in the recent years, at the pilot and commercial level [12], [13]. The additional cost related to the transport of the electrolyser from factory to the location, installation and commissioning, excluding civil work and connection to the rest of components within the P2X plant, should add between 10% and 20% of the data given in Table 2 [14]. Regarding the OPEX, electricity is markedly the main contributor but at the same time, it is important to reach high capacity factors, therefore there is a trade-off between the number of operational hours and electricity cost [15]. Beyond electricity, other factors such as maintenance cost are less technology-dependant and have been assumed to be in a range of 2-7% of the CAPEX [14], [16]–[18].

CAPEX (CHF/kW_{el})	2015	2020	2030
Alkaline	850-1100-1400	650-1500	460-920
PEM	900-2200-2600	800-2300	460-2000
SO	>2200	1600-5750	600-4600

Table 2: CAPEX of various electrolysis technologies relative to the electric capacity depending on the year. Data are taken from references [13], [16], [17], which at the same time synthesise other many relevant sources. All data are given in the form of ranges including a minimum and maximum value. In addition, a typical value is also given for alkaline and PEM technologies in 2015.

Alkaline is expected to remain the most low-cost solution in the coming years, but the extra cost associated with PEM electrolysis could become marginal by 2030 if R&D funding increases and production scales up. However, it is expected that the second factor matters more to reach a price of 400 CHF/kW_{el} by 2030. This could also be the case for SO electrolysis, but there is much more uncertainty for this technology according to experts taking part in elicitation study, as reflected by the broad given to the CAPEX of SO technology by 2030 [13].

Other performance indicators for electrolysers

In addition to the CAPEX, other criteria such as lifetime, efficiency and ageing should be considered to select an electrolyser for a given application. Table 3 gives the value at nominal conditions and if we compare with Table 2, we can see that CAPEX and efficiency are positively correlated across the three technologies. SO electrolysis performs at high temperature, between 700-900 °C, resulting in higher efficiency than PEM and alkaline technologies. As a consequence, the efficiency target for 2030 remains the same and R&D mainly focus on CAPEX. However, it is necessary to consider that the

[2] We use the subindex el and th for electric and thermal, in particular to refer to the nominal capacity of the technology. For thermal-based values, we always refer to the high heating value (HHV).

performance of an electrolyser system, in particular when using renewable electricity supply, may be far from these nominal conditions, e.g., due to partial loading. Large P2X systems can, however, integrate several stacks in parallel in order to improve the performance and/or increase the operational range.

The stack efficiency is affected by parameters such as operating temperature and pressure which at the same time depend on the load operation. The improvement of stack efficiency at partial load operation is counterbalanced with the electricity consumption of the BoP which does not decrease markedly with partial load operation. As a result, the efficiency of an alkaline electrolyser was reported to increase by only 2% when the load reduces from full load to 40% of the nominal [19]. This could be even negative if an external compressor is in place. Another value reported in the same study for PEM technology refers to a more marked increase of 7% in efficiency when the electrolyser systems operates at 62.5% load (with regard to 100% load). Interestingly, the operational load range of alkaline electrolysis has increased during the last decade in order to adapt this technology to the intermittent operation associated with renewable electricity supply and it can be as low as 20-25% of the nominal capacity for current systems available in the market [19].

Efficiency (%)	2015	2020	2030
Alkaline	53-75-78	58-80	62-81
PEM	53-80-82	64-89	64-89
SO	90-96-98	90-98	90-98

Table 3: Nominal system efficiency at the beginning of operation of various electrolysis technologies based on the high heating value (HHV) of hydrogen depending on the year. Data are taken from references [14], [16], [17], [19], [20] and excluding energy needs for hydrogen compression. All data correspond to ranges including a minimum and maximum value except for 2015 data for which a typical value is also given.

The operating temperature also has a positive impact on electricity consumption (i.e. efficiency increase) and sensitivities of 0.02 kWh_e/Nm^3/10 °C and 0.024 kWh_e/Nm^3/10 °C for alkaline and PEM technologies, respectively, have been reported [19]. Regarding pressure, hydrogen generated can be pressurized internally (i.e. increasing the operation pressure of the electrolyser) or externally (i.e. adding and additional compressor) but the former is optimal regarding overall efficiency at the expense of an increase of the stack degradation. The lifetime values of electrolyser systems, which are given in Table 4 for various technologies, are much related to degradation which also depends on operating conditions. Despite enormous improvements over the last decade, current degradation rates are still larger for PEM (up 3-8 µV/h) than for alkaline electrolysis (1-2 µV/h corresponding to approximately 0.5-1% efficiency degradation per year). Future projections for PEM and SO technologies still reflect great uncertainty in their lifetime and it is therefore expected that alkaline still continues to be the most reliable technology by 2030.

Lifetime (hr)	2015	2020	2030
Alkaline	60000-60000-96000	90000-100000	90000-100000
PEM	20000-40000-60000	60000-100000	65000-100000
SO	8000	25000	60000-100000

Table 4: Lifetime of various electrolysis technologies depending on the year. Data are taken from references [16], [17], [20], while reference [21] is used for the lifetime of SO electrolysis in 2020. Data for SO electrolysis in 2030 are in agreement with the objectives for other electrolysis technologies. All data correspond to ranges including a minimum and maximum value except for alkaline and PEM technologies in 2015 for which a typical value is also given, and SO in 2015 and 2020 for which a single datum is given.

Components for the different routes

The electrolyser is the core system for any P2X route, but other components, described in this section, are needed to transform it to the various products outlined in Table 1. We therefore discuss other components which allow the transformation of hydrogen into other products which can be integrated into the existing infrastructure already in place, e.g., synthetic methane, and/or add value to certain applications, e.g., renewable fuels for the chemical industry.

2.1.2 Power-to-Power (P2P) - route

In addition to an electrolyser, a P2P system also requires a hydrogen buffer to shift in time the electricity used for electrolysis (e.g., from renewable sources) and a fuel cell (FC) system or turbine to generate electricity for the application later on (e.g., meeting electricity peak demand).

Opposite to electrolyser systems for which current trends move towards centralised systems of several MWs or beyond, the market of FC systems integrates both the centralised and distributed scales. For example, considerable field trial efforts have been made across various geographies (e.g., Japan, Germany, South Korea and United Kingdom) for micro-CHP systems installed in individual and/or common buildings. Here we discuss for three different scales, namely micro combined heating and power (CHP) units for individual dwellings (a representative size is 1 $kW_{el)}$, CHP systems for commercial applications (with a typical installed capacity of 50 kW_{el} and 40 kW_{th}) and FC systems for utility applications with a typical size of 1.4 MW_{el} and 1.1 kW_{th}. For the latter, FC systems can however reach much higher installed capacities given their modularity. Data presented in Table 5 for the years 2020 and 2030 are technology agnostic since projections refers to targets for cost competitiveness based on production volumes. Based on current developments, it is however acknowledged that technologies such as polymer electrolyte membrane fuel cell (PEMFC) and molten carbonate fuel cell (MCFC) are suitable for micro-CHP and MW_{el} systems, respectively, while solid oxide fuel cell (SOFC) technology is used across both the micro and commercial scales. The range given in Table 5 for data in 2015 already includes the various technologies which are suitable for each scale.

Capex (CHF/kW_{el})		**2015**	**2020**	**2030**
FC system	**Micro-CHP**	14000-26000	8300	6400
	Commercial	13000-23000	4000	2300
	Utility scale	3000-3600	2300-4600	1700

Table 5: CAPEX for stationary FC systems relative to the electrical output. Data are taken from a reference which objectives for FCs at the EU level [22]. Data for 2015 are given in ranges including minimum and maximum, but data for 2020 and 2030 are based on a single data point based on expert projections. Data for 2030 are based on mass production while data for 2020 are based on significant scale-up of current productions at factory level, e.g., production capacity of 10000 and 50 units of micro-CHP and MW_{el} scale systems, respectively.

Performance parameters are on the other hand technology dependent. Table 6 shows selected performance parameters for various technologies based on current data in the field [23] [24].

Technology	Scale	Electrical efficiency (%)	Thermal efficiency (%)	Degradation rate (% p.a.)	Dynamic response	Maximum lifetime (hr)
PEMFC	**Micro-CHP**	25-35	55-65	1	Seconds	6000-8000
SOFC	**Micro-CHP**	45-55	35-45	1-2.5	Hours	20000-90000
	Commercial	50-60	30-40			
MCFC	**Utility scale**	43-47	38-42	1.5	Hours	20000-30000

Table 6: Current performance parameters for various FC technologies depending on the size [24]–[26].

Regarding the storage of hydrogen, the current CAPEX of compressed gas storage varies between 200 and 2000 CHF/kg$_{H2}$ depending on the pressure level, lower than 100 bar and higher than 500 bar, respectively. As mentioned above, alternatives for hydrogen storage such as liquefied hydrogen and metal hydrides still have much higher CAPEX, e.g., around 10000 CHF/kg$_{H2}$, despite recent progress in their technology readiness levels (TRLs). The Department of Energy (DOE) of the United States, reported a TRL between 5-7 for liquefied hydrogen, and between 7-9 for metal hydrides, which are already integrated into some niche applications such as industrial forklifts [27].

2.1.3 Power-to-Methane (P2M) - route

P2M requires a reactor to convert carbon dioxide (CO_2) to synthetic methane through hydrogenation. There are two key methods to obtain synthetic methane from hydrogen and carbon dioxide, namely thermochemical catalysis and biological catalysis. Table 7 gives the CAPEX of both technologies based on the high heating value (HHV) of the synthetic natural gas. For thermochemical methanation, economies of scale are very marked and the price per kW$_{th}$ installed can be reduced by more than half when the size of the system increases from 1 MW$_{th}$ to 10 MW$_{th}$, from 1150 CHF/kW$_{th}$ to 460 CHF/kW$_{th}$ [28]. It has also been reported that the current CAPEX for thermochemical reactors reduce to 200 CHF/kW$_{th}$ and 100 CHF/kW$_{th}$ for a 0.5 GW$_{th}$ and 1.8 GW$_{th}$ system [29], but these sizes may be not representative for Switzerland, at least in the coming years, considering that representative electrolyser systems correspond to a few MWs. On the other hand, cost trajectories for thermochemical rectors seem to include less aggressive learning factors than for electrolysis. Finally, OPEX values between 5-10% have been reported in the literature but a more recent calculation for a 1 MW$_{th}$ system increased this to 15% p.a. of CAPEX. Table 8 details the performance characteristics for both technologies. The upper value for the efficiency is achieved when heat losses are reused within the reactor.

Capex (CHF/kW$_{th}$)	**2015**	**2020**	**2030**
Thermochemical reactor	460-1150	300-700	250-600
Biological reactor	1100	300-700	250-700

Table 7: CAPEX of various methanation reactors depending on the year. Data are taken from references [14], [28], [30], [31]. Lower and upper values refer to the 1 MW$_{th}$ scale and 10 MW$_{th}$ scale, respectively. Future objectives for biological reactors are in agreement with those published for thermochemical reactors.

Table 8 reports the current efficiency and lifetime values for thermochemical and biological reactors, which are, in general, similar. The brackets inserted in the upper limit of the efficiency of thermochemical technology considers heat integration and re-use, which can increase the efficiency up to 95%.

Parameter	Efficiency (%)	Lifetime
Thermochemical reactor	78-(95)	10000-25000 hr for the catalysts, 20 year for reactor and BoP
Biological reactor	78-85	Living catalyst, 20 year for reactor and BoP

Table 8: Current performance parameters for methanation reactor technologies [4]. Upper efficiency values for thermochemical reactors correspond to systems where a heat recovery system is on place.

2.1.4 Power-to-Liquid (P2L) - route

Among synthetic fuels, methanol is a very interesting option due to its flexibility and its development would not require an alternative infrastructure in comparison with hydrogen. The synthesis of methanol is already a common process in the industrial sector based on syngas[3], i.e. the reaction of carbon monoxide and hydrogen. Alternatively, methanol production can be coupled with renewable energy sources and be produced via a route based on hydrogen generated from electrolysis and carbon dioxide. In this case, methanol can be directly synthesised from carbon dioxide or alternatively, first be converted to carbon monoxide (CO) via reverse water gas shift, and then methanol is produced in a second step. Lower CAPEX data are given for the first method as reported in Table 9. An alternative P2X route to produce liquid hydrocarbon fuels consists of using a Fischer-Tropsch reactor to produce various alkanes; the product distribution depends on the type of catalyst used [32]. For example, N-alkanes (long chain hydrocarbons) are the main product of the cobalt catalysed Fischer-Tropsch synthesis. Then, these N-alkanes can be upgraded down-stream to fuels which are suitable for industrial applications, e.g., synthetic jet fuel or diesel [33]. Based on the International Energy Agency, the CAPEX of Fischer-Tropsch reactors is expeted to decrease to 760 CHF/kW$_{th}$ by 2030 [34].

	Current CAPEX (CHF/kW$_{th}$)	OPEX (% CAPEX p.a.)	Lifetime (years)	Efficiency (%)
Methanol reactor	120-250-310	5-10	30-40	82
Fischer-Tropsch reactor	80-300	5-10	30-40	70-80%

Table 9: Key parameters for methanol and Fischer-Tropsch reactors involved in the production of methanol and alkanes via a PtL route [33], [35].

2.1.5 Technology Readiness Levels by component and route

TRLs refer to the progress made in a given technology towards being a ready-to-use product by final consumers. It is a concept originally developed by the National Aeronautics and Space Administration (NASA) in the 1970s [22]. TRLs allow for comparison among the maturity of various technologies. Regarding P2X, the different technologies utilized for the various routes have various TRLs at the moment. Electrolyser technologies, which are common to any route, are in general more mature, in particular alkaline technology, and PEM to a lesser extent (this however does not apply to SO electrolysis). Within the P2X concept, methanation reactor technologies have also become more mature recently, reaching the commercial level following some successful demonstration projects, e.g., a 6.3 MW$_{el}$ PtM plant in Werlte (Germany) using thermochemical technology for methanation [36], and the 1 MW$_{el}$ plant from the BiOCAT project in Copenhagen [37] [38]. Finally, Fischer-Tropsch and methanol reactors have already been widely applied for the chemical industry, but their implementation within P2L routes is still in development. Table 10 gives the TRLs of various technologies used across the different P2X routes.

[3] However, there is no methanol production in Switzerland.

Component	Route	Technology	TRL
Electrolysis	P2P, PtM, P2L	Alkaline	9. Commercial
		PEM	7-8. In demonstration and commercial
		SOEC	5-7. In development and demonstration
Fuel cell	P2P	PEMFC	7-8. In demonstration and commercial
	P2P	SOFC	7-8. In demonstration and commercial
	P2P	MCFC	7-8. In demonstration and commercial
Methanation	P2M	Thermochemical reactor	7-8. In demonstration and commercial
	P2M	Biological reactor	5-7. In development and demonstration
Fischer-Tropsch reactor	P2L	RWGS+FT	5-6. In development and demonstration
Methanol reactor	P2L	Low temperature	5-8. In development and commercial

Table 10: TRLs for the various technologies utilised across the various P2X routes [14], [22], [39]–[41]. For Fischer-Tropsch and methanol reactors, the lower and upper limits correspond to high and low temperature operation.

2.1.6 Levelized cost for various P2X routes

Figure 2 is a representation of the levelized cost for the various P2X routes, i.e. the present total cost associated with the main produced output (e.g., synthetic methane for a P2M system) throughout the life, accounting for round trip efficiency, degradation and capacity factor of the plant. The definition of the levelized cost, *LCOX* (CHF/MWh), is given by Equation 1. This indicator considers key aspects such as CAPEX, OPEX, lifetime, efficiency and capacity factor. The boundary is set at the P2X system and therefore the presented data do not include other factors such as associated infrastructure (for the use of key outputs within the energy system, e.g., extra infrastructure for the injection of hydrogen in the case of P2H). An important consideration is that the data presented below have not been harmonised, therefore it corresponds to different type of assumptions. For example, the standard cost of financing for hydrogen systems in Switzerland including risk, represented by a discount factor, has been considered to be 8% for Switzerland in the previous literature [18]. However, some of the considered studies are from neighbouring countries such as Germany and may have used different values. Despite this limitation, the data presented below can be used to stablish ranges for the cost of production across various P2X routes.

$$LCOX = \frac{CAPEX + \sum_{y=1}^{n} \frac{OPEX}{(1+r)^y}}{\sum_{y=1}^{n} \frac{E_{X_y}}{(1+r)^y}} \qquad (1)$$

We can notice importance differences in the production costs by route as well as great variation among the data for any route. The differences among the various P2X routes are due to the various number of processed involved as well as the different TRLs associated with them. P2H is the most cost effective route which a medium levelized cost of 144 CHF/MWh$_{th}$, overall ranging between 100-180 CHF/MWh$_{th}$ [14], [18], [42]–[44]. The levelized cost of P2H is very sensitive to the electricity price source and management strategy (which impacts the capacity factor), type of electrolyser technology, whether electricity grid fees are considered or not and system efficiency. For the Swiss context, the electricity supply including grid fees accounts for around 50% of the final levelized cost while grid charges contribute 20% [45]. Furthermore, PEM electrolysis corresponds to more than 20% of the LCOX for P2H systems on the MW$_{el}$ scale [42]. Producing hydrogen with P2H systems, with a cost over 100 CHF/MWh$_{th}$, is still much more costly than producing it with traditional methods such as natural gas steam reforming with cost around 60 CHF/MWh$_{th}$ based on a gas price level of 40 CHF/MWh$_{th}$ [45][46], [47].

The P2M route adds several extra factors to the LCOX, such as the CAPEX of the methanation reactor, its extra efficiency drop and the cost associated with the CO_2. This increases the levelized cost to a range between 170-250 CHF/MWh$_{th}$ (according to distribution in Figure 2). However, the total extra cost is very much related to the type of CO_2 source. For example, the total extra cost of P2M regarding P2H, associated with the CO_2 supply can vary from 35 CHF/MWh$_{th}$ for CO_2 supplied from biogas upgrading plants due to win-win situation with P2M plants up to 85 CHF/MWh$_{th}$ for CO_2 captured from the air. Therefore, the extrat cost of CO_2 captured from the air is 50 CHF/MWh$_{th}$. It is expected that the cost of other CO_2 supply options such as fossils power and cement plants lies in between since the CO_2 concentration is greater than in the atmosphere. Without including taxes and external costs, the cost of synthetic methane production is still at least five times higher than the cost of conventional natural gas in the wholesale market, around 30 CHF/MWh$_{th}$ excluding any taxes [34], [45]. The main output product from the P2L pathway is a liquid which is more convenient to store than synthetic methane resulting from P2M, but this comes with an extra cost, and the medium of the distribution goes up to 273 CHF/MWh$_{th}$, with a range between 210-390 CHF/MWh$_{th}$ [48], [49].

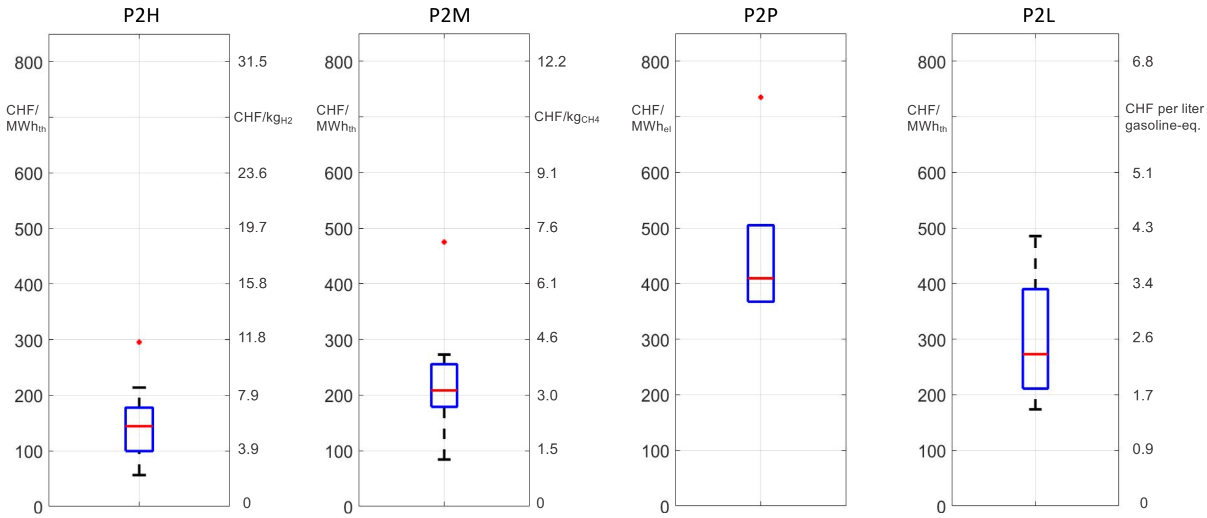

Figure 2: Distribution of the levelized cost for the various P2X routes based on current cost and performance data (representative for the year 2015). The boxplots include the median (middle quartile inside the box), 25th and 75th percentiles. The whiskers extend to the most extreme data points not considered outliers, and the outliers are plotted individually using the '•' symbol. For routes producing gas, data are based on the HHV; N.B.: for the P2L route, the unit "CHF per litre gasoline eq." represents an energy-related cost matrix with limited comparability to retail fuel prices which additionally entail a significant tax component.

The levelized cost increases dramatically when the generated gas is finally transformed back into electricity as shown in Figure 10. There is even more variability on the LCOX for this route because values depend on the former route integrated to generate the gas (i.e. P2H or P2M), the type of electricity generator (e.g., FC system or turbine) and the hydrogen storage needs, if relevant. Here, we focus on both P2P routes providing mid-term (hours) and seasonal storage. The medium cost is 420 CHF/MWh$_{el}$ for a 1 MW$_{el}$ system using P2H, hydrogen storage and PEMFC, which is also representative for a 100 MW$_{el}$ system based on P2M, the natural gas network and a combined gas cycle plant [50].

2.2 Environmental Perspective

The environmental performance of power-to-X technologies and systems needs to be evaluated employing a Life Cycle Assessment (LCA) approach, which takes into account production, use, and disposal/recycling of products, supply chains and related infrastructure [51], [52]. Only the LCA approach can provide a comprehensive and unbiased analysis with non-biased system boundaries. However, the LCA approach introduces additional complexity, especially for P2X generation pathways, since these often include multi-output processes and the values/benefits of by-products need to be considered. In the end, potential environmental benefits and drawbacks of P2X systems need to be quantified in comparison to "conventional" generation pathways of hydrogen, natural gas, electricity, chemical feedstocks and the associated utilization/services such as transport and heating (Figure 3). Furthermore, it needs to be considered whether the electricity used in P2X processes is "surplus/excess power", which would otherwise be curtailed and can therefore be considered as free of environmental burdens, or not. The future availability of such "excess power" in Switzerland depends on several factors such as future expansion of intermittent renewables in Switzerland, Switzerland's integration into the European electricity market and its development in terms of power plant park, the availability of other short- and long-terms storage options, etc.

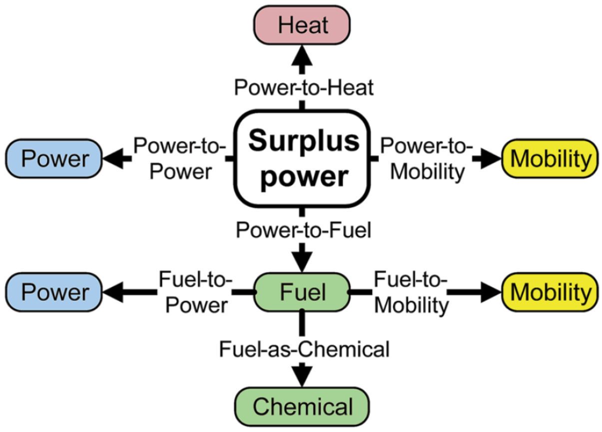

Figure 3: Schematic representation of different conversion pathways for surplus power [53].

For the environmental assessment, further complexity is added by different available technologies fulfilling the same purpose and different potential configurations of P2X pathways: different electrolyser and methanation technologies can be used, CO_2 can be extracted from various sources, and synthetic gases and liquids can be used for different purposes and therefore replace different conventional alternatives (Figure 4).

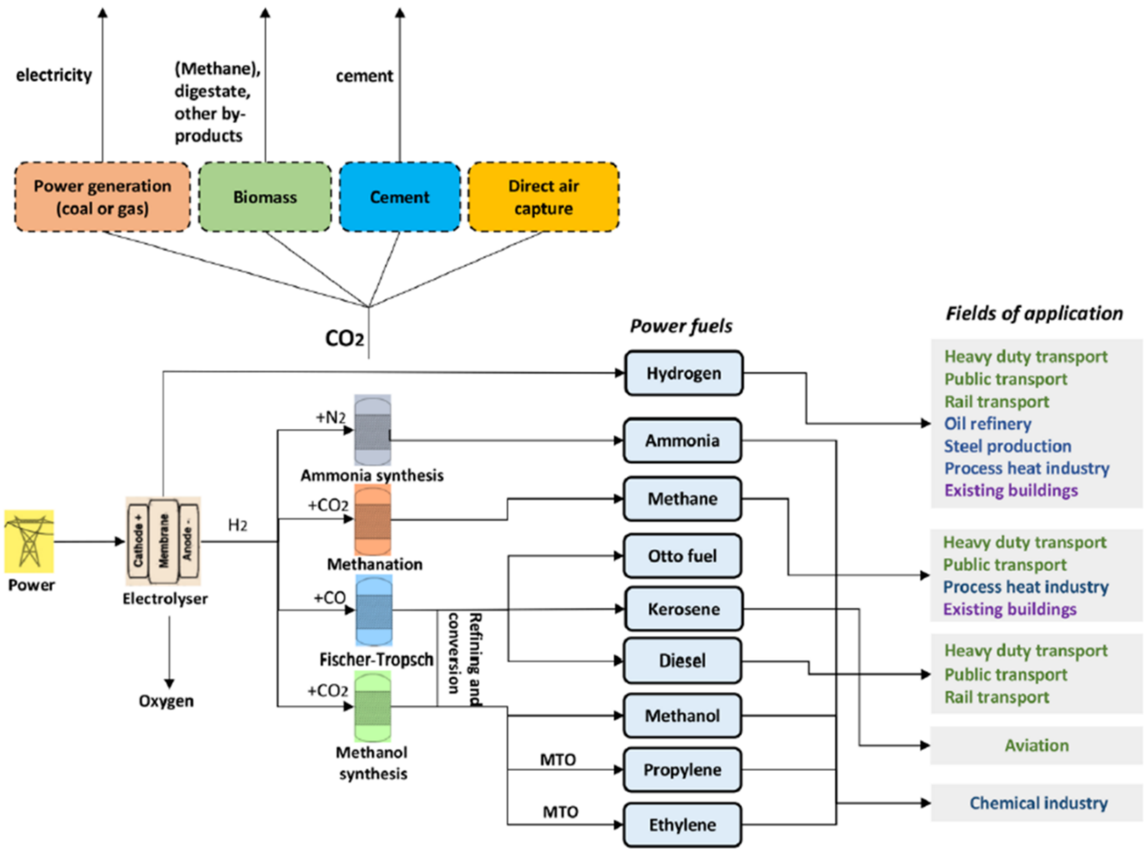

Figure 4: System scheme of different power-to-gas production chains with technology alternatives (based on [54]).

Overall, there are only few recent scientific publications evaluating the environmental performance of P2X with a life-cycle perspective [45], [50], [55]–[60]. None of these publications covers the complete P2X technology portfolio, reflection of Swiss boundary conditions is only partially given, and the spectrum of environmental burdens covered is often very limited, mostly focusing on greenhouse gas (GHG) emissions. Furthermore, some of these publications lack scientific rigour and/or transparency and therefore, only a very limited number of generally valid conclusions regarding the environmental benefits and drawbacks of P2X can be drawn[4]:

1. Power-to-hydrogen (1): Electricity supply for electrolysis is the dominating factor concerning the environmental performance of P2H. Using renewable electricity such as wind power or photovoltaics results in substantially lower life-cycle GHG emissions than conventional hydrogen production via steam methane reforming of natural gas (Figure 5). Also using current average Swiss electricity from the grid (including imports) is advantageous in terms of GHG emissions. Compared to steam methane reforming of natural gas, the threshold for the GHG-intensity of electricity used for electrolysis is around 210 g CO_2eq/kWh [56].[5]

[4] The following figures have been extracted from different recent publications; potentially different boundary conditions and assumptions in the different analyses need to be taken into account for interpretation of results. Direct comparison of results from different graphs might therefore be misleading.

[5] GHG intensities of electricity production in Switzerland: hydropower: about 10 g CO_{2eq}/kWh, wind power: 10-30 g CO_{2eq}/kWh, PV: 50-100 g CO_{2eq}/kWh, Swiss supply mix: 100-150 g CO_{2eq}/kWh, natural gas combined cycle power plant: 400-500 g CO_{2eq}/kWh.

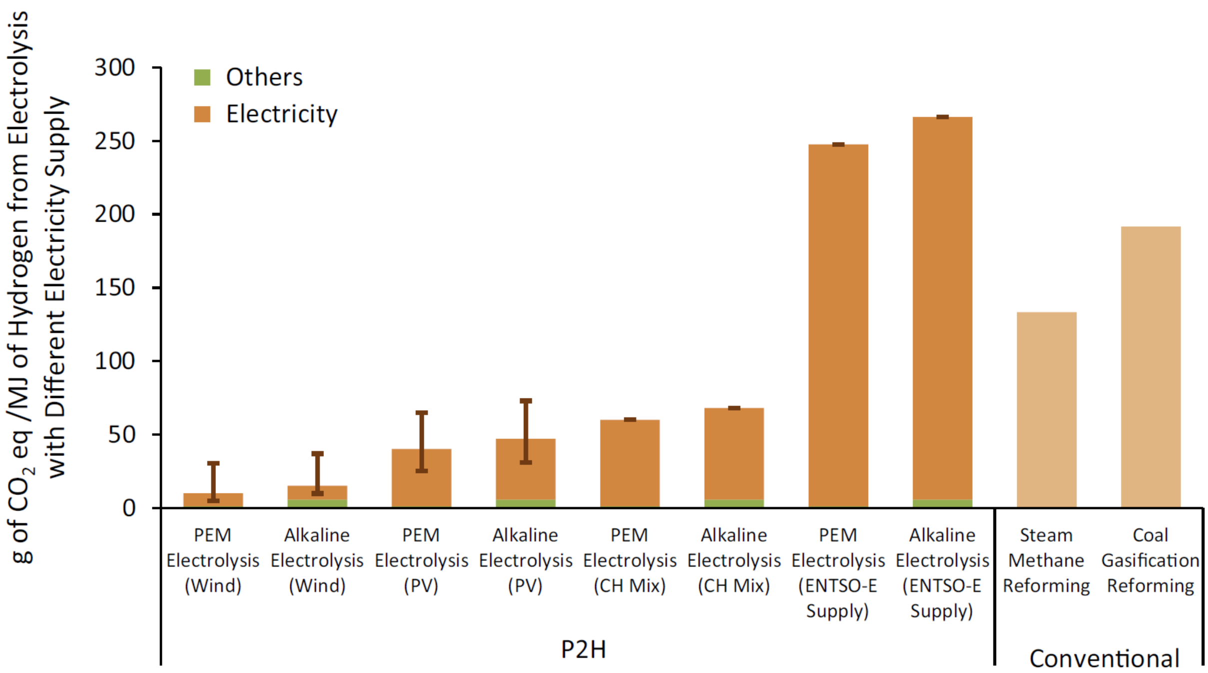

Figure 5: Life cycle GHG emissions of hydrogen production via electrolysis vs conventional production from natural gas and coal[56]. Error bars indicate variability of annual yields of photovoltaic and wind power generation in Switzerland depending on the location.

2. Power to hydrogen (2): Also regarding other environmental burdens than GHG emissions, "clean" electricity is a prerequisite for an environmental performance of P2H better than conventional steam methane reforming of natural gas (Figure 6).[45]

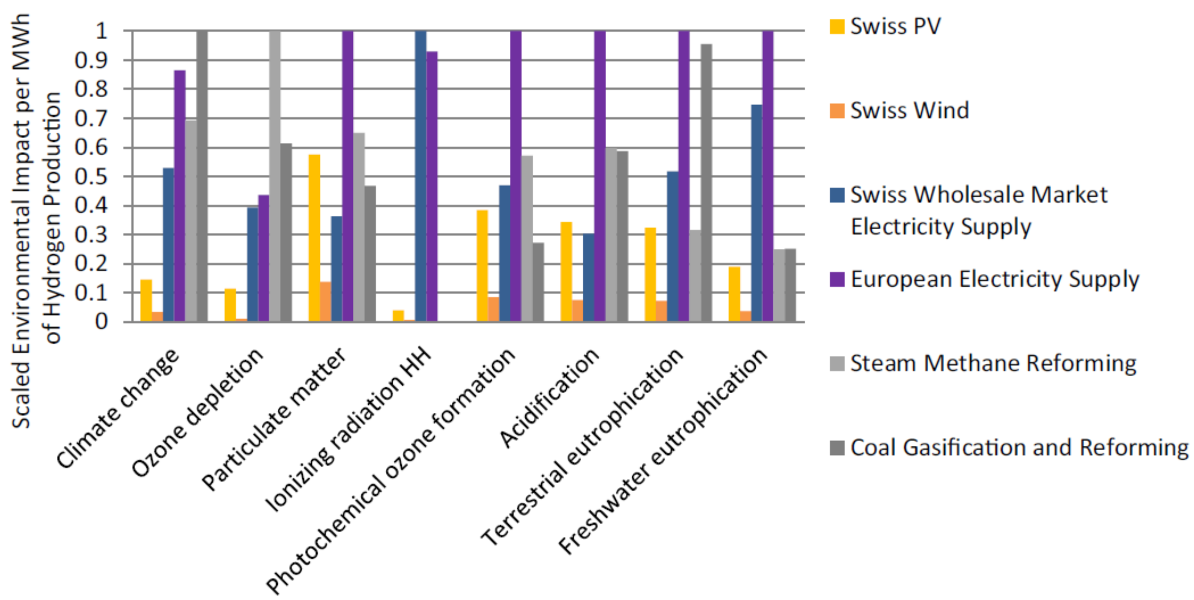

Figure 6: Life cycle environmental burdens of hydrogen production via electrolysis vs conventional production from natural gas and coal[45]. PV: photovoltaics.

3. Power to methane: Regarding life-cycle GHG emissions, direct air capture of CO_2 and biogenic CO_2 sources perform in general better than CO_2 from fossil or mineral sources such as power plants and cement production (Figure 7), since CO_2 from the atmosphere and biogenic sources does not represent an additional entry to the natural carbon cycle [61]. However, exceptions from this trend exist and quantitative comparison strongly depends on several factors such as energy sources for direct air capture of CO_2, biogenic carbon feedstocks, technology specification of cement and power plants, etc.[56], [59].

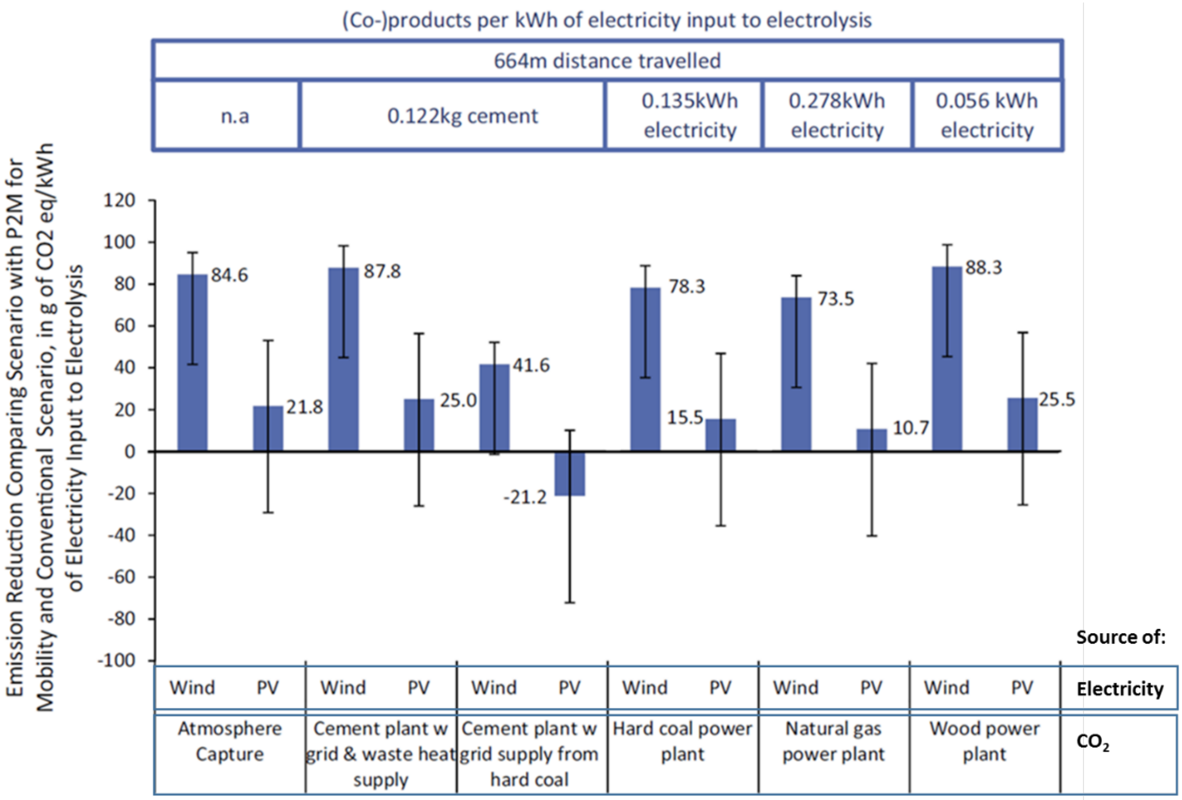

Figure 7: Reduction of life cycle GHG emissions using SNG compared to natural gas vehicles (conventional scenario), taking into account multi-functionality of processes for power generation and cement production via system expansion[56]. Error bars reflect variability of annual wind power and solar photovoltaics yields in Switzerland. PV: photovoltaics. In each case, 1 kWh of electricity is used for electrolysis and the resulting amount of SNG is used as vehicle fuel allowing for driving a distance of 664 meters in a mid-sized passenger vehicle. Cement and electricity are by-products of some processes capturing CO_2. Emission reductions are quantified in comparison to a natural gas vehicle driving the same distance and conventional supply of the by-product (without CO_2 capture).

4. Preferred use of “surplus electricity”: In order to avoid energy losses in P2X production pathways, hydrogen is the preferred product and substantially higher GHG emissions can be avoided by using hydrogen directly instead of further converting it to SNG (Figure 8)[56].

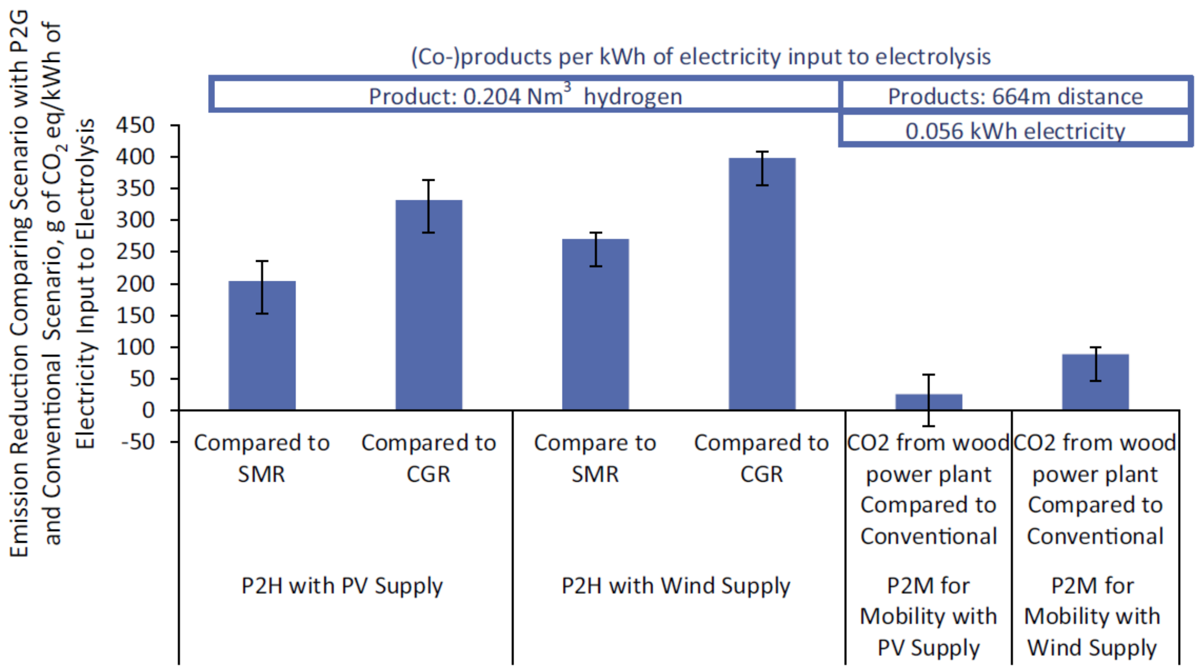

Figure 8: Reduction of life-cycle GHG emissions of P2H and P2M, respectively, compared to their conventional production (hydrogen) and use in natural gas vehicles, respectively[56]. Error bars reflect variability of annual wind power and solar photovoltaics yields in Switzerland. SMR: Steam methane reforming; CGR: coal gasification reforming; PV: photovoltaics.

5. Use of SNG as vehicle fuel: In comparison to battery electric and fuel cell electric passenger vehicles, SNG vehicles can only provide benefits in terms of life-cycle GHG emissions, if the CO_2-intensity of electricity used SNG production is extremely low. Already above a CO_2-intensity of about 100 g CO_{2eq}/kWh, SNG vehicles generate higher life-cycle GHG emissions than diesel and CNG cars, even if CO_2 for SNG production is captured from the air (Figure 9). A recent analysis [58] also shows that due to comparatively higher inefficiencies in the SNG supply chain, SNG vehicles perform worse for many other impact categories than battery electric vehicles, which can directly use renewable electricity.

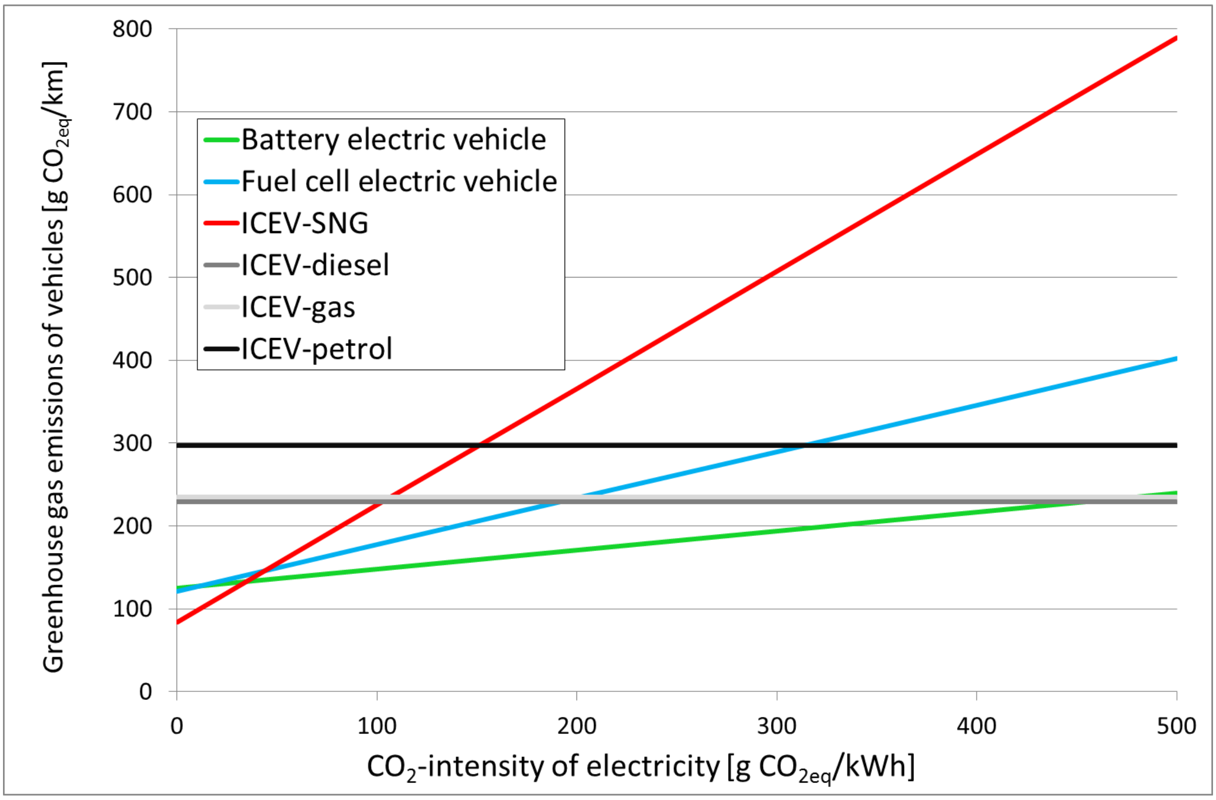

Figure 9: Life-cycle GHG emissions of passenger vehicles as a function of the CO_2-intensity of electricity used for charging batteries of battery electric vehicles, generating hydrogen for fuel cell vehicles or generating SNG for SNG vehicles. [62] In this case it is assumed that CO_2 for SNG production is directly captured from the atmosphere. ICEV: Internal combustion engine vehicle. For comparison: GHG intensities of electricity production in Switzerland: hydropower: about 10 g CO_{2eq}/kWh, wind power: 10-30 g CO_{2eq}/kWh, PV: 50-100 g CO_{2eq}/kWh, Swiss supply mix: 100-150 g CO_{2eq}/kWh, natural gas combined cycle power plant: 400-500 g CO_{2eq}/kWh.[63]

6. Re-electrification of hydrogen and SNG compared to other storage options: A recent integrated economic and environmental assessment of different electricity storage technologies [50] showed that P2M as an electricity storage option is most competitive to alternatives such as pumped hydro, batteries and compressed air storage as a long-term storage option, both from the economic as well as from the environmental perspective. For short-term electricity storage, batteries allow for much lower storage costs than P2M technologies.

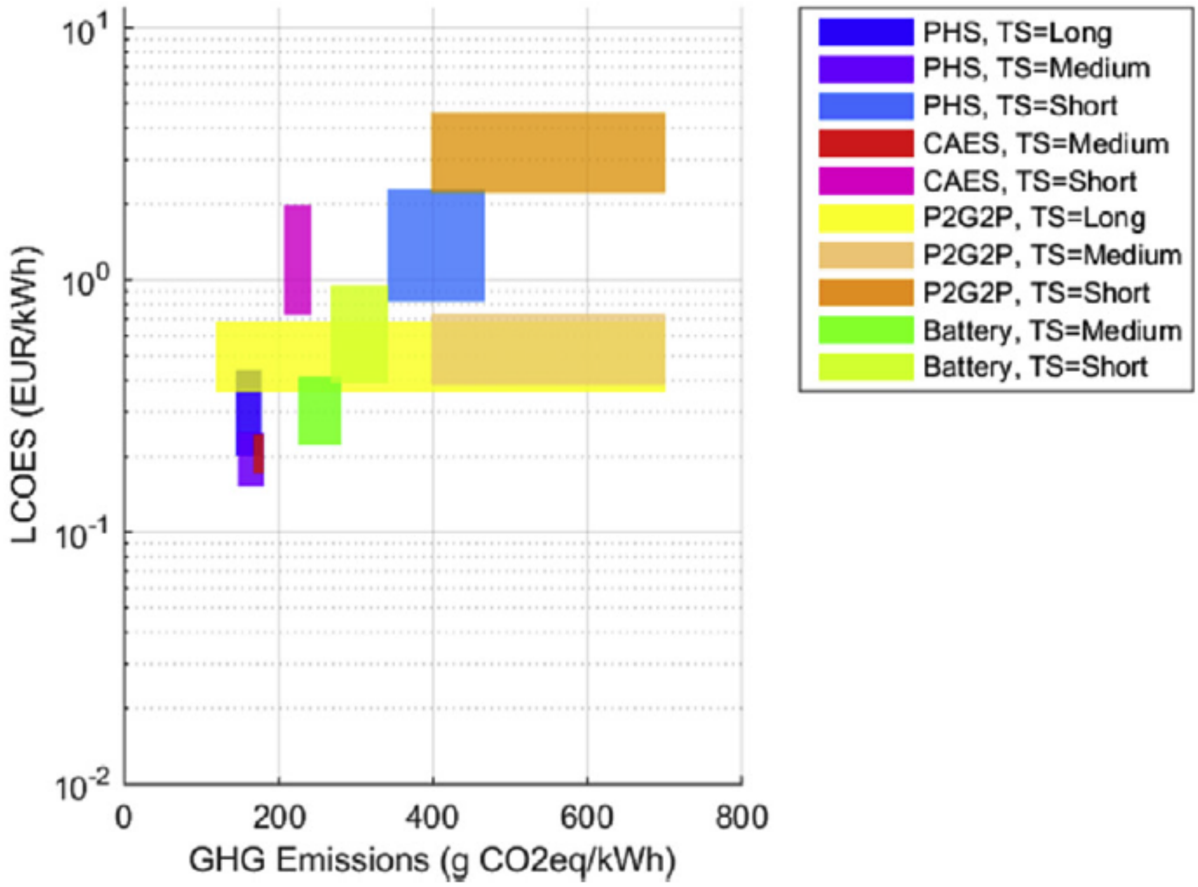

Figure 10: Levelized costs of electricity storage and associated life cycle GHG emissions for 100 MW electricity storage systems considering variations in technical factors (lifetime, efficiency, and costs) and Swiss grid mix supply stored at an electricity price of 0.10 EUR/kWh [50]. PHS: pumped hydro storage; CAES: compressed air energy storage; P2P: power-to-gas-to-power; TS: storage duration.

3 Embedding P2X into markets

3.1 Sources of carbon/CO_2 for synthetic hydrocarbon production

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For the production of hydrocarbons by converting hydrogen within P2X applications, i.e. methane CH_4, Methanol CH_3OH, Dimethylether CH_3OCH_3, Fischer Tropsch-Diesel $(–CH_2-)_n$ etc., a source of carbon is necessary, see also chapter 2. It is useful to consider the carbon cycles to find suitable carbon sources. Meier et al. [64] investigated the carbon flows for Switzerland, see figure 11. Carbon comes either from fossil sources (then always from outside Switzerland) or from biogenic sources; a small part is geogenic, i.e. is released from carbonate-based minerals. At the end of the use (which can be very short in case of packaging or very long in case of use in buildings or furniture etc.), the carbon more or less always ends in the atmosphere in form of CO_2, mostly due to a combustion process in e.g. engines, turbines or in an incineration plant. Part of the CO_2 is then reused to grow the biomass.

Therefore, carbon can always be taken from atmosphere as CO_2 or shortly before it is released to the atmosphere, e.g. from flue gases. In consequence, for the overall CO_2 balance it does not matter whether the carbon dioxide is of fossil, biogenic or geogenic origin, as long as it is a waste stream from a useful application and not only produced for the P2X purpose. While fossil carbon flows contain hardly oxygen, which is useful for most applications, biomass contains significantly more oxygen than fossil carbon flows. As a result, chemical conversion of biomass often leads to a by-product flow of CO_2 which usually is released to the atmosphere. Besides using this CO_2 stream, chemical conversion of biomass also offers the option to add renewable hydrogen already in the conversion step which increases the yield of useful carbon containing product and decreases the CO_2 byproduct flow.

In these cases, CO_2 can be considered a waste stream, as it is anyway in combustion processes. This means, that CO_2 does not necessarily have a financial value as other chemical feedstocks have. Due to the regulations of the climate change mitigation policy, avoiding CO_2 emissions has a financial value which depends on the the regulation scheme in which the avoided CO_2 emissions is considered. The best known scheme is the European Union Emissions Trading System ETS (28 EU countries plus Norway, Iceland and Liechtenstein), but there are also schemes within companies, fees for missing emissions targets (e.g. for car importers which have to reach average CO_2 emissions per km for the imported car fleet, cf. to section 3.4) and emissions compensation schemes such as KLIK (https://www.klik.ch/) for the importers of fossil fuels.

In the following sections, the most relevant sources of carbon (mainly carbon dioxide) for P2X processes are presented.

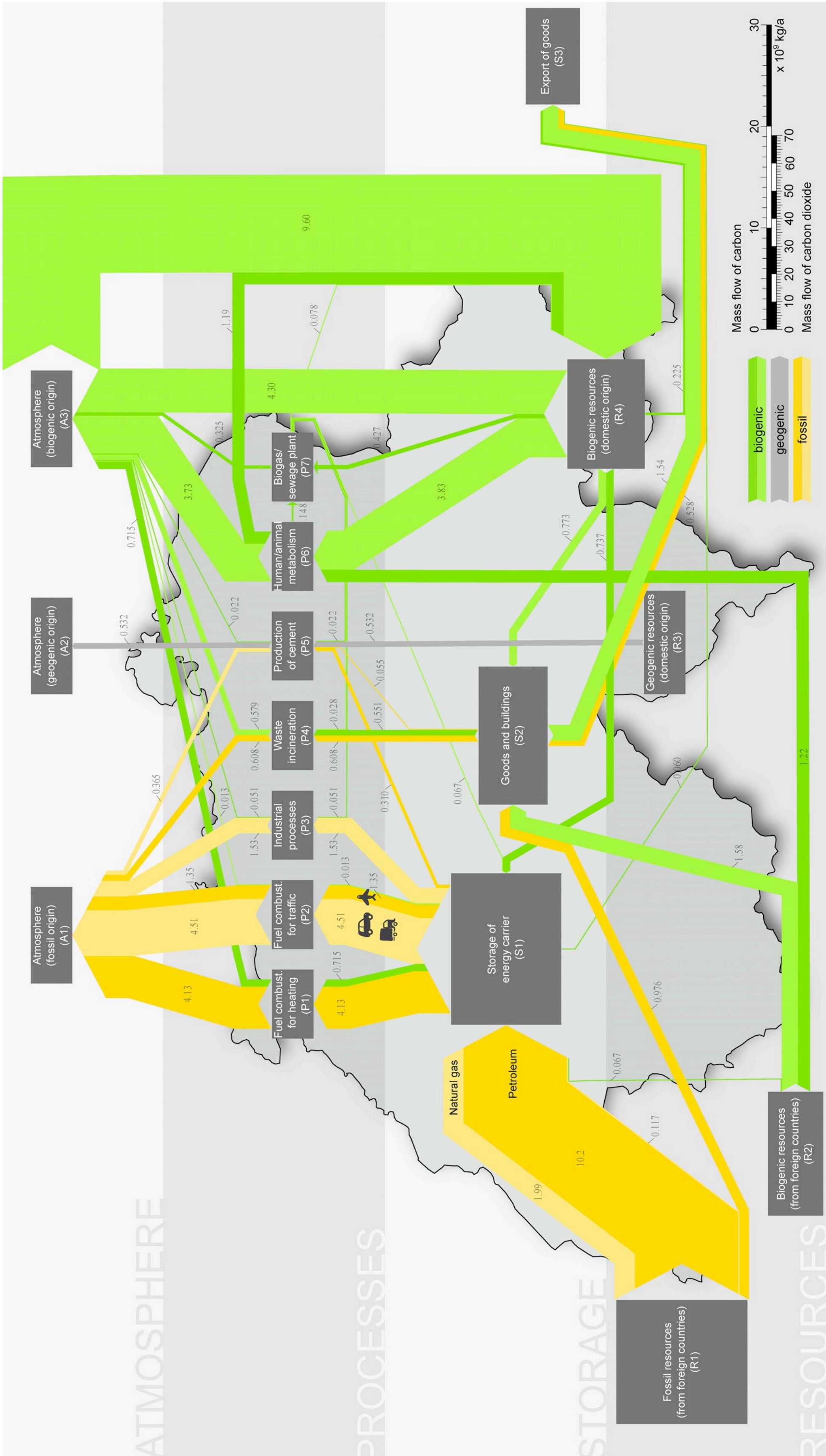

Figure 11: Mass flows of carbon in Switzerland in 2013 [64]. The numbers indicate millions of tons of carbon per year. The shape of the country indicates only whether a flow is purely inland or crosses the border. The diagram contains no further geographical information

3.1.1 Biogenic Sources:

Biogas is produced from biogenic substrates by means of anaerobic digestion. Typical substrates are sewage sludge, green wastes, agricultural residues and manure. Microorganisms convert these biomass streams in absence of air to methane (the thermodynamically favoured product) and mainly CO_2. Depending on the substrate and the process, the methane content of the biogas can reach 65% (in case of fats and sewage sludge as feedstock) [65]. Green waste digestion, e.g. by the Kompogas® process, yields CO_2 content of in average 45% which can vary from 40 to 50% within hours.

Besides methane and CO_2, biogas contains a number of impurities which usually have to be removed by special devices before further use: Sulphur species (H_2S, carbonyl sulfides, thiols, thioethers, disulfides etc.), hydrocarbons/terpenes (especially in case of green waste digestion), siloxanes (in case of sewage sludge digestion).

Type of feedstock	Typical methane contents	Typical CO_2 contents	Sulphur	Terpenes and/or aromatic compounds	Siloxanes	Comment
Sewage sludge	>60%	>40%	yes	hardly	yes	
Green waste	Around 55%	Up to 45 %	Yes	Yes	none	e.g. Kompogas®
Manure/agricultural residues			yes	low	none	

Table 11: Typical biogas qualities [66]

If the biogas is burned in a Combined Heat and Power plant (CHP), usually in an internal combustion engine, the carbon is completely released as CO_2, however strongly diluted by nitrogen. This makes it relatively unattractive to capture it. A rising number of biogas plants separates the CO_2 from the methane, which allows injecting the latter as biomethane into the natural gas grid. This procedure gains more and more interest due to the stable prices for biomethane and the decreasing prices for green electricity.

The separation of CO_2 and (bio-)methane is achieved either by pressure swing adsorption, pressurised water scrubbing, amine scrubbing or membranes. Especially the last two can be considered as state-of-the-art with very low methane slip (0.04% and 0.3% respectively, compared to 2% methane slip in the case of PSA and water scrubbing) which is very important to avoid GHG-intense CH_4 emissions. There is a clear tendency to build new plants with membranes, due to their low maintenance and simplicity. Besides electricity for pumps and blowers, amine scrubbing needs a heat source at >120°C on the site to regenerate the scrubbing liquid.

In Switzerland, there are around 100 biogas plants that produce more than 3 $GWh_{th,HHV}$ of biogas per year. Of these, 23 plants already today separate the CO_2 and inject biomethane into the natural gas grid (262 $GWh_{th,HHV}$ of biogas per year), while the rest (570 $GWh_{th,HHV}$ of biogas per year) uses the biogas in CHPs, see Table 12 [67]. If all these existing biogas plants would be used as CO_2 sources for $PtCH_4$, additional 565 $GWh_{th,HHV}$ of methane per year could be produced, which corresponds to around 50 Mill. Nm3/year.

Potential analysis in number of plants	Existing bioCH4 grid injection	Potential, new bioCH4 injection	Total potential through P2M
WWTP	15	64	79
Digester plants	8	9	17
Total	23	73	96

Table 12: Biomethane potential, in number of installations with >3 GWh per year of biogas production. (Data for 2015, [67]

A recent study by WSL [68] shows the total/sustainable/used/unused potential of the different biomass feedstocks in Switzerland. From the total potential of e.g. sewage sludge (4.9 PJ/year), already 3.5 PJ/y are used which corresponds to 970 GWh/y. The above mentioned 79 largest sewage sludge-based biogas plants (see table 12), represent about two thirds of that. Figure 12 shows also that anaerobic digestion of agricultural crop by-products, green wastes and especially manure has the potential to strongly increase the amount of available biomethane and biogenic CO_2.

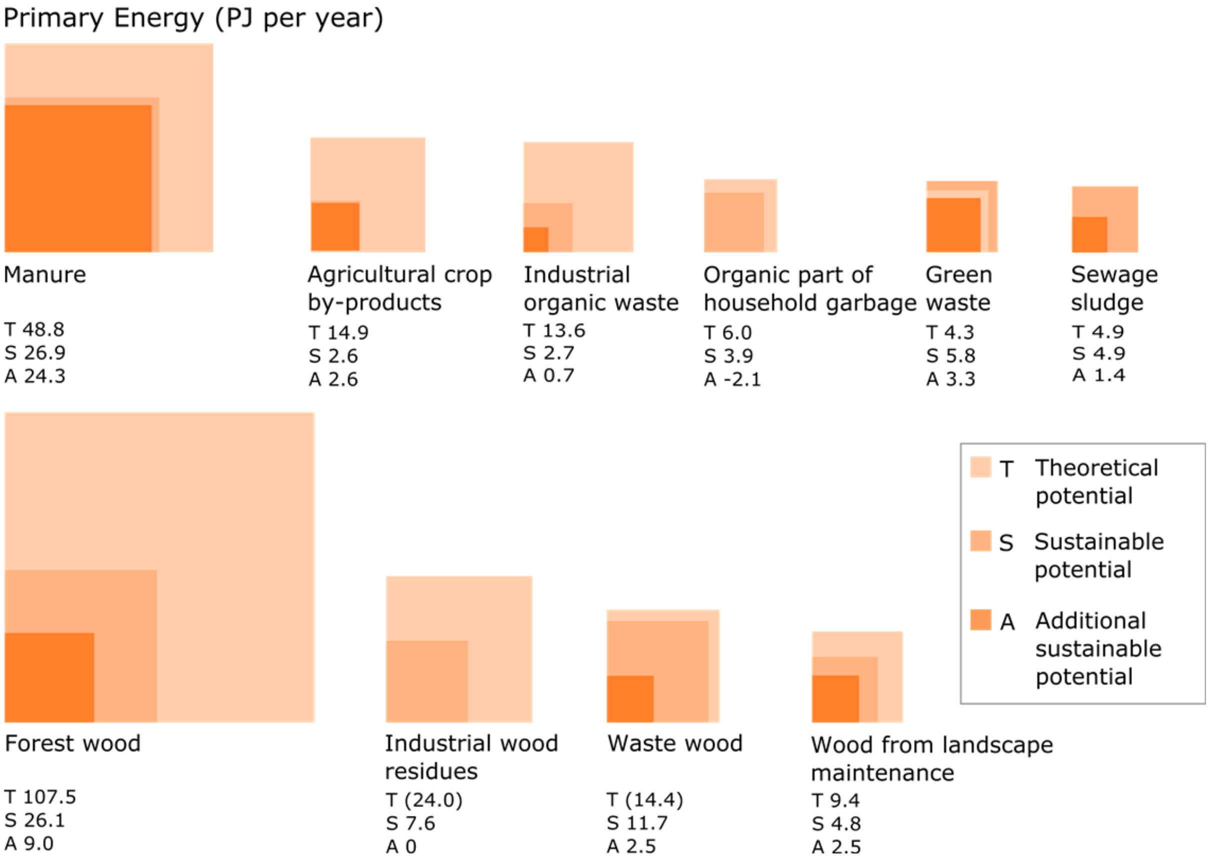

Figure 12: Primary energy potential of all 10 biomass types in petajoules (PJ) per year. Source: [68]

The same WSL study shows also the unused potential of dry biomass, especially forest wood, waste wood and wood from landscape maintenance. These 14 PJ/year correspond to 440 MW_{th}. Indirect wood gasification and methanation of the producer gas, followed by CO_2 removal, drying and H_2-recycle (see e.g. Lignogas-Study on indirect Gasification and downstream methanation [69]) can deliver renewable methane (RNG) and roughly about the same volumetric flow of biogenic CO_2. After gasification at low temperatures within a Dual Fluidized Bed gasifier (such as the FICFB in Güssing/A, Oberwart/A or Senden/D, or the Milena gasifier in Alkmaar/NL), the producer gas contains 20 to 24% of each CO and CO_2, around 40% of hydrogen, 10% of methane and a few % of olefins. In the subsequent methanation reactor, not only the Sabatier reaction, but also water ga shift reaction and hydrogenolysis of higher hydrocarbons take place leading to a gas of >40% CH_4, < 50% CO_2 and rest hydrogen (which is separated and recycled) [70]. This means that addition of sufficient green hydrogen into such a plant could double the RNG production by converting the CO_2 without prior separation. If e.g. 100 $MW_{th,LHV}$ of the unused wood potential was converted to around 62 $MW_{th,LHV}$ methane, more than 75 $MW_{th,LHV}$ hydrogen could be integrated. Alternatively, more than 50 Mill Nm3/y of biogenic CO_2 could be separated from the gasification/methanation plants using the offheat from the methanation to operate the regeneration of the amine scrubber for the CO_2 separation. Using one quarter of the unused wood within such plant would therefore double the flow of pure biogenic CO_2 which is available from existing biogas plants.

3.1.2 Industrial Sources

Besides the biomass-based plants (anaerobic digestion or wood gasification with subsequent methanation), also other industrial plants produce carbon or CO_2 rich gas streams. Due to the absence of steel manufacturing and coke ovens in Switzerland, the industrial CO_2 sources in Switzerland are waste incineration plants (29 WIPs) or cement plants (five plants). The fact that these sources are based on combustion processes implies that the CO_2 has to be separated from a gas stream which is highly diluted by nitrogen and unburned oxygen, on the one hand, and contains sulfur oxides, nitric oxides and many other impurities on the other hand. The CO_2 contents of these industrial sources have values between 0% and 20%. Teske et al. [71] list the plants, their locations and capacities together with those of the sewage sludge based biogas plants, see Table 13 and Figures 13 and 14 below. It can be seen that WIPs are responsible for roughly 60% of the CO_2 rich flue gases in Switzerland and the five cements pants for 38% while all the biomass-based plants represent to a maximum a few percent of it.

Due to the size of the WIP and cement plans, only amine scrubbing or chilled ammonia are possible options for the CO_2 separation, due to their lower energy consumption, high CO_2 selectivity and the strong economy of scale. The heat for the regeneration of the amine scrubber (>120°C) can be taken from cement plant, the WIP or from a connected methanation/methanol/Fischer-Tropsch unit. The choice between the two technologies has to be based on a pre-engineering study. Besides the presence of a heat source, also the available electricity price, the Sulphur content and the solvent price need to be considered for the determination of CAPEX and OPEX.

	CO_2 Sources		CO_2 production		Necessary Electrolyser capacity	Potential Methane production
Type (smallest/largest plant)	Number	Share	Mass (t/a)	Share	(MW_{el})	(TWh_{SNG}/a)
Cement production (all plants)	6	1%	2'710'000	38%	3598	14.6
Corneaux (NE)	1		177'000	7%	235	1.0
Würenlingen (AG)	1		590'000	22%	783	3.2
Waste incineration (all plants)	29	4%	4'238'000	60%	5626	22.8
Gamsen (VS)	1		40'000	1%	53	0.2
Hagenholz (ZH)	1		285'000	7%	378	1.5
Waste water treatment (all plants)	728	95%	170'000	2%	226	0.9
WWT > 30000 inhabitants	130	18%	130'000	76%	173	0.7
Aire (GE)	1		7'600	4%	10	< 0.1
All plants	763	100%	7'118'000	100%	9450	38.4

Table 13: Potential CO_2 sources and production quantities of synthetic methane via P2X in Switzerland [71]

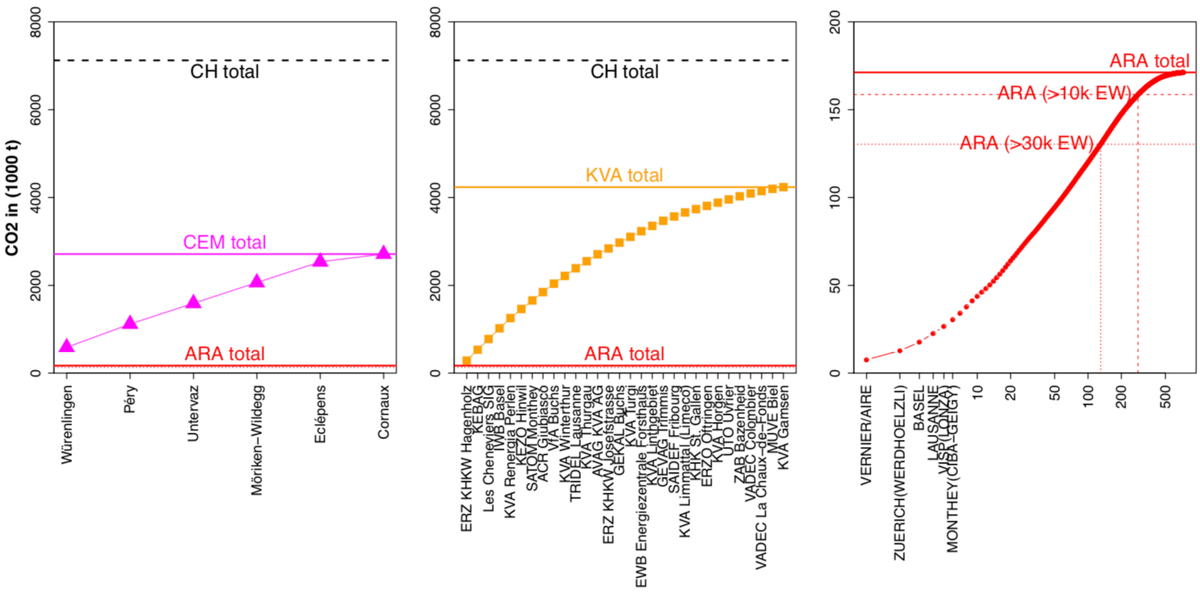

Figure 13: Cumulative CO_2 quantities of cement plants (CEM, left), waste incineration (KVA, middle) and sewage treatment (ARA, right) as of 2016 [71]. The graphs for cement plants and waste incineration plants also show the Swiss total CO_2 emissions (“CH total”, around 7’000’000t/a), and the sum of the CO_2 emissions from waste water treatment plants (“ARA total”, around 175’000 t/a)

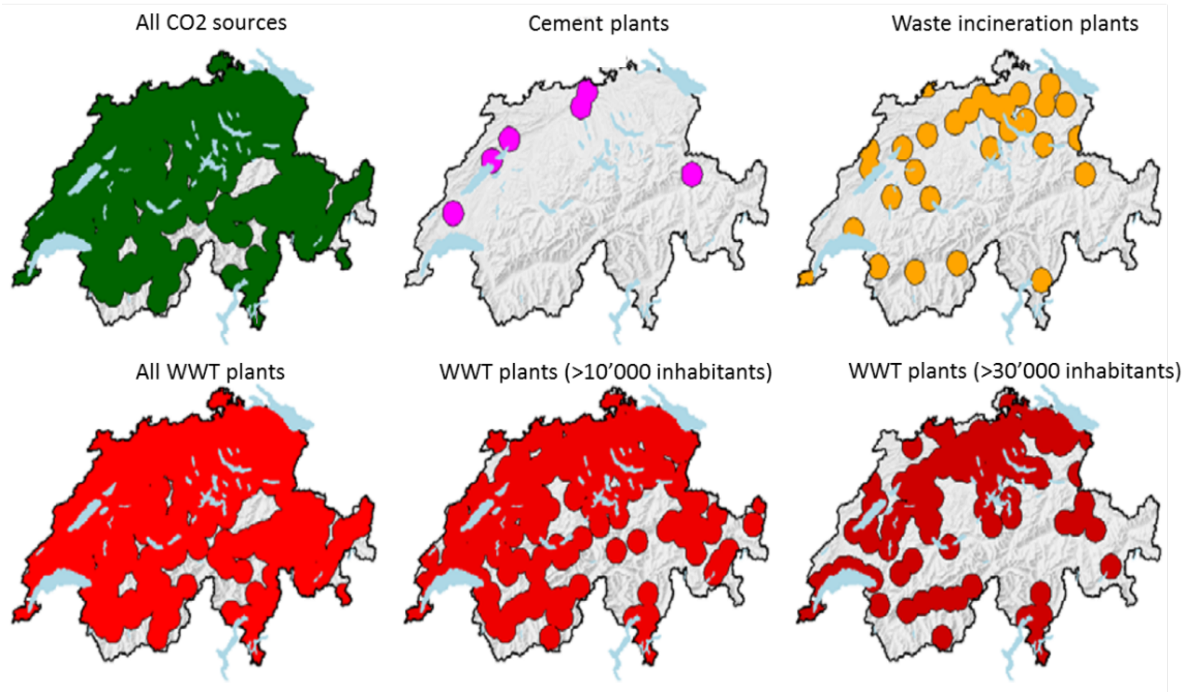

Figure 14: Spatial distribution of CO_2 sources in Switzerland as of 2016 [71]

Further, it can be seen that the CO_2 sources, especially the WWT cover large amounts of Switzerland, if a radius of 10 km around the CO_2 source is considered.

From this perspective, the available amount of CO_2 seems to be very large. Unfortunately, sources of green electricity and CO_2 sources are not necessarily in the same region. This is shown in Figure 15 below. If the economic and legal boundary conditions make it necessary to place the electrolysis very close to the power plant to avoid the grid use fee, and the CO_2 source should not be farther away than 10 km, by far not all of the industrial CO_2 potential can be used for P2X. If large amounts of CO_2 shall be used from these point sources, either the need to pay grid use fee has to be abandoned, or economic boundary conditions have to be adjusted. Still, if P2X plants are to be built farther away from the power plants, some costly adaptations of the electricity grid have to expected.

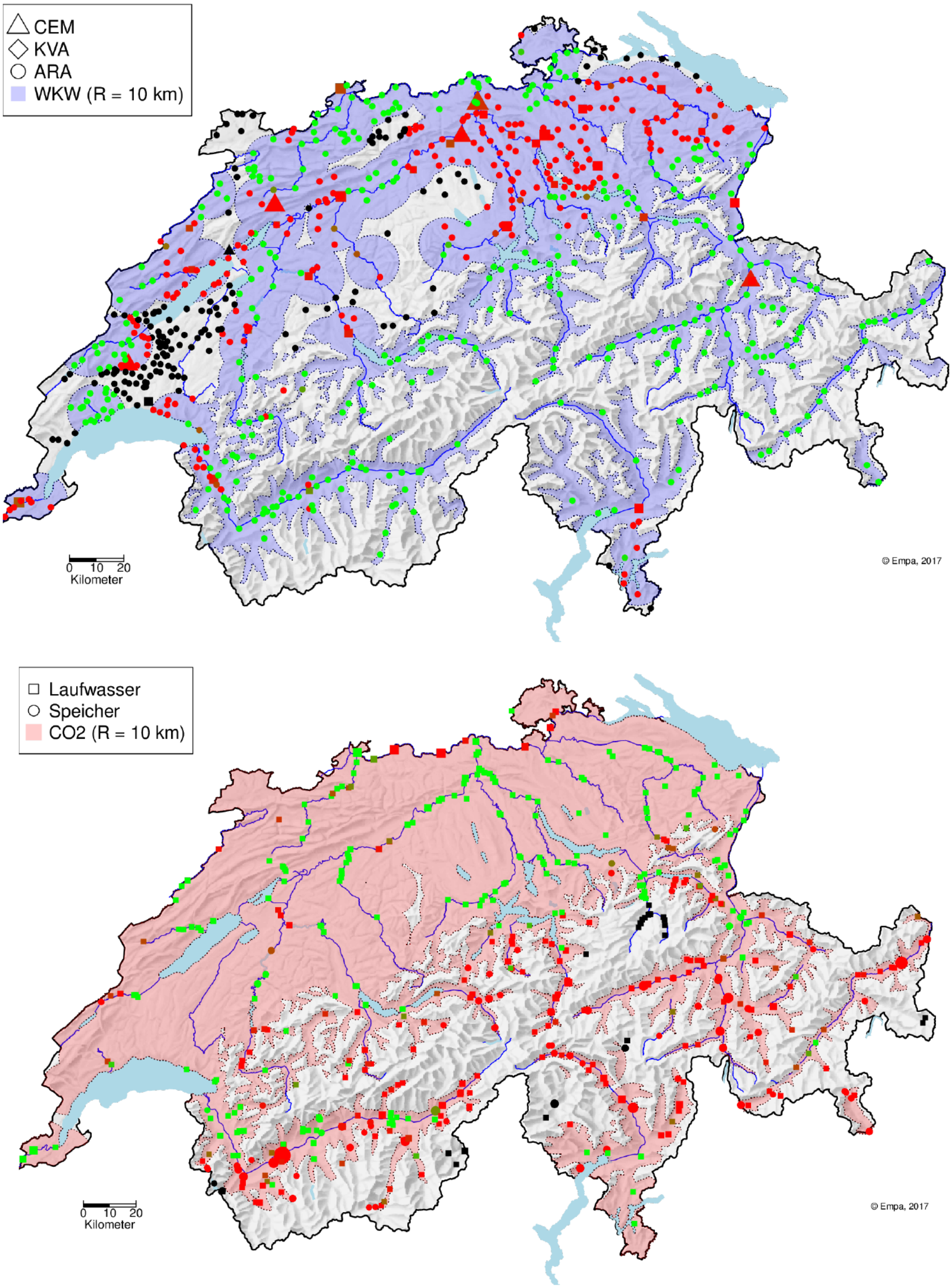

Figure 15: Comparison of spatial distribution of potential CO2 sources with power production [71]. Top: Red points indicate CO_2 sources which cannot be completely exploited with hydropower plants within 10 km distance; green points indicate where it is possible; black points indicate CO_2 sources more than 10 km away from hydropower plants. Bottom: Red points indicate hydropower plants whose capacity cannot be completely

exploited with CO_2 sources within 10 km distance; green points indicate where it is possible; black points indicate hydropower plants more than 10 km away from CO_2 sources

3.1.3 Direct Air Capture Technology Description

Direct air capture (DAC) as offered for example by the company Climeworks can deliver quite pure CO_2 independent of one of the aforementioned CO_2 sources. This process is a combined temperature/vacuum swing adsorption separation, i.e. CO_2 is adsorbed from the air on e.g. amine groups that cover large surface materials. In the next operation phase, the sorbent is set under partial vacuum and heated up to around 90°C. Under these conditions, the sorbent is regenerated and nearly pure CO_2 can be obtained at sub-atmospheric pressure which therefore has to be compressed before the next use.

The low CO_2 concentration in the air below 0.1 Vol.-% makes direct air capture more energy intensive and expensive compared to many other CO_2 capture options. The highest cost reported in the literature used in this study refer to direct CO_2 capture from the air (250 CHF per ton of CO_2 [72]), which results in additional costs of 50 CHF/MWh$_{th}$. However, since direct air capture technology is in an early commercial development stage, there exist substantial uncertainties related to the costs for direct air capture technology – capture costs of 600 CHF per ton of CO_2 [73] could imply substantially higher additional costs for methane production. It is expected that the costs of capture from other CO_2 sources, such as fossils power plants and cement plants, are lower since the CO_2 concentration of these flue gas streams is higher than the CO_2 concentration in the atmosphere [74]. Further, the economy of scale cannot be used because scale-up of such units so far happens by numbering up. The large heat demand at lower temperature level may be covered by the off-heat of a electrolyser combined with a heat pump and/or off heat at significantly higher temperature level, e.g. from a methanation or Fischer-Tropsch plant. So far, no detailed heat integration concept or such an application is public. With pilot plants at several sites, direct air capture technology is being developed and tested in Switzerland today.

3.2 Aspects for P2X technology integration into the power system

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Two main perspectives how the power grid can profit from P2X technologies are addressed here. Firstly, P2X can be used to manage the excess of electricity in the grid generated by the non-dispatchable fluctuating renewable energy sources whose production would otherwise be curtailed or exported if possible. Also, when using P2P technology (e.g. P2M coupled with gas fired power plants) the challenge known as "Dunkelflaute" coming with the new renewable sources can be solved, i.e. during longer periods of time without sun and wind when other sources of energy will be required. Secondly, P2X can be used to provide ancillary services (AS) to stabilize (long & short term) the grid in terms of its own system frequency. Both main perspectives for P2X are addressed in detail here. Yet another aspect can be considered: if installed at properly selected locations in the grid, P2X plants would also have the potential to relieve the grid infrastructure from line and transformer overloads by absorbing locally the generated power and eventually also to control the voltage if it exceeds the given limits. In practice, it will be rather difficult to install P2X plants exactly at locations of the Swiss grid where needed for these purposes. Therefore, this perspective is more theoretical than practical and it will not be discussed here.

3.2.1 Present and future situation of the Swiss power system

In future, the electricity mix in Switzerland is expected to change significantly. This is a consequence of the initiative named *Energiestrategie 2050,* which was introduced by the Swiss Federal Government in 2011 and the *Energiegesetz (EnG)*, which was adopted on the 21st May 2017. According to this strategy, the phase-out of nuclear power will gradually take place. To replace the electricity produced by the existing nuclear power plants, additional energy generation and new energy sources are required. A large portion of the energy should be generated by renewable energy sources, mainly by Photovoltaics (PV), wind, biomass, and geothermal as well as gas-steam power plants. The Swiss power grid has been designed for a centralized power generation with several large dispatchable power plants generating a pre-defined amount of power to cover a priori known consumption and grid losses. Under such a type of production, it is straightforward to control voltage and frequency of the grid, guaranteeing secure energy supply at all times. However, the whole energy production will become more decentralized, and by 2050 about 12 TWh/a is expected to be generated by photovoltaics [75] and about 5 TWh/a by wind power. Due to its strong dependency on seasonal and short time fluctuations, the exact amount of power generated by renewable energy sources is not only hard to predict for a given time instance but also it hardly matches the momentary consumption in the areas where it is generated. Thus, its peaks will be transported elsewhere which may lead to overloads of the existing infrastructure shown for different expected scenarios as depicted e.g. in Figure 16. In general, higher amounts of decentralised power injections will lead to voltage rises and congestion in power lines in the existing distribution grid. To handle these challenges, it is necessary to upgrade the current power grid. This includes, for example, upgrading overloaded cables and/or implementing energy storage systems. The grid integrated storage systems would play an important role in future to ensure the adequacy of electricity demand. They will be used to relieve the grid from congestions as well to supply the energy when needed. Therefore, it is significant to store the energy excess not only for days but also for a season. PtX is the only electricity-based technology known today that can be considered to act as a seasonal (long-time) storage for significant amounts of electricity in Switzerland.

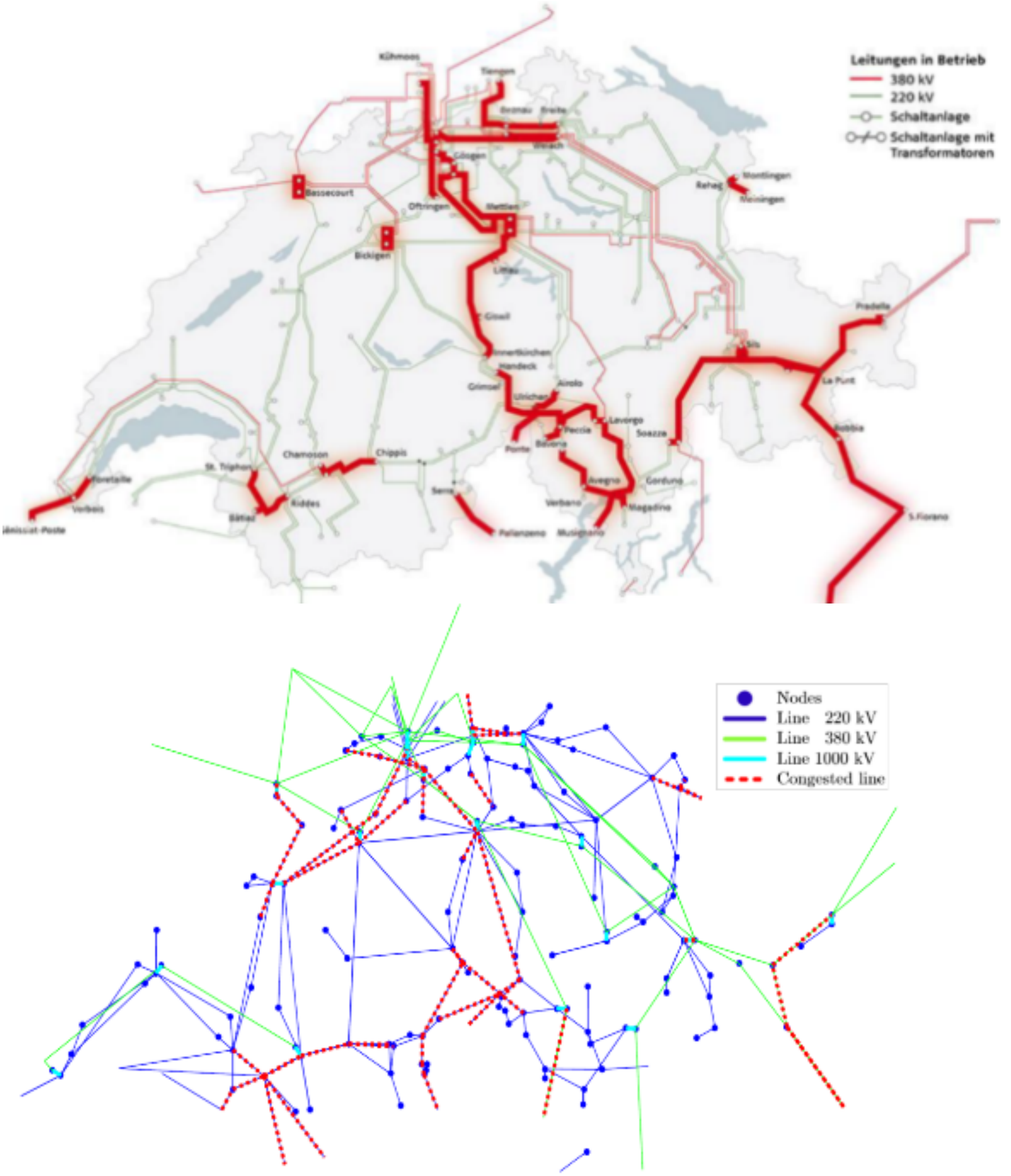

Figure 16: Examples of expected and simulated (over)loading of important transmission lines in Switzerland [8].

3.2.2 Import/Export grid considerations

Import and Export, see e.g. Figure 17, may offer a valuable opportunity to expose surpluses to the market and to add value. However, it can be assumed that in the future the expansion of wind and solar power plants in the neighbouring countries will have a similar (or even higher) grid penetration by new renewable sources than Switzerland. Comparing the levelized cost of electricity storage of the entire

PtP pathway (370-500 CHF/MWh$_{el}$) with the current expenditures for electricity trade (corresponding to specific average annual costs 40, 48 and 55 CHF/MWh$_{el}$ for the years 2016, 2017 and 2018 respectively [76][3], [77]), trade represents a less expensive option to provide seasonal flexibility. This statement is supported by the price developments on the spot market, where, for instance, more than 95% of the trade volume in Germany was traded at prices below 50 €/MWh in 2016 [78]. The corresponding differences in the average monthly spot market prices did not exceed 16 €/MWh. This comparison of electricity prices and PtP storage costs shows that electricity price spreads between months or seasons would need to be much higher as observed in the recent past until PtP becomes a cost-efficient monthly or seasonal flexibility option. Model-based long-term analyses for the year 2030 indicate increasing prices for electricity on European wholesale markets, if natural gas prices and prices for CO_2 emissions certificates increase [79]. However, the market price levels would be still below optimistic assumptions for the electricity production costs for the PtP pathway.

Cross border trade, considerations of long–term (energy) vs. short-term (power) excess

During daily hours of PV production, it is reasonable to assume that in future scenarios, the cross-border export of the surplus of electrical energy will hardly be possible without considering a high amount of daily energy storage systems (in terms of both capacity and power). The capacities of PV systems installed in Europe can make electricity exports less attractive, especially at noon, due to low prices. Moreover, neighbouring countries are following similar trends increasing PV capacities and maximizing their own production. Depending on the (slightly different) load and (very similar) generation profiles of the neighbouring countries, there will be surplus of the generated energy more or less at the same time.

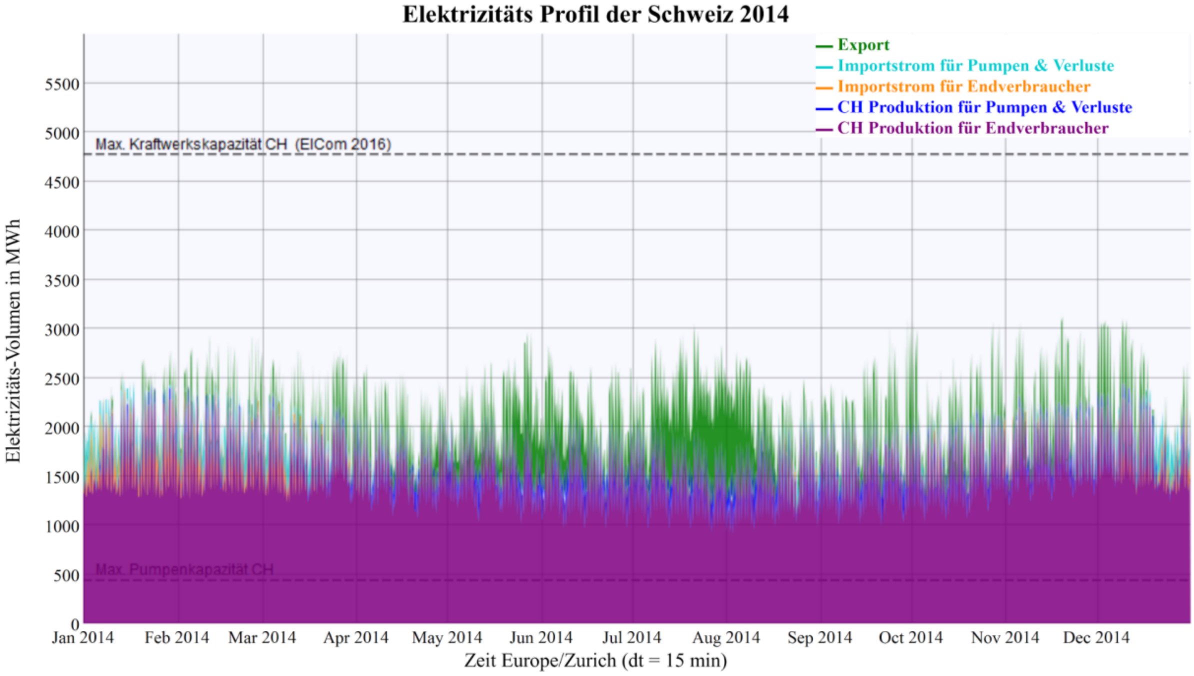

Figure 17: Import and Export in Switzerland during 2014, source [71]

In addition, the large PV surplus correlates seasonally with the surplus of hydropower, as long as climatic boundary conditions do not change significantly (glacier and snow melt). This could further reduce the cost-effectiveness of photovoltaics and hydropower if additional demand cannot be matched in a flexible and timely manner. The excess of the generated energy can be used locally better to run P2X plants than for trade. Nevertheless, simulations results of different scenarios considered, as in [8], suggest that there would exist short periods of time where available cross-border transmission capacity would help to relieve the Swiss grid locally from the short time (power) overloads.

Without conversion/storage or if no recipient/buyer is found (e.g. exports), PV production in the excess hours must be curtailed, thus resulting in a reduced total production during lifetime. As a consequence of this higher production prices and higher specific GHG emissions of PV electricity occur. Therefore, curtailment should always be the less attractive option to consider. However, curtailment is a reasonable alternative for cutting off a low number of hours of very high electricity production to dismiss the very expensive harvesting of those hours.

3.2.3 Utilizing P2X to manage excess of electricity in the grid

The intermittent nature of solar energy, with surpluses in the midday hours in summer and deficits in winter and at night, will pose considerable challenges for Switzerland's future energy system. The use of the temporal excess energy from photovoltaics should therefore occur reasonably, in a value-added manner and regulated across sectors. This means that the harvested solar energy should be transformed or consumed in near-term after it was produced, with as little storage needed as possible. By transforming the excess energy into other energy carriers (e.g. heat, hydrogen, synthetic natural gas, methanol, etc.), P2X plants offer a possibility to use otherwise unusable surplus electricity in another sector of the energy system like mobility, instead of curtailing it. Depending on the prices at the energy markets, an economic and ecological added value can be generated despite the energy losses in the conversions steps of up to 50%. The kWh based specific costs and green-house-gas (GHG) emissions of photovoltaics are decreasing as more energy is harvested. Thus, under appropriate boundary conditions this can help to reach an ecological and economic added value.

In contrast to nuclear energy with a 24/7 availability (base load energy) in Switzerland, photovoltaics has more of a natural ~ 8/7 availability. The difference between 24 and 8 hours daily production alone shows that the installed capacity and thus the maximum power of PV must be at least 3 times higher than that of the 3.3 GW of nuclear power installed today. In addition, in Switzerland with an average of 1000 full-load hours per year the installed peak power of the PV system can be calculated, so that compared to the installed nuclear power (7000 to 8000 full-load hours [80]), the installed peak power of the photovoltaic must be larger by a factor of about 7.5. In this context, in a first rough estimate, an installed peak power of $7.5 \times 3.3\ \mathrm{GW} = 24.8\ \mathrm{GW}$ results, which at 1000 full-load hours per year yields approx. 25 TWh from PV.

The future expansion of photovoltaics in the Swiss electricity market has been discussed in various studies and publications. With regard to the expected future expansion potentials, a study of the SFOE from 2012 [75] based on a 2005 PSI study [81] for a scenario with high renewable electricity penetration postulates roughly 0.4 TWh, 4.3 TWh and 11.1 TWh for the years 2020, 2035 and 2050, respectively. Another Study by Meteotest commissioned by SFOE [82] estimates for Switzerland a long-term PV potential for suitable rooftop areas of 15 TWh (18 TWh including all suitable facades). The authors comment that the made assumptions are very conservative. They argue that considering only PV potentials on roof tops and not taking into account potentials of PV on free field influences the results strongly. In this estimate, a constant and conservative efficiency of 10% for facade PV and 15 to 20% for roof top PV is assumed. Based on the study of Meteotest [82] and a study conducted by PSI estimates the potential of roof top PV to be between 11 TWh and 19 TWh [63]. In this estimate, a constant and conservative efficiency of 10% is assumed. If increasing efficiencies and newly emerging rooftops as well as other suitable areas such as noise protection walls, avalanche barriers and reservoir walls are taken into account, the “Umweltallianz” argues that the solar power potential can rise to around 30 - 35 TWh per year [83].

According to Swiss Electricity Statistics from 2016 [76], in 2015 a total of 1.1 TWh were produced by photovoltaic systems with an installed capacity of 1.4 GW. For the year 2016, in the "Swiss Statistics of Renewable Energy" (Edition 2016) [84], the generation of electricity from photovoltaics is approx. 1.3 GWh. This represents a further increase of PV production by approx. 20% compared to 2015. Thus, the real PV production in 2016 is already three times higher than in the most optimistic scenario of the SFOE for 2020.

While the studies mentioned above have examined the PV potential, no (quantitative) information on temporary surpluses was provided. However, this is essential for the consideration of technical limitations and feasibility of PV integration. Therefore in a technical feasibility study by the Empa and PSI of P2X in Switzerland [71] Swissgrid energy summary data from historical energy consumption and production of 2010 to 2016 were used to generate high-resolution synthetic profiles of producible amounts of energy in Switzerland. These profiles help to estimate the daily differences in the future temporary surpluses and deficits. From the historical profiles of the current production, the corresponding monthly power generation of nuclear plants (from electricity statistics of SFOE) were withdrawn, and estimated photovoltaic production was added. Photovoltaic production was modelled on the basis of the SFOE project "sonnendach.ch" [85] and interpolated for communities for which no data are available yet. The production potential of a maximum of about 50 TWh per year was subsequently determined on the basis of satellite data of solar irradiation [86], [87] such that all corresponding weather-related fluctuations were taken into account in the estimated production profiles too.

As mentioned above, with a future installed peak power of 25 GW photovoltaics, around 25 TWh can be produced annually which corresponds to the 1000 full-load hours per year. This requires about 50% of the good, very good and excellent suitable rooftop areas according to "sonnendach.ch" (15 TWh in summer, 9 TWh in winter). These 50% of suitable rooftop areas corresponds to approx. 33% of all rooftop areas in Switzerland; without considering the PV potential on facades, etc.

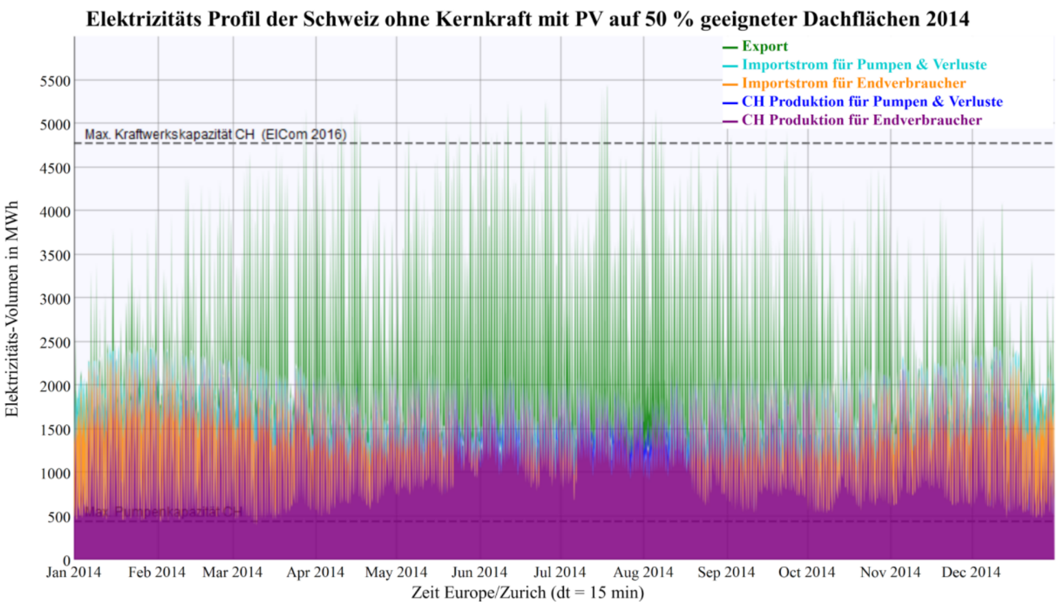

Figure 18: Original and synthesized electricity profile of Switzerland for 2014 based on Swissgrid data, source [71].

Based on today's power consumption profiles, the photovoltaic output at 50% of the suitable rooftop areas, regularly (around midday) exceeds both the today's Swiss power consumption and the maximum power of pumped hydro power plants by more than factor two. Figure 18 shows these surpluses in production peaks (green) as exports. These surpluses must either be instantaneously used or the PV production must be curtailed. By contrast, when phasing out the nuclear power generation without introducing other power plants (e.g. gas-fired combined cycle power plants), will cause a production deficit in the evening and night hours, see Figure 18 and Figure 19 with orange and light blue areas. Therefore, daily storage for day/night compensation are needed (short-time energy storage systems, such as batteries, compressed air storage, pumped storage, hydrogen storage, etc.), which ideally allow local decentralized energy storage. On the other hand, flexibly switchable electrical consumers such as P2X systems will be required. Figure 20 shows these daily deficits (positive values) and surpluses (negative values) for each day after balancing the day/night deficits on the basis of the synthetic profiles of the years 2010 up to 2016, depending on the percentage of used suitable PV rooftop areas.

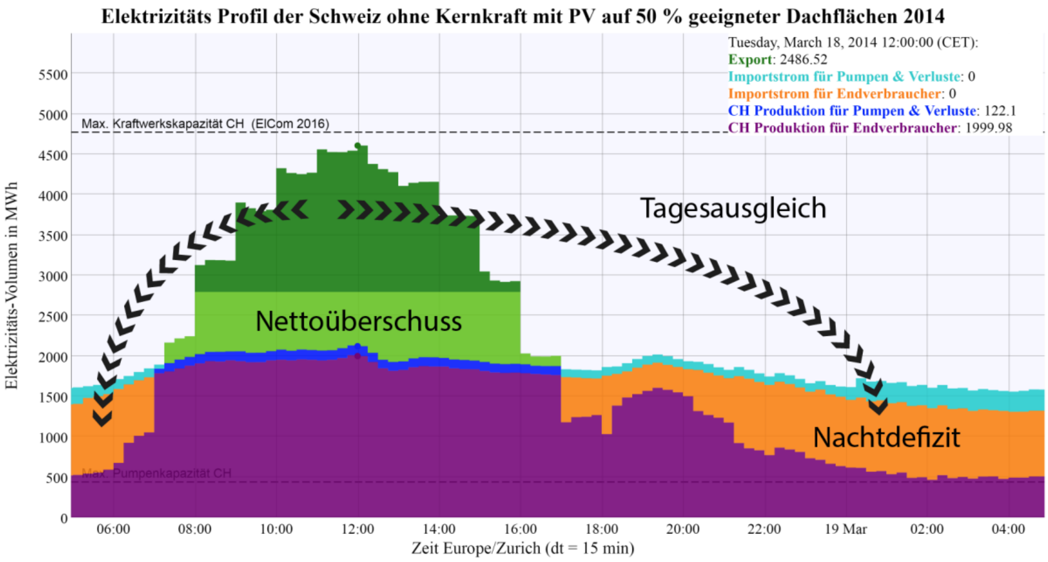

Figure 19: Extract of the electricity profile illustrating the day/night compensation, source [71].

Without a day/night compensation (short-time energy storage systems), which distributes the daily amounts of up to 130 GWh over 24 hours, much larger capacities would have to be installed for P2X to harvest the surplus energy in the summer days, but at a much lower number of operating hours. It is important that the daily short time energy storage will be emptied daily to provide free storage capacity for the next day. For these reasons, the operation of P2X systems only makes sense in combination with corresponding short term storage solutions [88]. P2X can also mitigate daily storage problems by generating hydrogen and hydrogen storage, especially as the electrolysers can offer up to 300% of their installed capacity as control power for a short time [89]. However, one must be aware that the electrolysis does not increase the electricity gap in winter, but only processes the surplus from renewable energies.

In general, P2X can only contribute to ensure that excess renewable electricity does not have to be curtailed or exported at unprofitable prices in the context of a smart, staggered and flexible consumption structure. Such a consumption structure serve to use the energy produced by renewables as efficiently as possible and to maximize the solar harvest's economical and ecological benefits. In general, the stored excess of energy produced by renewables should be used primarily as electricity and the storage time should be minimized before converting it into other forms of energy. This does not apply to pumped power plants which allow to store energy for a longer period of time with relatively small losses. The energy excess should be used for control services to maintain the grid stability first. Subsequently, the demand of flexible consumers, such as heat pumps (including refrigeration systems) should be met; if possible, through appropriate demand site management to the times when renewable electricity is abundant. Only after all these possibilities have been exhausted, the utilization of the remaining electricity surplus using storage systems and P2X is meaningful.

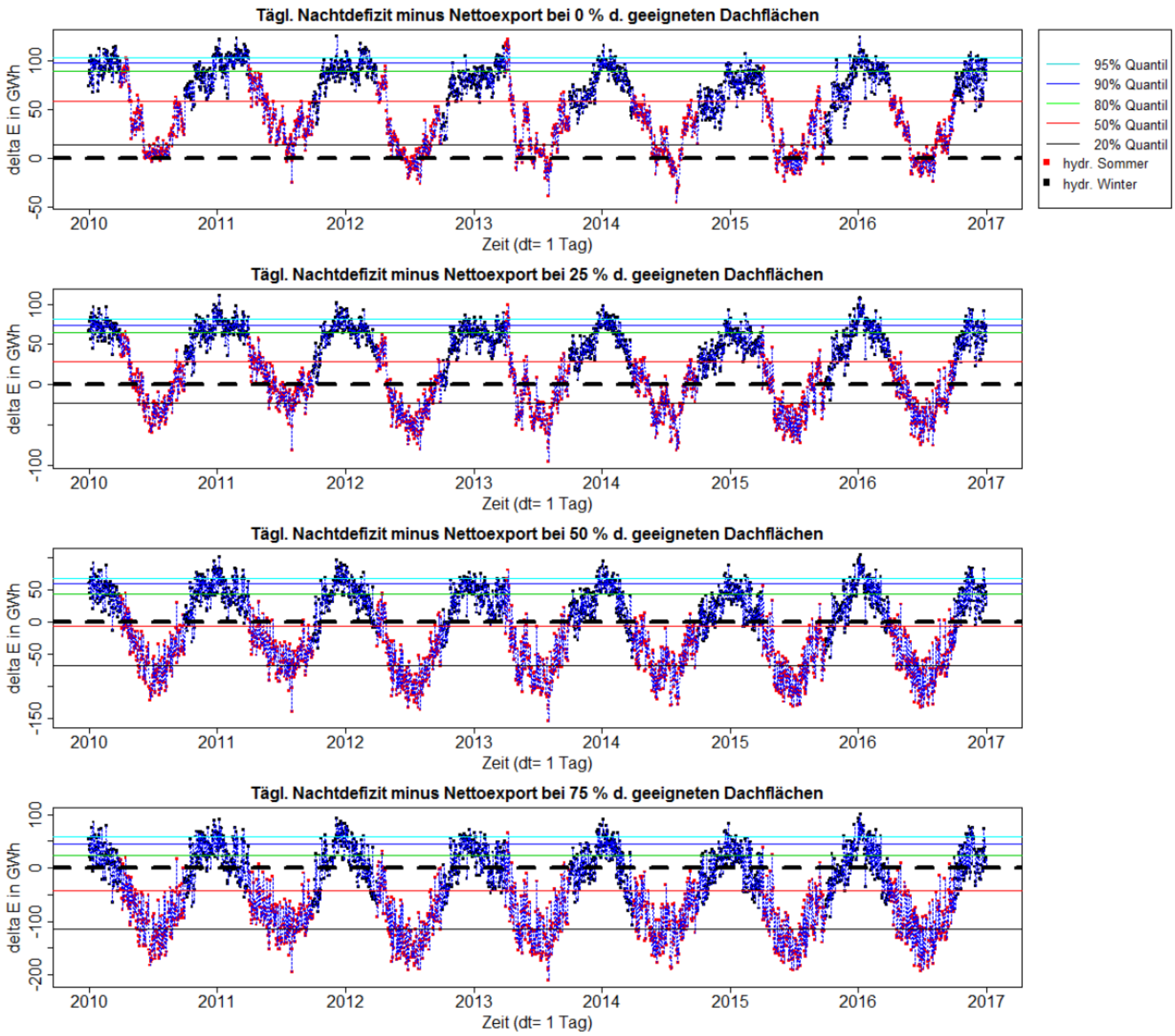

Figure 20: Daily surpluses or deficits of electricity in GWh after day/night compensation for the synthetized electricity profile of Switzerland for the year 2014.

3.2.4 Utilizing P2P to manage grid stability

All generators connected in today's AC grid contribute to maintain the balance between consumption and production, hence, to keep the system frequency constant at 50 Hz. The only storage in the system is conventionally the energy stored in the rotating masses (with the inertia H) of the synchronous machines. The change of the generator's speed ω serves as an energy buffer to compensate short-time changes in the load P_m and the generation P_e. Whenever there is an imbalance, the frequency changes according to the swing equation, which is described as:

$$\frac{d\omega}{dt} = \frac{1}{2H}(P_m - P_e)$$

This equation indicates that the system frequency will stay stable/constant only as long as P_m and P_e are the same. In the future power system, not only the loads (represented above by P_m) will vary in time but also the renewable generation (represented above by P_e) will fluctuate. At the same time, there will be less rotating masses, which can be represented by reducing the inertia H. The conventional synchronous generators will be replaced by renewable energy sources connected to the grid through power electronic devices. Therefore, the demand on short and long-time options to balance P_m and P_e is expected to increase in the future in order to preserve the stability of the power system. Also, note that the inverse idea to P2X (i.e. gas-to-power, e.g. gas fired power plants) being a conventional technology based on rotating machines would lead to an increase of the very valuable, stabilizing inertia H.

Active Power Reserve In today's power system operation, there is a three stages mechanism referred as primary, secondary and tertiary control reserves with corresponding markets behind providing the necessary so called ancillary services (AS) to balance the power system in order to provide long and short-term grid stability by keeping the system frequency constant. The service providers have to qualify and fulfil a number of technical requirements. Currently, there is a reserve energy and reserve power market on a weekly basis in which the transmission system operator Swissgrid selects the lowest priced bids. The cost is passed on to the end consumer [90].

P2X technologies (in both directions, such as electrolysers and gas turbines) can qualify to provide on their own 100% of today's active power control reserves, which are discussed here. They will fulfil the technical requirements in terms of their required dynamics and size in order to participate on the market.

Remark: In principle, P2X can also serve to control the grid voltage. However, the grid voltage problem is geographically rather a local phenomenon and the P2X plants can hardly be expected to be located exactly in places where needed from the perspective of providing this kind of ancillary service. The same is true in practice also for using P2X plants in order to relieve the overloaded grid infrastructure by absorbing the excess of power.

A. **Primary Control (PRL)** Primary control restores the power balance within seconds. The frequency is stabilised during its operation. Activation takes place in today's power plants through the turbine regulators/governors. The system frequency is monitored locally and in case of a deviation, the primary control is activated if there exist a deviation exceeding ± 10 mHz. The maximum allowed frequency deviation in the Swiss and the European power system is ± 200 mHz [90]. The current situation on the market is that there is already enough capacity available for the PRL. Today's PRL reserve for Switzerland is about ±68 MW. Many existing power plants can provide primary control reserves in terms of hundreds of megawatts, new storage technologies such batteries are currently installed to provide this service as well, e.g. the EKZ-Batteries in Dietikon and Volketswil can provide up to 1MW and 18 MW, respectively. As mentioned before, the market is managed at European level on a weekly basis. The average price in 2017 for the PRL was 2466 CHF/MW per week. This corresponds to the potential revenues on today's PRL market in the range of 10 Mio CHF/year. Service providers can directly participate on the PRL market if providing more than ± 1MW of active power. The maximum power reserve per bid placed by one provider is 25MW. This corresponds by ±70MW reserve to at least 3 different participating plants in the PRL ancillary service at any time. In case of plants smaller than ± 1MW or in case of asymmetric service (i.e. in practice if only increase of load is possible to provide), service providers can aggregate in pools. There are many pools on the Swiss and European market offering different conditions for participating service providers. In general, the earnings through the pool are lower compared to the direct market participation, realistic values lie around 60% of the actual market price. In terms of their size and type of operation, P2X could participate directly as well as through pools on the PRL market.

B. **Secondary Control (SRL)** After triggering primary control, secondary control is activated. The purpose of the secondary control is to preserve the desired energy exchange while maintaining the frequency at 50 Hz. The secondary control is activated automatically within seconds by the central grid controller. Usually, it is completed after 15 min. If the control deviation is not eliminated by then, the tertiary control will be trigger [90]. The secondary control market is growing in terms of new smart technologies. For example, Swisscom Energy Solutions offers "*tiko box*", which is a low-cost solution for the grid integration bias SRL. Today's SRL reserve is about ±400 MW. This market is operated also on a weekly basis and the average price in 2017 for the SRL was 5553 CHF/MW per week. Thus, the potential revenues on today's SRL market in Switzerland is about 120 Mio CHF per year. Service providers can directly participate on the Swiss market if providing more than ±5MW of active power. The maximum power reserve bid placed by one provider is limited to ±50MW (starting from 2018, bidding asymmetric reserves are allowed, e.g. consumption or generation only). Smaller service providers can enter the market through various pools with averages earning at the level of 60% of the market price. P2X could participate directly as well as through pools on this market.

C. **Tertiary Control (TRL)** To relief the secondary control reserve, tertiary control is used. The tertiary control reserve is very important for adjusting major, persistent control deviations after unexpectedly long-lasting load changes or production outages. As a difference of the primary and secondary control, this measure still not activated automatically. The triggering is carried out by the Swissgrid dispatcher, which sends a message to the service provider. To supply tertiary control, a power plant is required, which must intervene and readjust the power production irrespective of its scheduled generation [90]. Service providers can directly participate on the Swiss market if providing more than 5 MW of active power. The maximum bid placed by one provider is limited to 100MW. It is a Swiss market managed separately for power generation (+) and consumption (-) on a weekly basis. The average price in 2017 was in the range of 450 CHF/MW(+) and 680 CHF/MW (-) per week. This reserve had the size of 450 MW(+) and 300 MW(-), which corresponds to the potential revenues on each market in terms of 10 Mio CHF per year. P2X would fulfil all requirements to qualify on this market. For the positive reserve, a gas turbine driven power generation could be used.

Due to the higher service price, SRL would be financially the most attractive market to participate for P2X. P2X would differ from all today's solutions since it could provide all kinds of current control reserves (short & long time, sufficient large in size) to stabilize the grid at a competitive cost.

Ancillary Service	**Weekly average in 2017 [CHF/MW]**	**Size of reserve [MW]**	**Min bid size [MW]**	**Max bid size [MW]**	**Estimated market size [Mio CHF]**	**Possible to provide by P2X**
PRL	2466	±68	1	25	10	Yes
SRL	5535	±400	5	50	120	Yes
TRL(-)	680	-300	5	100	10	Yes
TRL(+)	450	+450	5	100	10	Yes

Table 14: Ancillary services for Switzerland. Statistics was prepared based on [91].

3.2.5 Challenges in analyses of the Swiss power grid

The electrical power grid consists of several grid levels with distinct nominal voltage. There are seven grid layers in Switzerland. Each level is interconnected through different transformer levels with ratings properly dimensioned in the past, i.e. before penetrating the grid by distributed renewable energy sources. The grid layers are owned, planned and operated by different bodies. For example, the high voltage transmission grid (level 1) belongs only to one transmission system operator (TSO) Swissgrid. On the other hand, the low voltage distribution grid (layer 7) is owned and operated by many local distribution network operators (DNO). There are in total more than 1'000 DNOs in Switzerland. It is a common practice that researchers, engineers and planners investigate the large-scale electrical power systems only separately in selected grid layers and in very small geographical regions of their particular interest. For a reliable simulation of a power grid, its mathematical models (grid components & topology with line parameters) and load flow data are required. These network representation and load flow data of the lower grid levels are frequently either not available or not disclosed. The available models cover typically only a single geographic region and a single grid layer. Keeping all this in mind, the following implications are common for today's grid analyses: (1) conclusions done for a geographically larger area are based on aggregated/projected results obtained through analyses of one or multiple small-scale simulations and (2) models/simulations involving several grid layers are hardly possible. A common practice is to include the results (measured or estimated) from the lower grid level as load/generation profiles at properly selected places (points of common coupling) in the simulation model of the upper grid level. This leads to some shortcomings of the power grid analyses, which is based on aggregations and projections summed up below:

- It is implicitly assumed that the lower grid level (included as load/generation profiles in points of common coupling in the upper grid level model) can take the higher power flows from the integrated distributed/renewable energy sources without overloading the infrastructure and violating the power and voltage limits.
    - More specifically, in today's P2X analyses it is assumed that the regional excess of electricity generated by many small PV installations (typically in the range of several kW with a relatively small capacity factor of approx. 10% leading to peaks in power production, which are not curtailed but utilized here to reach a high number of operating hours of P2X plants) can be transferred into gas using larger electrolyzing systems for economic reasons (in the range of several MW). This assumption does not have to hold in practice.
- Today's power grid has historically been designed and tailored at all his layer to few large centralized energy sources. Thus, not every segment of the lower grid layer can handle the large amount of power generated there by the decentralized energy sources.
    - Therefore, dimensioning the grid infrastructure and components such as transformers, cables and overhead lines, has to be carefully checked. In practice, one can encounter e.g. overloaded transformers and violations of thermal or local voltage limits in the low-voltage grids with high penetration by PV generation.

3.3 P2X as potential newcomer in markets for gaseous fuels

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The Swiss gas market is expected to play an important role within the Energy Strategy 2050 in all three scenarios. The energy perspectives foresee that gas is a substitution winner for other fossil fuels and that the demand for biomethane and hydrogen is rising [75].

3.3.1 Natural gas market

Today, the Swiss gas market refers mainly to natural gas and is a well-established and functional market in Switzerland. From a European perspective the Swiss natural gas market is a small but important market, due to its geographical location and its role as transfer market between northern and southern European countries.

The natural gas market is a partly regulated market. Consumers with an annual heat requirement of more than 5 GWh (referred to the Higher Heating Value - HHV) are free to choose their providers. The responsible federal authority is the Bundesamt für Energie (BFE). Technical requirements are dispensed from the "Schweizerischer Verein des Gas- und Wasserfaches" (SVGW). The gas providers are united within the "Verband der Schweizerischen Gasgesellschaft" (VSG).

Power-to-Methane applications are compatible with the natural gas (NG) market. The produced and purified synthetic natural gas (SNG) can be mixed with natural gas or even replace it without any negative consequences for the natural gas grid components and consumers.

Consumption and Application

Since 2000 the gas consumption increased about 25.8%. In 2016 the gas consumption totaled 39'029 GWh (HHV) (end user consumption 36'075 GWh). The majority of the gas is imported with a total of 38'721 GWh mainly from Europe (36%), Russia (35%) and Norway (21%). The minority is biomethane produced in Switzerland with a total of 308 GWh, which corresponds to a total of 0.8%. Gas is mainly used in households (41.8%), the industry (34.0%) and in services (23.1%) [92]. In all these sectors, the majority of the natural gas is used for heating purposes, thus the consumption underlies seasonal fluctuations. Gas mobility plays a subordinated role. In 2016, 0.23% of the Swiss passenger cars had a natural gas fuelled engine [93]. The total gas consumption for mobility is 186.17 GWh, with a biomethane content of 22.4%.

The energy perspectives assume in the "POM" scenario, that the gas consumption in Switzerland decreases until 2050 about 36% compared to the consumption in 2016. This future demand is covered with mainly imports and contains 5.70% biomethane produced in Switzerland. 3.05% of that calculated future demand is used in mobility. In 2050 gas is going to play a subordinate role for households. In the opposite gas is used for electricity production in gas combined cycle power plants. In the energy perspectives it is foreseen that of up to nine gas combined cycle power plants with each of a power of 550 MW are built to provide Switzerland with electricity. The planning and construction period for one of these power plants is six years. [75]

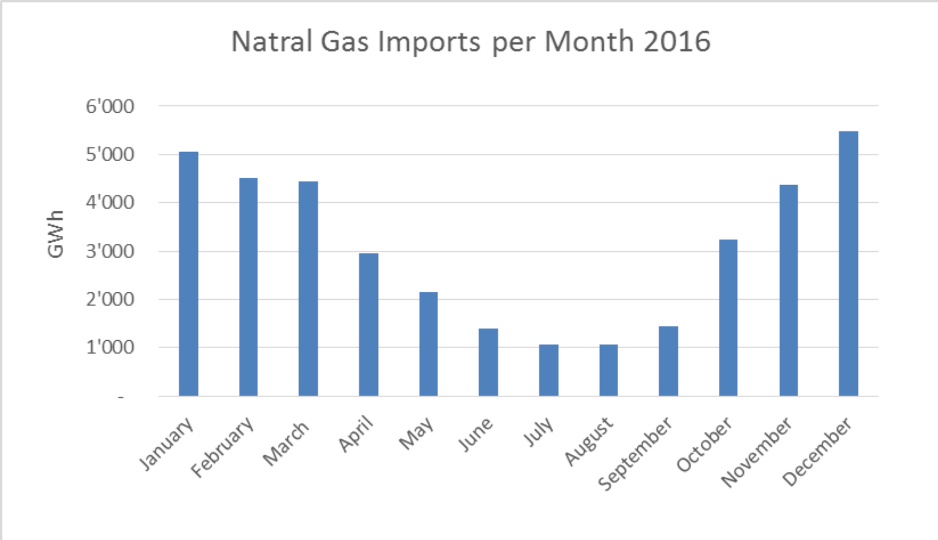

Figure 21: Natural Gas Imports per month 2016

Natural Gas Grid and Injection

The Swiss gas grid consist of the transit gas system and the regional and local natural gas grids. This includes approximately 2’150 km of high-pressure pipelines and about 15’800 km of distribution pipelines. The pressure varies from 20 mbarg to 85 barg. The Swiss natural gas grids are divided into six zones, which correspond to the control zones. [94]

The natural gas grid has twelve feed-in points from its surrounding countries. The most important entry point is Wallbach at the German-Swiss border, where about 80% of the natural gas imports are fed in. The main line of the transit gas transport system leads from Wallbach to the Swiss-Italian border at Griespass. The transit gas transport system connects the Swiss gas grid with those of Germany, France and Italy. From the transit gas transport system regional transport grids lead to different regions in Switzerland: the midland, the east, the west and central Switzerland. The imported methane flows from the north over Germany or France to the south. In 2018, a so called “reverse flow” is planned, which means that methane can also flow in the opposite direction through the transit gas transport lines from the south to the north. [95]

The Schweizerische Verein des Gas- und Wasserfaches (SVGW) has set regulations about the natural gas grid. The directive about the gas quality (SVGW: G18) defines the quality due to its heating characteristics and its gas components. The directive for the feed-in of renewable gases (SVGW: G13) includes SNG, so that the technical requirements of the products of Power-to-Methane plants are defined. SNG can be injected into the transmission or the distribution grid by connecting the Power-to-Methane plant to the grid with a pipeline and an injection station similar to those used for biomethane. The SNG must be compressed to the sufficient pressure of the grid. Power-to-Methane plants can be built along the widespread gas grid. Hence, the produced SNG can be directly fed into the gas grid without building additional pipelines.

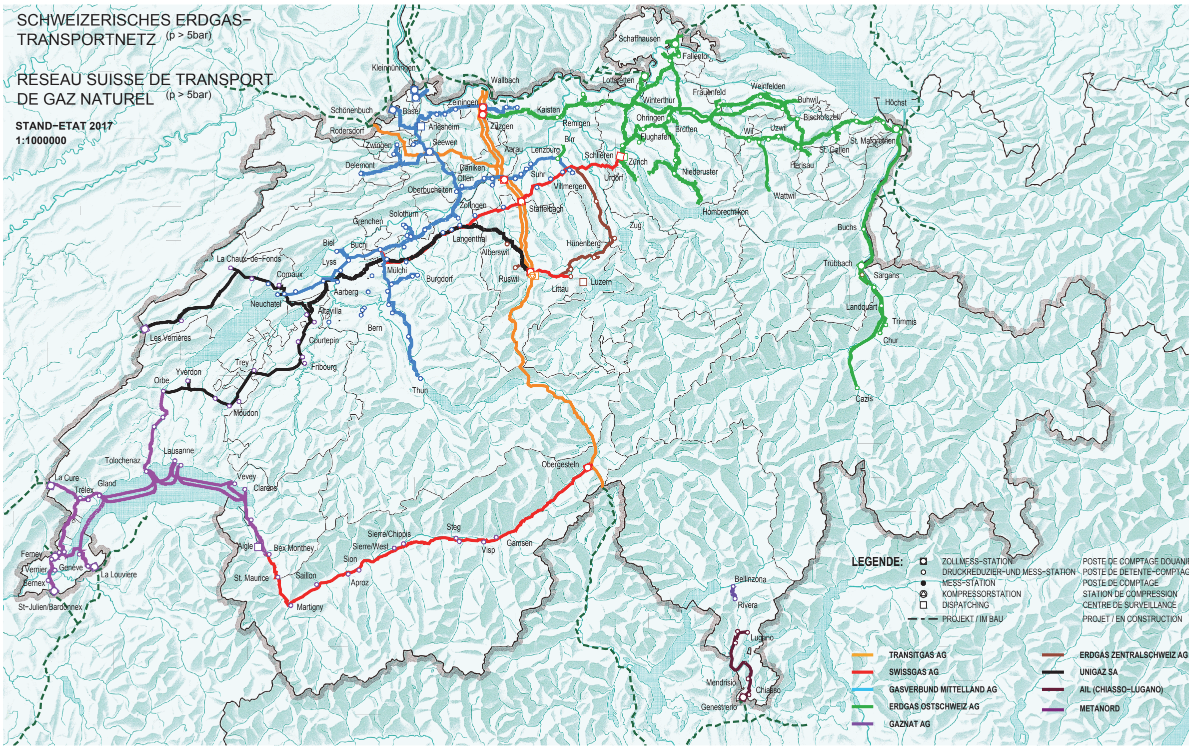

Figure 22: Map of Swiss Gas Grid [94]

Storage

Switzerland has access to a total capacity of 1'601.45 GWh (referred to the Lower Heating Value LHV). The majority of 94% (1'510.00 GWh) of this storage capacity is a cavern storage in Etrez (France). The minority of the storage capacity 6% (91.45 GWh) refers to ball and pipe storages and the linepack in Switzerland. [96]

Gas prices

There are about 100 local and regional gas suppliers in Switzerland. Customers can obtain gas for heating purposes and mobility. They can choose between natural gas and biomethane. The prices differ due to the annual consumption and the needed power levels. Furthermore, the prices in the same price category can differ with an approximate factor of 2 from different gas suppliers. The following table shows the minimum and maximum gas sales prices without CO_2 taxes for natural gas [97] and biomethane [98] for different consumer groups, without infrastructure costs. The majority of the customers pays about 7 Rp./kWh for natural gas and about 15 Rp./kWh for biomethane, these prices are guaranteed in contracted tariffs.

The third bar shows SNG production costs for different business cases from a feasibility study at KVA Linth [99], which is representative for other feasibility studies in Switzerland. The best business case reached a price of 12 Rp./kWh SNG. It can be seen that the SNG production costs are much higher than the natural gas prices. On the other hand if the SNG is produced with the best case scenario and is sold as biomethane, a profit of about to 2 Rp./kWh can be reached.

That means that there are already nowadays profitable business cases for Power-to-Methane plants, if the SNG can be sold for biomethane prices. The SNG production costs have to be calculated for every location of the Power-to-Methane plant, because there are no Swiss wide general regulations for these plants. Beside the capital and operation cost, the boundary conditions for the Power-to-Methane plant determine the business case the most, e.g. the price for the electricity supply. The more advantageous the boundary conditions for the Power-to-Methane plant, the lower the SNG production costs. The factors for a promising location and thus a profitable business case are the following:

- Guaranteed long-term low cost renewable electricity price
- The electricity supply for the Power-to-Methane plant is free from grid supply costs (this depends on the location of the Power-to-Methane plant)
- Power-to-Methane plant is located close to the gas grid
- SNG production on the specific site is accepted as renewable gas and can be sold as biomethane
- Low cost for CO2 supply
- Revenues from services in frequency control (negative and/or positive)
- Revenues from the sale of oxygen
- Revenues for the sale of heat
- Partnership with a car importer for reduction of fleet emissions

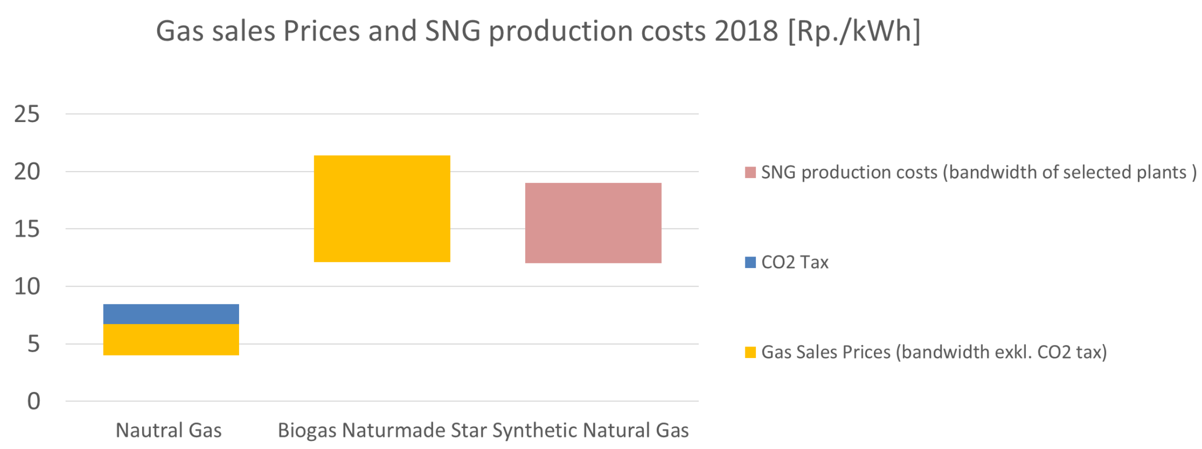

Figure 23: Gas Sales Prices and SNG production costs 2018 [97], [98]

Natural gas prices in mobility are linked to the price of gasoline. The liter equivalent of natural gas is roughly 30% cheaper than gasoline and costs about 10.5 Rp./kWh (HHV). The biomethane prices in mobility are higher and the biomethane is sold for a price around 18 Rp./kWh.

Gas industries' Position on Power-to-Gas

The Swiss gas association VSG proclaimed the aim to enlarge the amount of biomethane until 2030 up to a production of 4'400 GWh (HHV) per year, which is 12% of the end consumption in comparison to the 2016 consumption. The biomethane consumption should be reached with a better exploitation of the existing potential, the production with Power-to-Gas plants and imports with the development of an international register [100]. This register might help develop the physical export and import of biomethane. Because of their strategy the gas industry supports Swiss biomethane and the Power-to-Gas technology.

Expected developments

The worldwide consumption of natural gas is expected to increase; natural gas is the fastest growing fuel (1.6% per year) led by US shale gas; in 2035 it is expected to overtake coal to be the second-largest fuel source in the world [101]. Furthermore it is expected that the production costs and the prices for natural gas are increasing as well [101] [63]. This price increase might be caused on the one hand by the higher production costs and on the other hand, because the international demand of gas is increasing. Comparing different fossil fuels, gas has a lower climate impact and countries are expected to replace their consumption of fossil fuels like petrol or diesel with gas in order to achieve their climate targets. [101] There are different scenarios that forecast an increase of the natural gas price from 2018 to 2040 about factors of around 1.5 to around 5.

According to [63] the prices for natural gas are expected to increase. There are different scenarios that forecast an increase of the natural gas price from 2018 to 2040 about factors of around 1.5 to around 5.

3.3.2 Hydrogen market

The Swiss hydrogen market in the industry is a small and well-established market in Switzerland. Because of high transportation cost the hydrogen market has little international competition with other European countries. The hydrogen market is not regulated.

Consumption and Application

In Switzerland hydrogen is produced and delivered by several industrial producers. The annual consumption of hydrogen is largely determined by a few major customers and is around 13'000 tonnes per year (431 GWh (LHV)) and thus about 1% of the Swiss natural gas market. The largest producer for hydrogen is the refinery in Cressier for its own use, followed by the chemical site in Visp and the chloralkali electrolysis plant in Pratteln, producing hydrogen as a by-product [102].

The industrial hydrogen is mainly produced by reforming of naphta in refinery (38%), as by-product of chemical plants (29%) and by steam methane reforming (21%). Around 3% of the hydrogen demand is produced with water electrolysis. Hydrogen is used in a refinery in Cressier, for the fertilizer production in Visp (until April 2018), in the watch industry, in the chemical and pharma industry, for synthetic stone production and in the metal processing industry. [102]

With current consumption pattern in Switzerland, there are no major seasonal fluctuations in the hydrogen consumption [103]. Today, hydrogen plays a subordinate role in mobility and is only used in a pilot scale. There were four fuel stations in total and 36 fuel cell passenger cars (2016) in Switzerland. [104]

Gas grid

There is no installed hydrogen grid in Switzerland. The directive about the gas quality (SVGW: G18) defines the quality due to its heating characteristics and its gas components. This guidelines defines that hydrogen can be injected in a maximum of 2% of volume in the existing natural gas grid.

Power-to-Hydrogen applications have led to discussions about increasing the maximum content of hydrogen in a high single digit value. With a higher proportion of hydrogen in the gas grid, the combustion parameters change and the maximum possible amount of energy that can be transported decreases. There is no final study on the cost-benefit of increasing the maximum hydrogen content in the gas grid. Its change is expected to affect gas grid components, storage facilities, compressors and incinerators. That is why further investigation is needed to calculate the expected cost-benefit for necessary retrofits. [105]

There is no European standard for the maximum of hydrogen blended to the gas grid and it varies in different European countries from 0.1 to 10 % in volume.[34] The European gas grid runs through several countries, that is why it would make sense to discuss the level of hydrogen blended to the gas grid in a European context.

There are two hydrogen fueling stations for mobility applications in a pilot scale at Empa and Coop as well as one public hydrogen gas station in Hunzenschwil (Coop) and two half public gas stations at Empa and Messer AG. [104]

Storage

Transport and storage costs will play a significant role in the competitiveness of hydrogen to other energy carriers. The closer the consumer is located to the production, the lower the price for storage and transport. Long hydrogen transports can cost up to three times as large as much as the cost of hydrogen production. [34]

Hydrogen pipelines can be considered as the most cost-effective long-term choice for local hydrogen distribution if there is sufficiently large, sustained and localised demand; another option for long-term hydrogen storage is the just discussed blending to the natural gas grid. [34]

Cavern storages can be used as seasonal storage for hydrogen, the costs for this storage option depends strongly on the yearly cycles of storage. The levelized costs for a cavern hydrogen storage in 2030 is expected to cost around 0.4 €/kWh for one yearly cycle and around 0.22 €/kWh for 365 cycles per year. [34]

For short-term and small-scale applications hydrogen is stored as a gas or liquid in tanks, bottles or bundles of cylinders, also as mobile installatins on trailers. [34]

Hydrogen Prices

The sales prices for hydrogen from providers to Swiss industrial customers are subject of competition and are therefore not publicly available. A common sales price in Switzerland for one standard cubic meter of hydrogen (including transport) is about 1 CHF (33.4 Rp./kWh HHV) for industrial customers. [103] Electrolytic hydrogen from renewable electricity by Power-to-Hydrogen applications produce so called “green” hydrogen. The sales price for the production and transport of electrolytic hydrogen costs about 1 CHF (33.4 Rp./kWh HHV) per standard cubic meter of hydrogen for industrial customers. [103] It can be seen that the sales price (gas production cost plus transport) for hydrogen produced by steam methane reforming and electrolytic hydrogen from renewable electricity is about the same for the quantities traded on the Swiss hydrogen market today.

This equal sales price level independent of the production technologies has several reasons. The transport of hydrogen at quantities where it is delivered with trailers is the most expensive cost component of the overall sales price, so that the hydrogen production route (electrolysis or steam methane reforming) plays a sub-ordinated role in the pricing of hydrogen. Beside the refinery in Cressier and the chemical plant in Visp, there are no big chemical industries in Switzerland that produce hydrogen as "by-product" like in other European countries. For instance, in the German chemical industry hydrogen is a "co–product" and can therefore be offered in comparably large quantities and at significantly lower prices compared to smaller-scale dedicated hydrogen production. Due to the high transport costs for hydrogen via trailers, only delivery routes of less than 100 km are currently economic, so that under current conditions the majority of hydrogen producers in other European countries are no competitors for the Swiss hydrogen producers, unless they are closely located to Swiss hydrogen consumption sites.

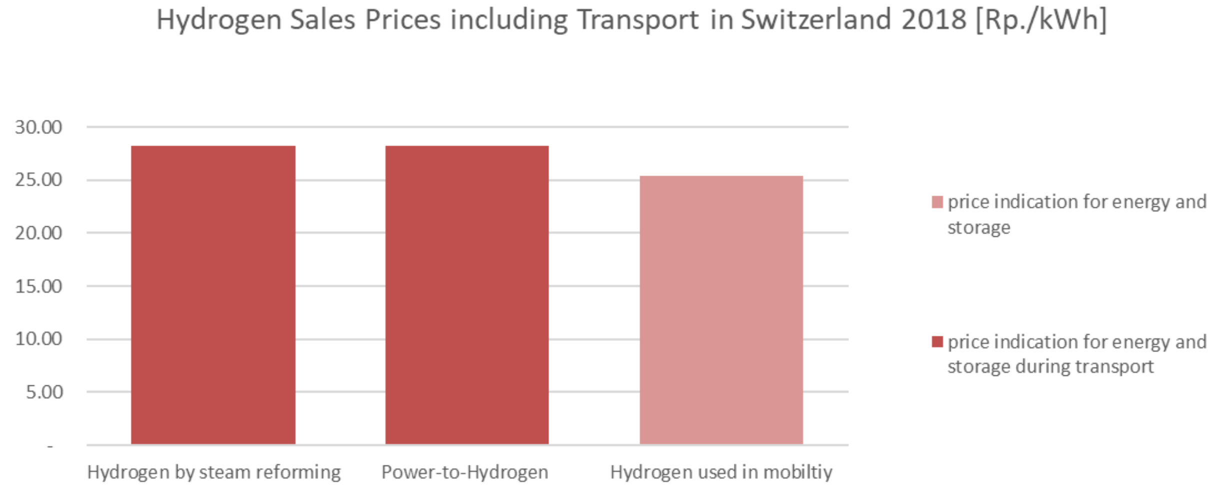

Figure 24: Hydrogen Prices

Expected Developments

For the scenarios of the Energy Perspectives [75] it is assumed that there will be no significant hydrogen infrastructure established until 2050. Hydrogen is taken into account as an energy storage for the electricity system, for example from excess electricity from solar PV to be used in winter for co-incineration in gas combined cycle power plants. Hydrogen is also taken into account as fuel in small fleets. That leads in the POM scenario in 2050 to a total amount of 2.5 PJ (694.4 GWh) of hydrogen for energy applications additional to the consumption in industrial applications.

3.4 P2X to pave pathways towards clean mobility solutions

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3.4.1 Introduction

In the context of a climate-constrained world, there are two main options for the decarbonization of transport: direct electrification via batteries and indirect electrification via electricity-based synthetic fuels (e-fuels). Technological, economic, ecological and non-financial customer limitations constrain the application of both options. Amongst others, a fair technology comparison of different means of transportation (MOT) needs to take into account the following aspects:

- Technological constraints (1)
    - Energy density required for MOT
    - Energy demand of MOT
    - Range of MOT
    - Infrastructure (like refuelling/ charging stations)
- Economic constraints (2)
    - Investment costs of MOT and related infrastructure
    - Total costs of ownership of MOT
- Ecological constraints (3)
    - Emission limits for GHGs
    - Emission limits for harmful substances
    - Recycling capability of MOT
- Non-financial customer constraints (4)
    - Range anxiety
    - Model variety

This part of the paper focuses on the technological (1) and economic (2) feasibility of P2X in the transportation sector. The technology assessment will span the maximum application space for direct and indirect electrification. Combined with the economic analysis, we derive realistic application scenarios for both decarbonization options. A discussion on the relevance of the transport sector for decarbonization considers the ecological aspects of e-fuels (3). Further ecological aspects like recycling capability as well as customer constraints (4) are not considered. For the latter, see for example [106].

3.4.2 Relevance of transportation sector for Swiss decarbonization

Nearly one third of the Swiss CO_2 emissions in 2015 (47.91 Mt CO_2-eq.) stems from the transport sector, see Figure 1. Thus, it is the biggest CO_2 emitter with 15.21 Mio. t CO_2-eq. emitted per year. Within the transport sector, the share of road transport amounts to 98% (14.89 Mt CO_2-eq.). Hence, emissions of other forms of transportation like domestic aviation are comparably low. This is due to the fact that only national aviation emissions of 0.14 Mt CO_2-eq. are taken into account for the Swiss CO_2 balance. This follows a decision in the UNFCCC's Kyoto Protocol that international aviation is not accounted within a national CO_2 balance. International aviation accounts for 4.90 Mt CO_2-eq. Within the road-based mobility, 69% can be ascribed to passenger cars (10.22 Mt CO_2-eq.), 17% to freight transport (2.54 Mt CO_2-eq.), and 14% to buses, two-wheelers and others.

Summing up, a 38 % share of the Swiss *domestic* CO_2 emissions can be traced back to road-based mobility, which is, for instance, still more than all industrial emissions. That stresses the high importance of decarbonizing this sector. At the same time, road-based mobility is not only the most important sector for decarbonizing Switzerland, but also the most challenging one as it relies on mobile energy demand. This demands for a high volumetric as well as gravimetric density of the energy carrier used for the propulsion of vehicles. Historically, oil was found to be a good solution due to its high energy density. On that basis, complex drivetrain technologies were developed, albeit the electric motor was invented even before the internal combustion engine. Still, the energy density of liquid fuels is unmatched. Nevertheless, battery electric vehicles (BEVs) as well as gas-powered vehicles have become competitive, due to great progress in battery technology and the storage of gaseous fuels. This development illustrates the crucial role of energy density for mobile applications of energy conversion and the challenges for research and development that derive from that fact.

While the energy demand of other sectors like buildings stagnates or even declines, the demand for transport (especially freight) is rapidly increasing [107][108]. If CO_2 emissions of the transport sector are to be mitigated significantly, vehicle technologies and especially fuel usage need to change drastically. Assessing the potential of synthetic fuels for the transport sector demands to distinguish between new and existing fleets. Fast CO_2 reductions in the transport sector requires addressing both the existing and new fleet of vehicles. While the new fleet can (to a certain share) directly be electrified via electric drive trains, the existing fleet can be indirectly electrified with renewable electricity based fuels (e-fuels). Common lifetimes of road-based vehicles (10-20 years, see e.g. [108][109]) set a temporal limit for the substitution of the existing fleet with new technologies. Together with the gradual ramp-up of new technologies (e.g. see [110]), conventional drive trains will amount for a large share of vehicles even in the mid-term future. For fast CO_2 reductions in the transport sector, it is crucial to address not only new vehicles but also the existing fleet. Therefore, two options can be considered: First, the retrofitting/ change of existing drive trains (e.g. change of gasoline to gas vehicles). Second, the substitution of fossil fuels by renewable synthetic fuels without any change in hardware (e.g. use of synthetic e-diesel instead of fossil diesel).

3.4.3 Application potential of e-fuels for the aviation sector

Beyond road transport, synthetic fuels represent one of the few CO_2 emission reduction options for aviation. The aviation sector, which is almost entirely based on fossil fuels, faces a rapidly increasing demand while technologies to substantially reduce CO_2 emissions are scarce and time-intensive to deploy because of long lead-time for licensing due to high safety standards. While the direct electrification of transport is a viable approach for reducing CO_2 emissions of a high portion of the ground-based transport, there is no reasonable substitute for liquid fuels for aviation because of the high energy density required for aviation. Synthetic fuels like e-kerosene represent a possible approach to provide low-carbon fuels for conventional aviation combustion technologies. Other measures to reduce aviation's carbon emissions are efficiency increases by retrofits or new aircraft designs and airline operational strategies like surface congestion management or optimized approach procedures [111].

Compared to Switzerland's *domestic* aviation, the CO_2 emissions from its *international* aviation are much higher. New regulations for international aviation starting in 2021 might create favourable conditions for the application of synthetic fuels. Currently, Swiss domestic aviation is not integrated into the Emission Trading Scheme of the European Union (EU ETS). This will change with the linkage of the Swiss and the EU ETS that was agreed on in January 2016 [112]. The entry into force of that agreement is planned until 2020. However, the CO_2 emissions from Switzerland's international aviation are of significantly higher importance. They are as high as one third of the Swiss road transport. Currently, there is no legal obligation to account for international aviation. In 2016, 191 member states of the International Civil Aviation Organization (ICAO) agreed on the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) [113]. Its aim is to freeze CO_2 emissions on 2020 levels and allow for carbon-neutral growth from 2021 on. Switzerland is one of the (currently) 76 nations that are participating in the first voluntary phase, which lasts until 2027. From 2027 on, the agreement is binding for all nations. Among the measures to reduce CO_2 emissions, sustainable aviation fuels might play a major role in achieving the goals set in CORSIA. Depending on the implementation of the carbon offsetting mechanism, CORSIA could create favourable market conditions for (liquid) synthetic fuels. A report on "CORSIA Sustainable Aviation Fuels" is planned to be published by ICAO until 2021 [114]. Since regulations are not yet finalized and since production technologies for liquid e-fuels are not yet available at large scale, the following will focus on road-based transport.

3.4.4 Application potential of e-fuels for the road-based transport sector

Figure 25 shows the trade-off between range and energy demand of vehicles. Displayed is the energy demand at the wheel. Considering efficiencies for different drivetrain technologies leads to the demand of stored energy of fuel or electricity. The two curves show exemplarily how the specific energy demand (per km) and the range are correlated. Introducing greater amounts of energy, that can be mounted onto a vehicle via fuel or battery, equals shifting the curves to the upper right. Higher energy demand, scaling with the vehicle mass, requires higher energy capacity stored on the vehicle. Left to right, the energy demand per km driven increases from cars (red area) over rigid trucks (18t, blue) to articulated trucks (40t, green). Assuming a maximum volume available for battery size, the two curves show the maximum battery capacity for these three types of vehicles. Hence, the area below the three curves in the plot indicate the application space for BEVs. Currently, BEVs can cover ranges of approximately 300 - 600 km for cars and 250 - 350 km for rigid trucks, while there are no battery-electric articulated trucks on the market yet. We marked average ranges for each vehicle type in Figure 25.

Considering the additional energy demand for auxiliary devices, e.g. the air conditioning or heating system, reduces these values for BEVs significantly because the energy is directly competing with the electrical energy used for propulsion. For internal combustion engine vehicles (ICEV) and fuel cell vehicles (FCVs), the effect is much less since e.g. waste heat can be used for heating the vehicle in winter. However, this has to be considered in the context of different drivetrain efficiencies. While BEVs achieve values of up to 90% tank-to-wheel, ICEVs and FCVs efficiencies range around 40%.

Excluding future developments that may push the curves to higher ranges (e.g. improvements in energy density of batteries, fast-charging or battery-swapping, e.g. see [115]), the current situation would suggest P2X technologies to decarbonize also the long-distance and heavy-duty part of the transportation sector. Assuming that long-distance car mobility will preferably be accomplished by limousines or SUVs (for comfort and safety reasons), P2X would in particular be interesting for ranges starting from 300 km. Regarding heavy-duty transport, a feasible range of several hundreds of kilometers is essential. Furthermore, long stopping times for charging batteries are not compatible with the high time pressure in the transport industry. Larger batteries would significantly increase weight and volume, the latter directly competing with the transport load. Battery-swapping might be a reasonable solution for the direct electrification of heavy-duty trucks, but its realization is challenging due to a number of reasons (high infrastructure costs, high amount of extra batteries necessary, etc.).

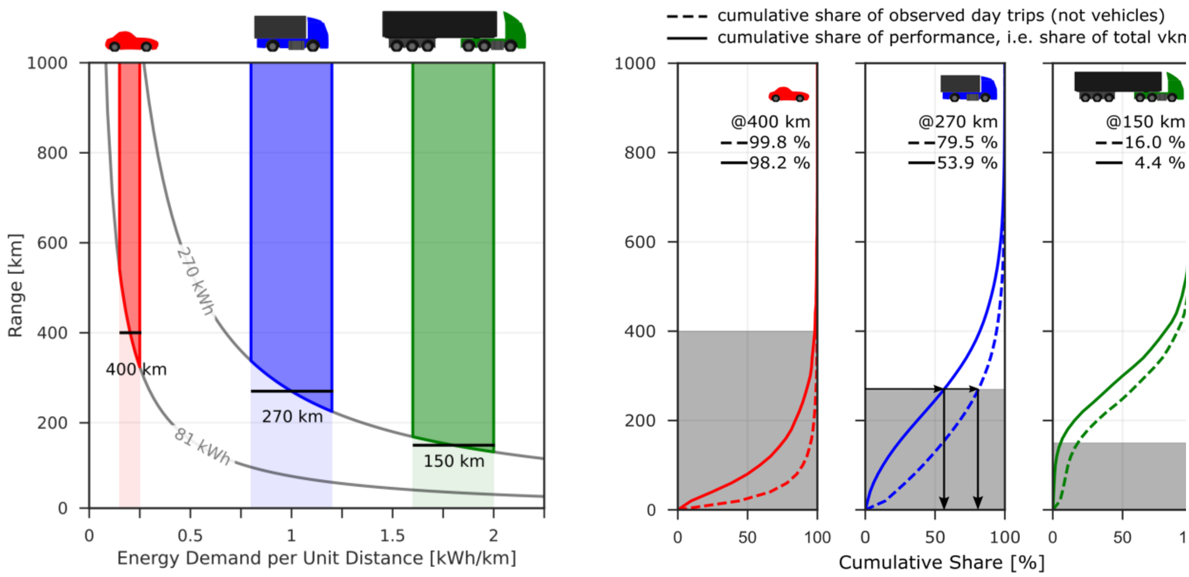


Figure 25: Direct vs. indirect electrification of cars and trucks [116]
Left panel: Trade-off between specific energy demand and range for cars (red), rigid trucks (18t, blue) and articulated trucks (40t, green). The hyperbolic curves indicate the amount of energy that is stored on a vehicle. In particular, the two displayed curves show the maximum battery capacities for each vehicle type (maximum values while average battery size is lower). Their intersection with the typical specific energy demand of each vehicle type results in the maximum distance that can be driven with the energy stored on the vehicle without recharging. Hence, the area below the three curves in the plot indicates the application space for BEVs.
Right panel: Cumulative share of observed day trips (dashed lines) and day trip performance (solid lines). For a given day trip distance, a horizontal line can be drawn (see arrows for the rigid trucks). Starting from the intersection with the CDT and the CDTP line, we go down vertically. This gives the values of: (1) how many trips (of all observed trips) are covered within the chosen day trip distance – e.g., for the rigid trucks, 79.5 % of all day trips are shorter than 270 km. (2) which day trip performance is covered up to the chosen day trip distance – e.g., for the rigid trucks, 53.9 % of the overall vehicle kilometers are performed by trips shorter than 270 km. (Calculations based on [117])

To identify the relevance of the highlighted areas in the right panel of Figure 25, one has to consider how far vehicles usually go within one day. The figure shows on the one hand the observed day trips (dashed lines) in Switzerland as a cumulative share of all day trip distances. On the other hand, it illustrates the performance of the observed trips (solid lines), again as a cumulative share of all day trip distances.

The observed cumulative share of day trips (CDT) for any distance (d) is calculated by the number of all observed trips (n_i) summed up from zero day trip distance up to the chosen distance d, divided by the total number of observed day trips (for all in [117] observed ranges from 0 km to d_{max}):

$$CDT(d) = \frac{number\ of\ observed\ day\ trips\ up\ to\ distance\ d}{total\ number\ of\ observed\ day\ trips} = \frac{\sum_{i=0}^{d} n_i}{\sum_{i=0}^{d_{max}} n_i}$$

The cumulative share of the day trip performance (CDTP) is derived by multiplying the numbers of observed trips with their specific day trip distance up to the chosen distance d, divided by the total fleet performance:

$$CDTP(d) = \frac{sum\ of\ vkm\ up\ to\ distance\ d}{total\ vkm\ performance} = \frac{\sum_{i=0}^{d} n_i \cdot i}{\sum_{i=0}^{d_{max}} n_i \cdot i}$$

The right panel of Figure 25 shows the CDT and the CDTP for passenger cars, rigid and articulated trucks. The horizontal lines correspond to the range that can currently be achieved with BEVs (mean values out of the range displayed in the left panel). For the passenger cars (rigid trucks, articulated trucks), 99.8% (79.5%. 16.0%) of all day trips are shorter than 400km (270km, 150km). This corresponds to 98.2% (53.9%, 4.4%) of the overall vehicle kilometres. Figure 25 is based on the day trips, not the mean daily distance driven. This is highly important because depending on what basis we discuss electrification, the outcomes are different. For the case of *passenger cars*, this would mean: According to Figure 2, 99.8% of all day trips are shorter than 400 km. However, not all 99.8% of all cars may be electrified directly via BEVs currently; only 99.8% of all day trips can be covered by direct electrification. Reality might be different: A possible scenario is that a car owner drives less than 400km for 363 days in the year, but wants to go for vacation once in the year where he needs a range capacity of 800 km. There are two ways to overcome that problem: either re-fueling or re-charging (which might be time-consuming), or taking a car with a higher energy capacity. Thus, according to the decision behavior, he/she might not go for a BEV, but a fuel-driven car with higher range. In conclusion, another way to investigate the electrification potential would be to take the maximum day trip distance of a vehicle owner out of all distances he is driving over the whole year. However, this observation is highly dependent of the car owner's willingness to change his/her behavior for the (on average) few high-distance trips.

For trucks, the situation is different as longer trips are more common. For *rigid trucks*, nearly 80% of all day trips can be electrified directly. However, this amounts only to approximately half of the fleet performance. Hence, low-distance mobility does not contribute equally to the performance of the fleet. The decarbonization impact of the remaining 20% of the fleet would be almost as high as the decarbonization of the low-distance 80%. Achieving this via power-based synthetic fuels offers high potential for decarbonization of the Swiss transport sector.

For *articulated trucks,* the predominant finding is that only little part of the fleet can be electrified directly. This is due to the high energy demand that would lead to heavy and high-volume batteries. As mass and volume directly compete with payload, BEVs are currently not considered for articulated trucks. Yet, there is no commercial product. Furthermore, legislature currently allows only little surplus weight for implementing alternative, low-carbon drivetrains.

In conclusion, long-distance freight mobility contributes significantly to the carbon emissions of the Swiss transport sector. E-fuels offer a suitable solution to fulfil the needs of long-distance freight transport (e.g. low charging/ fueling time, high range).

3.4.5 Well-to-wheel (WTW) efficiency of e-fuels for the road-based transport sector

Considering the entire conversion chain (WTW), vehicles operated with e-fuels need roughly three to four times as much electric power as BEVs. However, P2X technologies allow both geographical and temporal de-coupling of fuel production (by fluctuating renewable energy) and its use in vehicles. The direct use of PV and wind energy in BEVs offers the highest efficiency but is depending on fossil sources during periods with low renewable electricity generation (e.g. winter). In contrast, the production efficiencies of synthetic fuels range between 35 and 50% (on an LHV basis). More precisely, the power-to-fuel efficiencies (for an electrolysis efficiency of 60%) are 36% for OME_{3-5}, 40-42% for methylal, 43% for Fischer Tropsch-fuels, 48% for dimethyl ether, and 49% for both methane and methanol [118]. For these numbers, the CO_2 is considered to be available without additional energy demand. PCC or DAC will typically lower the power-to-fuel efficiency of e-fuels by 5-10 percentage points, if no waste-heat recovery system is used. In contrast, advances in electrolysis (major loss in efficiency) offer the potential to significantly increase the power-to-fuel efficiency.

In combination with Tank-to-Wheel efficiencies between 25 and 50%, the well-to-wheel (WTW) efficiencies of vehicles powered by e-fuels ranges between 15 and 25%. Despite the rather low synthesis efficiency, e-fuels are able to use renewable electricity generated in summer to provide energy services during other seasons of the year. Hence, the production of renewable energy can be decoupled from its use in vehicles, which would not be possible in the same amount for BEVs. In a holistic view, the combination of the efficiency potential of BEVs and the flexibility potential from e-fuel mobility would lead to a higher CO_2 reduction rate in the transport sector than with BEVs alone.

3.4.6 Impact of the electrification of transport on the electricity sector

Predicting full electrification of the transportation sector for the future, its actual sustainability is highly dependent on the electricity generation. The energy system has to be able to supply the additional amount of electricity needed by the (direct and indirect) electrification of transport. For BEVs, this means that whenever the amount of energy requested from charging stations exceeds the currently available energy from renewable sources, the gap has to be filled by fossil electricity generation or imports (with corresponding marginal CO_2 emissions).

There are two critical time dimensions that will play an important role if BEV penetration reaches significant numbers: Daily and seasonal differences in renewable electricity production could lead to bottlenecks when matched with the electricity demand. Vehicles are mostly driven during the day and charged overnight. This does not match with the solar peak during the day. Smart charging or home battery storages could solve this problem. In contrast, the lack of solar power during winter cannot be buffered as easily via storage of electricity. Here, e-fuels have the advantage of higher suitability for long-term storage. Thus, demand and supply can be matched not only inter-daily but also inter-seasonally – given that suitable storage facilities are available to do so. The supply reliability of energy for mobility will gain in importance with increasing shares of electrified vehicles. E-fuels are an option to decouple the fluctuating renewable electricity production from its use in vehicles, both temporally as well as regionally.

3.4.7 From tank-to-wheel to LCA

Relying on CO_2 as a feedstock, the production of e-fuels (except of hydrogen) will require carbon capture units. The CO_2 can either be captured from flue gas via post-combustion capture (PCC) or directly from air via direct air capture (DAC). Hence, the same amount of CO_2 emitted during combustion was bound during the synthesis of the fuel. Introducing e-fuels to the transport sector would require a shift from a tank-to-wheel to a well-to-wheel, if not an life cycle emission assessment (LCA). Otherwise, the positive impact of the carbon capture in the well-to-tank-part would be ignored.

Furthermore, direct electrification relies on a rather high consumption of resources needed for the production of electric motors and batteries, like cobalt or lithium. As these materials are not evenly distributed on earth, but concentrated on few countries like China or Chile, it is not only an economic but also a political uncertainty that sticks to BEVs. Even if these key elements would be available cost-effective in a long-term view, the ecological and social impacts of mining and processing the resources are important for a holistic technology comparison. In addition, the recycling of any MOTs should be considered in an LCA. Large-scale recycling of lithium-ion based batteries (with an acidic electrolyte) is not yet state-of-the-art and might be cost-intensive in the future. P2X-powered ICEVs mainly require steel-based materials which are recycled extensively.

3.4.8 Economic evaluation of e-fuels for the ground-based transport sector

Low share of energy costs on total cost of ownership as a prerequisite

Synthetic fuels are much more expensive than conventional fossil fuels and even more expensive than renewable biogenic fuels (at least at the beginning) [119], why their economic feasibility often is put into question. However, the share of energy costs for road vehicles on their total costs of ownership (TCO) is low, why the use of synthetic fuels is much more realistic than in other energy conversion applications as heat or power generators. In the following, the introduction of synthetic fuels is described regarding total cost of ownership aspects (TCO) for a compact passenger car and a 28 t truck.

Figure 26 shows typical cost profiles of a compact passenger car with a mileage of 15’000 km/a over 4 years on the left side and a 28 t heavy duty truck on the right side with 80’000 km/a over 4 years. The share of fuel energy costs (without fuel taxation) for the passenger car example is at about 10% and for the heavy duty truck example at 12 – 15% compared to the total cost of ownership (TCO). A low share of energy cost leads to moderate increase of TCO even for significantly more expensive fuels. This impact will be shown in the first part of the chapter.

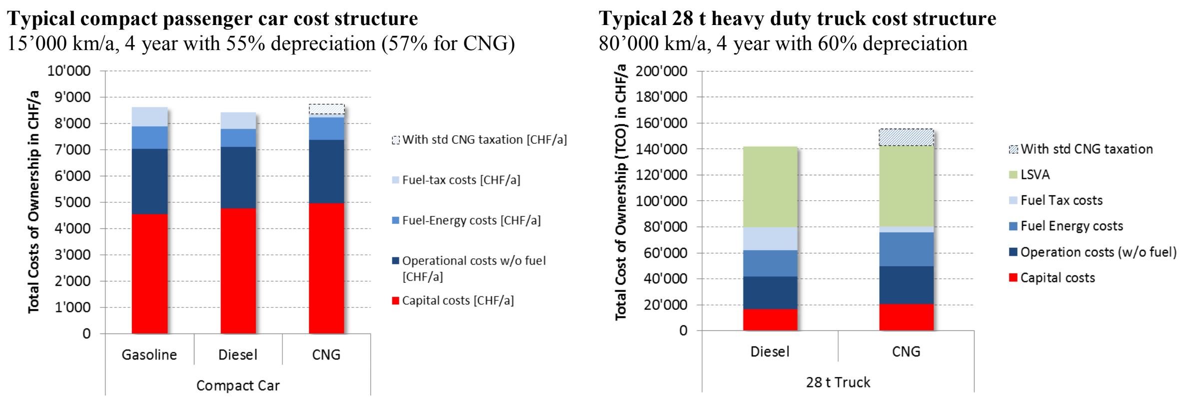


Figure 26: Total Cost of Ownership (TCO) structure of a compact passenger car with gasoline, diesel and CNG engine (left) and a 28 t truck with diesel and CNG engine (right); CNG with reduced fuel taxation; the difference to the standard CNG taxation is indicated as separate cost item (dashed line)

For the passenger car example, the capital costs (Figure 26, red bar) alone are covering roughly 50% of the total costs of ownership while in the heavy duty truck example, the fees (fuel taxation and the performance-based traffic tax (LSVA), light blue and green bar) are responsible for roughly 50% of the TCO. This means, that the purchase price in the passenger car sector and taxation policy in the heavy duty truck sector, have a major impact on their TCOs.

For CNG, a temporary reduced fuel taxation of 0.2222 CHF/kg is applied actually in Switzerland instead of the standard taxation of 0.8092 CHF/kg. To give the whole picture, the full standard taxation is indicated in Figure 26 too. This low share of energy costs will be even reduced in future by the foreseeable hybridization of the conventional internal combustion engine based powertrains.

Business case concept for synthetic fuels

The production costs of synthetic fuels are depending from several general and also some local conditions. For our calculation, the production costs of hydrogen, synthetic methane and synthetic diesel in Table 15 are used[6].

	Hydrogen [CHF/kWh$_{LHV}$]	Synthetic Methane [CHF/kWh$_{LHV}$]	Synthetic Diesel [CHF/kWh$_{LHV}$]
P2X plant (1st generation)	0.10 – 0.18	0.17 – 0.25	0.22 – 0.38

Table 15: Assumed hydrogen, methane and synthetic diesel production costs for a 1st generation P2X plant with 7'500 operational hours and a 2nd generation P2X plant with 3'500 operational hours in the multi MW-range (see chapter 2.1.6)

Electricity and capital costs (depreciation and interests) of synthetic fuels are responsible for roughly 70% of these costs while CO_2 supply, maintenance and repair is typically 30% [71]. Due to increasing electricity price with increasing operational hours, the reduction from annually 7'500 operational hours (1st generation P2X plant) to 3'500 operational hours (2nd generation P2X plant) would increase the production costs by roughly 20% only. For a 7'500 h/a operation, the electricity costs are in the range of 60%, falling down for a 3'500 h/a operation to 40% while the capital costs are increasing accordingly.

The production costs of synthetic fuels have to be compared with energy price of fossil fuels at the border, which are shown in Table 17. Thereby, the end-user fuel price at the fueling station was back-calculated according to information from mineral oil and gas industry.

Fossil fuels	Fuel production cost [CHF/kWh$_{LHV}$]	Distribution/ fueling station [CHF/kWh$_{LHV}$]	End-user Energy costs [CHF/kWh$_{LHV}$]	Fuel taxation [CHF/kWh$_{LHV}$]	End-user fuel price, incl. tax/VAT [CHF/kWh]
Gasoline (8.72 kWh/l)	0.063	0.032	0.095	0.084	0.193 (1.68 CHF/l)
Diesel	0.055	0.028	0.084	0.077	0.173 (1.71 CHF/l)
CNG (w/o biogas)	0.020	0.095	0.115	0.017	0.142 (1.85 CHF/kg)

Table 16: Cost structure of fossil gasoline, diesel and CNG fuels

Replacing now the fossil fuel production cost by the production costs of synthetic fuels, the end-user price at the fueling station would be significantly increased, as Table 18 shows. Due to a lack of data, doubled distribution and fueling station costs for H_2 are assumed compared to CNG/synthetic methane due to roughly doubled investment costs and higher maintenance costs.

Synthetic fuels	Fuel production cost [CHF/kWh$_{LHV}$]	Distribution/ fueling station [CHF/kWh$_{LHV}$]	End-user Energy costs [CHF/kWh$_{LHV}$]	Fuel taxation [CHF/kWh$_{LHV}$]	End-user fuel price, incl. tax/VAT [CHF/kWh$_{LHV}$]

[6] The potential of electricity based fuels (e-fuels) for low emission transport in the EU; dena/LBST (2017)

Synthetic diesel	0.300	0.028	0.328	0	0.354 (3.50 CHF/l)
Synthetic methane	0.210	0.095	0.305	0	0.346 (4.53 CHF/kg)
Hydrogen	0.140	0.328	0.468	0	0.539 (9.89 CHF/kg)

Table 17: Cost structure of fossil gasoline (reference) and synthetic diesel, methane and hydrogen (gaseous fuels in CHF/kg); fuel tax exemption for renewable synthetic fuels assumed

Figure 27 shows the TCO of the above mentioned passenger car and the heavy duty truck example, including the end-user costs of synthetic fuels according Table 17 compared with the reference gasoline vehicle (passenger car) respectively the reference diesel vehicle (28 t heavy duty truck). Thereby, an additional purchase price of 25’000 CHF for the hydrogen driven compact car as well as a 2.5 times higher purchase price for the hydrogen driven truck was assumed compared to the gasoline reference passenger car respectively the 28 t diesel truck. Considering the actual fuel tax exemption for renewable fuels, the integration of the synthetic fuels are leading to roughly 20% higher TCOs for the diesel and gas driven compact cars respectively to 25 - 30% higher TCOs for the diesel and gas driven 28 t truck.

It can be seen, that synthetic fuels are not competitive for the passenger cars in this comparison nor for the synthetic diesel and synthetic methane operated 28 t truck. Due to the actual LSVA and fuel tax exemption for electric powered trucks, hydrogen operated trucks would have a lower TCO as diesel trucks.

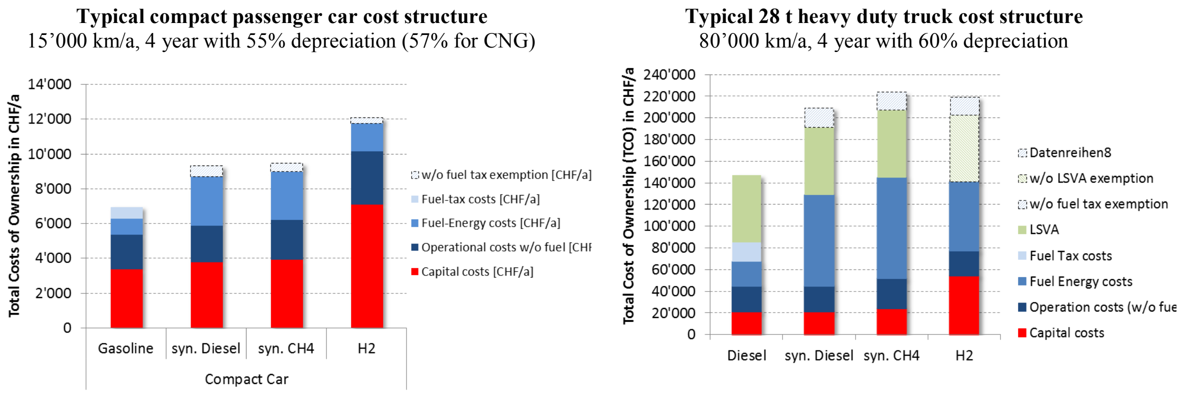


Figure 27: Left diagram: Total cost of ownership calculation for a gasoline reference compact car vehicle and with synthetic diesel, methane and hydrogen operated vehicles - without considering a scale based cost reduction for methane and hydrogen vehicles; Right diagram: Total cost of ownership calculation for a 28 t diesel truck and with synthetic diesel, methane and hydrogen operated vehicles

However, the comparison in Figure 27 does not consider the different situation of gasoline and diesel vehicles with a very high market penetration and fully optimized energy distribution and fueling station on the one side as well as methane and hydrogen vehicles on the other side in (expensive) niche markets. Furthermore, the comparison does not consider the CO_2 reduction compared to the gasoline reference vehicle which is leading to reduced penalties in case of the non-compliance with the targets of the CO_2 law. In the following, the impact of an increased market penetration on the TCO shall be shown as well as the ecologic benefit of reduced CO_2 emissions.

The degree of utilization of expensive infrastructures as gas or hydrogen fueling stations has an important impact on the end-user fuel prize. Figure 28 show the cost calculation of a standard single dispenser CNG station. Mark “A” shows the end-user CNG price at the actual market penetration of CNG vehicles in Switzerland (roughly 14’000 passenger cars) related to the number of CNG fueling stations (roughly 140 stations), resulting in roughly 100 CNG passenger cars per fueling station. If the number of CNG passenger cars could be increased to 200 (mark “B”) or 400 passenger cars per fueling station (mark “C”), which would mean 14’000 respectively 42’000 additional CNG passenger cars in Switzerland at the given fueling station number, the end-user fuel price would be reduced from 1.85 CHF/kg (1.26 CHF/l-eq) to 1.40 CHF/kg (0.95 CHF/l-eq) respectively to 1.06 CHF/kg (0.75 CHF/l-eq). Regarding turnover at a fueling station, 1 heavy duty truck would correspond to roughly 30 passenger cars.

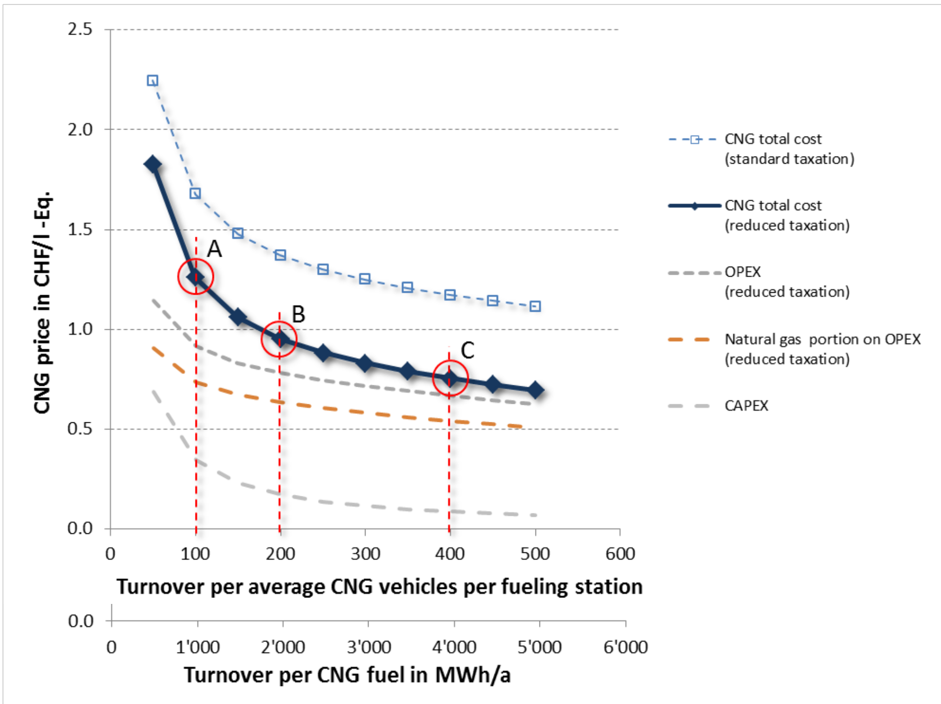


Figure 28: CNG end user cost as a function of the CNG vehicle or CNG sales volume. Solid bold line for reduced fuel taxation of 0.2222 CHF/kg CNG and dotted line for standard fuel taxation of 0.8092 CHF/kg CNG)

Increasing the market penetration of CNG vehicles from 100 vehicles per fueling station to 400 vehicles per fueling station (expressed as passenger car vehicle fuel consumption equivalents per fueling station) would reduce the distribution and trade costs by 0.05 – 0.06 CHF/kWh$_{LHV}$, which has a major impact on end-user fuel price, as can be seen in Table 18.

For hydrogen fueling stations, a similar cost degradation with increasing utilization can be assumed. For the following cost calculations, the above used factor of 2 for fuel distribution and fueling station costs of hydrogen compared to CNG are still used in Table 18.

No such cost reduction is possible for gasoline and diesel vehicles because of their fully developed market.

Synthetic fuels at 400 vehicles per fueling station	Synthetic fuel production cost [CHF/kWh$_{LHV}$]	Distribution/ fueling station [CHF/kWh$_{LHV}$]	End-user Energy costs [CHF/kWh$_{LHV}$]	Fuel taxation [CHF/kWh$_{LHV}$]	End-user fuel price, incl. tax/VAT [CHF/l], [CHF/kg]
Synthetic methane	0.210	0.038	0.248	0	0.285 (3.73 CHF/kg)
Hydrogen	0.140	0.175	0.315	0	0.375 (7.74 CHF/kg)

Table 18: Cost structure of synthetic methane and hydrogen at a market penetration of 400 passenger cars per fueling station (Considering the actual fuel tax exemption for renewable fuels)

Beside reduced infrastructure costs, higher market penetration would lead for gas and hydrogen vehicles to lower vehicle production costs. Assuming a bisection of the additional vehicle costs at a fourfold increase in production, the capital costs for CNG vehicles would approach those of gasoline vehicles.

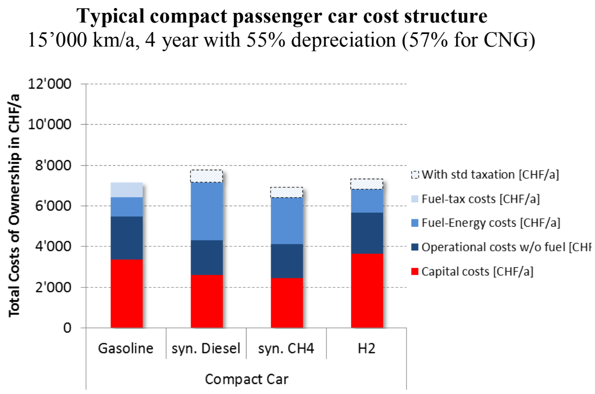
A further impact on vehicle costs is given by the CO_2 regulations for passenger cars and delivery vehicles. This regulation sets a target value for the average CO_2 emissions of an importer or of a pool of several importers. In case of non-compliance with this target value, a penalty of 95 CHF per gram of exceedance and sold vehicle has to be paid (according the draft CO_2 law for after 2020). Selling diesel, CNG or hydrogen vehicles instead of gasoline vehicles is of interest for the importer because this would lead to reduced average CO_2 emission. For a diesel compact car, a CO_2 reduction of 10% can be assumed due to the higher efficiency. For CNG vehicles, a CO_2 reduction of 22% can be assumed due to the lower C-content in the fuel and an additional CO_2-reduction of 10% due to the biogas portion in the CNG fuel is credited (in total: 30%). Due to the system boundaries of the CO_2 regulation, hydrogen driven vehicles are accounted with zero CO_2 emissions. As long as the average CO_2 emission value of an importer is above the corresponding target, the sale of diesel, CNG or hydrogen vehicles instead of gasoline vehicles would lead directly to a reduced penalty (hereinafter referred to as ecological benefit). Including the ecologic benefit of diesel, CNG and hydrogen vehicles compared to a gasoline compact car with a standard CO_2 value of 120 g/km in the new world-wide light duty vehicle test procedure (WLTP), following shift in end-user price of the different vehicles could be assumed (Table 19).

Compact car	Original purchase price [CHF]	@ 1% market penetration [CHF]	Ecologic benefit [CHF]	End-user vehicle price [CHF]
Gasoline vehicle (ref.)	32’500	0	0	32’500
Diesel vehicle	34’200	0	-1’140	33’010
CNG vehicle	34’200	-850	-3’420	29’930
Hydrogen vehicle	57’500	-12’500	-11’400	33’600

Table 19: Vehicle costs, including a minimal market penetration for CNG and H2 vehicles the ecologic benefit compared to a gasoline vehicle and the resulting end-user vehicle price.

Considering finally the cost reduction at increased market penetration (400 vehicles per fueling station) as well as the ecologic benefit of the vehicles, expressed as the CO_2 penalty savings compared to a gasoline vehicle (Table 19), the TCO of the synthetic methane and the hydrogen driven compact cars would become quite similar to those gasoline vehicles, even without fuel tax exemption.

For the 28 t heavy duty truck example, the TCOs without LSVA and fuel tax exemption of the synthetic fuel driven trucks are higher than of the fossil diesel driven truck. This is mainly, because there is actually no ecologic benefit accountable as this is the case for passenger cars and light duty trucks. It is expected, that a similar CO_2 regulation will be applied in the time frame of 2025 – 2030, which will then change the picture.



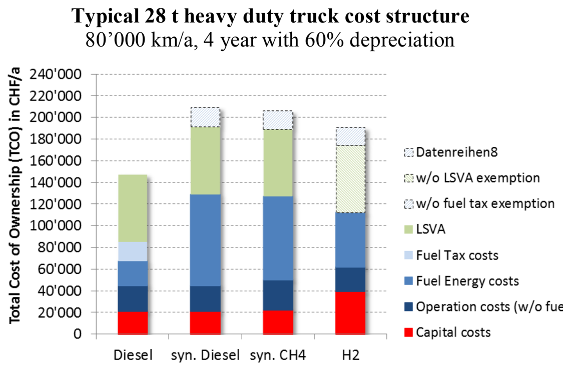


Figure 29: Left diagram: Total cost of ownership calculation for a gasoline reference compact car vehicle and with synthetic diesel, methane and hydrogen operated vehicles - considering a scale based cost reduction for methane and hydrogen vehicles (400 passenger car vehicle equivalents per fueling station); Right diagram: Total cost of ownership calculation for a 28 t diesel truck and with synthetic diesel, methane and hydrogen operated vehicles

As a result of the economic evaluation, one can conclude, that synthetic fuels have a market potential in the passenger car sector, even if no tax of fee exemption is in force. The prerequisites are on the one side, that the vehicles achieve a minimal market share of 400 passenger car vehicle equivalents per fueling station, which is reducing the capital costs of the (expensive) infrastructure by higher utilization and the vehicle production costs by higher production number. A second important impact is the consideration of the ecologic benefit (due to the missing CO_2 legislation for heavy duty trucks in Switzerland here only included for the passenger car calculation).

In the heavy duty truck domain, hydrogen driven fuel cell vehicles have at least a temporary market potential as long as the LSVA exemption is in force. To achieve a market potential, the production costs of synthetic fuels have to be reduced more than assumed within this report.

3.5 P2X in Industry

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3.5.1 The Swiss industry sector

In Switzerland, energy consumption in industry represented 18.5% of the final energy demand in 2017, with natural gas and electricity accounting for more than two thirds of the total industrial energy input [120]. While most of the energy carriers are used to provide energy services (heat, lighting, mechanical drive, etc.), a small share is also used as feedstock, for instance, in the chemical industry. More than half of the final energy demand was used for generation of process heat [121]. With about on quarter (2017) of the industry's final energy consumption, the chemical industries represent one of the sectors with the highest energy consumption [121]. Conversely to other countries, where mass-production of basic chemicals represents a significant share of the chemical industry, the Swiss chemical sector is very versatile, producing over 30'000 products. Chemical industry in Switzerland targets production of specialized chemical products, which mainly refer to life-science products such as pharmaceutical products, vitamins, fine chemicals, diagnostics and plant protection.

Considering energy and process-related emissions, the industry sector is one of the main CO_2 sources in Switzerland and accounts for 19% (7 Mt) of the total national CO_2 emissions in 2017 [122]. Most of the emissions (70%) result from combustion of fossil fuels, while the remaining 30% are process-related emissions primarily associated with cement production [122]. The chemical industry and the non-metallic minerals sector (including cement production) are those industry sectors with the highest CO_2 emissions in Switzerland. Large point sources with more than 350 kt of CO_2 per year are the five largest cement plants, most of them located along the Jura Mountains, the chemical plant located in Visp and the refinery in Cressier [123].

3.5.2 Hydrogen in industry and the refinery sectors

Hydrogen consumption in Switzerland is estimated for the year 2018 to about 13'000 tons with the refinery in Cressier representing the largest single consumer with circa 85% of the total hydrogen consumption [102]. Other small-scale consumers for hydrogen belong to the watch industry, chemical and pharma industry, synthetic gemstone production and other uses. About 90% of the hydrogen is produced from fossil fuels. Hydrogen for the refinery in Cressier is produced on-site from naphta and methane, and hydrogen from LONZA chemical plant in Visp from liquefied petroleum gas (Figure 30) [102]. A small fraction is produced from electricity either via chlor-alkali electrolysis or water electrolysis. The largest chlor-alkali electrolysis plant in Switzerland is located in Pratteln. Water electrolysis is only used in Monthey for synthetic stone production. Since the closure of the fertilizer production in Visp in early 2018, which was besides the refinery a major consumer of hydrogen, there is a significant overcapacity hydrogen production in Switzerland with about 21'500 tons of hydrogen per year. A small amount of hydrogen is trade mainly with France, Germany and Italy (Figure 31).

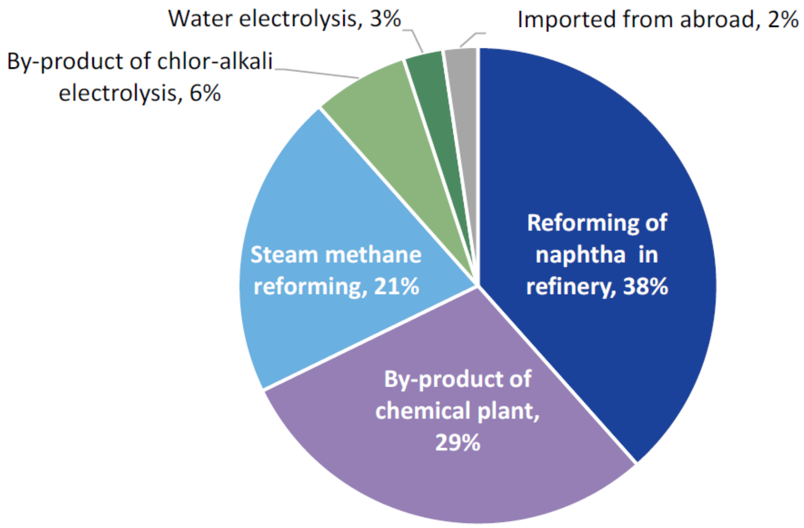

Figure 30: Estimated Swiss hydrogen production and imports [102]

Around 95% of global hydrogen is produced and consumed at the same location, and is not traded on a common market or transported over longer distances. This applies also to the hydrogen economy in Switzerlandi. One reason is, that transport costs can become a significant cost component for the supply of hydrogen, specifically when hydrogen is delivered as a gas via road transportation. For a distance of around 100 km, the corresponding transport costs for large consumers amount to more than 16 CHF/MWh_{th} (0.65 CHF/kg_{H2}) [34]. Hydrogen delivery costs depend not only on the distance but also on the quantity transported, which is determined by the usage of hydrogen.

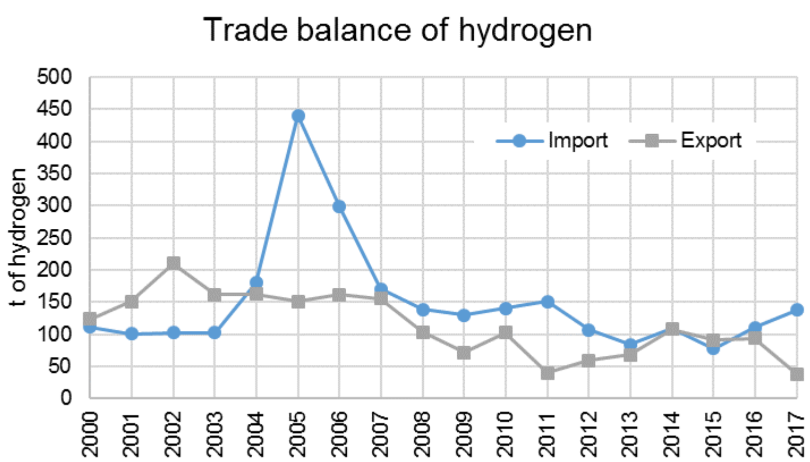

Figure 31: Trade balance of hydrogen from 2000 until 2017 [124]

From a general industry perspective, and not purely related to the Swiss context, it can be stated that hydrogen is used in several industrial production processes, in particular in the chemical sector, where hydrogen is an energy carrier and feedstock for base chemicals, synthetic fuels and lubricants. Hydrogen can also be used as reduction gas or inert gas, for instance in the iron ore industry for crude steel production, as well as for flat glass production. In the semiconductor industry, ultra-high purity hydrogen can be a carrier-gas for thin-film deposition. It is also used to control the atmosphere for the production of semiconductor circuits. Furthermore, hydrogen is consumed in various applications for steel treatment. Because of its high thermal conductivity and other advantageous properties, hydrogen is also used for efficient generator cooling. In synthetic gemstone manufacturing, hydrogen allows to achieve high combustion temperatures needed in the process. Depending on the hydrogen usage, different levels of purity are required which also determines the requirements for the production process of hydrogen, and hence the technologies needed.

From the possible applications of hydrogen in the industry, shown in Figure 32, not all applications exist in the Swiss industry, which in particular concerns potential large-scale industrial hydrogen consuming applications, such as base chemical production, fertilizer production and steel production. For example, in Switzerland, steel is mainly produced from recycled steel via electric induction technology unlike crude steel production from iron ore which offers the major potential for hydrogen usage in the steel industry. Another example relates to hydrogen usage to produce ammonia which is no option anymore since the discontinuation of the operation of the fertilizer plant in Visp.

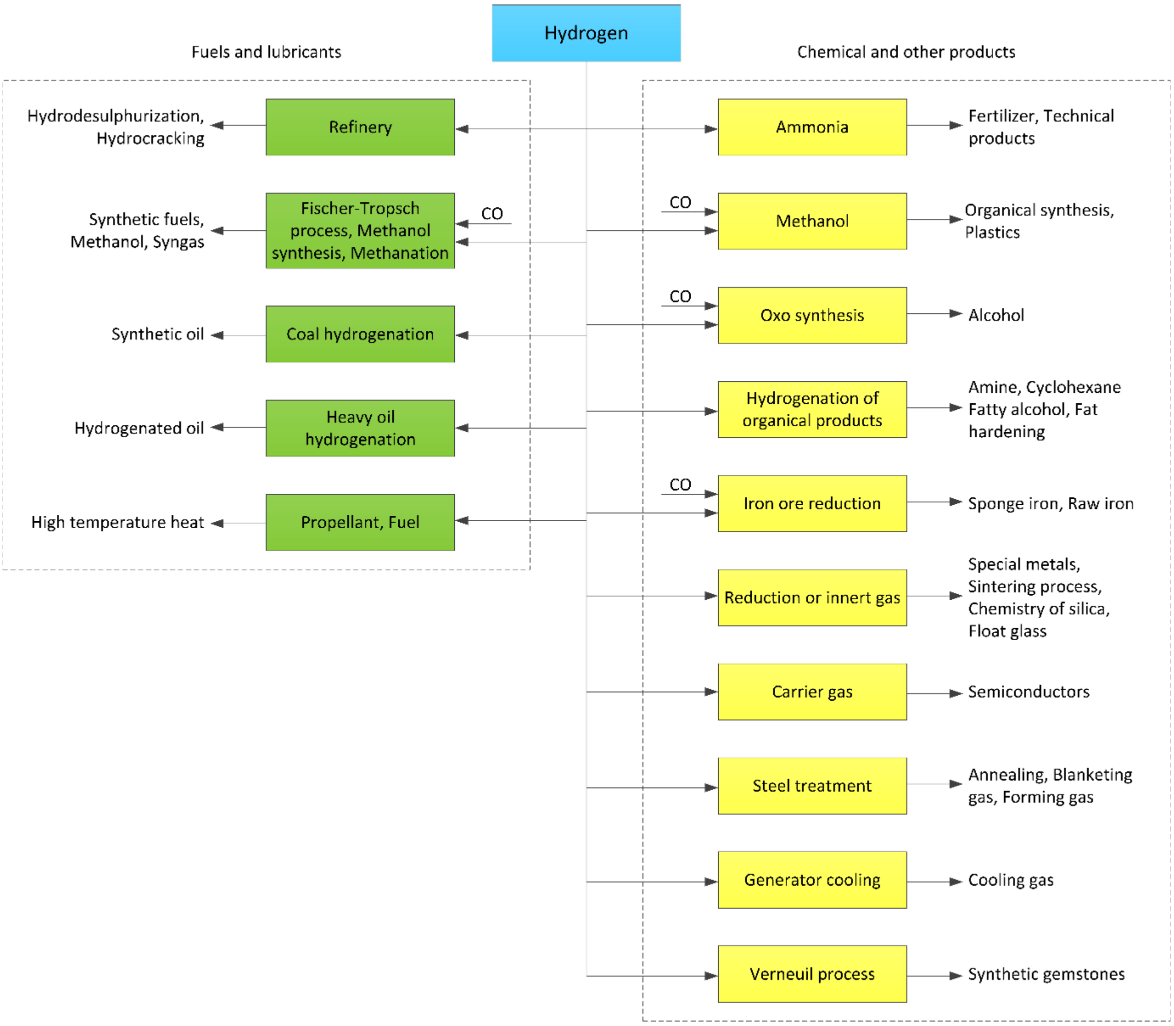

Figure 32: Industrial applications of hydrogen (based on [125] and [126])

In some industrial production processes hydrogen is a by-product and either sold or used in other production process, which is the case for hydrocracking and hydrodesulphurization in refineries, for the chlor-alkali electrolysis and for the production of acetylene. Hydrocracking breaks long chain hydrocarbons into shorter chains. Hydrodesulphurization (sweetening) removes sulphur from refinery products [127]. In large production clusters of the chemical industry (e.g. in Leuna/Bitterfeld and in the area of Hamburg in Germany) hydrogen networks are being operated in order to connect hydrogen producers and consumers, and to use synergies between the different chemical processes.

3.5.3 Outlook and potential opportunities for P2X in industry

In order to reduce CO_2 emissions in industry, there are several options, which encompass, for instance, improved energy efficiency, increased electrification, Carbondioxid Capture and Usage/Storage (CCUS) and the substitution of fossil fuels with low-carbon fuels, including hydrogen. The different decabonization options have technical, economic or other limits, and might be very application-specific. The industrial sector has the potential to kick-start a hydrogen economy [128]. Today, large industrial production facilities and integrated networks for chemical products allow to supply hydrogen typically generated through steam methane reforming at comparably low costs. This represents a competitive challenge for P2X. In large industrial production clusters and hydrogen networks, P2X technology can be integrated as complementary hydrogen supply technology (see also Hypos pilot project in Germany [129]). Often, industrial processes run continuously and require reliable input of feedstock products, such as hydrogen. For the integration of P2X technology operated based on variable renewable electricity, this implies a system design with a sufficient production capacity to supply the required quantity of feedstock products and to integrate a storage system to prevent feedstock supply interruption. The competitiveness of hydrogen from P2X technologies, however, depends substantially on the existence of stringent climate policy, given the current low hydrogen supply costs resulting from production from fossil fuels.

Hydrogen in the steel sector

In the iron and steel sector, coal and coke could almost completely be substituted by hydrogen, which can be an alternative reductant to coking coal which is the common reduction agent for iron ore (reacting the oxygen with carbon from iron ore, generating CO_2) in a blast furnace process. An alternative and innovative process, called direct reduction via hydrogen (DRI-H), avoid usage of coking coal. This process is currently at demonstration phase and could be a stepping stone for energy-efficient and low-carbon steelmaking. The process is based on the reaction of oxygen with hydrogen, which generates water as by-product [126]. Hydrogen is one possible alternative to decarbonize the steel sector, especially where CCS is difficult to implement into the steelmaking process. But on the other hand, this requires construction of new furnaces. In Switzerland, however, the few quantities of steel are recycled from scrap in electric arc furnaces which does not require any coal or coke, and hence not emission-intensive. As such, hydrogen has hardly any role to play in the Swiss steel industry. Nevertheless, on global level, the demand for hydrogen in the steel sector could rise in the future. Assuming the current production volume, the global demand for hydrogen produced with DRI-H technology would be around 90 Mt of hydrogen [128]. To deploy this currently rather immature DRI-H technology, further technology research and innovation would be needed to achieve commercialization.

Hydrogen in refineries

In Switzerland the only refinery in Cressier covers 25% of the domestic demand for oil products. Currently, the hydrogen used in this refinery is produced on-site by steam methane reforming. To be competitive, hydrogen produced from P2X technology would need to be supplied at comparably low costs like steam methane reforming (ca. 1.6 CHF per kg_{H2} see section 2.1.6). For large-scale hydrogen production using natural gas, as it is the case in refineries, steam methane reforming with CCUS is an option to significantly reduce CO_2 emissions, provided there exists political and social acceptance for this technology and the necessary CO_2 storage potential or possibilities to reuse CO_2. For Europe, the

International Energy Agency estimates hydrogen production costs of less than 2.5 CHF per kg_{H2} for steam methane reforming with CCUS [34]. Other sources, such [130], state 2.2 – 3.9 CHF per kg_{H2} to be economically competitive with the steam reforming process. Future prospects of hydrogen use in refineries is closely related to climate change mitigation policy. If climate policy addresses the emissions related to the consumption of oil products in the demand sectors, i.e. in the buildings and transport sectors, this leads to a reduction in the supply of oil products and hence a reduced refinery operation. Consequently, less hydrogen is needed for the refining process. As such, hydrogen produced from P2X technology would be rather needed as low-carbon fuel in the demand sectors than as input for refining processes. Although the costs for hydrogen produced by electrolysis is expected to decrease in the future, hydrogen produced via electrolysis may become competitive as fuel in the transport sector earlier than as energy carrier in refineries as a substitute for hydrogen produced by steam reforming [130].

Beyond conventional fuel refining there might arise a need of hydrogen for biofuel production in future. Upgrading of second-generation, sustainable biofuels produced from lignocellulosic biomass demands considerable amounts of hydrogen, if hydro-deoxygenation is used to remove oxygen to improve the quality biofuels [131]. This process requires around 38 kg of hydrogen per ton of biodiesel produced [34]. It remains to be investigated to what extend biofuel production in Switzerland may require hydrogen produced in P2X technology in future.

Hydrogen for the generation of process heat

In the Swiss industry, production of process heat is largely based on fossil fuels satisfying heat demand of different temperature levels in the energy-intensive industry sectors, namely food industry, pulp and paper, chemical/pharma industry, non-metal mineral industry and metal industry. Most of the process heat needed in Swiss industry is above 120°C (estimation based on [121], [132]) with particular high process temperatures (>600°C) in the cement, chemical and metal industry. The temperature level of process heat is one determinant for the available substitution technologies. Heat at temperature levels below 140°C can potentially be generated using highly efficient heat pump technology, specifically if new refrigerants are developed. For higher temperature levels, heat pumps are less appropriate [119]. Heat at high temperature levels can be generated through direct electric heating and combustion-based heat generation where hydrogen or synthetic hydrocarbons are potential low-carbon fuels. According to the International Energy Agency, process heat production from hydrogen and hydrogen-based synthetic fuels is comparably costly if other options are available, such as CCUS and bioenergy [34]. Not specifically for Switzerland but for other geographies, the International Energy Agency calculates that at least a CO_2 price of 200 CHF/tCO_2 as threshold where the cheapest hydrogen-based fuels become competitive to fossil fuel-based process heat production under stringent climate policy. There are a number of challenges associated to hydrogen-based process heat production, which refer to the combustion properties of hydrogen, corrosion and brittleness of hydrogen equipment, the intermittency of hydrogen supply when largely based on wind and solar electricity production, and storage of hydrogen, which requires compared to hydrocarbon fuels different safety measures [34]. Depending on the application, switching from fossil fuels to hydrogen may require substantial system re-design and to replace significant parts of the energy conversion units of an industrial complex, such as piping, kilns, burners. This not only causes equipment and installation costs but also represents a potential risk for long outages of the industrial production, which is associated with a risk of reduced revenues. The alternative to direct hydrogen use for process heat production to substitute fossil fuels is to use synthetic hydrocarbons. Although production cost for synthetic methane is expected to be higher than for hydrogen [119], synthetic methane has the advantage that is can be used with the existing gas infrastructure and equipment.

System integration

Given the variety of different industries and the multitude of inputs and outputs of industrial processes, integration of P2X technologies in the various industrial sectors is a challenge and opportunity at the same time. Figure 33 gives an example of a system integration with hydrogen electrolysis and methanation. System integration means that the main products and byproducts from P2X can be used on-site while byproducts or emissions from industrial processes can be used as input for P2X technology. The latter aspect specifically concerns large industrial CO_2 point sources which represent potential suppliers of CO_2 to produce synthetic hydrocarbons (see also section 3.1.2). Compared to the residential and the transport sector, the industrial sector is more appropriate for CO_2 capture, because most of the industries represent stationary point sources with a high CO_2 concentration in the flue gas. Capturing CO_2 from flue gas is typically less expensive than CO_2 directly captured from the air. Besides the cement plants, further potential CO_2 sources can be in the chemical industry.

Heat integration is another challenge that is relevant P2X systems, particularly for solid oxide electrolyzers that operate at a high temperature, for which waste heat from industrial processes could potentially be recovered for preheating purposes. Industries with high temperature waste heat in Switzerland are the chemical industry, cement production and steel industry.

From water electrolysis and from methanation, oxygen is produced that can be used in industry. Options for oxygen valorisation in industry are: Blast furnaces and electric arc furnaces in the steel industry, glass melting, oxycombustion in power plants, gasification processes, medical care or desulphurisation of biogas. However, oxygen valorisation is only economically reasonable if it can be used on site, because oxygen is usually transported in its liquid form and liquefication would represent a significant costs component.

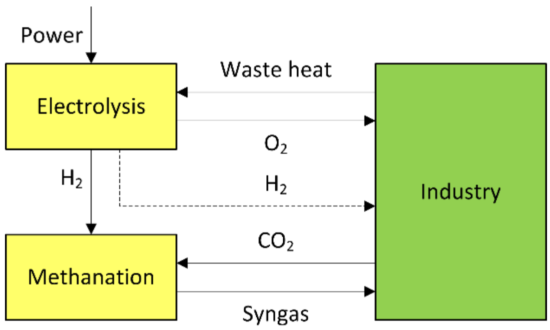

Figure 33: Exemplarily scheme for system integration of hydrogen electrolysis into industry

The literature-based research conducted for this White Paper reveals, that the role of P2X technology in the Swiss industry has not been investigated intensively and further dedicated research could help to identify opportunities and challenges of the integration of P2X in specific industry sectors. Generally, it can be stated that earlier opportunities for the deployment of P2X in industry occur for those applications where hydrogen is not delivered via integrated structures and where hydrogen purchase costs are relatively high [125].

3.6 Combining revenues from different P2X markets

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3.6.1 Economic rationale for combining applications

The different pathways of the power-to-x technology allow for a number of distinct applications, serving the different markets described in this chapter. Accordingly, the business case of power-to-x plants can potentially build on combining multiple revenue streams (see Figure 34 for an overview, and section 2.1 above for a technical overview). The variety of markets and potential revenue streams of power-to-x plants is also illustrated by a review of ca. 200 existent studies of power-to-x economic potentials, which identified hydrogen-to-fuel, hydrogen-to-gas, and hydrogen-to-power as the most common applications considered in studies from academia and companies interested in the matter [133].

Key process step	Main output product	Potential markets
Electrolysis	*Hydrogen*	• Hydrogen market (industrial uses) • Natural gas market (H2 injection in natural gas grid) • Mobility fuel market (H2 as fuel) • Ancillary services market
Methanation	*Methane*	• Natural gas market • Biogas market • Mobility fuel market (CNG)
Fischer-Tropsch process	*Synthetic fuel*	• Mobility fuel market (synthetic fuel) • Industrial market for synthetic fuel
Methanol synthesis	*Methanol*	• Mobility fuel market (methanol) • Industrial market for methanol
Electrification (fuel cell)	*Electricity*	• Electricity market (future, spot market, intraday) • Ancillary services market

Figure 34: P2X process steps, output products, and markets

From an economic point of view, the multi-market/application nature of the power-to-x technology has two advantages: First, it gives the option to expand an investment in the future, e.g. by adding the methanation step to an electrolysis plant (in case that the production of methane becomes more profitable compared to the production of hydrogen). Such “real options” need to be accounted for in the appraisal of return and risk of investment projects [134], [135].

Second, the availability of several distinct markets allows for operational flexibility, e.g. converting hydrogen to electricity or using the hydrogen to produce methane instead. Several applications can also be combined with the provision of ancillary services for power grids. The possibility to serve different markets not only potentially increases revenues [136], [137], but can also impact the overall market risk exposure and hence the cost of capital of investment projects, as has been shown for the case of battery electricity storage [138].

While the viability of P2X projects will clearly depend on specific investment costs and price projections for considered markets, two general prerequisites for taking the economic advantages of combining applications need to be considered: The combinations have to be feasible, and revenues on different markets have to potentially be more attractive if combined in terms of their risk/return profile. These prerequisites are discussed in the following.

3.6.2 Feasibility of combining applications

While the combination of different P2X applications can offer technical and economic advantages, there are likewise technical and economic limitations of combining different process steps in one plant. To assess advantages and limitations, 9 expert interviews have been conducted for this white paper during Mar-Apr 2018, including professionals from P2X research (3 experts from Switzerland, France) and the P2X industry (6 experts from Switzerland, Austria, Germany). All interviews were conducted under the "Chatham House Rule" and hence no references to interviewees or their affiliations are made. Statements were triangulated iteratively, and complemented by information available from literature. Overall, advantages of and limitations to combining applications are assessed as follows:

Combination of electrolysis and power generation via fuel cell: If the power-to-hydrogen-to-power pathway is chosen, the combination of electrolysis and re-electrification (e.g. via fuel cell) in one plant has logistical advantages: No specific infrastructure for the transport of hydrogen is needed, and losses during the transport of hydrogen are minimized. For usage in typical fuel cells, the hydrogen does not need to be at high pressure, which simplifies the setup of on-site hydrogen storage. However, it should be noted that the economic viability of directly re-electrifying hydrogen (and thus effectively using the P2X plant as a battery) is questionable (compare also section 3.2.3 above); accordingly, studies from other countries rather consider using hydrogen for higher value applications, such as mobility or industrial uses [43], [136].

Combination of electrolysis and methanation: As above, the combination in one plant simplifies logistics as no transport of hydrogen is needed. In addition, instances are conceivable where waste heat from the methanation process can be used for the electrolysis, for example to maintain the temperature during periods where no hydrogen is produced due to unfavorable electricity prices. The value of the waste heat differs between methanation approaches [31]: While chemical methanation operates at 300–500 °C and typically delivers waste heat around 200°C, biological methanation typically operates at much lower temperatures (around 60°C–70°C) where the waste heat is hardly useable. It should also be noted that in locations where heat networks exist (e.g. chemical parks) or other waste heat sinks are available (e.g. CO2 scrubbing in CCS), the synergy of using methanation waste heat for the electrolysis becomes less relevant.

Independently from a potential use of waste heat, technical limitations need to be taken into account for the combination of electrolysis and methanation in one plant: First, commercial considerations might suggest that electrolysis and methanation are operated not fully synchronized but under separate optimization considerations, for instance allowing the electrolysis to follow a fluctuating electricity provision while the methanation keeps operating at a constant temperature to keep efficiency high. In these instances, a hydrogen tank is required to disentangle the operation programs of the two processes; the size of the hydrogen tank (and potentially also the size of a CO_2 tank) then determines the flexibility in operation. A large-enough hydrogen tank between the processes also allows to scale each process independently, and allows to potentially later expand the electrolysis or methanation capacity (i.e. realize a real option). A second limitation concerns the location: While the electrolysis depends on cheap electricity provision (e.g. using excess generation of a wind farm, or from waste incineration plants), the methanation requires access to the natural gas grid, and a CO2 source [139]. In practice, the CO2 source often determines the location of methanation plants, so if electrolysis shall be combined in the same plant, it also has to be located in the proximity of CO_2 source (e.g. cement factories, wastewater treatment plants), which is not necessarily close to the production of (cheap) electricity (especially as grid fees have to be paid). A special case can occur when co-locating an electrolysis + methanation plant with a waste incineration plant, as the latter can provide electricity, a CO2 source, and waste heat at the same time.

Combination of electrolysis and Fischer Tropsch process: Following Steynberg [140], here we consider Fischer Tropsch as the conversion of synthesis gas containing hydrogen and carbon monoxide to hydrocarbon products, where oxygenated hydrocarbons like methanol are excluded (see next paragraph). The combination of electrolysis for hydrogen production with a Fischer Tropsch process has similar advantages as mentioned above. Losses from transporting hydrogen to the site can be avoided. No additional benefits have been identified by the interviewees. Adding a Fischer Tropsch process however adds several noteworthy challenges: The necessary systems are large process plants, which need a lot of available land space (around 1ha necessary). These plants can only be realized sensibly at very large scale and are not easily scalable. Also the Fischer Tropsch process nowadays still needs CO (not CO_2), therefore a CO source is needed, or an expensive water gas shift reaction needs to be conducted. Experts believe the shift reaction to be the standard approach (see also van Vliet et al. [141] for an overview of different processes used in industry). Fischer Tropsch cannot be easily ramped up and down, since it needs to be steered to generate certain lengths of molecular chains and then do fractionation.

Combination of electrolysis and methanol synthesis: These processes fit together well, similarly and for similar reasons as electrolysis and methanation do, compare also [142]. Again, the key benefit of the combination is the elimination of hydrogen transport. We identified however several limitations that need to be considered: Methanol can be transported as a liquid quite easily after the synthesis, while for methane after methanation proximity of a gas grid or a filling station is needed for further utilization. The reactor can be operated quite flexibly, in case the raw methanol is collected in a tank. The distillation can then be conducted batch by batch afterwards, since it is not a flexible process. For methanol synthesis CO or CO2 are needed.

Combination of P2X pathways with ancillary services: Given the challenging economics of P2X pathways to date, the provision of ancillary services for the electricity system is often regarded a key additional revenue stream adding to the commercial viability of P2X projects. In principle, services such as primary control reserve and secondary control reserve can be provided both by the electrolysis process (as electricity consumer) and by a fuel cell (as electricity producer). Current PEM electrolysis plants are flexible enough to provide even primary reserve (frequency control), being able to ramp from 10% to 100% capacity in ca. 1 second. Also alkaline fuel cells are highly flexible.

In the combination of electrolysis and methanation, it has to be considered that methanation is less flexible as it requires a heat management for the exothermal reactions (esp. in case of the higher temperature chemical methanation); the provision of ancillary services is therefore limited by the hydrogen storage available between the two processes. Also large chemical processes such as Fischer Tropsch should typically operate as stable possible for efficiency reasons, so if combined with electrolysis likewise buffer tanks will be required to offer ancillary services.

Finally, there might be commercial limitations for offering ancillary services: For instance, given the high capital intensity of an electrolysis plant, it might be advantageous to only offer positive reserve power (i.e. the electrolysis process is running and can be stopped if need be) as compared to negative reserve power (where the plant is idle and only ramps up if needed). Also, additional capabilities are required to bring reserve power to the market (e.g. optimize bids for weekly/daily auctions) that go well beyond skills as they are otherwise required for operating a P2X asset.

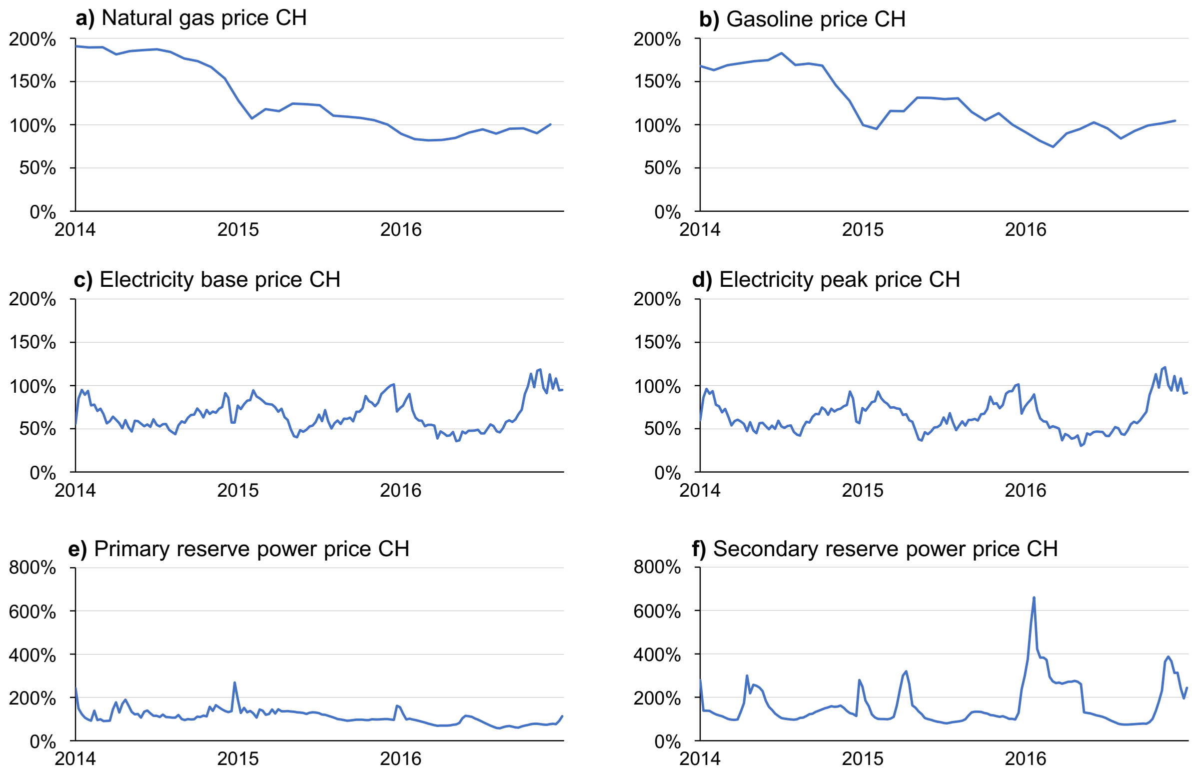
3.6.3 Revenue streams and risk effects from combining applications

As outlined in chapters 3.1–3.5, the different P2X pathways generate products and services that can be commercialized in different markets. The extent to which the multi-market flexibility creates a valuable real option (either in extension investment or in production flexibility), and accordingly improves the risk profile of investment projects, depends on the correlation of prices that can be achieved on the different markets [138]. Figure 35 shows the changes of prices over time for six relevant markets in the Swiss context: The natural gas market, the transport fuel (gasoline) market, the electricity base load market, the electricity peak load market, as well as two ancillary services products (primary and secondary reserve power). All numbers are normalized (Dec 2015 = 100%).

As the historical prices show, there have been considerable price changes in all markets during 2014-2016. The prices for natural gas and gasoline are highly correlated (see Table 20). As long as different energy carriers such as oil and gas constitute alternatives e.g. for heating, the correlation of prices between natural gas and gasoline is likely to remain high. Accordingly, the possibility to switch production outputs between methane and synthetic fuel seems less relevant from a risk point of view.

The prices for electricity and ancillary services, in contrast, are less correlated with the fuel prices of natural gas and gasoline. Having the flexibility to serve both the electricity market and the natural gas market therefore adds to the attractiveness of P2X projects from a risk point of view.

For ancillary services it should be noted, however, that future remuneration is uncertain and subject to regulatory decisions on market access, the level of European market integration etc. compare section 3.2.4 above). Accordingly, revenues from ancillary services are considered rather as an “upside” to P2X business cases (in the magnitude of 2% –10%) by the experts involved.



Note: All price data are normalized to December 2015 = 100%. Natural gas prices and gasoline prices are as reported in the producer and import price indices published by the Swiss Federal Statistical Office on a monthly basis. Electricity prices are based on daily EPEX Swissix spot auctions, aggregated on weeks. Reserve power prices are summarized from weekly Swissgrid auction results.

Figure 35: Prices over time on markets relevant for different P2X applications

	Natural gas price CH	Gasoline price CH	Electricity base price CH	Electricity peak price CH	Primary reserve power price CH	Secondary reserve power price CH
Natural gas price CH	1.000					
Gasoline price CH	0.962	1.000				
Electricity base price CH	-0.091	-0.149	1.000			
Electricity peak price CH	-0.060	-0.118	0.996	1.000		
Primary reserve power price CH	0.001	-0.054	0.177	0.164	1.000	
Secondary reserve power price CH	-0.252	-0.293	-0.163	-0.165	0.371	1.000

Table 20: Correlation between monthly average prices on different markets

In sum, the linkages to different sectors, and accordingly the possibility to serve different markets, is an important characteristic of the P2X technology. While switching production between different pathways might be less relevant in daily operation, the "real option" of extending for instance an electrolysis plant with the methanation step could become relevant in the future. As the analysis showed, the key limitation for the combination of applications is the location of the plant, which determines the access to (cheap) electricity, the gas network, a potential heat network, as well as a CO_2 source. Given the magnitude of investment cost for utility-scale power-to-x plants, their location should be chosen with the optionality for later extension in mind.

4 Innovation policy and regulatory aspects.

4.1 Innovation policy aspects of P2X

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While the previous sections have analyzed the current state of P2X, here we aim to derive policy implications on how to enable or induce further innovation and thus cost reductions of the technology. To this end, we proceed in three steps. First, drawing from innovation literature, we introduce important learning concepts, and present a framework on the degree and locus of technological complexity, which can be used to derive "technology-savvy" policy recommendations. Second, using expert interviews, we locate P2X sub-systems and different setups integrating different sub-systems in that framework. Third, based on these findings, we derive policy recommendations on innovation policy for P2X in Switzerland. Note that we do not focus on policy recommendations concerning basic R&D as the sub-systems, components and processes used in P2X have already reached a certain degree of maturity (see Section 2.1.5). Hence, the focus is rather on how innovation potentials can be tapped to further increase efficiency and reduce the cost of P2X.

4.1.1 The relevance of different types of learning for innovation

Innovation literature differentiates between four learning mechanisms of innovative actors [143]–[145]:

1. Learning-by-searching, i.e., knowledge generation through formalized R&D activities within an organization's boundaries
2. Learning-by-doing, i.e., knowledge generation through producing a technology or product
3. Learning-by-using, i.e., knowledge generation through using a technology or product
4. Learning-by-interacting, i.e., knowledge generation through interacting with up- or downstream activities (e.g., users or suppliers).

In addition, knowledge spillovers form other industries or scientific advances can explain technological advances in a technology or product [143], [146], [147]. Learning-by-searching typically produces formalized knowledge (codified e.g., in patents), which can result in radical innovation, e.g., in the form of new products or processes (ibid). Conversely, the later three learning mechanisms are more related to tacit knowledge, i.e. knowledge that is hard or impossible to codify and transfer [144], [148]. These mechanisms are typically related to incremental innovation and – given the relative maturity of P2X – highly relevant for deriving innovation-centered policy recommendations in this white paper. While often marginalized in the public debate, the accumulation of incremental innovation in itself can result in major progress and radical innovation over longer periods [149], [150]. The latter three learning processes rely on experience and feedback from the production and use phase. Hence, changes in the product design or the production of a technology (such as scaling up) typically results in (incremental) innovation. This accumulated innovation can lead to substantial technological improvements and cost reductions [151]. An empirical observation of these learning effects (together with economies of scale) is the so-called 'learning-curve', which denotes that specific unit costs (e.g., CHF/MWh) of a technology decrease at a certain percentage (the learning rate) with each doubling of the technology's cumulative deployment (Wright's law). Learning curves have been established empirically for many technologies, including (renewable) energy as well as battery storage technologies [20], [152]–[154]. In other words, learning-by-doing, learning-by-using, and/or learning-by-interacting are very relevant for these technologies.

More recently, innovation literature has also identified the key determinants of the relative importance of these three mechanisms: the degree and locus of technological complexity [151], [155][156]. The complexity of the *technology's design* drives the importance of learning-by-using and of interactive learning between technology producers and technology users. *Design complexity* can be defined as the number of subsystems and components and their interrelatedness (i.e., how many components have to be adjusted if one component is changed). The complexity of the *manufacturing process* drives the importance of learning-by-doing and interactive learning between producers and manufacturing equipment suppliers. *Manufacturing complexity* is defined by the number of production process steps and their interrelatedness (i.e., how many production process steps have to be changed if one has to be changed). As both dimensions of complexity are relatively independent of each other, a matrix can be spanned [151], as shown in Figure 36. Different technologies can be allotted to different parts of the matrix (as indicated by the examples in the figure).

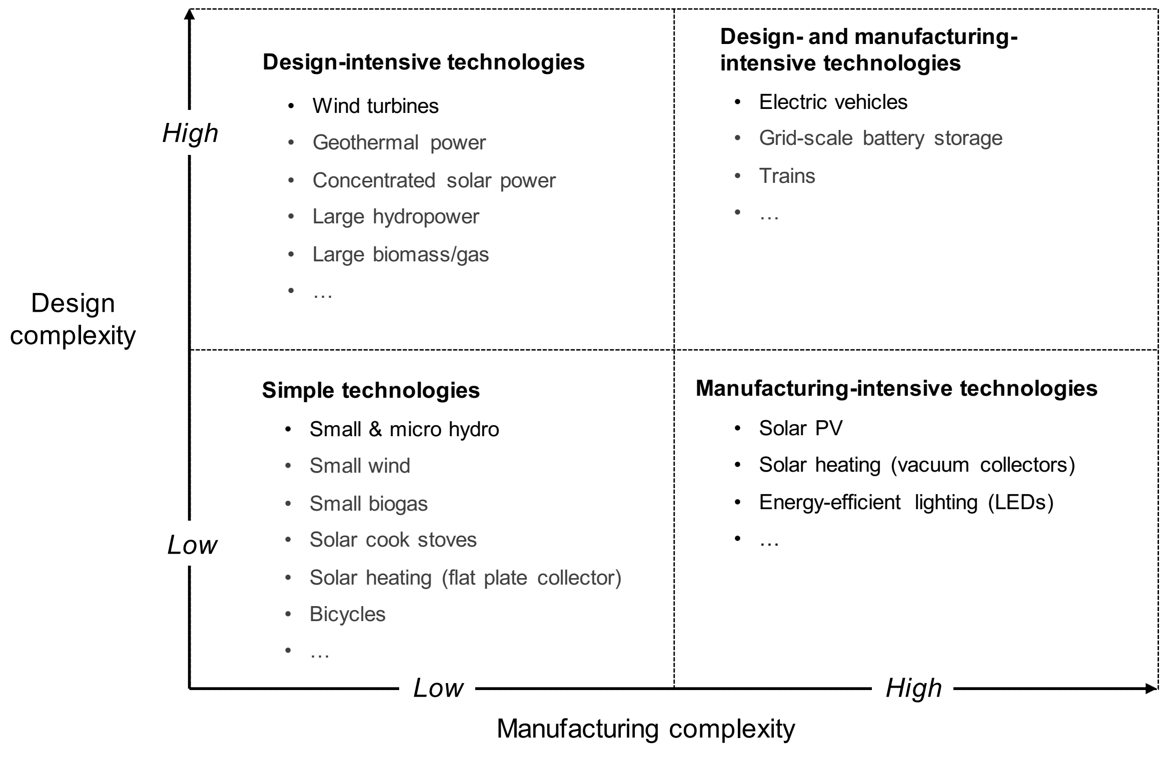

Figure 36: A typology of technologies based on the degree and locus of technological complexity adapted from [155]

Given the relevance of different learning patterns in these technologies, public policy aiming at enabling or inducing innovation should be tailored accordingly [151], [155], [157]. In other words, policy should be technology-savvy. For technologies with high design complexity, policy should consequently enable learning-by-doing and user-producer interaction (ibid). To this end, stable markets with geographical (and cultural) proximity of users to producers (home markets) should be supported. In order to provide innovation incentives, competition on technological performance (e.g., efficiency) should be promoted. For technologies with high manufacturing complexity, in contrast, large and increasing markets need to be created, designed in a way to guarantee high cost-competition (ibid). Interaction between producers and manufacturing equipment providers helps especially in the early phases of scaling up manufacturing.

4.1.2 The degree and locus of complexity of P2X

While recent literature on technology-savvy policy design has discussed several renewable energy technologies [151], [158] as well as battery storage [156][157], P2X has not been analyzed to date. For this white paper, we use structured interviews with nine P2X experts from industry (the entire value chain) and academia to determine the level of complexity along both dimensions, design and manufacturing. All interviews were conducted during Mar-Apr 2018 under the "Chatham House Rule" and hence no references to interviewees or their affiliations are made. More specifically, we proceeded in two steps: First, we focus on the design and manufacturing complexity of six different potential sub-systems of P2X plants and use two questions per subsystem and complexity dimension (one asking about the number of components and one about their interrelatedness). Wind and PV, which are well analysed, were used as reference points during these interviews (see also Figure 37). Second, we determined the complexity of integrating these sub-systems in different plant set-ups. Here we only relied on one question per setup on the interrelatedness of the different set-up sub-systems. Figure 37 summarizes the results of the first step.

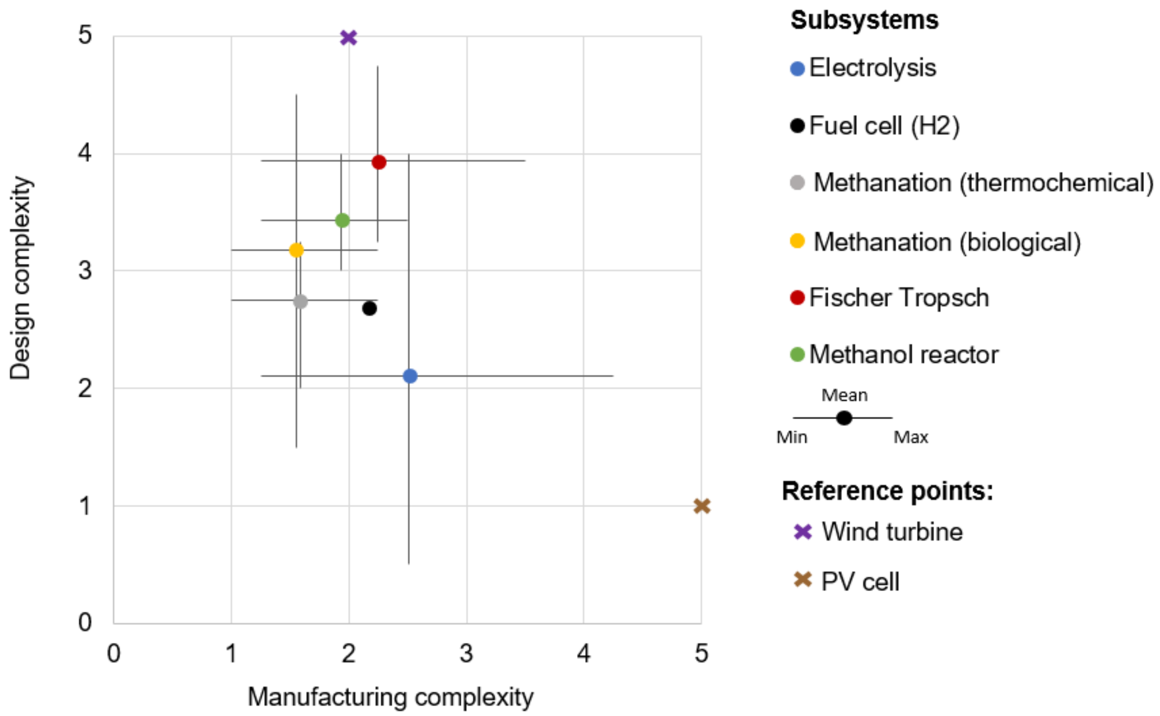

Figure 37: The degree and locus of complexity of P2X sub-systems according to our expert interviews

According to our interviewees, most subsystems would fall in the design-intensive technology category, with the exception of the electrolysis. In the following, we discuss where interviewees and literature identified complexity and innovation potentials of the six sub-systems.

The **electrolysis** is regarded as rather mature and not very complex technology, where components (e.g. stacks, tanks, pumps) can be adjusted relatively independent of each other. This also enables relatively easy scaling of electrolysis. In terms of manufacturing, many steps have to be executed. These are partly interrelated. Some automated complex manufacturing processes are used, however only for individual components and not for the assembly of the entire system.

The **fuel cell** (low-temperature PEM) is seen as a slightly more complex technology than the electrolysis despite using less components. However, these are more interrelated, i.e., more components have to be adjusted if one is changed (e.g., the water discharge). The manufacturing of fuel cells is also based on few and rather independent steps.

The **thermochemical methanation** (Sabbatier) reaction is regarded as medium complex in terms of its design. While there are relatively few components, they are relatively strongly interrelated. The production is based on rather few and independent steps, which mostly comprise labor-intensive metalworking.

The **biological methanation** sub-system is regarded as a more complex technology than its chemical alternative as more parts are used, which are also more interrelated. In terms of manufacturing, again mostly labor-intensive metalwork is needed. There are slightly more steps involved (due to the increased number of parts), but also these are rather independent and non-automated.

The sub-system needed for the **Fischer-Tropsch reaction** is seen as the most complex of all sub-systems analyzed for this white paper. It is essentially a chemical plant with many interlinked components. Its manufacturing complexity is higher due to the higher number of steps (needed to produce the higher number of parts). The steps are also slightly more interrelated than in the case of methanation. Importantly, Fischer-Tropsch reaction is characterized by strong economies of scale.

Finally, also the **methanol reaction** sub-system is seen as rather complex, albeit with less (and less interrelated) parts than the Fischer-Tropsch sub-system. Due to this, also the manufacturing requires less steps. Economies of scale are also highly relevant in methanol reaction.

The results of the second step of our analysis, i.e. the estimation of the complexity of the integration of the different sub-systems in plant setups, are shown in Figure 38.

Interviewees provided additional information to underscore their ratings. Here we provide some of the most important insights from these statements by setup:

The i**ntegration of electrolysis and (PEM) fuel cell** is regarded as relatively simple as the two subsystems are decoupled by the use of a hydrogen storage tank. This allows even relatively independent sizing of the systems (compare section 3.6).

The integration of **electrolysis and methanation** is more complex. While the use of a hydrogen tank can reduce the interrelatedness of both sub-systems, using excess heat of the methanation for the electrolysis requires adjustments of the former sub-system to the latter. Importantly, the integration of the CO2 source needs to be considered and can require mutual adjustments and innovation on the control side. If the CO2 and electricity stems from the same source (e.g., when using P2CH4 in a waste incineration plant) the integration is further complicated.

The integration of **electrolysis with a Fischer-Tropsch reaction or a methanol reaction** are also regarded as relatively complex. Both chemical processes are complex themselves and coupling them with an electrolysis makes adjustments necessary.

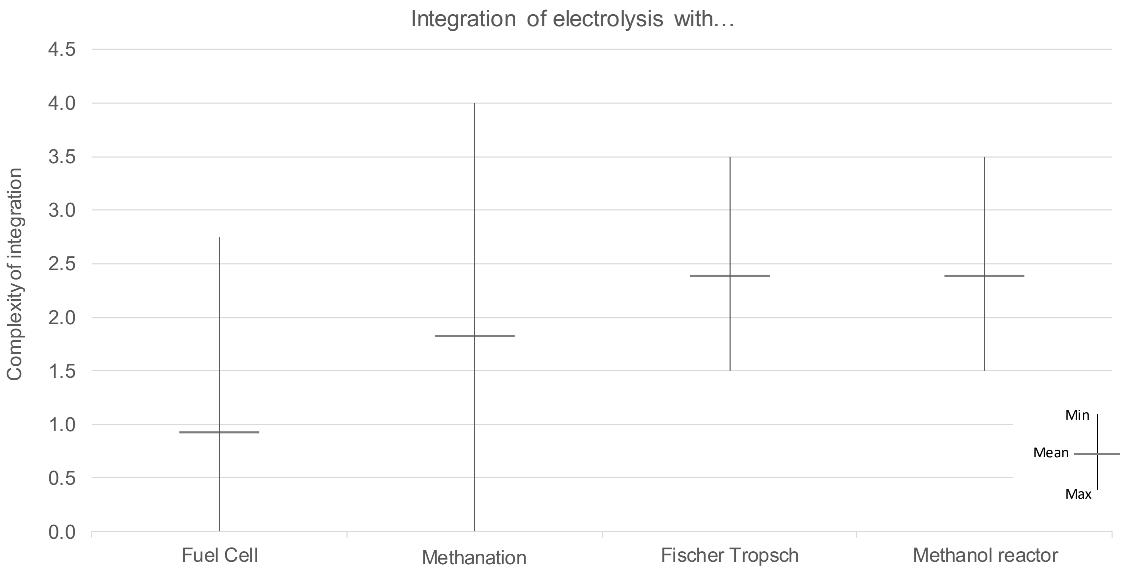

Figure 38: The degree of complexity of integrating an electrolysis with four alternative sub-systems

4.1.3 Implications for Swiss P2X innovation policy

These results enable us to derive several implications for policy makers that aim to enable or induce learning-by-doing, -using, and -interacting and thereby drive P2X down along its learning curve. First, as most sub-systems can be regarded as design-intensive technologies, learning-by-using and interaction of technology integrators with technology users seem to be the most relevant learning processes. To this end, a home market is conducive, characterized by stable demand. "For these technologies, deployment policies need to be understood as R&D policies rather than merely as subsidies" [151], p. 115. Due to the relatively low manufacturing complexity of the components, large and increasing market scale is not required, which could be regarded unrealistic anyway in the case of Switzerland.

In terms of setups, supporting pure P2Hydrogen2P setups cannot be expected to result in substantial learning-by-using, -doing- or -interacting. The complexity of their integration is too low. This is different for methanation, Fischer Tropsch and methanol setups. The interviews point out that economies of scale are particularly relevant in case of the latter two sub-systems. Hence, for setups including either or both of these processes, large plants would be required. Given Switzerland's market size, this seems overly ambitious. Consequently, R&D support to enable learning-by-searching in P2X setups using Fischer-Tropsch and/or methanol reaction seems to be a more realistic option in Switzerland. In addition research and technology demonstration collaborations with countries that have larger potential market sizes can be an option. Policy supporting methanation setups, where economies of scale are not as important as for e.g., Fischer-Tropsch, seems more appropriate for Switzerland from an innovation policy point of view.

Supporting P2X plants in different use environments (using different CO2 and power sources) could result in higher learning-by-using than simply supporting one standardized setting. In order to increase the user-producer interaction, networks of local users, producers and regulators should be formed around these projects. To this end, one option would be to make grants only available to consortia that include users and producers. Furthermore, performance incentives should be provided, e.g., by providing grants for innovative product features. At the same time, policy support should be adjusted periodically to account for technological learning and the resulting cost reductions. To enable cost-based adjustments, policy support should be tied to reporting of cost and performance data (at least to the policy maker). Finally, in order to reduce the cost of deployment policies for such P2X setups, de-risking tools, which reduce the financing cost of P2X projects, could be used. Loan guarantees could be provided, e.g., though the Technology Fund contracted by the Swiss Federal Office for the Environment.

4.2 View on P2X from the legal perspective – the regulatory framework

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4.2.1 Law Affecting all P2X Systems

This chapter discusses legal provisions that affect all Power-to-X-sytems, regardless of the final product (e.g., hydrogen or methane).

a) Planning and approval procedures

Art. 8 subsection 2 of the Spatial Planning Act (SPA, SR 700) demands that projects with severe impacts on spatial planning and the environment have a basis in the structure plan.

Such severe impacts may result, for example, from an exceptionally large demand of space or considerable effects on the environment or the landscape. Examples from the energy sector include large power plants, wind farms and high-voltage installations. [159]

Currently, there is no indication that Power-to-X-installations may reach a comparable power output to power plants that require a basis in the structure plan. Also, Power-to-X-plants do not have the same effects on the landscape and the environment that renewable energy installations such as wind turbines may have. Therefore, Power-to-X-installations will presumably not require a basis in the structure plan.

However, industry-scale P2X-installations may require a planning approval according to Art. 16 et seqq. of the Electricity Act (ElecA, SR 734.0). Other installations would require a building permit in accordance with cantonal law.

b) Environmental law

Large-scale P2X-installations may require an Environmental Impact Assessment (EIA) according to the EIA-Regulation (SR 814.011).

This would be the case if the installation occupies more than 5’000 m^2 of space or if it produces more than 1’000 t of chemical products annually, section 70.5 of the annex to the EIA-Regulation.

The same would be true for P2X-installations that store more than 50’000 m^3 of gas or more than 5’000 m^3 of liquids, section 22.3 annex to the EIA-Regulation.

An EIA-requirement would also exist if the installation includes a gas power plant that has a capacity of more than 50 MWth, section 21.2 lit. a annex to the EIA-Regulation.

c) Safety regulations:

Potentially dangerous chemicals such as hydrogen and methane need to adhere to the Classification, Labelling, Packaging (CLP)-requirements under the Chemicals Ordinance (ChemO, SR 813.11), which incorporates the European Union CLP requirements into Swiss law. Both hydrogen and methane require the warning labels H220 and H280, the prevention directions P210, the response directions P377 and

P381 as well as the storage direction P403; see annex 2 section 1 ChemO, annex VI Tab. 3.1 EU CLP-Regulation 1272/2008.

Both substances also require the safety data sheet according to Art. 5 subsection 1, annex 2 section 3.1 ChemO, Art. 31 EU REACH-Regulation 1907/2006. In addition, methane is registered under REACH (no. 01-2119474442-39).

In addition, all pressurized appliances must adhere to the requirements of the Pressurized Appliance Ordinance (Druckgeräteverordnung, SR 930.114).

Finally, certain installations that may pose an extraordinary danger in the case of a major accident are subject to specific safety requirements, which are stipulated in the Major Accidents Ordinance (MAO, SR 814.012). Under the MAO, the operators of these installations have to implement specific procedures to prevent damage in the case of a major accident. These especially include the measures according to Art. 3, annex 2.1-2.5 MAO. The MAO also includes the right of the enforcement agency to control the measures and the corresponding reports by the operator and, where necessary, order additional measures (see, for example, Art. 6-8b MAO).

The MAO is applicable to installations that, inter alia, handle materials in quantities larger than the thresholds specified by Art. 1 subsection 2 lit. a, annex 1.1 MAO.

For hydrogen, that threshold is 5’000.00 kilograms, annex 1.1 tab. 3 no. 26 MAO. For methane, the threshold is 20’000.00 kilograms, annex 1.1 tab. 42, due to the classification of H220 under the EU CLP-Regulation.

The MAO is also applicable to certain high-pressure pipelines for gaseous and liquid combustibles and fuels, Art. 1 subsection 2 lit. f, annex 1.3 MAO. These are pipelines with an operating pressure of more than 5 bar that fulfill the additional pressure and diameter requirements in annex 1.3 MAO. Pipelines that do not meet these thresholds can, under exceptional circumstances, be subjected to the provisions of the MAO by the enforcement agency, if the specific installation poses a grave damage potential to the population or the environment, Art. 1 subsection 3 lit. d MAO.

d) P2X as final consumer:

The characteristic of an electricity consumer as a “Final Consumer” has potentially severe financial implications. Final Consumers must pay the grid tariffs according to Art. 14 subsection 2 Electricity Supply Act (ESA, SR 734.7). These include the grid surcharge that is used to finance, inter alia, the subsidies for renewable energy producers, if the distribution grid operators – as is commonly the case – pass them on to the Final Consumers under Art. 35 subsection 1 Energy Act (EnA, SR 730.0).

The term “Final Consumer” is defined in Art. 4 subsection 1 lit. b ESA as consumers that buy electricity for their own consumption. The law explicitly exempts two categories of consumers from the term “Final Consumer”, namely the consumption of electriticy for the operation of a power plant and the electricity used to power pumps in pumped storage hydropower plants.

It seems questionable whether the storage of electricity is a “final consumption” in this sense.[160] At least where the electricty is later fed back into the grid, one could argue that this electricity was only stored, not consumed.

The Association of Swiss Electricity Companies (Vereinigung Schweizerischer Elektrizitäts-unternehmen, VSE) has addressed this issue in one of their publications.[161] According to this document, storage facilities should not be regarded as final consumers if they obtain electricity from the grid solely for the purpose of storage, and later feed the electricity back into the grid at the same location.

Despite the VSE's role under the Swiss principle of Subsidiarity (Art. 3 subsection 2 ESA), Courts as well as the regulator ElCom would be allowed to deviate from this position. Also, the VSE's handbook does not offer an exemption for P2X-installations that do not feed electricity back into the grid. Therefore, considerable uncertainty as to the characteristic of a P2X-installation as a Final Consumer remains.

In cases where the P2X-installation consumes electricity from the public grid (and not exclusively directly from, for example, a wind farm), the wording of Art. 4 subsection 1 lit. b ESA would allow for them to be classified as Final Consumers. While there is an argument that storage facilities can feed electriticity back into the grid and therefore not simply "consume" electricity, this would again only apply to P2X-installations that actually feed electricity back into the grid. Also, there is considerable uncertainty as to whether the exemption for pumped storage hydropower plants should be extended to other storage facilities or whether, as an *argumentum e contrario*, it shows that storage facilities are normally Final Consumers. An attempt to explicitly classify all storage systems except for pumped hydro systems as Final Consumers in a revised Electricity Supply Ordinance was withdrawn after significant criticism during the consultation.

4.2.2 Law Affecting P2X in the Electricity Market

This section discusses legal provisions that only affect P2X-installations which feed electricity back into the public grid.

a) P2X as a Power Generator

There is no legal definition of a power generator, despite the multiple uses of this term in the Electricity Supply Act. The term has legal implications, since, *inter alia*, power generators are entitled to grid access even outside of the construction zone (*Bauzone*), Art. 5 subsection 2 ESA. Even though P2X-plants serve as storage facilities, the electricity produced from P2X and fed into the grid could make these installations power generators, if the (e.g. gas) power plant or fuel cell is considered a part of the P2X-installation.

b) Grid Access

If P2X-installations that produce electricity were held to be power generators (see section 4.2.2 a), they would be entitled to grid access even outside of the construction zone (Bauzone), Art. 5 subsection 2 ESA. Otherwise, they may have grid access according to the rules governing final consumers (Art. 5 subsection 2 ESA), which means that they would only be entitled to grid access if they were located within the construction zone or settlements and buildings outside of the construction zone that are inhabited throughout the entire year.

c) P2X as Renewable Energy

If the P2X-plant obtains electricity directly from a renewable energy plant (such as a PV installation, a wind power plant or a biogas plant), the electricity produced by the P2X-plant could be considered renewable energy. As a result, the financial incentives granted by Art. 19 et seqq. EnA may also apply to renewable energy producers that do not feed electricity directly into the grid, but deliver it to a P2X storage facility, which then feeds electricity back into the grid. However, since an explicit provision in the law (such as § 19 subsection 3 of the German Renewable Energy Act, EEG 2017) is missing in Switzerland, considerable uncertainty remains. Also, P2X-plants that obtain electricity from the public grid would likely not fall under these rules, since the origin of the electricity (renewable/non-renewable) could not be verified.

d) Electricity Grid Stabilization

P2X-installations that feed electricity back into the grid may offer systems services (including balancing energy).

P2X could offer balancing energy in two ways: By storing electricity when there is a surplus in the grid (negative balancing energy/demand response) or by feeding electricity into the grid in times of additional demand (positive balancing energy). Despite the fact that the Electricity Supply Act only explicitly refers to balancing energy provided by power plants (Art. 4 subsection 1 lit. e), other consumers may potentially also be allowed to offer (negative) balancing energy. In any case, participating P2X-plants would have to fulfill the prequalification requirements stipulated by Swissgrid.[160] In addition, P2X-installations could also compensate for reactive energy in the grid, and offer black start capability.

As far as unbundling law allows the use of storage capabilities by grid operators (see the following section), P2X-installations could be regarded as part of the electricity grid. In this case, grid operators could refinance the expenses for such installations through the grid fees. However, costs could only be reimbursed if the investment in the P2X-installation was necessary to guarantee the safety, operability and efficiency of the grid under Art. 15 subsection 1 ESA.[160] Under the existing regulatory practice of the ElCom, only currently (i.e. acutely) necessary investments are likely to be held as necessary and can therefore be refinanced through the grid fees.[162] This means that investments in the long-term storage capacity of the grid may not be reimbursed. This is problematic for investments in P2X-technology, since the need for storage may only appear in the future.

Under the new Art. 15 subsection 1 ESA which entered into force on June 1, 2019, investments into innovative grid measures may also be reimbursed, and this would likely also apply to P2X-technology. However, the relatively low caps on the costs stipulated in the new Art. 13b Electricity Supply Ordinance (ESO, SR 734.71) may prevent a large-scale rollout.

If the feed-in of electricity from renewable sources necessitates investments into P2X-technology at the distribution grid level, such costs could also be reimbursed under Art. 22 subsection 3 ESO. In this case, the ElCom would have to approve the costs, following which Swissgrid would have to reimburse the distribution grid operator.

e) Unbundling law

Since unbundling law requires the separation of grid operations from the other aspects of the electricity supply (especially power production), operation of storage facilities by grid operators seems problematic. However, since Swiss law only calls for the unbundling of the financial reporting for distribution grid operators (Art. 10 subsection 3 ESA), such operators would likely be able to operate P2X-plants, as long as these activities are separated from the grid operation in the financial reporting.[160]

For Swissgrid as the transmission systems operator, stricter rules apply. According to Art. 18 subsection 6 ESA, Swissgrid is not allowed to participate in the production of electricity. Under the rationale of this provision, it may be argued that it should only prevent Swissgrid from the production of electricity if such participation would endanger the functioning of the market. Therefore, the operation of storage plants for e.g. the purpose of black start capability may be allowed. However, even if this were held to be true, this would only leave few opportunities for Swissgrid to operate P2X plants. Swissgrid would especially be barred from using P2X plants to provide balancing energy, since this energy must be contracted from power plant operators under EU wholesale market rules, which the Electricity Supply Act strives to respect (see also Art. 20 subsection 2 lit. b ESA).

It is debatable to which extent Art. 18 subsection 6 sentence 2 ESA allows Swissgrid to produce electricity on its own or feed stored electricity back into the grid, respectively.[160] The provision, which is an exception to the law described above, allows Swissgrid to procure and deliver electricity for reasons that are necessary for the operation of the grid, namely for the provision of systems services. However, it could be argued that this provision only allows Swissgrid to buy and deliver electricity for balancing purposes, and not to produce it on its own. The uncertainty is exacerbated by the fact that the terms “procure and deliver” are not used in the remainder of Art. 18 subsection 6 ESA.

At the European Union level, new rules on the unbundling of storage systems are being introduced. In Art. 36 and Art. 54 of the revised Electricity Internal Market Directive (Directive (EU) 2019/944), the principle that grid operators should not operate storage systems is explicitly mentioned. However, these provisions include notable exceptions to this rule if the regulatory authorities find that no sufficient storage capacities can be offered by the other market participants.

4.2.3 Law Affecting P2X in the Gas Market

This section discusses legal provisions that affect the direct sale of gas produced in Power-to-Gas-plants, as opposed to the use of gas to produce heat or electricity.

a) Grid access

The gas grid access of P2X-facilities could be ensured either through Art. 13 subsection 1 Pipelines Act (PipeA, SR 746.1) or through competition law, Art. 7 subsection 2 lit. a Cartel Act (CartA, SR 251). P2X-operators likely cannot rely on the *Verbändevereinbarung zum Netzzugang beim Erdgas* (downloadable at www.ksdl-erdgas.ch), an agreement governing non-discriminatory access to the gas transmission grids, since this document is geared towards large *consumers* of gas, not producers that want to feed the gas into the grid (see the preamble of the agreement, which mentions industrial buyers of electricity, as well as Art. 2.4.1 of the agreement, which defines “final consumers” as consumers that use gas as process energy).

b) P2M as biogas

Gas from P2M-facilities could potentially be regarded as “biogas” under Art. 15 subsection 1 lit. b EnA, which would lead to an obligation to contract for the gas grid operator. This could be the case where Power-to-Gas-installations use electricity from renewable energy plants. However, the Energy Act does not define the term “biogas”, and in other acts, the legislator uses substitutes such as “biogenous gas” or “biogenous fuels”. It is therefore unclear what exactly falls under the term biogas.

First, it would be possible to define “biogas” identically to the term “biogenous gas” under Art. 2 lit. c Energy Promotion Ordinance (EnFV, SR 730.03). This term only applies to gas from photosynthesis, so it does not cover hydrogen or methane produced in Power-to-Gas-plants.

Second, one could define "biogas" in accordance with the term "biogenous fuels" used in Art. 2 subsection 3 lit. d Mineral Oil Tax Act (MinOTA, SR 641.61). Under such an approach, gas from Power-to-Gas-installations may qualify as biogas if certain ecological criteria are met (see the following section on the Mineral Oil Tax Act for details).

Third, it could be argued that the term "biogas" should be defined independently from terms used in other statutes. In this case, it would be unclear wether gas from Power-to-Gas-installations could be considered "biogas".

c) Mineral Oil Tax

When used as fuel, both hydrogen and synthetic methane from renewable energy constitute "biogenous fuels" under Art. 2a MinOTA, 19a lit. f, lit. g Mineral Oil Tax Ordinance (MinOTO, SR 641.611), when (only) renewable energy is used in their production. They are thus exempt from the Mineral Oil Tax, Art. 12b et seqq. Mineral Oil Tax Act, 19a et seqq., annex 2 Mineral Oil Tax Ordinance, if certain additional conditions are met:

Art. 12b MinOTA stipulates, *inter alia*, that the tax exemption is only granted when

- the biogenous fuels cause significantly fewer greenhouse gas emissions (well-to-wheel) than fossil gasoline (lit. a)
- the overall environmental impact is not significantly higher than with fossil gasoline (lit. b)
- the biogenous fuels were produced under socially acceptable conditions.

When creating these criteria, the legislator was predominantly considering biogenous fuels from crops (which especially explains the land use criteria in Art. 12b subsection 1 lit. c, lit. d MinOTA). They are further elaborated in Art. 19c and 19d MinOTO. The most important provisions for Power-to-X-fuels are Art. 19c subsection 1 lit. a and lit. b. Lit. a states that the biogenous fuel must lower the overall greenhouse gas emissions by at least 40 % compared to fossil gasoline, and according to lit. b, the environmental impact may not be more than 25 % higher than in the case of fossil gasoline.

Currently, the tax exemption is only in force until June 30, 2020. However, the exemption should be extended in the upcoming revision of the law and the competent parliamentary commissions have decided to prolong the exemption until the revision enters into law, or the end of 2021 at the latest. When used as a combustible, hydrogen and synthetic methane do not fall under the Mineral Oil Tax.

4.2.4 Law Affecting P2X in the Transport Sector

This section discusses legal provisions that affect the use of liquid or gaseous fuels produced in P2X-facilities.

a) CO_2-tax and certification law

In addition, according to Art. 26 and 27 CO_2 Act, 86 CO_2 Ordinance (SR 641.711), anyone who falls under the Mineral Oil Tax must compensate for a share of the carbon emissions resulting from the fuels imported or produced by that person. One option to fulfill this requirement is the implementation of emission reduction projects in Switzerland, Art. 90 subsection 1 lit. a CO_2 Ordinance. Projects to reduce carbon emissions through the use of P2X-products from renewable energy may be eligible as compensation projects under Art. 7 CO_2 Act, if the requirements under Art. 5 CO_2 Ordinance are met. This includes, inter alia, quantifiable emission reductions and the fact that the project would not be economically feasible without the additional revenue through the sale of emission reduction certificates.

This means that fuel importers that use fossil fuels may have an incentive to invest in Power-to-X projects, creating an additional revenue stream for such installations.

b) P2X-fuels as biofuel

Under Art. 26 CO_2 Ordinance, for vehicles that run fully or partially on natural gas, the carbon emissions are lowered by the biogenous share of the gas mixture. It seems questionable whether this provision also applies to biogenous synthetic hydrogen or methane. In accordance with its rationale, the support of climate-friendly fuels, one could argue that this provision must also be extended to synthetic hydrogen or methane from Power-to-Gas-plants, if the latter exclusively used renewable energy to generate the gas. However, the Swiss Federal Office of Energy (SFOE) seems to hold the view that biogenous hydrogen does not benefit from this provision.[164] Due to the absence of legal cases on this issue, the situation remains uncertain. A consultation draft for a new Art. 12a subsection 2 Energy Efficiency Ordinance (SR 730.02) sets the accepted biogenous share of the swiss gas mixture at 20 %. It would aid the introduction of storage gases in the mobility sector if they were included in the process of determining this accepted share in the future.

c) Mineral Oil Tax

As shown under 3.7.3 above, when used as fuel, hydrogen and synthetic methane from P2M are exempt from the Mineral Oil Tax if the energy used stems from renewable sources and certain ecological criteria are met.

4.2.5 Law Affecting P2X in the Heating Market

Under the Cantonal Model Laws on Energy (MuKEn 2014, which are not directly applicable, but which the cantons may implement), there are no provisions that hinder the use of gas or liquids from P2X-facilities for heating. However, there are also no provisions that truly incentivize such a use.

For example, Art. 1.15 subsection 1 MuKEn 2014 requires that boilers using fossil fuels have to be able to use the heat of condensation. This requirement would not apply to boilers using P2X-fuels, which are not fossil. Despite this advantage, technology for the use of condensation heat in fossil-fueled boilers is increasingly commonplace (see the commentary on Art. 1.15 subsection 1 in the annex to the MuKen 2014, p. 91). This mitigates the advantage for P2X in the marketplace.

However, the carbon tax legislation may offer advantages for the use of P2X-products in the heating sector. The CO_2-tax for fossil energy carriers other than coal has to be paid by those who fall under the mineral oil tax, Art. 30 lit. b CO_2 Act (SR 641.71), and affects energy carriers used for heating, lighting and energy production in thermic power plants (Art. 29 subsection 1, Art. 2 subsection 1 CO_2 Act). Since Art. 30 lit. b CO_2 Act only references "fossil" energy carriers, it may be argued that synthetic energy carriers never fall under this provision. This would create an incentive to use biogenous synthetic fuels over fossil fuels. Also, hydrogen and methane used as a combustible do not fall under the CO_2 tax.

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Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA)

Carbondioxid Capture and Usage/Storage (CCUS)

Chemicals Ordinance (ChemO, SR 813.11)

Classification, Labelling, Packaging (CLP)

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Cumulative share of the Day Trip Performance (CDTP)

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Direct Air Capture (DAC)

Direct reduction via hydrogen (DRI-H)

Distribution Network Operators (DNO)

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Emission Trading Scheme of the European Union (EU ETS)

Eidgenössische Materialprüfungs- und Forschungsanstalt (EMPA)

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Levelized cost (LCOX)

Life Cycle Assessment (LCA)

Lower Heating Value (LHV)

Major Accidents Ordinance (MAO, SR 814.012)

Means of Transportation (MOT)

Mineral Oil Tax Act (MinOTA, SR 641.61)

Mineral Oil Tax Ordinance (MinOTO, SR 641.611)

Molten Carbonate Fuel Cell (MCFC)

Natural Gas (NG)

Operational expenditures (OPEX)

performance-based traffic tax (LSVA)

PhotoVoltaics (PV)

Pipelines Act (PipeA, SR 746.1)

Polymer electrolyte membrane (PEM)

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Power-to-Hydrogen (P2H)

Power-to-Liquid (P2L)

Power-to-Methane (P2M)

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Power-to-X (P2X)

Primary Control (PRL)

Paul Scherrer Institut (PSI)

Registration, Evaluation, Authorisation and Restriction of Chemicals (REACH)

Renewable methane (RNG)

Research and Development (R&D)

Reverse water gas shift (rWGS)

Schweizerischer Verein des Gas- und Wasserfaches (SVGW)

Secondary Control (SRL)

Secondary Control (SRL)

Solid Oxide (SO)

Solid Oxide Fuel Cell (SOFC)

Steam methane reforming (SMR)

Storage duration (TS)

Swiss Competence Centers for Energy Research (SCCER)

Swiss Federal Office of Energy (SFOE)

Synthetic Natural Gas (SNG)

Spatial Planning Act (SPA, SR 700)

Technology readiness level (TRL)

Tertiary Control (TRL)

Total Costs of Ownership (TCO)

Transmission System Operator (TSO)

United Nations Framework Convention on Climate Change (UNFCCC)

Verband der Schweizerischen Gasgesellschaft (VSG)

Vereinigung Schweizerischer Elektrizitätsunternehmen (VSE)

Well-to-Wheel (WTW)

World-wide Light duty vehicle Test Procedure (WLTP)

world-wide light duty vehicle test procedure (WLTP)

Swiss Federal Institute for Forest, Snow and Landscape Research (WSL)

Waste Water Treatment (WWT)

Zurich University of Applied Sciences (ZHAW)

Glossary

- *Alkaline electrolysis*: uses an alkaline solution, e.g. sodium hydroxide or potassium hydroxide, as an electrolyte and is the most mature technology commercially available for hydrogen production with efficiencies in the range of 50-70%
- *Amine scrubbing*: exothermic, reversible reaction between a weak acid such as CO2 and a weak base such as an alkanolamine, the reaction uses various alkanolamines to remove acidic components such as hydrogen sulfide (H2S) and CO2 from gas streams[7]
- *Anaerobic digestion*: chemical processes in which organic matter is broken down by microorganisms in the absence of oxygen[8]
- *Ancillary services*: markets for grid balancing (frequency regulation)
- *Balance-of-the plant*: auxiliary system components of a power plant
- *Battery electric vehicle (BEV)*: vehicles that use an electric motor to provide power to the wheels [165]
- *Biogas upgrading*: refines raw biogas into clean biomethane (removal of impurities) to be injected in the natural gas grid[9]
- *Biogenic CO_2 sources*: conversion of wood residues through indirect wood gasification and methanation of the producedr gas, followed by CO_2 removal
- *Biogenic substrates*: sewage sludge, green wastes, agricultural residues and manure
- *Biological reactor*: uses methanogenic microorganisms under anaerobic conditions
- *Capacity factor*: is defined as the ratio of the total delivered electricity over the amount of electricity that the PV system would generate if operated baseload and at nominal conditions.
- *CHP*: a device that uses a heat engine or a power source to produce electricity and useful heat
- *CO2 scrubbing*: technology absorbing CO2 emissions in the flue gas from industrial plants
- *Coal gasification reforming (CGR)*: gasification of coal can produce power, liquid fuels, chemicals, and hydrogen[10]
- *Curtailment*: shutting down renewable power plants for grid safety for instance
- *Design complexity*: number of subsystems and components and their interrelatedness (i.e., how many components have to be adjusted if one component is changed)
- *Direct air capture*: carbon capture method that separates CO2 from air
- *Dry reforming of methane (DRM)*: produces hydrogen and carbon monoxide from the reaction of carbon dioxide with hydrocarbons such as methane[11]
- *Electrolysis*: electro-chemical process to convert electricity into a gaseous form of energy
- *Emission Trading Scheme of the European Union (EU ETS)*: a market where emission allowances and emission reduction certificates are traded allowing for CO2 emissions reduction at the least cost
- *Endothermic reaction*: chemical process absorbing energy in the form of heat
- *Fischer-Tropsch*: processes converting gases containing hydrogen and carbon monoxide to hydrocarbon products: CO2 + H2 → CO + H2O; CO + H2 → CxHyOH + H2O
- *Flexible power plants*: dispatchable electricity such as flexible gas power plants
- *Higher Heating Value*: accounts for the latent heat of water vaporization in the reaction products
- *Internal combustion engine vehicle (ICEV)*: vehicles that use an internal combustion engine operating with diesel, petrol or compressed natural gas as fuel to provide power to the wheels [165]

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[7] https://hub.globalccsinstitute.com/publications/final-report-project-pioneer/amine-scrubbing-process

[8] https://www.britannica.com/science/anaerobic-digestion

[9] https://biogts.com/products/biogas-upgrading-unit/

[10] https://www.energy.gov/eere/fuelcells/hydrogen-production-coal-gasification

[11] https://en.wikipedia.org/wiki/Carbon_dioxide_reforming

- *Levelized cost*: an economic indicator of total cost to build and operate a power plant over its lifetime per unit of energy output
- *Life Cycle Assessment (LCA)*: provides insights on the environmental performance taking into account production, use, and disposal/recycling of products, supply chains and related infrastructure
- *Lower Heating Value*: assumes that the latent heat of water vaporization in the reaction products is not recovered[12]
- *Manufacturing complexity*: is defined by the number of production process steps and their interrelatedness (i.e., how many production process steps have to be changed if one has to be changed)
- *Methanation*: hydrogen and carbon dioxide are combined through a chemical or a biological catalytic reaction
- *Methanol synthesis*: hydrogenation of carbon monoxide or of carbon dioxide: CO2 + 3 H2 ↔ CH3OH + H2O
- *Molten Carbonate Fuel Cell (MCFC)*: composed of an electrolyte of molten carbonate salt mixture and operating at temperatures higher than 600 °C[13]
- *Polymer Electrolyte Membrane (PEM)*: uses proton transfer polymer membranes as electrolyte and separation material between the different sections of the electrolysis cell
- *Power-to-X (P2X)*: Power-to-Hydrogen, Power-to-Liquids, Power-to-Methane, Power-to-Power: a class of innovative technologies that use an electro-chemical process to convert electricity into a gaseous or liquid energy carrier or chemical product
- *Pressure swing adsorption*: technology used to separate gas species from a mixture of gases under pressure according to their molecular characteristics and affinity for an adsorbent material[14]
- *Primary control reserve:* the grid frequency is balanced to within ±200 mHz by balancing electricity supply and demand for a short amount of time
- *Pump storage:* uses surplus power to pump water from a lower reservoir to be stored in an upper reservoir
- *rWGS: reverse water gas shift*: produces water from carbon dioxide and hydrogen and generates carbon monoxide as a by-product[15]
- *Secondary control reserve:* balancing electricity supply and demand; operates for up to 15 minutes
- *Steam methane reforming:* chemical process in which methane from natural gas is heated with steam to produce carbon monoxide and hydrogen[16]
- *Synthetic liquid fuel:* fuels resulting from the conversion of hydrogen into liquid hydrocarbons
- *Synthetic Natural Gas (SNG):* synthetic gas (substitute for natural gas) produced from coal or electrolysis for instance
- *Total Cost of Ownership (TCO):* purchase price of an asset plus the costs of operation[17]
- *UNFCCC:* United Nations Framework Convention on Climate Change
- *Well-to-Wheel (WTW):* includes resource extraction, fuel production, delivery of the fuel to vehicle and end use of fuel in vehicle operations[18]

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12 https://h2tools.org/hyarc/calculator-tools/lower-and-higher-heating-values-fuels

13 https://en.wikipedia.org/wiki/Molten_carbonate_fuel_cell

14 https://en.wikipedia.org/wiki/Pressure_swing_adsorption

15 https://marspedia.org/Reverse_Water-Gas_Shift_Reaction

16 https://www.studentenergy.org/topics/steam-methane-reforming

17 https://www.investopedia.com/terms/t/totalcostofownership.asp

18 https://definedterm.com/well_to_wheel_wtw

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