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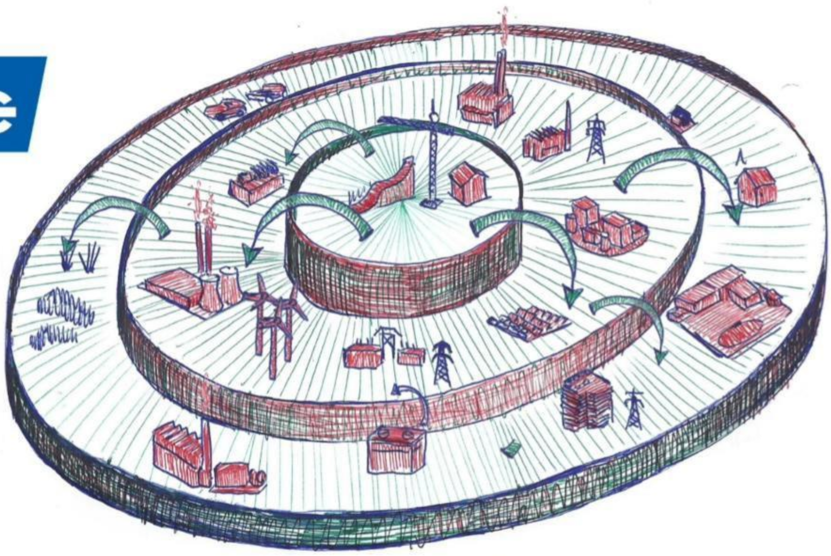
Final Report

The role of synthetic fuels in a net-zero emission electricity system in Switzerland



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Zusammenfassung

Im Jahr 2023 hat das Schweizer Parlament das Klima- und Innovationsgesetz[1] verabschiedet, das eine verbindliche Verpflichtung zur Erreichung des Netto-Null-Ziels bis 2050 vorsieht. Grüner Wasserstoff und seine Derivate werden in diesem Rahmen als eine Option für kohlenstoffneutrale Energieträger für den Strom-, Wärme- und Verkehrssektor betrachtet. Für das Schweizer Elektrizitätssystem werden synthetische Brennstoffe derzeit diskutiert, um im Sommer überschüssige Stromerzeugung zu speichern und im Winter Strom zu liefern, wenn die Schweiz strukturell weniger Strom erzeugt als sie benötigt. Ein solches saisonales Ungleichgewicht bleibt wahrscheinlich trotz der Verabschiedung des so genannten "Mantelerlasses" bestehen, der die Grundlage für das Erreichen des Ziels von 45 TWh erneuerbarer Elektrizität im Jahr 2050 schafft.

In diesem Bericht bewerten wir die Rolle synthetischer Brennstoffe in der Schweizer Stromversorgung. Hierfür verwenden wir die Modellierungsplattform Nexus-e, um Szenarien für das Schweizer Stromsystem im Jahr 2050 zu analysieren. Solche Szenarien sind das Ergebnis einer mathematischen Optimierung und stellen jeweils die Option mit den niedrigsten Gesamtkosten der Stromversorgung dar und unterliegen verschiedensten Annahmen. Insbesondere gehen wir davon aus, dass (1) das Ziel von 45 TWh Elektrizitätserzeugung aus Erneuerbaren Energien erreicht wird und, dass (2) großtechnische unterirdische Speicher für synthetische Gase in Form von ausgekleideten Felskavernen (LRCs) in der Schweiz zur Verfügung stehen. Weiterhin werden (3) Wasserstoffkraftwerke nur innerhalb des Strommarktes analysiert. Eine mögliche Rolle, die Wasserstoffkraftwerke als Reservekraftwerke außerhalb des Strommarktes spielen könnten, wurde nicht betrachtet.

Wir untersuchen drei Hauptszenarien kombiniert mit vielfältigen Sensitivitäten, um folgende Fragen zu beantworten: Welche Importpreise für Wasserstoff und synthetische Brennstoffe (z.B. E-Methan) müssen realisiert werden, damit diese Energieträger für die Stromversorgung kosteneffizient werden? Unter welchen Bedingungen wird die saisonale Speicherung mit Wasserstoff in der Schweiz zu einer kosteneffizienten Lösung? Wie hoch sind die Kosten für die inländische Herstellung und Lieferung von Wasserstoff und E-Methan an andere energieverbrauchende Sektoren in der Schweiz, wie z.B. Industrie und Transport.

Aus unseren Ergebnissen lassen sich die folgenden fünf Schlussfolgerungen ableiten:

1. ***Wasserstoff- und E-Methan-Importe werden nur dann Teil einer kosteneffizienten Stromversorgung in der Schweiz, wenn niedrige Importpreise realisiert werden können.***

   Um die Schweizer Stromerzeugung und -nachfrage im Winter auszugleichen, spielt importierter Wasserstoff eine Rolle, wenn er zu einem Preis von weniger als 3 CHF/kg-H2 an die Endkunden geliefert werden kann, einschließlich internationalem Transport, inländischer Verteilung und Speicherung. Bei sehr niedrigen Preisen von 1 CHF/kg-H2 kann Wasserstoff-basierte Stromerzeugung bis zu 12 Prozent des jährlichen Schweizer Strombedarfs decken. Für E-Methan müssen die Kosten unter 100 CHF/MWh-CH4 fallen. Im Gegensatz zu Wasserstoff kann E-Methan die bestehende Erdgasinfrastruktur nutzen, inklusive Transport, Speicherung (im Ausland) und Erzeugungsanlagen. Gleichzeitig sind die Produktionskosten für E-Methan höher, da zusätzlich zur Elektrolyse ein Methanisierungssystem sowie eine Kohlenstoffquelle benötigt werden, z. B. durch direkte Luftabscheidung oder Kohlenstoffkreisläufe.

[1] https://www.admin.ch/gov/en/start/documentation/votes/20230618/climate-and-innovation-act.html

2. ***In keinem unserer Szenarien wird die saisonale Speicherung von synthetischen Brennstoffen für die Stromerzeugung Teil einer kosteneffizienten Schweizer Stromversorgung.***

Während einzelne Quellen[2] nahelegen, dass die saisonale Speicherung von Wasserstoff, d.h. die inländische Produktion mit anschließender Speicherung und Wiederverstromung, erforderlich ist, um die "Dunkelflaute" in anderen Ländern zu überwinden, zeigen wir, dass die Schweiz im Vergleich zu vielen anderen Ländern eine andere Ausgangsposition hat. Mit ihren Staudämmen und einer Speicherkapazität von rund 9 TWh Strom verfügt die Schweiz bereits über eine Speicherkapazität für erneuerbare Energien, an der es vielen anderen Ländern mangelt.

3. ***Die Schweiz kann Wasserstoff zu einem ähnlichen Preis wie andere europäische Länder produzieren und liefern.***

In unseren Szenarien liegen die mittleren Wasserstofgestehungskosten (LCOH) in der Schweiz im Jahr 2050 zwischen 1-6,7 CHF/kg-H2, was stark von den Stromeinkaufspreisen, den Investitionskosten der Elektrolyseure und von Regulierungen wie den Netznutzungsgebühren abhängt. In unserem Modell werden die Elektrolyseure zu einem durchschnittlichen Strompreis von 11-53 CHF/MWh-el und einer optimalen Auslastung der Elektrolyseure von 24%-33% (2100-3200 Volllaststunden) pro Jahr betrieben. Die Kosten für die Lieferung von Wasserstoff an Endkunden, z. B. in der Industrie oder im Verkehrswesen, sind wesentlich höher als die LCOH und liegen zwischen 2,8 und 8,6 CHF/kg-H2. Die höheren Preise sind hauptsächlich auf die Verteilung und Speicherung des Wasserstoffs zurückzuführen, damit er bei Bedarf an den Kunden geliefert werden kann.

4. ***Die Gesamtkosten für die Versorgung mit E-Methan sind ähnlich hoch wie die für die Versorgung mit Wasserstoff.***

Die Herstellung von E-Methan ist zwar teurer als die von Wasserstoff, aber es kann in der bestehenden Gasinfrastruktur transportiert und gepuffert werden, während die Infrastruktur für Wasserstoff noch aufgebaut oder bestehende Erdgasleitungen umgebaut werden müssen. Die mittlereren Gestehungskosten von E-Methan hängen auch stark von den Strombezugspreisen, den Investitionskosten für Elektrolyseure und der Höhe von Nutzungsgebühren für das Strom- und Gasnetz, aber auch von der Quelle und den Kosten für Kohlenstoff ab. Beispielsweise gehen wir in diesem Bericht von Direct Air Capture (DAC) als Kohlenstoffquelle aus. Unser Modell schlägt die Verwendung von Wasserstoffspeichern bei der Methanproduktion vor, da die Speicherung es ermöglicht, dass sowohl die Methanisierung als auch die DAC mehr Stunden im Jahr laufen und somit eine höhere Auslastung und niedrigere Investitionskosten erzielt werden können - während die Elektrolyseure weiterhin in den Stunden mit niedrigen Preisen laufen können. Alternative Kohlenstoffquellen zu den angenommenen DAC-Anlagen könnten Kohlenstoffkreisläufe oder die Nutzung von heimischem biogenem CO2 sein. Da für die Produktion von 1 MWh E-Methan rund 200 kg CO2 benötigt werden, könnten mit dem heute möglichen inländischen biogenen CO2 jährlich 10 TWh E-Methan in der Schweiz produziert werden.

[2] DOI 10.1088/1748-9326/ac4dc8

5. ***Die inländische Produktion von synthetischen Treibstoffen könnte aufgrund von "diseconomies of scale" eine interessante Nische sein***

Wir stellen fest, dass in den Szenarien mit einem niedrigeren Wasserstoffproduktionsziel auch die LCOH niedriger sind als in den Szenarien mit höheren Zielen. Bei einer geringeren Produktion können Elektrolyseure weitgehend mit Strom betrieben werden, der sonst in Stunden mit niedrigen Strompreisen gedrosselt oder exportiert würde. Bei einer höheren Produktion muss zusätzliche Stromerzeugung aus erneuerbaren Energien installiert werden, um den zusätzlichen Bedarf zu decken, was die LCOH in die Höhe treibt. Die heimische Wasserstoffproduktion könnte somit eine interessante Nische werden, um von diesen Möglichkeiten zu profitieren. Darüber hinaus wird auch die künftige politische Gestaltung der Netzentgelte und Fördermechanismen die LCOH beeinflussen.

Die Ergebnisse dieser Studie sollen einen quantitativen Einblick in die Rolle der synthetischen Brennstoffe in einem Netto-Null-Emissions-Stromsystem in der Schweiz geben, dienen aber nicht als Prognosen. Die Modellierung des Schweizer Elektrizitätssystems unterliegt vielen Annahmen und Vereinfachungen. Im Folgenden skizzieren wir drei Annahmen, die von besonderer Relevanz für diese Studie sind.

Erstens gehen wir davon aus, dass die Schweiz in allen unseren Szenarien das im "Mantelerlass" festgelegte Ziel von 45 TWh Erneuerbare Energien erreicht. Wir räumen aber auch ein, dass es noch offen ist, ob ein solch starker Ausbau der erneuerbaren Energien, der zumindest teilweise auf Freiflächen erfolgt, realisiert werden kann. Die Verwirklichung dieses Ziels und insbesondere die Frage, wie viel erneuerbare Winterstromerzeugung eingesetzt werden kann, dürfte die Rolle von Wasserstoff in der Schweizer Stromversorgung beeinflussen. Windkraft und alpine Photovoltaik sind besonders vielversprechende Technologien mit einem hohen Anteil an der Winterstromerzeugung, deren Einsatz in der Schweiz in der Vergangenheit jedoch schwierig war. Auch die Verfügbarkeit anderer Technologien wie Kernenergie oder Geothermie beeinflusst wahrscheinlich die Rolle von Wasserstoff. Während wir in dieser Studie von einer Betriebsdauer von 60 Jahren für alle vier bestehenden Kernreaktoren ausgehen, vernachlässigen wir die Option einer längeren Lebensdauer dieser oder neuer Kernkraftwerke.

Zweitens gehen wir in den meisten Szenarien davon aus, dass in der Schweiz großtechnische unterirdische Speicher für synthetische Gase in Form von ausgekleideten Felskavernen (LRCs) zur Verfügung stehen. Dieser Speichertyp wird derzeit in der Schweiz jedoch erst in einem frühen Stadium untersucht und erfordert eine neue Regulierung und Finanzierung. Wenn synthetische Brennstoffe nicht lagerfähig sind, müssen sie genau dann produziert oder importiert werden, wenn sie benötigt werden. Um die Stromversorgungssicherheit mit synthetischen Brennstoffen zu erhöhen, sollte die Schweiz in der Lage sein, den Brennstoff zumindest in einem gewissen Umfang über einen längeren Zeitraum zu speichern oder sich den Zugang zu Speicherkapazitäten im Ausland zu sichern. Eine weitere Option ist die Umwandlung von Wasserstoff in flüssige, gut speicherbare Derivate wie E-Methanol oder E-Ammoniak. Eine solche Umwandlung ist jedoch mit weiteren Effizienzverlusten verbunden.

Drittens berücksichtigen unsere Ergebnisse nicht die potenziellen Bedenken hinsichtlich der Versorgungssicherheit mit Elektrizität und der Rolle, die Wasserstoffkraftwerke als Reservekraftwerke außerhalb des Strommarktes spielen könnten. Synthetische Brennstoffe könnten in Kraftwerken als strategische Reserve eingesetzt werden, aber es ist schwierig abzuschätzen, wie groß eine strategische Reserve im Jahr 2050 sein müsste. Auch stünde diese in Konkurrenz mit konventionellen Kraftwerken mit Kohlenstoffabscheidung. Unsicherheiten und Risiken ergeben sich insbesondere aus der politischen und regulatorischen Anbindung an die EU und den Entwicklungen innerhalb der EU.

Summary

In 2023, the Swiss parliament adopted the Climate and Innovation Act[3], which sets a binding obligation to achieve a net zero target by 2050. Generally, green hydrogen and its derivatives are considered as one option for carbon-neutral energy carriers for the electricity, heat, and transport sector. For the electricity system, these synthetic fuels are currently discussed to help store excess generation in summer and provide electricity in winter, when Switzerland structurally generates less electricity than it demands. Such seasonal imbalance likely remains despite adopting the so-called "*Mantelerlass*", which creates a foundation to reach the renewable electricity target of 45 TWh in 2050.

In this report, we assess the role of synthetic fuels in the Swiss electricity supply. We use the Nexus-e modeling platform to develop scenarios for the Swiss electricity system by 2050. These scenarios are outcomes of computational optimization and present the option with the lowest total cost of power supply and are subject to various assumptions. In particular, we assume that (1) the target of 45 TWh of electricity generation from renewable energies is achieved and that (2) large-scale underground storage facilities for synthetic gases in the form of lined rock caverns (LRCs) are available in Switzerland. Furthermore, (3) hydrogen power plants are only analyzed within the electricity market. A possible role that hydrogen power plants could play as reserve power plants outside the electricity market was not considered.

We investigate three main scenarios to answer the following questions: what import prices for hydrogen and synthetic fuels (i.e., e-methane) must be realized so that these energy carriers become cost-efficient for electricity supply? Under which conditions does seasonal storage with hydrogen become part of the cost-efficient solution within Switzerland? What is the cost of producing and supplying domestic hydrogen and e-methane to other energy consuming sectors in Switzerland, such as industry and transport.

Our results provide the following five main conclusions:

1. ***Hydrogen and e-methane imports become part of cost-efficient electricity supply in Switzerland only if low import prices can be realized.***

   To balance Swiss generation and demand in winter, imported hydrogen starts playing a role if it can be provided to end-customers at a price of less than 3 CHF/kg-H2, including international transport, domestic distribution and storage. With very low prices of 1 CHF/kg-H2, hydrogen becomes responsible for covering 12 percent of the annual Swiss electricity demand. For e-methane, costs have to fall below 100 CHF/MWh-CH4. In contrast to hydrogen, e-methane can use the existing natural gas infrastructure, including transport, storage (abroad), and generation units. At the same time, e-methane has higher production costs as it requires a methanation system in addition to the electrolysis system as well as a source of carbon, for example, via direct air capture or carbon cycling.

[3] https://www.admin.ch/gov/en/start/documentation/votes/20230618/climate-and-innovation-act.html

2. ***In none of our scenarios, does seasonal storage of synthetic fuels for electricity become a part of a cost-efficient Swiss electricity supply****.*

While literature suggest that seasonal storage of hydrogen, which is the domestic production with subsequent storage and re-electrification, is required to overcome dark doldrums ("*Dunkelflaute*") in other countries[4], we outline that Switzerland has a different starting position compared to many other countries. With its hydro dams and a storage capacity of around 9 TWh of electricity, Switzerland already has a renewable storage capacity that many other countries are lacking.

3. ***Switzerland can produce and supply hydrogen at a price similar to other European countries.***

In our scenarios, the levelized cost of hydrogen production (LCOH) in Switzerland ranges between 1-6.7 CHF/kg-H2 in 2050, depending heavily on electricity purchase prices, electrolyzer investment costs, and regulation such as grid usage fees. In our model, electrolyzers are operated at an average electricity price of 11-53 CHF/MWh-el, with an optimal utilization of electrolyzers at 24%-33% (2100-3200 full load hours) per year. The costs to ultimately supply hydrogen to end-customers, e.g., industry or transport, are substantially higher than the LCOH, ranging from 2.8 to 8.6 CHF/kg-H2. The higher prices are mainly due to distributing and buffering hydrogen so that it can be provided to the customer when needed.

4. **Supplying e-methane comes at similar total costs as supplying hydrogen.**

Producing e-methane is more expensive than producing hydrogen but it can be transported and buffered in existing gas infrastructure, whereas the infrastructure for hydrogen still has to be built up or existing natural gas pipelines have to be converted. E-methane's levelized cost of production also depends heavily on electricity purchase prices, electrolyzer investment costs, and grid usage fees but additionally the source and cost of carbon, e.g., in this report we assume Direct Air Capture (DAC). Our model suggests using hydrogen storage when producing methane because the storage allows both the methanation and the DAC to run for more hours of the year and thus achieve a higher utilization and lower investment costs – while electrolyzers can still run in low-price hours. Alternative carbon sources to the assumed DAC units could be carbon cycling or the use of domestic biogenic CO2. As producing 1 MWh of e-methane requires roughly 200 kg of CO2, with the currently possible domestic biogenic CO2, 10 TWh of e-methane could be produced annually in Switzerland.

5. ***Domestic production of synthetic fuels might be an interesting niche due to "diseconomies of scale".***

Interestingly, we observe that in the scenarios with a lower hydrogen production target, the LCOH is also lower compared to the scenarios with higher targets. With lower production, electrolyzers can operate to a large extent with electricity that would otherwise be curtailed or exported in hours of low electricity prices. With higher production, additional renewable electricity generation has to be installed to cover the additional demand, driving up the LCOH. Domestic hydrogen production could thus become an interesting niche to benefit from these opportunities. Furthermore, future policy design on grid fees and support mechanisms will also influence the LCOH.

[4] DOI 10.1088/1748-9326/ac4dc8

The results of this study are intended to provide quantitative insight into the role of synthetic fuels in a net-zero emission electricity system in Switzerland but do not serve as forecasts. The modeling of the Swiss electricity system is subject to many assumptions and simplifications of which we outline three in the following.

First, we assume that in all our scenarios, Switzerland achieves the 45 TWh Renewables target set by the "*Mantelerlass*". However, we also acknowledge the fact that it is still open whether such a strong expansion of renewables that is placed at least partially on open land can be realized. The realization of this goal and especially how much renewable winter electricity generation can be deployed likely affects the role of hydrogen in Switzerland's electricity supply. Wind power and alpine PV are especially promising technologies with a high share of winter production, but deploying them has been challenging in Switzerland in the past. Also the availability of other technologies such as nuclear power or geothermal likely affects hydrogen's role. While in this study we assume an operating time of 60 years for all four existing nuclear reactors, we neglect the option for an extended lifetime of these or new nuclear power plants.

Second, in most scenarios we assume that large-scale underground storage in Switzerland is available for synthetic gases in the form of lined rock caverns (LRCs). However, currently this storage type is only investigated at an early stage in Switzerland and requires new regulation and financing. If synthetic fuels are not storable, they need to be produced or imported exactly when required. To increase the security of electricity supply with synthetic fuels, we would argue that Switzerland should be able to store the fuel at least to a reasonable level over a longer duration or secure access to storage capacities abroad. Another option is to convert hydrogen into liquid derivatives that are easily stored such as e-methanol or e-ammonia. However, such conversion comes with further efficiency losses.

Third, our results do not take into account potential concerns of system adequacy and the role that hydrogen power plants could play as backup power plants outside of the electricity market. Synthetic fuels could be utilized in power plants for a strategic reserve but it is difficult to assess how large a strategic reserve in 2050 would need to be. It would also be in competition with conventional power plants with carbon capture. Uncertainties and risks evolve particularly around the political and regulatory linkage to the EU and developments within the EU.

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1. Introduction

In 2023, the Swiss parliament voted for the "*Mantelerlass*" and set binding targets for the expansion of renewable electricity production in Switzerland: 35 TWh should be produced by "new renewables" (i.e., renewables excluding hydropower) by 2035 and 45 TWh by 2050. Switzerland will likely face a situation in 2050 that is characterized with higher electricity prices in winter than in summer and higher winter net-imports compared to today, mainly due to three reasons: First, solar photovoltaics (PV) systems installed on rooftops, typically referred to as Rooftop PV, will likely be responsible for the largest share of such new renewables but produces only 20-30% of their annual electricity production during the winter months (October to March) in Switzerland. Second, electrifying the heating and transport sector will cause an increase in electricity demand with a stronger increase in winter. Third, the existing nuclear generators will likely be decommissioned before 2050, whereas constructing new nuclear power plants is prohibited.

Hydrogen and its derivatives, such as e-methane or e-methanol – typically referred to as synthetic or e-fuels – could provide electricity in winter when its system value is higher. Synthetic fuels can either be imported or produced within Switzerland, using electricity that is available at low costs or that would otherwise be curtailed. Like imported fuels, domestically produced fuels can then be stored seasonally or provided to other sectors such as industry or transport (e.g. aviation). In these sectors, synthetic fuels might substitute fossil fuels and thereby help reduce emissions and fuel imports.

In this project, we assess the role of synthetic fuels in the Swiss electricity supply. We do so in the context of a Swiss electricity system based on high shares of renewables, achieving the targets set by the "*Mantelerlass*". In three scenarios, we address the following questions:

- At which price would **imported synthetic fuels** be used to supply electricity?
- Under which conditions does **seasonal storage** with synthetic fuels become a cost-effective solution for Switzerland?
- What is the cost of **producing synthetic fuels** in Switzerland under given production targets?

We use the Nexus-e modeling platform to answer these questions. The remainder of this report is structured as follows: First, we provide a background on the discussion in literature, industry, and academia on the role of synthetic fuels in the Swiss energy system (section 2). We then outline the method and data (section 3), focusing on how we represent hydrogen and synthetic fuels in Switzerland in Nexus-e. Finally, we present and discuss the results of the three main scenarios (section 4). We provide access to all scenario results in our interactive webviewer on www.nexus-e.org.

2. Background – Synthetic fuels for the Swiss energy system

In this section, we provide a background on the ongoing discussions for the role of synthetic fuels in the Swiss energy system. To do so, we first briefly summarize Switzerland's climate and energy policies (section 2.1). Based on an extensive literature review, we then highlight literature insights on expected demand for synthetic fuels (section 2.2), potential infrastructure (section 2.3), and production costs for synthetic fuels (section 2.4).

2.1. Climate and energy policies in Switzerland

In 2020, Switzerland had a demand for primary energy carriers of 278 TWh, of which more than 70% was imported – 131 TWh of crude oil, natural gas, and coal and 70 TWh of nuclear fuels.[5] Most of the imported fossil fuels are used for space heating, domestic hot water and transport. In contrast to many other countries, the Swiss industry sectors are responsible for a rather low share of the country's energy demand. As Switzerland is landlocked, it imports energy carriers through EU countries. Also, Switzerland has no domestic large-scale gas storage. Burning these imported fossil fuels results in annual emissions of around 45 Mt-CO2e.

In June 2023, the Swiss Voters approved the Climate and Innovation Act[6], which sets a binding obligation to achieve a net zero emission target for 2050. It sets sector-specific targets, including (domestic and international) aviation and shipping, and acknowledges the need for carbon offsetting (domestically or abroad), mainly for non-avoidable emissions in the agriculture sector (see Figure 1). To achieve this target, Switzerland put three key climate policies in place: A CO2 levy on (heating) fuels of CHF 120 per t-CO2, of which two thirds are directly returned to the population, and one third is used for supporting building efficiency programs; a CO2 tax on (transport) fuels of 1.5 Rp. per liter (equal to CHF 6 per t-CO2); and participation in the EU Emission Trading System (ETS) of large emitters that are responsible for 11 percent of domestic CO2 emissions. These measures should push forward the efficient use and substitution of fossil fuels by electrification and synthetic fuels. Additionally Switzerland offers tax reduction for companies that reduce their CO2 emissions.

[5] Swiss Federal Office of Energy (SFOE). 2021b. "Schweizerische Gesamtenergiestatistik 2020, Statistique Globale Suisse de l ' Énergie 2020."
[6] https://www.admin.ch/gov/en/start/documentation/votes/20230618/climate-and-innovation-act.html

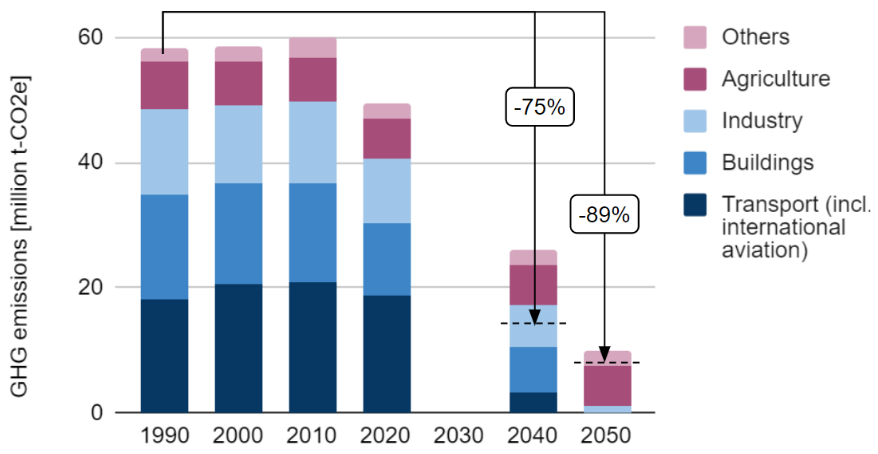

Figure 1: Historical CO2-equivalent emissions (1990-2020) and reduction targets set by the Climate and Innovation Act. Reduction targets include sector specific targets (bars) and economy-wide targets (dashed lines). Please note that economy-wide targets are more stringent than individual sector targets.

Electricity generation in Switzerland is already almost carbon neutral. In 2022, the Swiss electricity mix included 52.8 percent hydropower, 36.4 percent nuclear power, 1.7 percent thermal power plants, and 9.1 percent new renewables, including solar photovoltaics (PV), waste incineration, and wind.[7] From these technologies, only the thermal and waste plants have operational carbon emissions. As more than 50% of the waste is biogenic[8], capturing and storing the carbon from the exhaust gas is a suitable option for negative emissions. The Swiss electricity system is highly interconnected with the European system and the Swiss power grid is an important transit hub with about half of the power flows on the Swiss high voltage grid being transit flows. Additionally, Swiss power companies trade intensively on neighboring markets.

In 2017, Switzerland adopted the Energy Strategy 2050, which outlines a strong focus on energy efficiency and renewables while phasing out nuclear power. While electrification reduces primary energy demand due to (typically) more efficient processes, it causes higher electricity demand. To account for the projected higher electricity demand and a planned nuclear phase-out, the Swiss parliament approved the "*Mantelerlass*" in 2023. This law sets binding targets for expanding renewable energies in Switzerland: 35 TWh production from "*new renewables*" (i.e., renewables excluding hydropower) by 2035 and 45 TWh by 2050. To achieve these, the "Mantelerlass" also defines supporting measures: Renewables of a specific size should be treated of national interest, meaning their realization takes precedence over interests of cantonal and municipal importance. Renewables outside the construction zone should have higher chances of getting approved compared to today and financial risks for renewable investments should be addressed by Contracts for Differences.[9]

2.2. Demand for Synthetic Fuels in Switzerland

Although hydrogen and its derivatives are not directly part of current Swiss climate and energy policies, they might support them. Synthetic fuels can either be imported or produced within Switzerland, using electricity that is available at low costs or that otherwise would be curtailed. Domestically produced fuels can then be stored seasonally and re-electrified later in time or provided to other sectors such as

[7] Schweizerische Elektrizitätsstatistik 2022, SFOE, https://www.bfe.admin.ch/bfe/de/home/versorgung/statistik-und-geodaten/energiestatistiken/elektrizitaetsstatistik.html
[8] https://vbsa.ch/wp-content/uploads/2020/01/CO2-Report/co2-emissionen-aus-kehrichtverwertungsanlagen-kva.html
[9] https://www.investopedia.com/terms/c/contractfordifferences.asp

industry or transport. In these sectors, synthetic fuels might substitute fossil fuels and thereby help reduce emissions and fuel imports. Whether, in the end, there will be a demand for hydrogen and its derivatives in Switzerland is yet unclear and debated heavily.

Two major studies have outlined the demand for hydrogen and synthetic fuels in a net-zero Swiss energy system: the *Energieperspektiven 2050+,*[10] published in 2020 by the Swiss Federal Office of Energy (SFOE); and the *Energiezukunft 2050,*[11] published in 2022 by the Association of Swiss Electricity Companies (Verband Schweizerischer Elektrizitätsunternehmen, VSE).

The *Energieperspektiven 2050+* (in the following referred to as "EP2050+") indicates a relatively low demand for hydrogen (see Figure 2, left). In the baseline scenario (Zero Basis), hydrogen is only utilized in the transport sector (4.4 TWh-H2-LHV[12]), whereas in the other energy demand sectors, efficiency measures, direct electrification, and the expansion of heat networks are instead applied to achieve emission reduction targets. In transport, the EP2050+ assumes that a certain amount of fuel cell electric vehicles (FCEV) are used for road freight and passenger transport. Only in the scenario with lower electrification (Zero B) is hydrogen also used for electricity and heat generation (10 TWh). The SFOE, however, recently published a new report[13] acknowledging that battery electric cars will become established earlier and more strongly than assumed, mostly due to higher efficiency and lower costs. Based on a recent study by EBP[14], SFOE adjusts the hydrogen demand for transport to half of what has been assumed in the EP2050+. However, in the same report, the SFOE also mentions that hydrogen likely gains more importance for providing process heat in industry, mainly due to increased gas prices and greater uncertainty regarding the procurement of natural gas and biogas. However, it is also explained that for low-temperature process heat (< 200°C), large heat pumps offer the possibility of electrification and require around six times less renewable electricity than green hydrogen. Also for medium-temperature process heat, more efficient alternatives to hydrogen, such as direct-electric processes, are available. Only for high-temperature process heat, hydrogen seems to be one of the few options available. However, a non-published 2023 SFOE survey revealed that more companies prioritize electrification than relying on hydrogen in the future.

Across all EP2050+ scenarios, 1.9 TWh-H2-LHV are generated domestically per annum and are covering around 1 percent of the Swiss final energy demand. It is assumed that hydrogen is produced at run-of-river plants as soon as the electricity market price falls below 4 Rp./kWh. In that case, run-of-river plants provide electricity for electrolysis instead of feeding the produced electricity into the grid. The report mentions that around 30-60 electrolyzers with a total capacity of 1.5 GW are required (resulting in an utilization of around 15 percent). Switzerland is further assumed to be connected to the European hydrogen backbone (see section 2.3) to import the remaining hydrogen demands.

The *Energiezukunft 2050* (in the following referred to as "EZ2050") gives a different picture and indicates a higher use of hydrogen in all scenarios compared to the EP2050+ (see Figure 2, right). The EZ2050 outlines four scenarios along two dimensions. One dimension refers to Switzerland's energy policy relationship with Europe (integrated vs. isolation), and the other dimension refers to the domestic acceptance of new energy infrastructures and technologies (defensive vs. offensive; offensive is defined as a higher acceptance). When acceptance of energy infrastructures is low, and Switzerland acts rather

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[10] https://www.bfe.admin.ch/bfe/en/home/policy/energy-perspectives-2050-plus.html/

[11] https://www.strom.ch/de/energiezukunft-2050/startseite

[12] In this report, we will provide the lower heating value (LHV), which is defined as the amount of heat released by combusting a specified quantity (initially at 25°C) and returning the temperature of the combustion products to 150°C, assuming that latent heat of vaporization of water in the reaction products is not recovered. One kg of hydrogen has a LHV of 33.3 kWh/kg.

[13] https://www.newsd.admin.ch/newsd/message/attachments/84123.pdf

[14] EBP, 2023. Verständnis Ladeinfrastruktur 2050 – Wie lädt die Schweiz in Zukunft? https://www.newsd.admin.ch/newsd/message/attachments/78058.pdf

isolated (def - iso), 14.1 TWh-H2-LHV are used, mostly for electricity generation in combined cycle turbines (12.4 TWh-H2-LHV) and only a small amount for transport (1.7 TWh-H2-LHV). The use of hydrogen increases even further (18.8 TWh-H2-LHV) when Switzerland perceives a higher acceptance of energy infrastructure (off-iso). Here, hydrogen is also used in Combined Heat and Power plants and for industrial process heat. When Switzerland is better integrated into Europe (def - int; off - int), the use of hydrogen in both sectors roughly doubles, amounting in both scenarios to 26.9 TWh-H2-LHV, thereby covering around 18 percent of the Swiss final energy demand. The main driver of hydrogen demand in all scenarios is electricity provision in winter.

In the EZ2050 scenarios, almost all hydrogen is being imported in 2050. Only in the "def - iso" scenario a small portion of hydrogen (0.6 TWh-H2-LHV) is produced domestically. For all scenarios, the authors assume that imported hydrogen is available at a price of 2.5 CHF/kg-H2, whereas the price for domestically produced hydrogen is a variable and depends on the scenario boundary conditions. Note that during the ramp-up of the hydrogen market and infrastructure before 2050, in the EZ2050, domestic production is required and electrolyzers demand around 1.5 TWh of electricity.

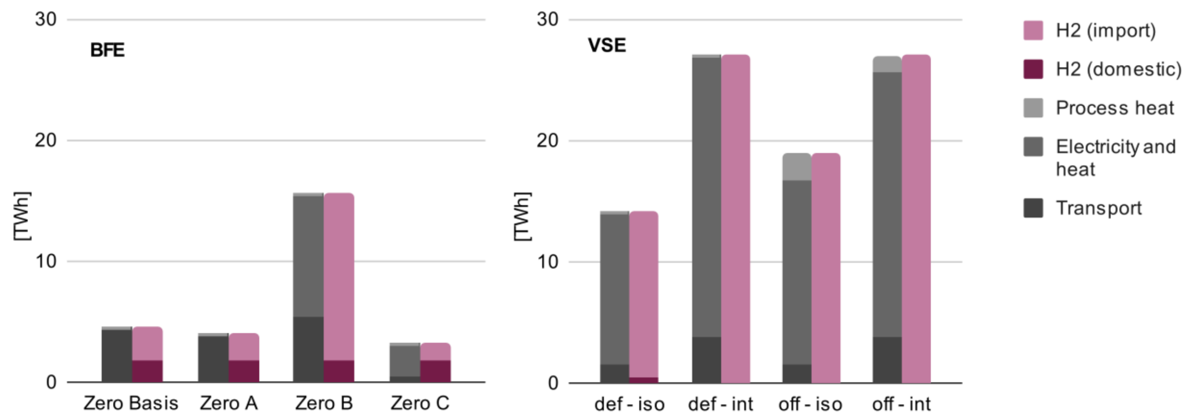

Figure 2: Hydrogen demand in TWh-H2-LHV in the SFOE EP2050+ (left, not adjusted to recent publication) and VSE EZ2050 (right).

Besides hydrogen, both studies also outline the use of fossil, biogenic, and other synthetic fuels. In the EP2050+, all scenarios have a high use of bio-methane and synthetic fuels (see Figure 3, left). 3.5 TWh of domestic bio-methane is assumed to be available and always fully utilized. On top, the SFOE assumes that bio-methane can be imported, while utilization varies between the scenarios (8.1 - 13.1 TWh-CH4-LHV). Bio-methane is mostly used for electricity and heat generation as well as industrial processes. Synthetic fuels are mainly required for domestic aviation, road freight transport, and road passenger transport, as the study assumes a residual stock of conventional vehicles and plug-in hybrids in road passenger transport in 2050. While in the scenario with a higher level of electrification (Zero-A), demand for imported bio-methane and synthetic fuels is reduced, we observe the contrary in the scenarios with a lower electrification (Zero-B, Zero-C). Based on the new report[15], the SFOE adjusts its projections for synthetic fuels and acknowledges that especially imported bio-methane might play a much smaller role in electricity and heat provision. Instead, a higher level of electrification and hydrogen might be used. Also, the residual stock of conventional vehicles in 2050 is likely much smaller than assumed initially in the EP2050+, which should significantly reduce the demand for synthetic petrol and diesel.

[15] https://www.newsd.admin.ch/newsd/message/attachments/84123.pdf

The EZ 2050 outlines a substantially lower use of biogenic and synthetic fuels (see **Error! Reference source not found.**). A key difference is that it does not allow for any bio-methane imports. Also, domestic bio-methane is not used in the two integrated scenarios. In the "off-int" scenario, there is no demand for biogenic and synthetic fuels. Almost all of the required synthetic fuels are used for providing electricity and heat. In two scenarios, a small portion is being used for industrial process heat.

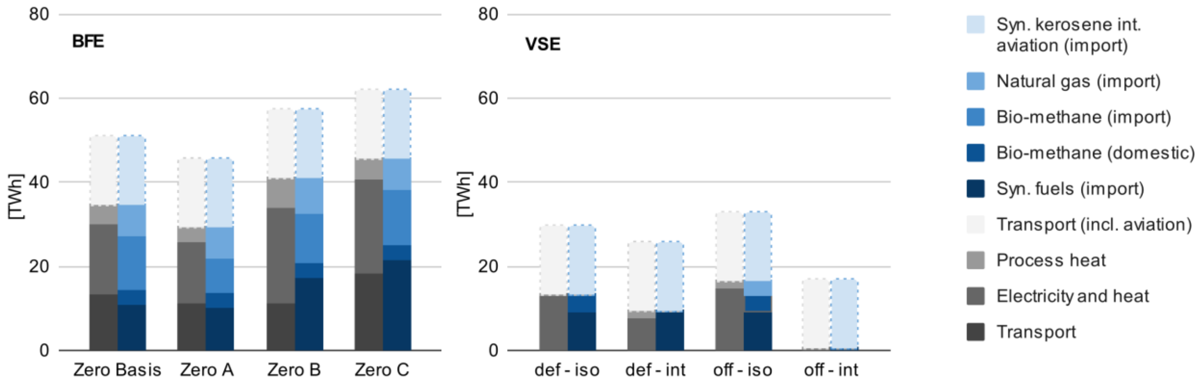

Figure 3: Demand for biogenic and synthetic fuels (except hydrogen) in TWh-LHV in the EP2050+ (left) and the EZ 2050 (right). Please note that although both studies neglect the demand for international aviation despite Swiss climate policy covering this sector, we add such demand in all scenarios.

The total demand for hydrogen, biogas, and synthetic fuels does not differ substantially between the two studies' scenarios and lies roughly in the range of 40 to 60 TWh-LHV (including international aviation; see Figure 4). Whereas the EZ2050 assumes a higher availability of low-cost hydrogen, EP2050+ assumes a higher availability of imported biogas. Interestingly, in both studies, the amount of domestically sourced fuels (i.e., Swiss biogas, hydrogen produced in Switzerland) is rather small within 0 – 13 percent of the total demand for chemical energy carriers.

Also note that, compared to the situation in 2020, when Switzerland imported roughly 170 TWh of chemical energy carriers, both studies show a substantial reduction of imports – but also that Switzerland likely remains an energy import country.

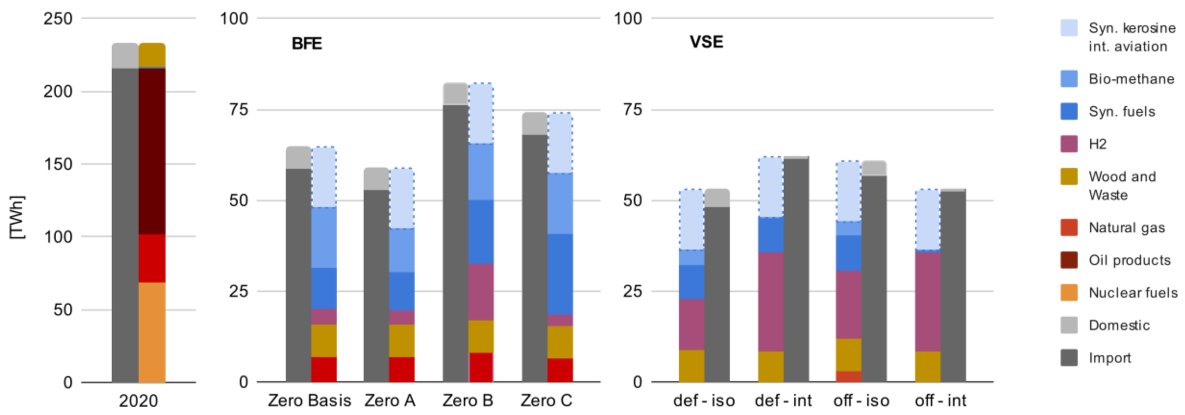

Figure 4: Total demand for chemical energy carriers historically (2020, left) and in the EP2050+ (center, not adjusted to recent publication) and the EZ2050 (right). Please note that the axis for the historical numbers is different.

2.3. Infrastructure for Synthetic Fuels in Switzerland

While the infrastructure of natural gas and oil products is well established and can be used for biogas and e-methane with minor modifications, no large-scale hydrogen network exists yet – neither in Switzerland nor in Europe. Today, hydrogen is mainly transported via trucks as compressed gas.

To allow for hydrogen transport in large quantities, European gas suppliers, including the Swiss Gas Industry Association (gazenergie) and fluxswiss, have published proposals for constructing a hydrogen pipeline network (see Figure 5) and plan to establish such a hydrogen transmission system by 2040[16]. For Switzerland as a landlocked country, a connection to this so-called "hydrogen backbone" is required to allow for good import conditions in terms of price and quantity. As indicated in Figure 5, parts of the European hydrogen backbone are planned to consist of repurposed natural gas pipelines. Here, the idea is to build up a parallel structure of natural gas and hydrogen and make use of double lines, which are currently used for natural gas only. The conversion of individual lines of such parallel structure promises cost savings compared to new construction and is perceived as more likely than a gradual conversion of both lines from 100 percent natural gas to 100 percent hydrogen. The plan in Switzerland is to repurpose one of the two "Transitgas" pipelines, the shortest connection between North-West Europe and Italy. With North Africa as one of the most promising regions for producing renewable hydrogen[17], the pipeline through Switzerland might enable good access to imports outside of Europe.

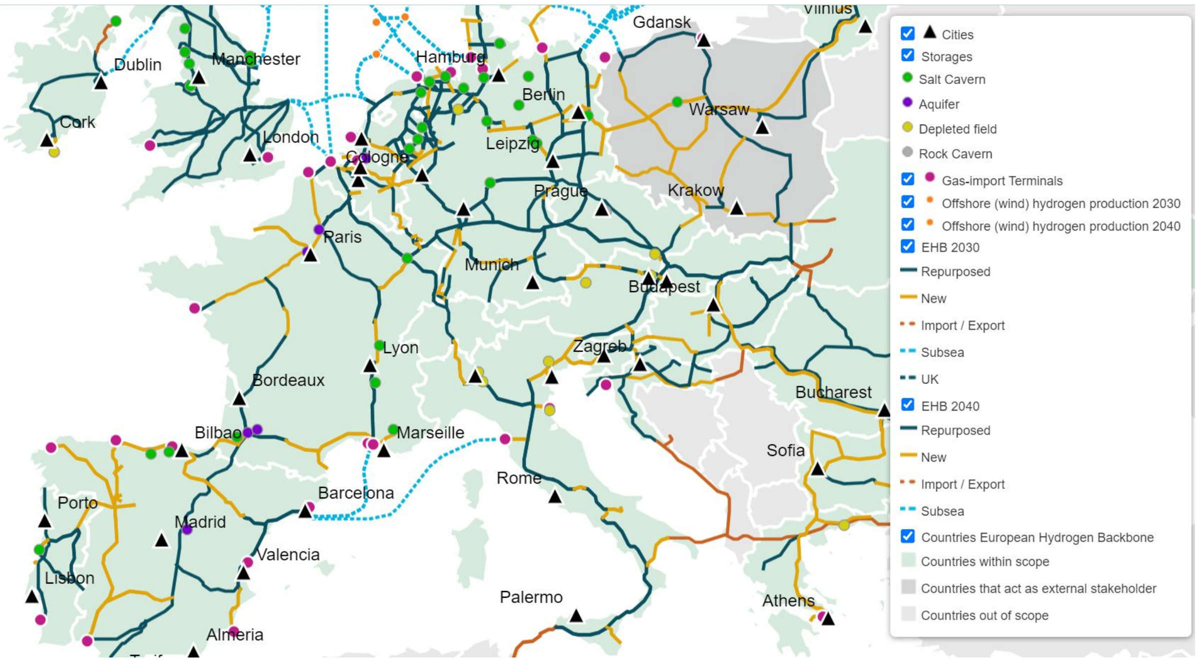

Figure 5: European Hydrogen Backbone Map 2040, source: https://ehb.eu/page/european-hydrogen-backbone-maps.

Besides pipelines for transport, large-scale, ultra-long-duration energy storage facilities[18] are important parts of the energy infrastructure. In Switzerland, building large gas storage facilities has not yet been

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16 https://ehb.eu/

17 See gazenergie's expected import quantities, https://gazenergie.ch/fileadmin/user_upload/e-paper/GE-H2-Barometer/H2-Baro-Nr3-202304-DE.pdf

18 Ultra-long-duration energy storage can cover durations longer than 100 h (4 days), https://www.sciencedirect.com/science/article/pii/S2542435123004075

possible due to technical (e.g., lack of knowledge of the subsurface), economic and political reasons.[19,20] Switzerland has small commercial storage volumes on its territory to meet daily demand (e.g., tube storage in Urdorf[21]). Further, an agreement with France guarantees the gas utilities Gaznat and Gasverbund Mittelland non-discriminatory access to French gas storage facilities (approx. 7.5 percent of annual Swiss natural gas consumption). The EU has seasonal storage capacities covering 25 percent of its annual natural gas consumption.

Table 1 gives an overview of general options for natural gas and hydrogen storage and their potential for Switzerland. Hydrogen can be stored as a compressed gas, liquid, or as part of a chemical structure[22]. Storing hydrogen as a compressed gas presents challenges related to the storage tanks' materials and additional energy demand for compressing the gas. Storing hydrogen in liquid form requires even more energy as it has to be cooled down in an energy-intensive process below -253 °C.[23,24] In addition, hydrogen can be stored chemically by being absorbed or reacting with other chemical compounds such as metals or organic matter. The challenges of storing hydrogen in chemical form lie mainly in the hydrogenation and dehydrogenation processes, which require high temperatures and pressures[25]. According to the International Energy Agency (IEA), storing gaseous hydrogen in geological storage facilities, such as salt caverns, depleted natural gas or oil reservoirs, and aquifers, is the best option for large-scale and long-term storage[26]. Salt caverns can achieve high efficiency of up to 98% without contaminating the stored hydrogen[27] and are already used for storing hydrogen at petrochemical facilities in the United Kingdom and in Texas in the United States. However, proposals for new salt cavern storage have encountered public opposition, with concerns that range from ground shifting above caverns and the impacts of saline discharge from solution mining on marine wildlife to general concerns about hydrogen safety[28]. Depleted oil and natural gas reservoirs contain impurities that must be removed if the hydrogen is to be used in high-purity applications such as low-temperature fuel cells[29].

However, this would be a possible option if there is not a high demand for pure hydrogen. Aquifers are also subject to hydrogen loss due to reactions with rocks, fluids, and microorganisms[30]; however, this does not preclude their potential as a storage option if these losses are accounted for.[31] An alternative

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[19] https://www.newsd.admin.ch/newsd/message/attachments/73764.pdf

[20] Switzerland has, for example, natural gas fields, which were never explored. Emptied gas fields could be used as natural storages for synthetic fuels.

[21] https://bis-austria.bilfinger.com/referenzen/energie-versorgung-hydro/gasspeicher-versorgung/erdgasroehrenspeicher-urdorf/

[22] FSEC, Hydrogen basics – storage, http://www.fsec.ucf.edu/en/consumer/hydrogen/basics/storage.htm (2020)

[23] R. Krishna, et al., Hydrogen storage for energy application, Hydrog. Storage (Sep. 2012), 10.5772/51238

[24] M. Ni, An overview of hydrogen storage technologies, Energy Explor Exploit, 24 (3) (Jun. 2006), pp. 197-209, 10.1260/014459806779367455

[25] J.W. Sheffield, K.B. Martin, R. Folkson, 5 - electricity and hydrogen as energy vectors for transportation vehicles, R. Folkson (Ed.), Alternative Fuels and advanced vehicle Technologies for improved environmental performance, Woodhead Publishing, (2014), pp. 117-137

[26] IEA, The future of hydrogen – analysis, Technology (2019), [Online]. Available: https://www.iea.org/reports/the-future-of-hydrogen, Accessed 15th Sep 2020

[27] Radowitz, World's first liquid hydrogen fuel cell cruise ship planned for Norway's fjords | Recharge | Latest renewable energy news (2020), https://www.rechargenews.com/transition/world-s-first-liquid-hydrogen-fuel-cell-cruise-ship-planned-for-norway-s-fjords/2-1-749070

[28] https://www.sciencedirect.com/science/article/pii/S2542435123004075

[29] A.S. Lord, P.H. Kobos, D.J. Borns, Geologic storage of hydrogen: scaling up to meet city transportation demands, Int J Hydrogen Energy, 39 (28) (2014), Article 28, 10.1016/j.ijhydene.2014.07.121

[30] IEA, The future of hydrogen – analysis, Technology (2019), https://www.iea.org/reports/the-future-of-hydrogen,

[31] A. Lemieux, K. Sharp, A. Shkarupin, Preliminary assessment of underground hydrogen storage sites in Ontario, Canada, Int J Hydrogen Energy, 44 (29) (Jun. 2019), pp. 15193-15204, 10.1016/j.ijhydene.2019.04.113

but more for commercial purposes with multiple charging and discharging cycles are lined rock caverns (LRC).

Table 1: Overview of natural gas and hydrogen storage options and their potential for Switzerland.

	Aquifer	**Salt caverns**	**Rock Caverns (e.g., LRC)**	**Liquified**	**Spherical and cylindrical storage**
*Typical Storage volume [m Nm3] **	1000	60	25	90	<1
*Pressure [bar] **	80-150	250	230-300	-	60
*Storage Cycles per year **	1	1-4	6-12	-	-
*Construction time **	>10	10	5	-	-
*Costs **	Low	Low (0.1-0.5 CHF/kWh)**	Medium	High	High (10-40 CHF/kWh)**
Technical maturity for hydrogen	Low***	Low***	Low***	-	High***
*Potential for gas storage in Switzerland **	-	No potential****	Current project of GAZNAT at Oberwald. Total potential there 1.48 TWh (4% of Swiss annual gas consumption). Only preliminary studies, earliest availability 2030	LNG in Schweizerhalle and gravel pit on transit pipeline, both 1.5 TWh each. Cost 350 - 500 million per project	Potential available in Switzerland, but less suitable for seasonal storage

*: https://www.newsd.admin.ch/newsd/message/attachments/73764.pdf
**: https://www.sciencedirect.com/science/article/pii/S2542435123004075
***: https://www.sciencedirect.com/science/article/pii/S0360319921005838
****: https://www.sciencedirect.com/science/article/pii/S0360319919347299#fig5

In Switzerland, a few large-scale gas storage projects are being explored.[32] Gaznat investigates the option to store up to 1.48 TWh of natural gas (about 4% of Swiss consumption) in four caverns in Oberwald (VS) using LRC technology. The project is at an early stage and could be operational earliest by 2030. Other sites for LRC storage have been explored in Switzerland at Collonges (VS), Innertkirchen (BE) and the canton of Neuchâtel, but were abandoned due to lack of favorable results or conflicts with other (hydrogeological) projects. For the Innertkirchen project, which included two caverns, investment costs were estimated at 209 million CHF, annual operating costs at 3 million CHF, and financing costs at 11 million CHF.

[32] https://www.newsd.admin.ch/newsd/message/attachments/73764.pdf

The gas supplier "*Gasverbund Mittelland*" is investigating the possibility of storing gas in liquid form but has not yet decided on the realization of the project. These include a possible storage facility at the Schweizerhalle industrial site in Muttenz with three liquified natural gas (LNG) storage facilities of 75,000 m3 each and, in addition, a storage facility in a gravel pit directly connected to the transit gas pipeline with a volume of 225,000 m^3. Both concepts could store 1.5 TWh each. In the first concept in Muttenz, LNG would be delivered by rail or ship. The construction costs for the three tanks are estimated at CHF 350 million, and the construction time would be 3 to 5 years. In the second concept at the transit gas pipeline, self-liquefaction with gas directly from the pipeline could also be implemented, so that no transport costs for LNG would be incurred. Costs for this storage concept would be higher at around CHF 500 million, with a construction period of 3 to 5 years. A decision on the realization of the project has not yet been made.

Finally, it is expected that further storage sites will be identified due to the implementation of motion 20.4063, which aims to expand knowledge of the Swiss subsurface through a national exploration campaign. Also, research projects are exploring large-scale gas storage options. For example, the project "USC-FlexStore",[33] carried out jointly by Switzerland and Austria, aims to store hydrogen and CO2 in a depleted natural gas reservoir that will foster their conversion to methane on site. However, as there are no depleted natural gas reservoirs in Switzerland, this technology might not be suitable for a seasonal storage facility in Switzerland.

An alternative to gas storage could be methanol. E-methanol can be synthesized from electrolytic hydrogen and carbon oxides, is liquid at ambient temperature and pressure, and can thus be stored in large aboveground tanks, just as oil products are today, at costs of around 0.01–0.05 €/kWh. For example, today, Switzerland stores oil reserves in the form of petrol, diesel, aviation kerosene, and heating oil to cover demand for four and a half months (aviation kerosene only 3 months). The reserve was created in the 1940s and was first touched in 2005 due to the consequences of Hurricane Katrina and the latest due to the energy crisis in 2022.[34]

2.4. Costs for Synthetic Fuels

Whether synthetic fuels will have a demand in Switzerland depends largely on their costs. For hydrogen, the EP2050+ and the EZ2050 differ substantially in price calculations. For 2050, the EP2050+ outlines end-customer costs of 6 CHF/kg-H2 and 6.3 CHF/kg-H2 for domestically produced and imported hydrogen, respectively. The EK2050 outlines much lower costs of 2.9 CHF/kg-H2 and 2.5 CHF/kg-H2 for domestically produced and imported hydrogen respectively but neglects distribution costs within Switzerland, which are estimated at around 1.7 CHF/kg-H2.[35] In a recent publication by the German Association for Gas and Water (VSGW), the authors outlined end-customer hydrogen prices in Germany of 5 CHF/kg-H2 in 2045, including expected taxes.[36]

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[33] https://www.underground-sun-conversion.at/flexstore/das-projekt.html

[34] Bericht zur wirtschaftlichen Landesversorgung, 2017–2020, https://www.bwl.admin.ch/bwl/de/home/dokumentation/grundlagendokumente.html

[35] https://gazenergie.ch/fileadmin/user_upload/e-paper/GE-H2-Barometer/H2-Baro-Nr3-202304-DE.pdf

[36] https://www.dvgw.de/leistungen/publikationen/publikationsliste/wasserstoff-preise-und-kosten-in-der-zukunft

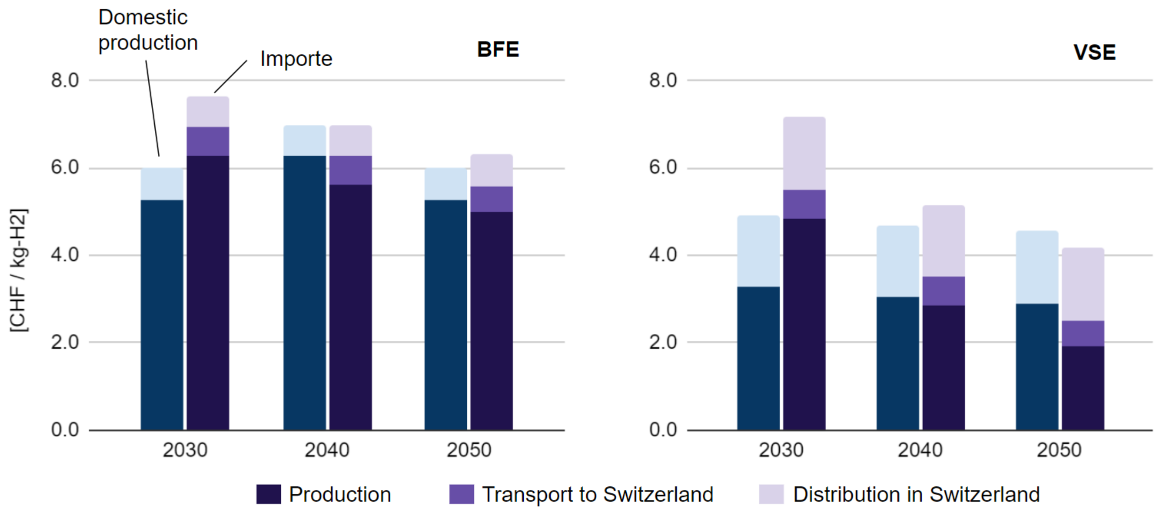

Figure 6: End-customer price for hydrogen mentioned in the SFOE EP2050+ (left) and the VSE EZ2050 (right). The prices for the EZ2050 are based on the scenario that assumes an electricity price for electrolyzers of 40 CHF/MWh-el. As VSE does not provide information on the transport cost to Switzerland, the same value as in the SFOE study is assumed here.

The end-customer price comprises hydrogen production, international transport (only for imports), and domestic distribution costs (plus potential taxes and fees). The production costs – also referred to as levelized costs of hydrogen (LCOH) – are mainly affected by the investment cost of the electrolyzer, its utilization (how many hours in the year the electrolyzer runs at full capacity) financing cost, and the electricity price at the time of hydrogen production. According to E-Bridge, today's LCOH for *green* hydrogen is at about 5.8 CHF/kg-H2[37], almost double what VSE foresees for 2030. E-Bridge also provides current cost assumptions for *blue* and *grey* hydrogen (see Box 1), which are substantially lower than current prices for *green* hydrogen. A recent report from BCG outlines that hydrogen projects currently in development show *green* hydrogen production costs in the range of 5-8 CHF/kg-H2 for central Europe.[38] BCG highlights that the cost projections made in the last years are not materializing due to a deteriorated macroeconomic context, higher energy market prices, and structural challenges in the wind power and electrolyzer supply chains.[39]

Also, for 2030 LCOH forecasts, BCG assumes no further decrease in the LCOH due to the outlined reasons. In strong contrast, the IEA outlines an LCOH for Central Europe of 2.7 CHF/kg-H2 in 2030, considering electrolyzer investment costs of 320 CHF/kW[40], so substantially lower compared to the assumptions by E-Bridge and BCG. Also, a recent learning curve study[41] projects the LCOH to fall in the range of $1.6-1.9 per kg-H2 by 2030 in the US. As financing costs, electricity prices, and utilization of the electrolyzer vary substantially between regions, the LCOH is region-specific. In an IEA study, cost projections for 2030 range from 1.6 EUR/kg (Chile) to 3.8 EUR/kg (Japan). In the Global Hydrogen Outlook[42], Deloitte projects an LCOH for 2030 between 2 USD/kg and 3.5 USD/kg. For 2050, Deloitte expects an ongoing decline of LCOH due to technology learning and economies of scale, achieving

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37 https://e-bridge.de/kompetenzen/wasserstoff/h2index/

38 https://media-publications.bcg.com/Turning-the-European-Green-H2-Dream-into-Reality.pdf

39 This is also reflected in assumed higher electrolyser overnight investment costs (1'7000 EUR/kW) compared to E-Bridge (1'200 EUR/kW).

40 https://www.iea.org/news/oman-s-huge-renewable-hydrogen-potential-can-bring-multiple-benefits-in-its-journey-to-net-zero-emissions?utm_source=SendGrid&utm_medium=Email&utm_campaign=IEA+newsletters

41 https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4300331; study outlines learning curves for electrolyser system costs of 83–86%, meaning that costs declined by 14–17% compared to the price levels prior to the doubling of cumulative installments.

42 https://www.deloitte.com/global/en/issues/climate/green-hydrogen.html

prices between 1.4 USD/kg and 2.1 USD/kg. See Figure 7 for an overview of LCOH forecasts until 2050.

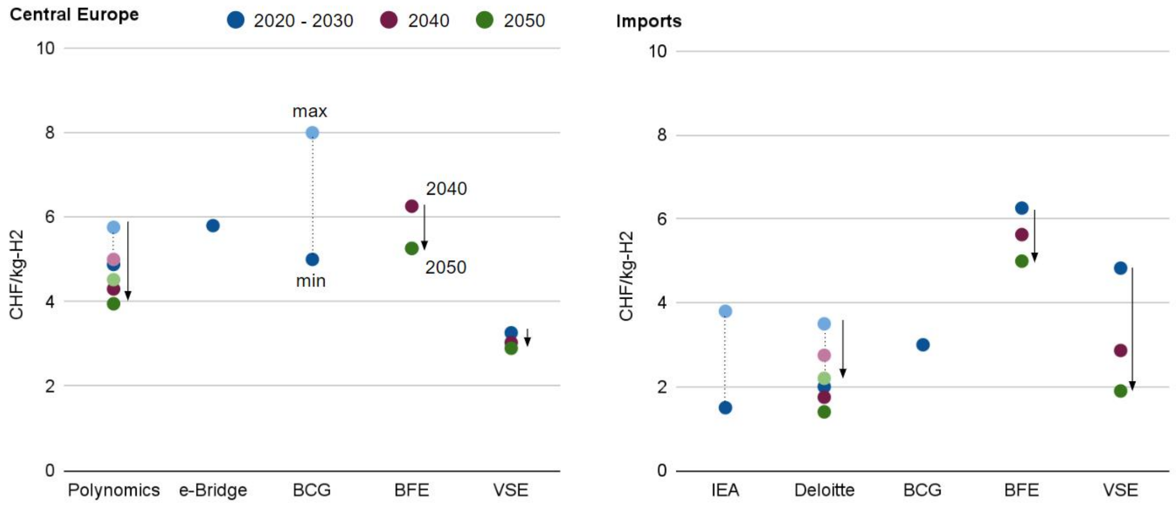

Figure 7: LCOH in 2030 (blue dots), 2040 (red dots), and 2050 (green dots) for production in Central Europe (left) and potential import countries (right). To represent the range of costs within one study, we show the maximum (darker dots) and minimum (brighter) values.

Importing hydrogen to Switzerland likely requires intercontinental transport of hydrogen. The most discussed sources of hydrogen are MENA countries such as Morocco and Oman, as well as North America, Chile, and Australia. The EP2050+ outlines costs of 0.6-3.0 CHF/kg-H2 for intercontinental transport via pipeline and even >3 CHF/kg-H2 for shipping. BCG assumes around 1.5 USD/kg-H2 for transporting hydrogen from Saudi Arabia. The German Association of the Gas Industry (DVGW) assumes 0.8-1.2 EUR/kg-H2 for transporting hydrogen from Australia to Germany. Besides intercontinental transport, domestic distribution is required to bring hydrogen to end customers. The EP2050+ outlines distribution costs of 0.7 CHF/kg-H2, the VSE 1.7 CHF/kg-H2. The VSGW study assumes 0.8 EUR/kg-H2 for distribution costs in Germany.[43]

In summary, cost projections for hydrogen production, transport, and distribution vary heavily across studies, putting a substantial uncertainty on including hydrogen import prices in an energy system model. We conclude that hydrogen end-customer prices for 2050 are roughly 2-10 CHF/kg-H2. Cost projections for producing hydrogen derivatives such as e-methane entail at least similar uncertainty as for producing hydrogen. While on the one hand additional assumptions on methanation and CO2 cycling, availability and price have to be made, e-methane can be stored and transported in the extensive existing natural gas system (with some restrictions). The EZ2050 outlines prices of 98 CHF/MWh-CH4. A 2019 study[44] outlines cost projections for e-methane production by 2050 in the range of 40-170 CHF/MWh-CH4, depending on electricity prices, and the utilization of the electrolysis and methanation system. To account for distribution by gas suppliers, additional costs of 45-50 CHF/MWh-CH4 are expected, resulting in end-customer prices of 85-220 CHF/MWh-CH4.[45] They assume that carbon-neutral CO2 is available for 90 EUR/t-CO2 plus an additional 10 EUR/t-CO2 for transporting costs. Further, they neglect grid fees for consuming electricity. Producing e-methanol has a very similar

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[43] https://www.dvgw.de/leistungen/publikationen/publikationsliste/wasserstoff-preise-und-kosten-in-der-zukunft

[44] https://doi.org/10.1016/j.apenergy.2019.113594

[45] In 2020 and 2021, gas prices for end-customer were roughly 90 CHF/MWh-CH4, whereas natural gas market prices were around 20 CHF/MWh-CH4.The CO2 tax is responsible for around 15-20 CHF/MWh of such difference, the remainder is for transmission, distribution and margin, which would all also apply for e-methane

production cost compared to e-methane. For both, carbon must be cycled or purchased, both can reuse existing fossil fuel infrastructure for storage and transport, and the round-trip efficiencies are alike.[46]

***Box 1**: Different types of hydrogen and their definition*

In this report, we refer to *green* hydrogen, which is made by using clean electricity from renewable energy sources, such as solar, wind or hydro power, to electrolyze water. Electrolyzers use an electrochemical reaction to split water into its components of hydrogen and oxygen, emitting no carbon dioxide in the process. However, to ensure that the production of green hydrogen does not result in a higher carbon intensity of the electricity mix (by demanding low-carbon electricity that would otherwise reduce the carbon intensity of the electricity mix), the EU Commission defined in a first delegated act the specific conditions for green hydrogen, introducing the principle of "additionality" for hydrogen production. The act outlines three options to fulfill the additionality criteria[a]:

i. First, the electrolyzer is directly connected to a renewable energy plant, which must have been commissioned no earlier than 36 months before the electrolyzer.

ii. Second, the electrolyzer is grid-connected, and this grid has a share of renewables above 90% or a carbon intensity below 18 gCO2eq/MJ. However, in this option, a temporal and geographical correlation between electrolysis and renewable energy production must be ensured.

iii. Third, if the electrolyzer is grid-connected and its operator either generates electricity in a corresponding amount or purchases it via a Power Purchase Agreement (PPA) from a renewable energy source.

These rules are phased in and designed to become more stringent until 2028. They apply to domestic and third-country producers seeking to export renewable hydrogen to the EU. To our understanding, Switzerland already fulfills the second option for green hydrogen, and – although the rules of the EU act do not apply in Switzerland – Switzerland could produce green hydrogen according to such regulation.

There are also other types of hydrogen. For example, grey hydrogen is produced mainly from natural gas using steam reforming, which brings together natural gas and heated water in the form of steam.[ii] The output is hydrogen, but carbon dioxide is also produced as a by-product. Blue hydrogen is essentially the same as grey hydrogen but with the use of carbon capture and storage to trap and store the carbon.

[i] https://www.cmshs-bloggt.de/rechtsthemen/sustainability/sustainability-environment-and-climate-change/erneuerbare-energien-eu-regeln-fuer-erneuerbaren-wasserstoff/

[ii] https://www.nationalgrid.com/stories/energy-explained/hydrogen-colour-spectrum#:~:text=Green%20hydrogen%2C%20blue%20hydrogen%2C%20brown,between%20the%20types%20of%20hydrogen.

[46] https://www.sciencedirect.com/science/article/pii/S2542435123004075

3. Method and Scenarios

In this section, we provide an overview of the model used for this study and the scenarios assessed. To this end, we first provide an overview of the Nexus-e modeling platform (section 3.1). Next, we describe how we model hydrogen and synthetic fuels in Nexus-e (section 3.2), and the scenarios that were analyzed (section 3.3).

3.1. Nexus-e Overview

In this project, we use the Nexus-e modeling platform to develop scenarios for the Swiss electricity system by 2050. These scenarios are outcomes of computational optimization and present the option with the lowest total system cost of power supply.

The modeling platform comprises different models describing the Swiss energy system embedded in the European power system. For this project, we use the model for the centralized power system (i.e., CentIv)[47] and the model for the decentralized power system (DistIv)[48]. CentIv and DistIv are used in interaction to find a scenario that provides sufficient electricity with the lowest total system cost for a given electricity demand. This optimization considers the existing infrastructure, such as power generation, storage options, and power grids. We examine the year 2050 and take into account the current electricity infrastructure, the expected increase in electricity demand and the domestic synthetic fuel production. CentIv/DistIv then calculate the additional electricity and synthetic fuel production infrastructure needed to meet the higher demand. To add electricity infrastructure, CentIv/DistIv can choose between the included technologies (so-called candidate units) based on their operating and investment costs and technical characteristics such as production profile or efficiency. Depending on the scenario, the additional electricity infrastructure must also compensate for the potential phase-out of nuclear power. According to current law, we do not consider new nuclear plants as candidate units.

In this process, CentIv is responsible for the central power infrastructure, such as wind farms, hydropower, electrolyzer, hydrogen storage, hydrogen-fired power plants, and methanation units. DistIv, on the other hand, is responsible for the distributed power infrastructure, such as rooftop PV and local battery storage. We distinguish between a centralized and a distributed electricity system because investment decisions and local electricity prices are very different for the central and distributed infrastructure. For example, the profitability of a wind farm depends on the prices at which electricity can be sold on the electricity market, whereas the purchase decision for a rooftop PV system depends on self-consumption, feed-in tariff, and avoided electricity costs.

The balancing of supply and demand takes place every hour and is supported by flexible electricity generation and demand. For example, the flexibility of pumped hydro storage is used if the generation profiles of PV and wind do not match hourly demand. Other flexibility options include stationary and mobile battery storage, chemical energy sources such as natural gas with carbon capture and storage, and demand-side management. In addition to these high temporal requirements, there are also spatial requirements. The transmission grid is mapped in detail (281 power lines, 25 transformers, 173 nodes), and load flows resulting from demand and supply are calculated. For this purpose, both the electricity demand and the generation plants are allocated to the respective nodes of the transmission network. The demand is allocated proportionally to the population, while all centralized and decentralized electricity generators' locations and potentials are known and allocated to the nearest node.

[47] see CentIv Model Description
[48] See DistIv Model Description

As Switzerland is closely embedded in the European electricity grid and has substantial electricity trade with neighboring countries (France, Germany, Austria, and Italy), CentIv/DistIv also consider the direct European environment. For this purpose, the respective national electricity demand and electricity generation and storage units within each neighboring country are assigned to one node per country. These nodes are connected to the Swiss transmission grid and to the neighboring countries (e.g., France-Germany). The electricity trade with the neighboring countries is limited by the physical grid capacities and "net transfer capacities" (NTC). The development of electricity generation in neighboring countries is not a result of CentIv/DistIv optimization but is given as input.

The input parameters for the model include a variety of techno-economic parameters (e.g., electricity demand, development of electricity generation capacity in neighboring countries). The model includes learning effects (decreasing prices of the technologies over time) and current subsidies (for example, feed-in tariffs and investment grants). The included technical potential of photovoltaics for rooftop installations is 47 GW based on Sonnendach data[49]. The included technical potential for wind power is set to 30 GW based on a recent SFOE/Meteotest study[50]. The potential for biomass, including waste incineration, is set to 0.4 GW. We also assume that the electricity generation from hydropower (run-of-river, pumped hydro storage, hydro dams) increases slightly compared to today's levels based on EP2050+. Renewable production profiles are based on a single year. Electricity demand assumptions follow the "Zero Basis" scenario of the EP2050+, which considers increasing electricity demand mainly due to the electrification of the transportation and heating sectors with electric vehicles and heat pumps. The development of the electricity generation capacities in the neighboring countries is based on the ENTSO-E TYNDP scenarios[51]. The NTCs are based on the latest ENTSO-E ERAA[52] and are assumed to be identical for both directions (e.g., CH-FR, FR-CH). All assumptions and input data used in Nexus-e are described in the "Nexus-e Input Data and System Setup" report[53]. The main model output comprises installed electricity generation and storage capacities, hourly electricity generation and storage, imports and exports with neighboring countries, electricity dispatch prices, renewable energy curtailment, and total electricity system costs (excluding costs for the distribution grid).

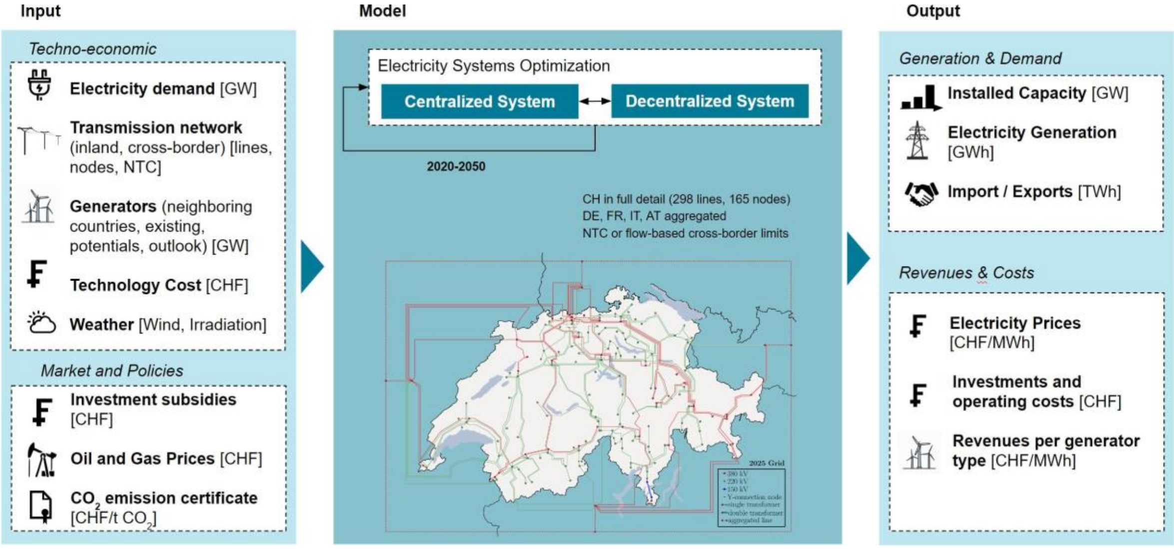

Figure 8: Nexus-e overview.

49 see www.sonnendach.ch. We only allowed for rooftops with a good PV fit.

50 see "Windpotenzial Schweiz 2022"

51 see "ENTSO-E 10-Year Network Development Plan 2022"

52 European Network of Transmission System Operators for Electricity (ENTSO-E). European Resource Adequacy Assessment 2021 Edition (2021). https://www.entsoe.eu/outlooks/eraa/eraa-downloads/

53 see "Nexus-e Input Data and System Setup"

3.2. Modeling of hydrogen and synthetic fuels in Nexus-e

To assess the role of hydrogen and other synthetic fuels, we include a "*Power-to-Gas-to-Power*" candidate unit in CentIv.[54] This candidate unit consists of multiple components, including an electrolyzer, a hydrogen storage, a hydrogen-to-power technology (i.e., hydrogen-fueled gas turbine or a fuel cell), and a methanation reactor (see Figure 9). We model 15 candidate P2G2P units with costs and sizes outlined in Table 2 and positioned as shown in Figure 10. Note that component costs are purely exogenous. We thus do not include cost degression due to deployment in Switzerland and rather assume that global technological learning is responsible for 2050 prices. Twelve of the units include pressurized tanks as a storage option, and three of the units, located in the Aarmassif with potentially suitable rock quality, include a lined rock cavern (LRC) storage.

The electrolyzer uses electricity as an input to split water into hydrogen and oxygen. Both dynamic adjustment as well as partial operation (down to 5%) is possible for proton exchange membrane (PEM) electrolyzers[55] which are expected to dominate the market by 2050[56]. Therefore it is assumed that the electrolyzer is infinitely flexible and both ramp limits as well as minimum power output limits are disregarded. The methanation units employ the Sabatier reaction to produce methane and water using CO2 from the integrated DAC unit and hydrogen from domestic electrolysis or imports. Heat from the exothermic Sabatier reaction fulfills the heating demand of the DAC unit under a coupled operation but electricity is still required as an input.

Note that to consider the exhaust heat by electrolyzers and methanation units, we assume that the exhaust heat substitutes the use of heat pumps in our scenarios and thus lowers electricity demand. We do so as we do not directly represent heat flows in our electricity system model.

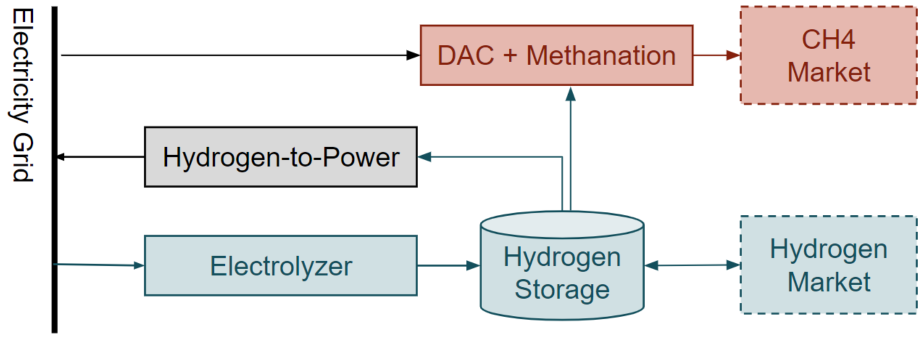

Figure 9: Layout of the modeled P2G2P candidate units. The black color indicates the electricity pathway, the blue color indicates the hydrogen pathway and the green color indicates the e-methane pathway.

[54] Raycheva et al., forthcoming, The role of power to gas in generation expansion planning

[55] M. Götz, J. Lefebvre, F.Mörs, A. M. Koch, F. Graf, S. Bajohr, R. Reimert, T. Kolb, Renewable power-to-gas: A technological and economic review, Renewable Energy 85 (2016) 1371–1390. doi:10.1016/j.renene. 2015.07.066.

[56] J. Ikäheimo, R. Weiss, J. Kiviluoma, E. Pursiheimo, T. J. Lindroos, Impact of power-to-gas on the cost and design of the future low-carbon urban energy system, Applied Energy 305 (2022) 117713. doi:10.1016/j.apenergy.2021.117713.

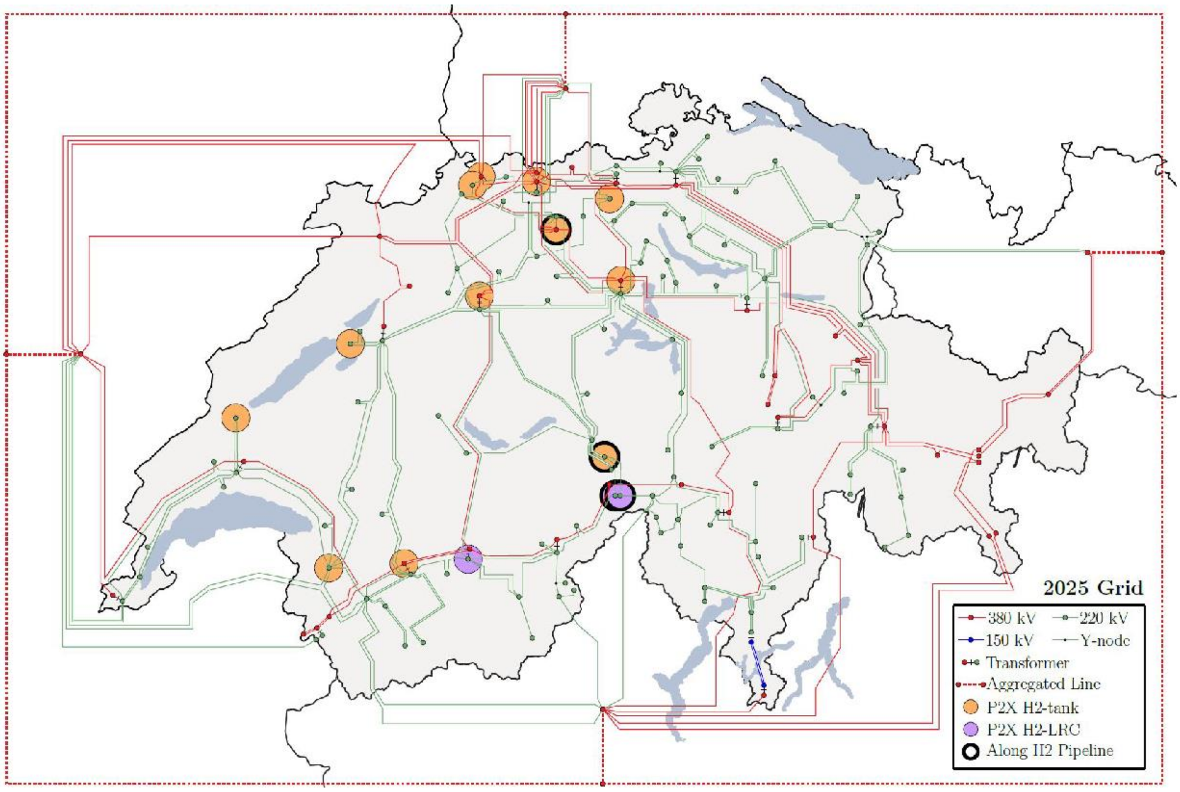

Figure 10: Location of P2G2P candidate units in relation to the electricity grid. The locations of all P2G2P units are selected to ensure access to natural gas and hydrogen infrastructure.

Table 2: Overview of techno-economic parameters for the P2G2P candidate unit and its components.

Electrolyzer	**Value (2050)**	**Unit**	**Source**
Investment cost (CAPEX)	375	CHF/kW-el	1
Annual Operating and maintenance Cost (OPEX)	0.025	Share of CAPEX	1
Lifetime	25	a	1
LHV Efficiency (excl. heat prod.)	0.74	kWh-LHV-H2/kWh-el	1
Heat Prod.	0	kWh-heat	

Hydrogen-fired power plant	**Value (2050)**	**Unit**	**Source**
Investment cost (CAPEX)	1000	CHF/kW-el	2,3,4
Operating and Maintenance Cost (OPEX)	25	CHF/kW-el/a	2,3,4
Lifetime	25	a	2,3,4
LHV Efficiency (excl. heat prod.)	0.64	kWh-el/kWh-H2-LHV	2,3,4

Continuation of Table 2

Lined Rock Cavern Hydrogen Storage	**Value (2050)**	**Unit**	**Source**
Investment cost (CAPEX)	1.8	CHF/kWh-LHV-H2	5
Operating and Maintenance Cost (OPEX)	0.026	CHF/kW-H2-LHV/a	5
Lifetime	30	a	5
Minimum capacity	17	GWh-LHV-H2	5
Maximum capacity	250	GWh-LHV-H2	5
Roundtrip Efficiency	100	%	5
max withdraw	0.062	1/d	5
max injection	0.037	1/d	5

Cylindrical Tank Hydrogen Storage	**Value (2050)**	**Unit**	**Source**
Investment cost (CAPEX)	8.5	CHF/kWh-H2-kWh	6
Operating and Maintenance Cost (OPEX)	0	CHF/kW-H2-LHV/a	6
Lifetime	18	a	6
Minimum capacity	0	[GWh-LHV-H2]	6
Roundtrip Efficiency	100	%	6
max withdraw	0.062	1/d	5
max injection	0.037	1/d	5

Methanation reactor	**Value (2050)**	**Unit**	**Source**
Investment cost (CAPEX)	615	CHF/kW-CH4-LHV	2
Operating and Maintenance Cost (OPEX)	0.025	Share of CAPEX	2
Lifetime	30	a	2
LHV Efficiency (excl. heat prod.)	0.77	kWh-LHV-CH4/(kWh-LHV-H2 + kWh-el)	2
Electricity input	0.094	kWh-el/kWh-LHV-CH4	2
Hydrogen Input	36.12	g-H2/kWh-LHV-CH4	2
CO2 Input	197.4	g-CO2/kWh-LHV-CH4	2

Continuation of Table 2

Direct Air Capture	Value (2050)	Unit	Source
Investment cost (CAPEX)	200	CHF/t-CO2	7
Operating and Maintenance Cost (OPEX)	0.025	Share of CAPEX	7
Lifetime	30	a	7
Heat Demand	Provided by exothermic Methanation	kWh-th/kg-CO2	1
Electricity input	0.182	kWh-el/kg-CO2	7

1: TYNDP 2022, https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP_2022_Scenario_Building_Guidelines_Version_April_2022.pdf
2: IEAHydrogen 2020, https://www.iea.org/reports/the-future-of-hydrogen/data-and-assumptions
3: Petkov 2020, https://doi.org/10.1016/j.apenergy.2020.115197
4: Glenk 2022, https://doi.org/10.1038/s41467-022-29520-0
5: Lord 2014, https://doi.org/10.1016/j.ijhydene.2014.07.121
6: Schmidt 2019, https://doi.org/10.1016/j.joule.2018.12.008
7: Fasahi 2019: https://doi.org/10.1016/j.jclepro.2019.03.086

3.3. Scenarios

To assess the role of hydrogen and other synthetic fuels in the Swiss electricity system, we define a reference scenario and three main scenarios with multiple sets of sensitivities. We include a mandatory 45 TWh renewable energy target in all scenarios according to the "*Mantelerlass*" (excluding hydropower).

3.3.1. Reference scenario

The reference scenario represents the least cost pathway (according to our optimization, considering all the required assumptions) for how Switzerland can achieve its climate and energy targets – **without** considering hydrogen or synthetic fuels for electricity generation in Switzerland. It includes the input data as described in section 3.1 and a nuclear phase-out after 60 years of operating time. Several neighboring EU countries do include synthetic hydrogen-based generators within their generation fleet based on the TYNDP ‘22 scenarios. The reference price set for their synthetic hydrogen consumption is 6 CHF/kg-H2.

3.3.2. Scenario 1: Hydrogen and synthetic fuel (methane) imports

In scenario 1, we investigate the question of what import price for hydrogen and synthetic fuels (i.e., e-methane) has to be realized so that these energy carriers begin to play a role in the Swiss power supply. To do so, we assume a European hydrogen or e-methane market where all model regions (Switzerland, Austria, Germany, France and Italy) can buy hydrogen or e-methane for electricity generation at the same price. For Swiss neighbors, capacities for hydrogen-based power plants are defined according to TYNDP '22. For Switzerland, the model decides on the capacities endogenously. As a sensitivity, we vary the price for hydrogen between 1 and 6 CHF/kg-H2 and the price for e-methane between 50 and 150 CHF/MWh-CH4-LHV. The varying fuel prices are also applied to all EU generators. For the e-methane sensitivity, all EU hydrogen-based units are instead assumed to utilize e-methane at the same fuel prices as Swiss units. As another sensitivity, we also run all cases with a constraint for a fully balanced electricity trade (imports = exports) during the winter months of October to March. This constraint addresses the discussion during the "*Mantelerlass*", in which a goal for maximum net-imports was set.[57] Figure 11 depicts the considered components of the P2G2P unit in scenario 1.

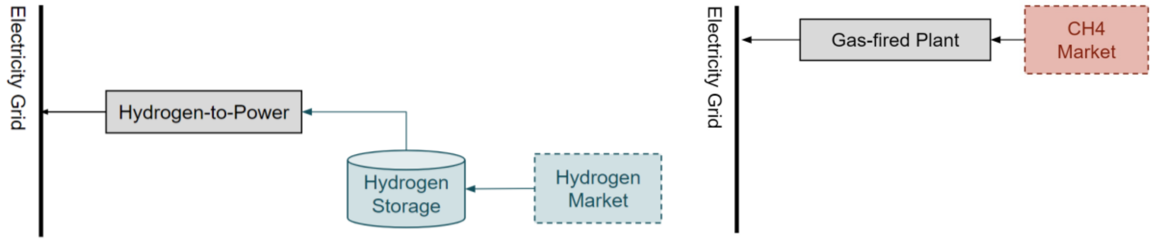

Figure 11: Considered components of the P2G2P candidate unit for electricity generation with hydrogen in scenario 1 (left). Alternatively, electricity generation with e-methane is represented with a gas-fired power plant (right).

3.3.3.Scenario 2: Hydrogen as a seasonal storage

In scenario 2, we investigate under which conditions seasonal storage with hydrogen becomes a cost-effective solution for electricity generation in Switzerland. Here, we do not allow imports of hydrogen and synthetic fuels. As in the reference scenario, all neighboring EU countries still utilize synthetic hydrogen-fired units and the reference price for synthetic hydrogen. As a combination of sensitivities, we vary the constraint for the winter import balance from 15 TWh down to 0 TWh in steps of 5 TWh, and we vary the net transfer capacities from 100% down to 30% in steps of 10%, allowing us to test the impact of electricity trading limitations on seasonal storage in Switzerland. Assessing a system with restricted NTCs became relevant with the introduction of the EU Clean Energy Package in 2020, which requires that by the end of 2025, all European transmission system operators make at least 70 percent of the relevant cross-border electricity network capacity available for trading. Without a framework agreement, Swiss cross-border lines would not be subject to this rule and permitted flows on these lines could temporarily be reduced by neighboring countries to allow them to achieve the 70 percent rules on cross-border lines to other countries - resulting in additional costs for both Switzerland and EU member states. In an extreme case and as a rough approximation of the potential effect, this could limit cross-border capacities towards Switzerland to 30 percent. Figure 12 depicts the considered components of the P2G2P unit in scenario 2.

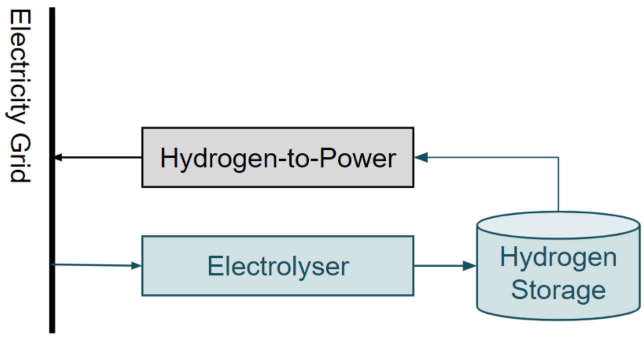

Figure 12: Considered components of the P2G2P candidate unit in scenario 2.

[57] ElCom, 2023, Winterproduktionsfähigkeit, Einschätzungen der ElCom zur Stromversorgungssicherheit Schweiz bis 2035

3.3.4.Scenario 3: Production targets for hydrogen and e-methane

In scenario 3, we investigate the cost of *producing* hydrogen and e-methane for other energy sectors such as industry and transport in Switzerland. Here, we do not allow for importing or re-electrifying hydrogen and synthetic fuels. Again as in the reference scenario, all neighboring EU countries still utilize synthetic hydrogen-fired units and the reference price for synthetic hydrogen. As a sensitivity, for hydrogen, we vary the production targets from 0-1’000 kt-H2 (≙ 33 TWh-H2-LHV) in steps of 250 kt-H2. The upper boundary of the production target hereby represents the upper boundary of hydrogen demand in Switzerland mentioned in literature.[58] Similarly for e-methane, as a sensitivity, we vary the production targets between 0-30 TWh-CH4-LHV. Also here the upper boundary is based on literature.[59] In a first set of cases, we assume that hydrogen or e-methane can be produced at any time of the year and derive a levelized cost to produce each fuel. In a second set of cases, we then also derive the cost of *supplying* hydrogen and e-methane to end-customers by assuming that the hydrogen or e-methane has to be provided constantly over the year to end customers and by also accounting for the distribution and storage costs of hydrogen and e-methane. Figure 13 depicts the considered components of the P2G2P unit in scenario 3 for the hydrogen and e-methane production targets.

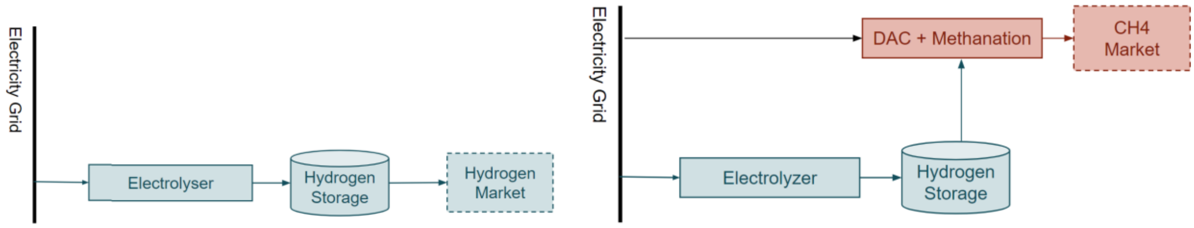

Figure 13: Considered components of the P2G2P candidate unit in scenario 2 for hydrogen production targets (left) and e-methane production targets (right).

In yet another sensitivity, we assess the levelized production and supply costs for hydrogen and e-methane with more conservative assumptions on technical developments and regulations. Table 3 outlines the assumptions for this pessimistic sensitivity.

[58] The VSE EZ2050 outlines a hydrogen demand of 27 TWh-H2-LHV in two of their four scenarios.

[59] The SFOE EP2050+ outlines a demand for synthetic fuel (excluding hydrogen) of around 20 TWh plus 16 TWh for synthetic kerosine

Table 3: Overview of assumptions for e-methane production and supply costs.

	Reference		**Less Optimistic**	
	Value	Source	Value	Source
Electrolyzer investment costs [CHF/kW-el]	375	5	1'800	6
Hydrogen storage costs [CHF/kWh-el]	1.8 (LRC)	4	8.5 (Cylindrical Storage)	3
DAC investment costs [CHF/t-CO2]	200	1	600	2
Electricity Grid Fees [CHF/kg-H2]	0	-	2.52 [60]	7
Hydrogen Distribution [CHF/kg-H2]	0.7	8	1.7	9

2: https://www.sciencedirect.com/science/article/pii/S2590332223003007
1: https://doi.org/10.1016/j.jclepro.2019.03.086
3: https://doi.org/10.1016/j.joule.2018.12.008
4: https://doi.org/10.1016/j.ijhydene.2021.08.028
5: https://www.iea.org/reports/the-future-of-hydrogen
6:
https://media-publications.bcg.com/Turning-the-European-Green-H2-Dream-into-Reality.pdf
7: similar to industry connected to grid level ("Netzebene") 5
7: https://www.bfe.admin.ch/bfe/en/home/policy/energy-perspectives-2050-plus.html/
8: https://www.strom.ch/de/energiezukunft-2050/startseite

[60] We assume a grid fee of 5.6 Rp./kWh, which is similar to industry connected to grid level ("Netzebene") 5. Considering the efficiency of electrolyser, 45 kWh of electricity is required to produce 1 kg of hydrogen. More distributed electrolyzers that are connected to grid level 7, would need to pay higher fees of around 9 Rp./kWh.

4. Results

In this section, we present the results of the reference scenario and of the three main scenarios.

4.1. Reference Scenario

In our reference scenario, we see a strong increase of domestic electricity production (see Figure 14, left) to achieve the renewable energy target and to cover the increase in electricity demand. Note that the electricity demand is an exogenous model input (see Section 3) and is assumed to increase mainly due to the uptake of electric vehicles and heat pumps, whereas efficiency gains mitigate this increase. From the production side, we see the assumed nuclear power phase-out before 2050. We assume that the four nuclear reactors in Switzerland (Beznau 1, Beznau 2, Leibstadt, Gösgen) are phased-out after 60 years of operating lifetime. Hydropower capacities are assumed to increase by 2050 by including selected projects from the "*Runder Tisch der Wasserkraft*".[61]

The largest portion of the added generating capacity is from rooftop PV (32.7 GW, 36.6 TWh). Additionally, batteries (0.8 GW), alpine PV (1.2 GW, 1.9 TWh), and wind turbines (0.9 GW, 2.1 TWh) are being installed until 2050. Besides new installations, we also observe higher utilization of hydro pumps, which are increasingly utilized to support the integration of intermittent renewable electricity generation. Monthly electricity generation profiles indicate pronounced seasonal patterns (see Figure 14, right). Run-of-river hydro plants and rooftop solar PV produce electricity mostly in summer. Electricity demand, however, is especially high in winter. It is important to note that although we see some curtailment during the summer months (5 TWh), most electricity that is not used to cover domestic demand can be exported (see Box 2).

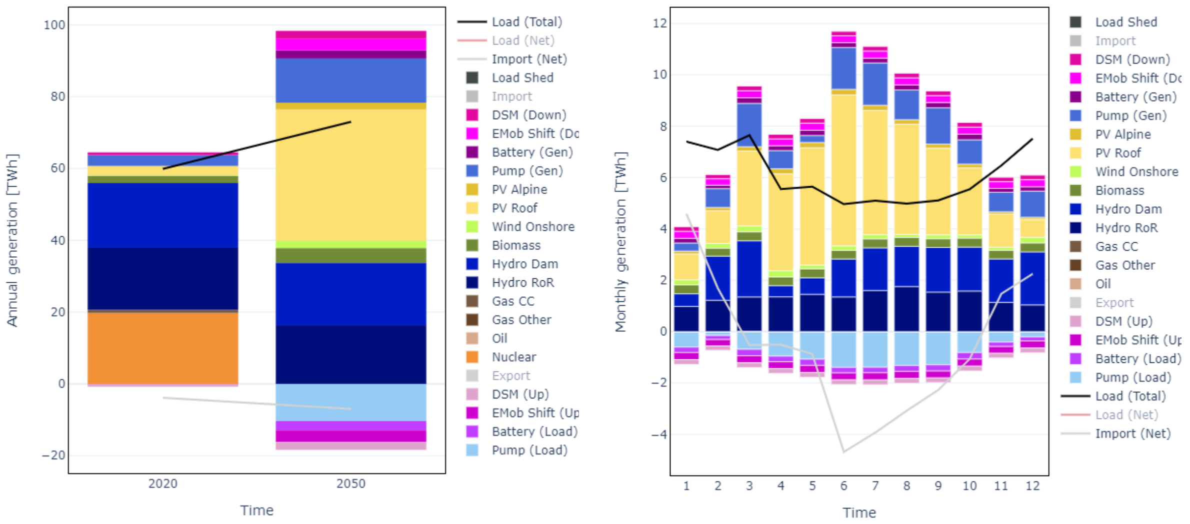

Figure 14: Annual (left) and monthly (2050, right) electricity generation in the reference scenario.

Such seasonal patterns also impact electricity trading. Generally, Switzerland imports from and exports to the neighboring countries every hour. And, whereas, over a year, Switzerland exports 7 TWh more

[61] https://www.admin.ch/gov/de/start/dokumentation/medienmitteilungen.msg-id-86432.html; Please note that the "Mantelerlass" includes simplified approval procedures for the 15 hydropower projects in the "Runder Tisch der Wasserkraft" plus the planned Chlus hydropower plant in Grisons.

than it imports, its net imports in winter rise from historically 4 TWh up to 8.5 TWh in 2050 (see Figure 1b). Note that when comparing historical and simulated values for winter imports in 2020, we see that our model underestimates annual and winter imports by around 2 TWh. Also, variations of net imports, similar to the patterns observed historically, are likely to happen also in the future. In some years, the net imports in the reference scenario could thus be higher or lower than the 8.5 TWh shown here for

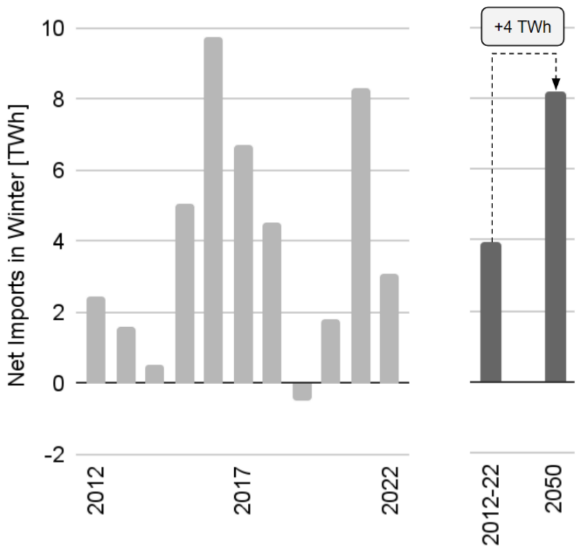

Figure 15: Net imports in winter (October to March) historically (left) and simulated for 2050 (right).

2050.

Our results show that the annual average electricity price will increase slightly by 2050 (see Figure 16, left). The monthly electricity prices indicate why we see such an increase (see Figure 16, right). Whereas the simulated prices for 2020 do not show substantial differences between months, in 2050, we observe a pronounced price spread between winter and summer. Especially in winter, monthly prices increase substantially. Such seasonal price patterns mainly come from expensive power plants, such as synthetic gas units or natural gas-fired power plants with carbon capture and storage, which are running and price setting when wind and solar are insufficient to cover all demand.

The system costs in the reference scenario mainly comprise investment costs into rooftop PV and electricity trading with the neighboring countries. Annual system costs in the year 2050 amount to CHF 1.8 bn. This includes annualized investment for new capacities, variable and fixed operating costs as well as costs for imports and revenues from exports. Note that the system costs in this analysis do not include transmission or distribution grid costs.

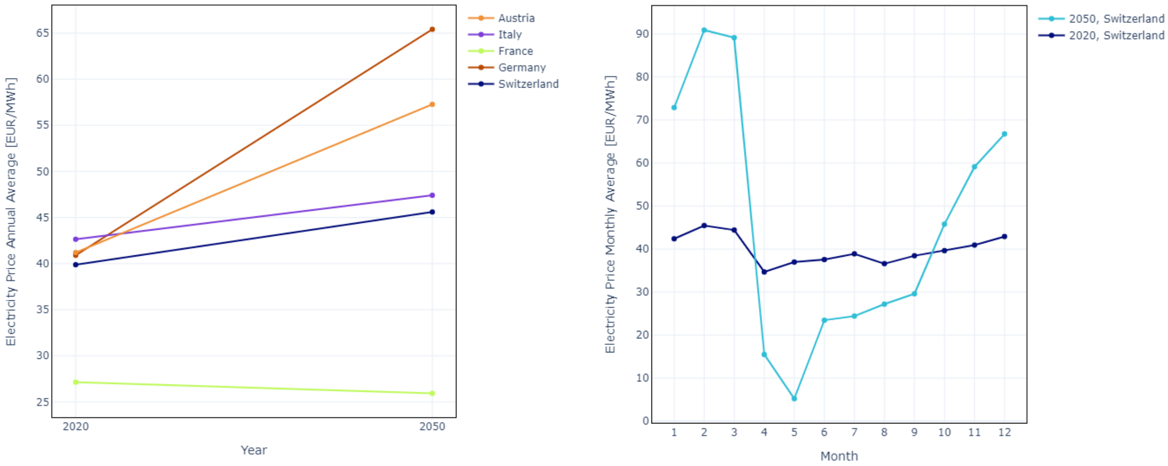

Figure 16: Annual (left) and monthly (2050, right) electricity market prices in the reference scenario.

Box 1: *Why can Switzerland, in our scenarios, still export in summer and import in winter?*

In the reference scenario, Switzerland has winter net-imports of 8.5 TWh. On the other hand, Switzerland has net exports of 15.5 TWh in summer. Switzerland can do so in our scenarios as European countries have a different electricity mix to Switzerland today and likely also in the future. To represent the developments in the neighboring countries, we rely on the TYNDP '22 report. Figure a and Figure b depict the considered installed capacities in the neighboring countries (plus Switzerland) and their resulting electricity generation in our model. Neighboring countries focus also on installing PV but also heavily on wind power. As the latter produces more than 60 percent during the winter months, we do not see such a seasonal pattern as in Switzerland.

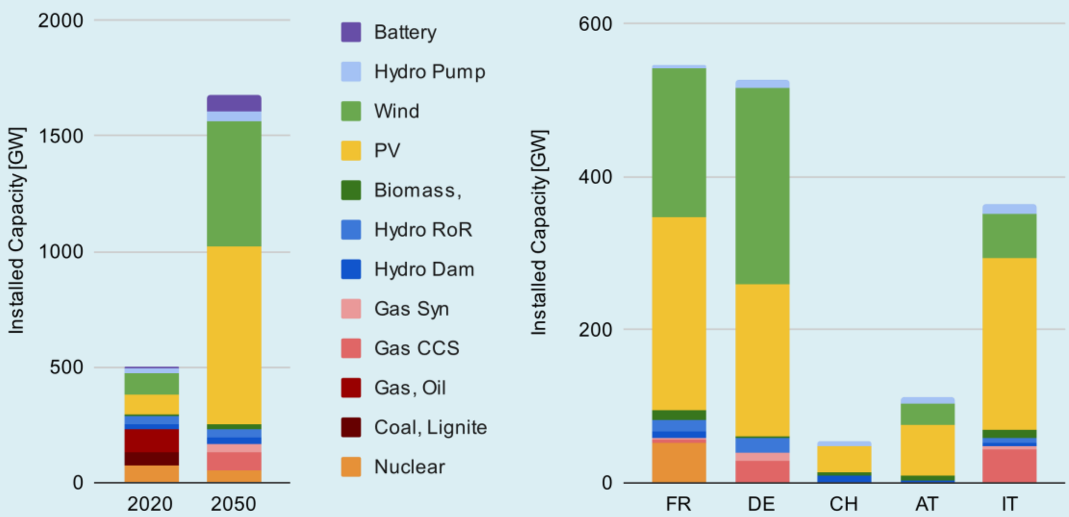

Figure a: Installed capacity in Switzerland and its neighboring countries

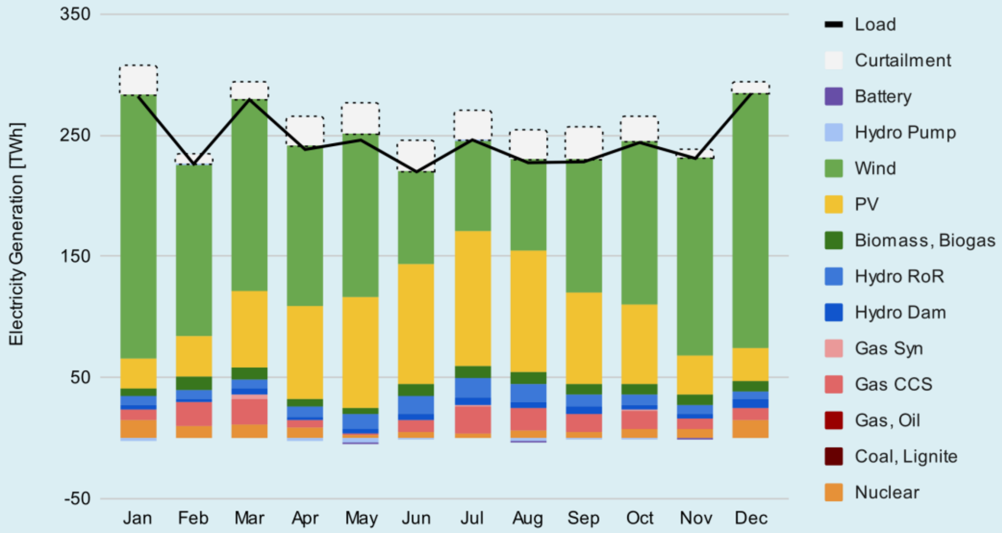

Figure b: Total monthly electricity generation in 2050 in Switzerland and its neighboring countries

i: https://2022.entsos-tyndp-scenarios.eu

4.2. Scenario 1: Hydrogen and e-methane import prices

In scenario 1, we investigate the question of what import price for hydrogen and synthetic fuels (i.e., e-methane) has to be realized so that these energy carriers begin to play a role in supplying electricity in Switzerland. In the following, we will first outline the results for hydrogen (section 4.2.1) and then for e-methane (section 4.2.2)

4.2.1. Hydrogen import

Varying the hydrogen import price between 1-6 CHF/kg-H2 allows us to identify the threshold when the model starts building hydrogen-fired power plants (H2PP) within Switzerland and running these units with imported hydrogen. Figure 17 outlines the annual electricity generation with hydrogen depending on its import price – with and without a balanced winter trading. Please note that the price represents the end-customer price, which includes hydrogen production, international transport, and domestic distribution. It is, therefore, the price the owner of the H2PP has to pay per burned kg-H2. We assume the same hydrogen price for the installed H2PP in the neighboring countries.

In the scenarios with unrestricted trading, we see that hydrogen end-customer prices have to drop below 2 CHF/kg-H2 so that hydrogen is used for electricity generation. With an import price of 1 CHF/kg-H2, 3.2 TWh of electricity is generated annually with imported hydrogen (covering 4.4 percent of Swiss annual electricity demand). For this, 96 kt-H2 are required annually, valued at CHF 96 million. In the sensitivity where we set a constraint for a fully balanced winter trading (meaning that imports must be exactly the same as exports over the duration of the six winter months) we see a different picture, and observe some use of hydrogen (0.1 TWh) at 3 CHF/kg-H2. With even lower import prices, the electricity generation based on hydrogen increases to 1.6 TWh (2 CHF/kg-H2, 2.2 percent of demand) and 8.5 TWh (1 CHF/kg-H2, 11.6 percent of demand). The reason is that with a requirement for balanced winter trading, Switzerland needs to increase its domestic generation during these months. With lower import prices, electricity generation with hydrogen becomes cost-competitive to installing additional wind or alpine PV capacity.

Our results correspond with the findings in EP2050+ that hydrogen is not used for electricity generation with an end-customer price of around 6 CHF/kg-H2. Similar to the EZ2050, we also see that hydrogen is being utilized at a price of 2.5 CHF/kg but at a very different scale. Whereas the EZ2050 outlines 12.4 - 23 TWh electricity generation at such a price, our results show 0.1-1.6 TWh (the second when requiring balanced winter trading). The main difference to the EZ2050 is that our scenarios by definition have much higher domestic renewable generation as we require achieving the targets set by the "*Mantelerlass*".

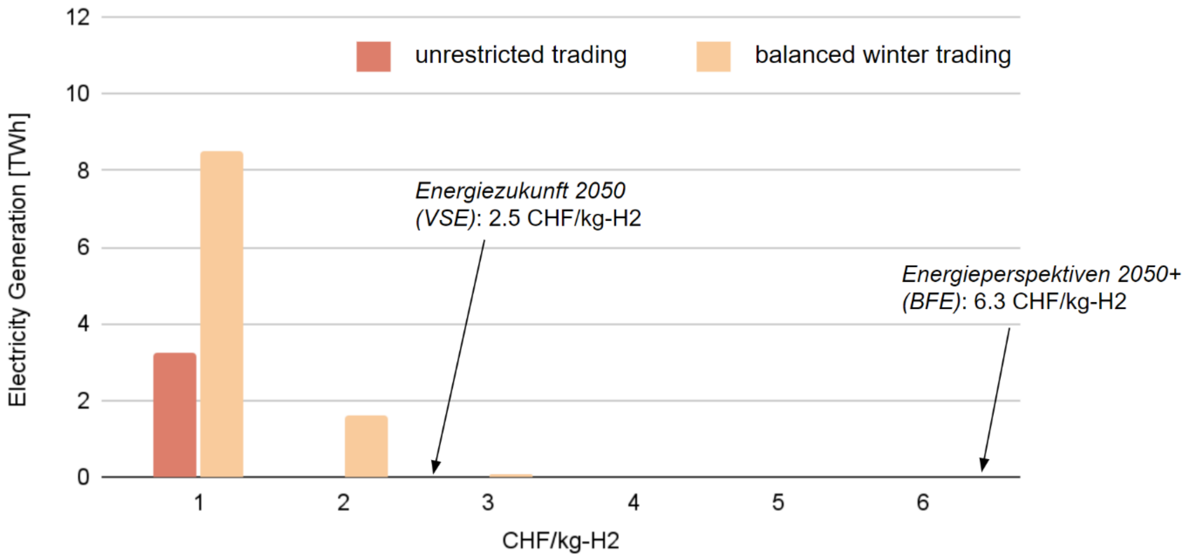

Figure 17: Electricity Generation by H2PP under varying import costs for hydrogen.

Figure 18 depicts the annual electricity generation for 2020 and for the two 2050 scenario sets. In most scenarios, hydrogen plays no role. Only when reducing the hydrogen import price to 1-3 CHF/kg-H2, we see that the model starts utilizing hydrogen for electricity generation. Consequently, investments in domestic renewables are reduced, imports are replaced by domestic generation, and annual net exports increase.

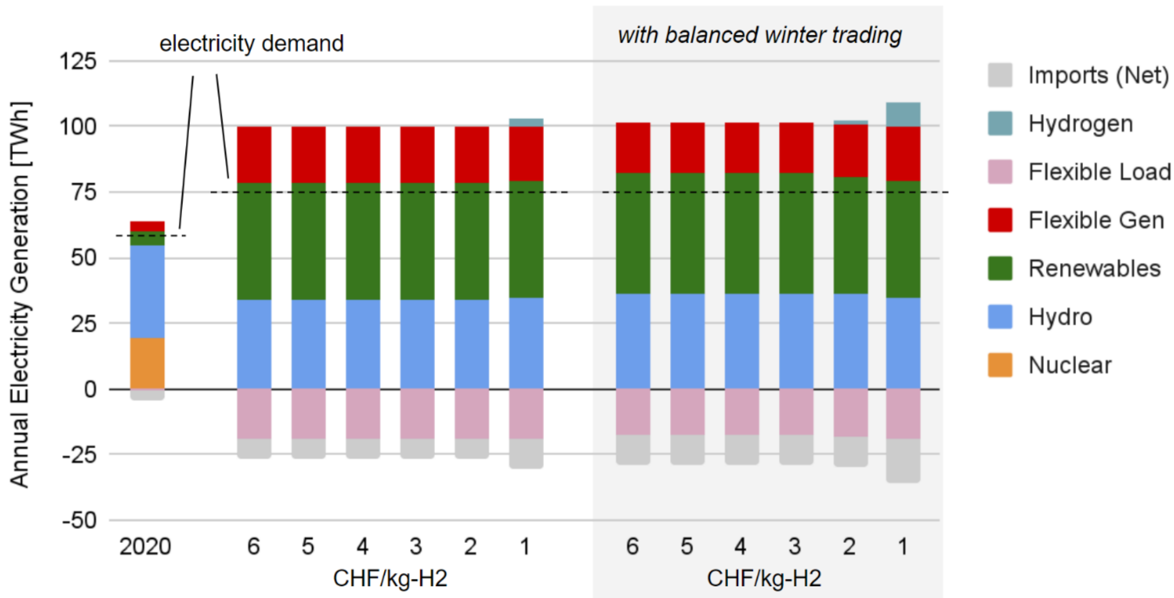

Figure 18: Annual electricity generation for scenario sets without and with balanced winter trading constraint for different prices for hydrogen in scenario 1.

To understand the general impact of a requirement for balanced winter trading, in Figure 19, we compare the monthly electricity generation of both scenarios with the hydrogen price of 6 CHF/kg-H2. With unrestricted trading, the scenario equals the reference scenario. With balanced trading, however, the model has to increase the domestic electricity generation in winter. To do so, the model decides to install an additional 12 TWh of wind turbines (which produce around two-thirds of their electricity in winter). At the same time, the model also reduces investments into rooftop PV by 10 TWh. The model thus increases winter and decreases summer generation..

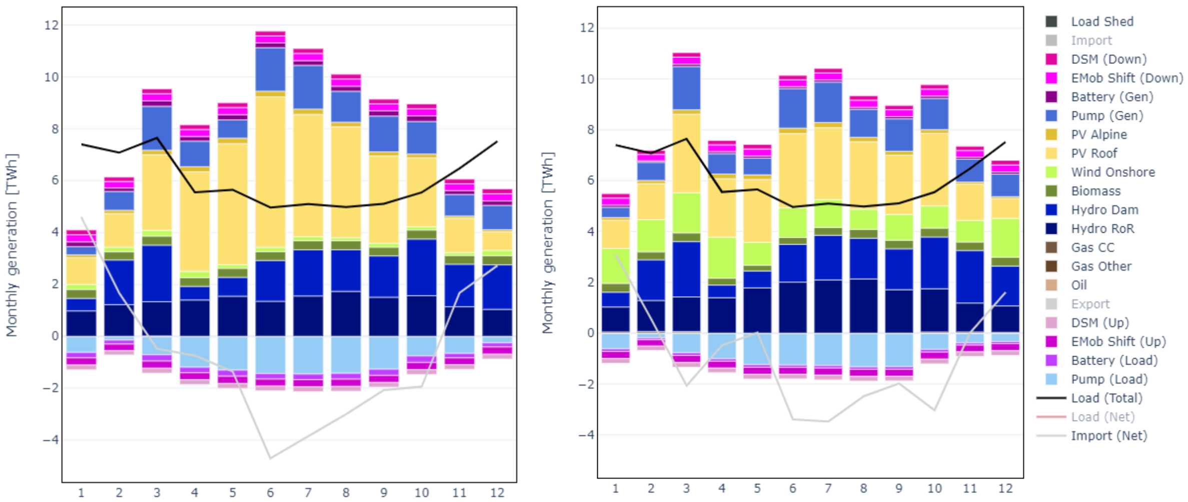

Figure 19: Monthly electricity generation for the "6 CHF/kg-H2" scenarios with unrestricted (left) and balanced winter trading (right).

Lowering the hydrogen price has a strong effect on electricity market prices. Figure 20 depicts the monthly electricity prices in 2050 for Switzerland and its neighboring countries for the "6 CHF/kg-H2" and the "1 CHF/kg-H2" scenarios, both with unrestricted trading. In all countries, electricity prices are substantially lower, especially in winter, as all represented countries utilize some electricity generation based on hydrogen. As these units are often price-setting when dispatched, the lower hydrogen prices reduce peak market prices in winter.

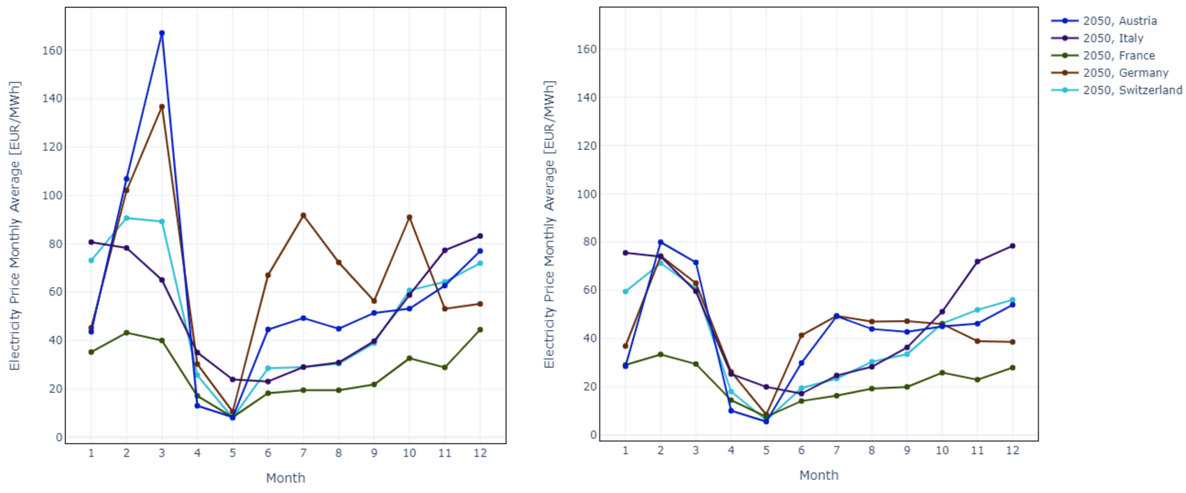

Figure 20: Monthly electricity prices in 2050 for the "6 CHF/kg-H2" (left) and the "1 CHF/kg-H2" (right) scenarios with unrestricted trading.

4.2.2.E-methane import

We also assess the potential role of e-methane as an energy carrier for electricity generation in Switzerland. We vary the import price for e-methane between 50 and 150 CHF/MWh-CH4-LHV. Figure 21Figure 22 outlines the annual electricity generation with e-methane depending on its import price – with and without balanced winter trading. Note that the price represents the end-customer price in Switzerland and the neighboring countries.

In the scenarios with unrestricted trading, we don't see that e-methane is being utilized for electricity generation. Even at the lowest considered import price of 50 CHF/MWh-CH4, no e-methane is being used for electricity generation. With a fully balanced winter trading constraint, we observe some use of e-methane (0.1 TWh, <1 percent of demand) already at 100 CHF/MWh-CH4. With even lower import prices, the electricity generation based on e-methane increases to 0.8 TWh (75 CHF/MWh-CH4, 1 percent of demand) and 6.4 TWh (50 CHFMWh-CH4, 8.8 percent of demand). The reason is that with a requirement for balanced winter trading with its neighbors, as seen before, Switzerland needs to increase its domestic generation during these months. With lower import prices, using e-methane becomes cost-competitive and such capacities are installed instead of renewables with a higher winter electricity generation.

Similar to hydrogen, our results correspond with the EZ2050 that at an end-customer price of around 100 CHF/MWh-CH4, e-methane might be a cost-competitive option, but the scale is again very different. While the EZ2050 show a potential for e-methane for electricity generation via combined-heat and power of 9.5 TWh at 98 CHF/MWh, our results only indicate a use of 0.1 TWh at that price (in the balanced winter trading) and even only 0.7 if prices reduce even further to 75 CHF/MWh. The EP2050+ shows only in the scenario with low electrification that e-methane is used, but for heating only.

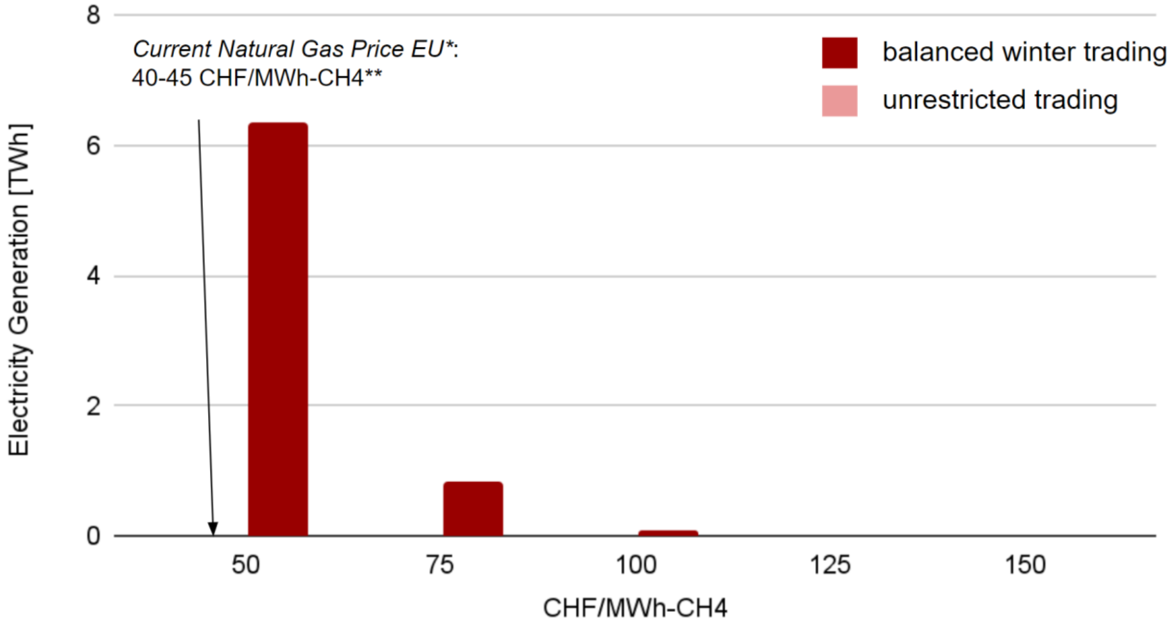

*Figure 21: Electricity generation with e-methane under varying import prices, *: https://tradingeconomics.com/commodity/eu-natural-gas, **: Plus additional 15-20 CHF/MWh-CH4 for carbon emission certificates (80 EUR/t-CO2, 0.2 t-CO2/MWh-CH4).*

4.2.3. Discussion

Our results indicate that sufficiently cheap hydrogen or e-methane could become part of a cost-effective strategy for Switzerland. Hydrogen starts being utilized at an end-customer price of <3 CHF/kg-H2 and e-methane at <100 CHF/MWh-CH4. Not surprisingly, the results are very similar per MWh-LHV (1 kg-H2 = 33.3 kWh-LHV). The literature review outlines hydrogen and e-methane end-customer prices of 2-10 CHF/kg-H2 and 85-220 CHF/MWh-CH4 (see section 2.4). So, both technologies can become cost-competitive options for the Swiss electricity supply if the most optimistic price projection can be realized.

Our results are under the assumption that Switzerland achieves the 45 TWh renewable energy target defined in the "*Mantelerlass,*" and wind turbines and alpine PV can be placed according to their socio-techno-economic potential. Our model suggests installing 18 TWh of open-field wind and alpine PV to achieve a balanced winter trading. Today, however, only 47 wind turbines with an annual generation of 0.2 TWh are installed, and alpine PV is a promising but also new technology with unclear social acceptance.

The advantage of e-methane compared to hydrogen is that the existing natural gas infrastructure, including transport, storage, and generation units, can be used without significant modifications. However, it remains to be seen how the natural gas infrastructure will be maintained. For example, the canton Basel-Stadt will dismantle the gas distribution grid gradually between 2026 and 2037 and will instead extend its district heating network.[62] The gas supply for industry, however, will not be dismantled. The disadvantage of e-methane is the higher production cost, as it requires electrolysis and methanation systems. Also, the source of emission-free carbon can be a challenge and expensive (e.g., DAC).

In our scenarios we assume that imported hydrogen and e-methane are available for electricity generation when required. However, both fuels face the challenge of being stored in large quantities for

[62] https://www.bazonline.ch/ausstieg-bis-2037-basel-stadt-plant-schritte-zur-stilllegung-des-gasnetzes-847042867648

a reasonable cost. As indicated in section 2.3, there is currently no large-scale underground storage in Switzerland, and whether this will change by 2050 remains to be seen. If synthetic fuels are not storable, they need to be produced or imported exactly when required. To increase the security of electricity supply with synthetic fuels, we would argue that Switzerland should be able to store the fuel at least to a reasonable level over a longer duration or secure access to storage capacities abroad. Another option is to convert hydrogen into liquid derivatives that are easily stored such as e-methanol or e-ammonia. However, such conversion comes with further efficiency losses.

4.3. Scenario 2: Hydrogen and synthetic fuels as a seasonal storage

In scenario 2, we investigate under which conditions seasonal storage with hydrogen would become a cost-competitive option for Switzerland. Note that this assessment focuses on seasonal storage participating in the electricity market and not as a strategic reserve to provide electricity in a shortage situation (see Box 2). In this scenario, we do not include the option to import hydrogen or other synthetic fuels.

4.3.1. Hydrogen for seasonal storage

If we include the option for seasonal storage in the reference scenario, we still do not observe any investments into electrolysis and hydrogen storage systems. As explained in Box 1, if Switzerland is well integrated into a European net-zero electricity system in 2050, in our results, Switzerland can trade electricity with its neighbors throughout the year. As developments in the neighboring countries are, however, uncertain and trading with them might be limited due to the EU Clean Energy Package that might reduce cross-border NTCs, we also assess whether, under these conditions, seasonal storage in Switzerland becomes cost-competitive. In a first sensitivity, we require a fully balanced winter trading (import equals export during winter), and in a second set of sensitivities, we vary the NTCs from 100 to 30 percent.

However, in all of these scenarios, our model does not suggest investing in any additional seasonal storage, even if we include the option of lined rock caverns (LRC), which are still unavailable in Switzerland (see Figure 22). Instead, to achieve balanced trading in winter, we can see higher annual wind power electricity generation compared to the reference scenario (from 2 TWh/a to 14.1 TWh/a). Also, with reduced NTCs, we see a trend towards more domestic renewable production in winter.

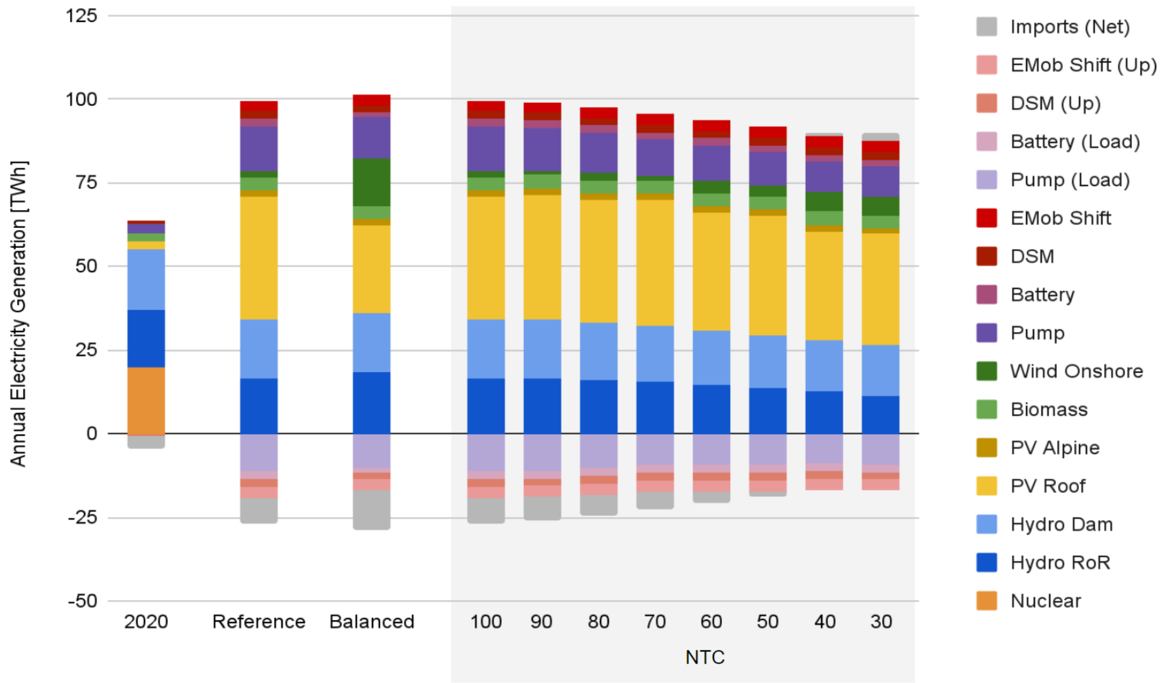

Figure 22: Annual electricity generation in 2020 and 2050 for the reference scenario, for the scenario with balanced electricity trading, and the scenarios with reduced NTCs.

Figure 23 shows the monthly electricity generation in 2050 for the reference, the balanced winter trading, and the NTC30 scenario. In the scenario with balanced winter trading, we see that the higher wind power contributes to domestic electricity generation in winter. Whereas in December and January, Switzerland shows net exports, in March and October, Switzerland has net imports. Reducing the NTCs to 30% has powerful implications on trading but also for domestic generation. We also observe a shift to winter generation, which is to ensure covering electricity demand in winter and avoid too high curtailment in summer, as exporting capacities are also restricted.

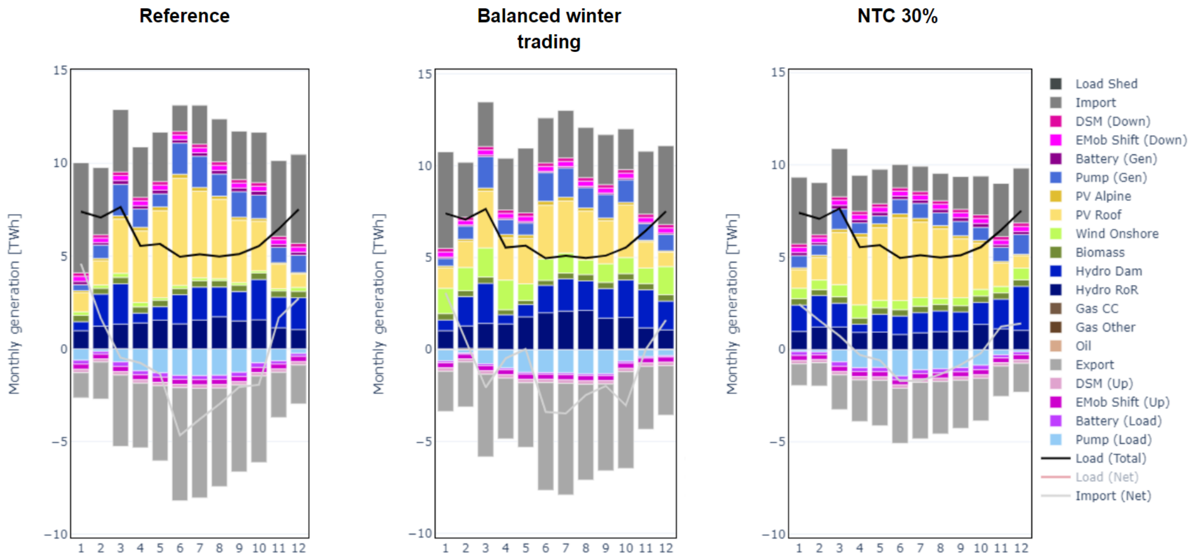

Figure 23: Monthly electricity generation in 2050 in the reference, balanced winter trade, and NTC30 scenario.

Also note that, generally, with putting additional constraints on Switzerland such as reduced NTC or a balanced winter trading, the system costs are increasing substantially. Figure 24 depicts the annual system costs (excluding grid investment costs) for the scenarios with varying NTCs. It becomes clear that system costs are increasing heavily when reducing the NTCs. In the NTC30 scenario, they rise to more than 3 bn CHF, from 1.8 bn CHF in the reference scenario when the NTCs are at 100 percent.

This cost increase, however, is driven mainly by electricity trading. While Switzerland has substantial trade benefits in most scenarios it has to start spending more on imports and loses all export revenues from NTC levels below 60 percent of full capacity. With reduced NTCs, Switzerland has to forego profits from exports in summer, and more domestic renewables must be curtailed. Also, import costs in winter increase as the flexibility in which hours to import is reduced.

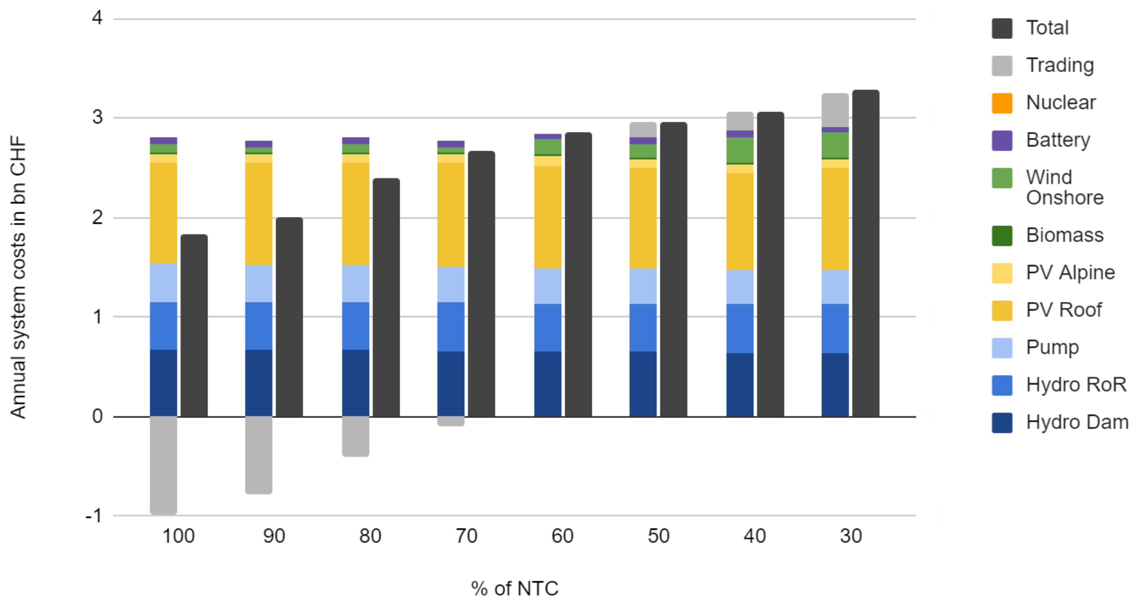

Figure 24: Annual system costs (excluding grid investment costs) in the different NTC scenarios

***Box 2**: Hydrogen (and derivates) for building a strategic reserve*

In response to the turmoil in the energy markets in 2022, Switzerland has set up a strategic reserve for electricity generation (Art. 9 StromVG). Such a reserve should provide electricity in a shortage situation when the market does not close (see Figure a).

The Federal Council brought two of these measures into force in fall 2022: First, a hydropower reserve of 400 GWh was to be held by several hydropower storage operators from the beginning of December 2022 until mid-May 2023, when the storage levels rise again due to natural water inflows. While the costs for 775-1525 GWh of hydropower reserve for 2022/23 were initially estimated at EUR 15 to 30 million, the actual costs amounted to EUR 300 million, and that is for a significantly smaller reserve.[i] Also, for the winter 2023/24, a hydropower reserve has been established. Again, 400 GWh were procured at a total cost of EUR 55.5 million.[ii] The costs for the reserve in winter 2023/24 are much lower as electricity price forecasts for this period were also much lower compared to last winter. Second, the federal government purchased eight modular, mobile TM2500 gas turbines (which can also run on oil and hydrogen) with a total output of around 250 MW and total costs of CHF 470 million for four years (excluding operating costs). Assuming each plant runs for two whole weeks per year, they generate 84 GWh at a price of CHF 1400/MWh plus fuel and CO_2 emission certificates. A third measure is emergency power groups. Arising costs for these three measures are passed on to end consumers. For 2024, the increase in end customer electricity prices due to the strategic reserve amounts to 1.2 Rp/kWh.

To compare: all subsidies for new renewables and existing hydropower are financed with a "*Netzzuschlag*" adding 2.3 Rp/kWh to the end-customer prices.

In a future system, hydrogen (derivatives) could be utilized in power plants for a strategic reserve. However, how large a strategic reserve in 2050 would need to be is difficult to assess. Uncertainties and risks evolve particularly around the political and regulatory linkage to the EU and developments within the EU. In parallel to a strategic reserve for electricity generation, Switzerland requires stocks of oil products stored in tanks acting as backup capacities for heating and transport demand and are currently required to last for at least 90 days. With an ongoing decarbonization, these reserves are likely shifting towards being used as backup capacities for electricity demand. As the tanks contain fossil fuels and are likely to be emptied in the future, the storage volume could be used for storing synthetic gasses instead.

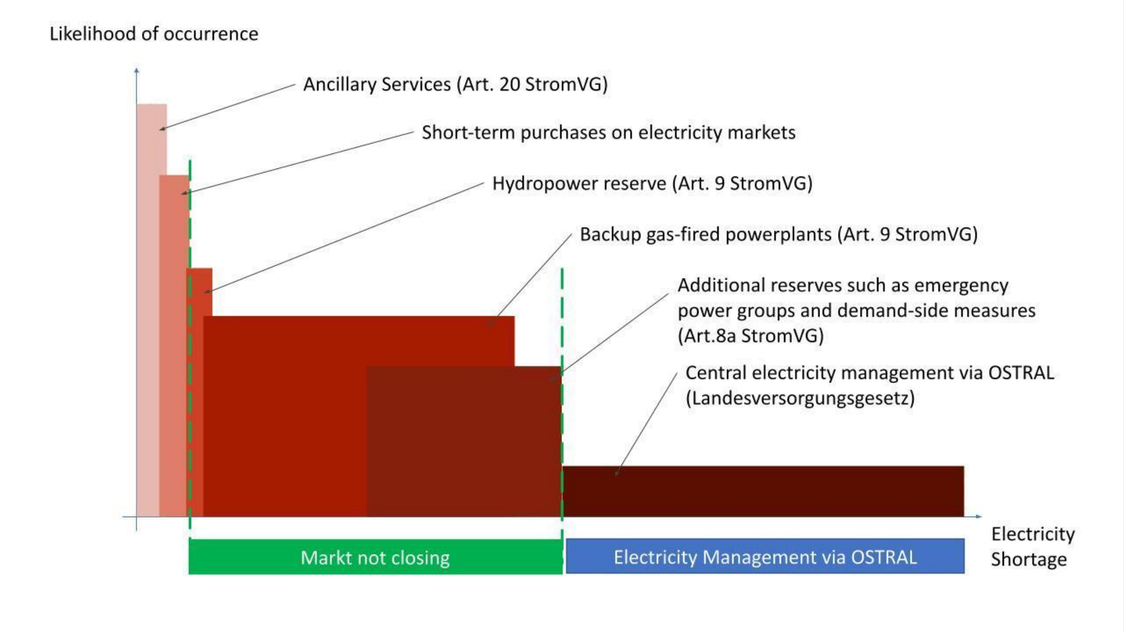

Figure a: Cascade of measures for situations with an imbalance between supply and demand. These range from short-term options for small deficits to management in the event of a serious electricity shortage

i: Schweizerische Elekrizitätskommission ElCom, 2022, *https://www.admin.ch/gov/de/start/dokumentation/medienmitteilungen.msg-id-90036.html*
ii: https://www.admin.ch/gov/de/start/dokumentation/medienmitteilungen.msg-id-97726.html

4.3.2. Synthetic fuels for seasonal storage

Our results also imply that other synthetic fuels than hydrogen will not be employed for seasonal storage. While we do not assess other synthetic fuels for seasonal storage, hydrogen with LRC would likely be the lowest-cost option for seasonal storage with synthetic gas in Switzerland. For example, a recent study on e-methanol for seasonal storage outlines 16-20 percent higher costs for methanol storage with aboveground tanks than underground storage.[63]

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[63] https://www.sciencedirect.com/science/article/pii/S2542435123004075

However, for a strategic reserve, storing the synthetic fuel in Switzerland might be necessary to increase the security of supply with backup power plants. In this case, synthetic liquids that are easy to store, such as e-methane, could be a suitable alternative but this analysis goes beyond the scope of the present study.

4.4. Scenario 3: Production targets for hydrogen and e-methane

In scenario 3, we investigate the impact of mandated hydrogen and e-methane production targets on the Swiss electricity system. We then derive the production costs and end-customer prices for synthetic fuels produced in Switzerland. We do not allow imports of these fuels nor re-electrification of hydrogen and e-methane; the respective energy carrier is instead provided to other energy sectors in Switzerland. In the following, we will first outline the results for a hydrogen production target (section 4.4.1) and then for an e-methane production target (section 4.4.2)

4.4.1. Hydrogen production target

For hydrogen, we vary the production targets from 0 - 1000 kt-H2 (≙ 33 TWh-LHV-H2, the upper bound in the EZ2050 scenarios) in steps of 250 kt-H2. Hydrogen can be produced at any time of the year to fulfill the target. Figure 25 outlines the annual system costs in 2050 under varying hydrogen production targets. Generally, system costs are increasing with a higher target, primarily due to the investments into electrolyzers and additional renewables but also due to lower exports and increased imports. To produce, for example, 1000 kt of hydrogen annually, Swiss annual system costs increase by 1.2 bn CHF from 1.8 bn CHF to 3 bn CHF.[64] Note that Switzerland has substantial net-benefits from electricity trading in all scenarios.

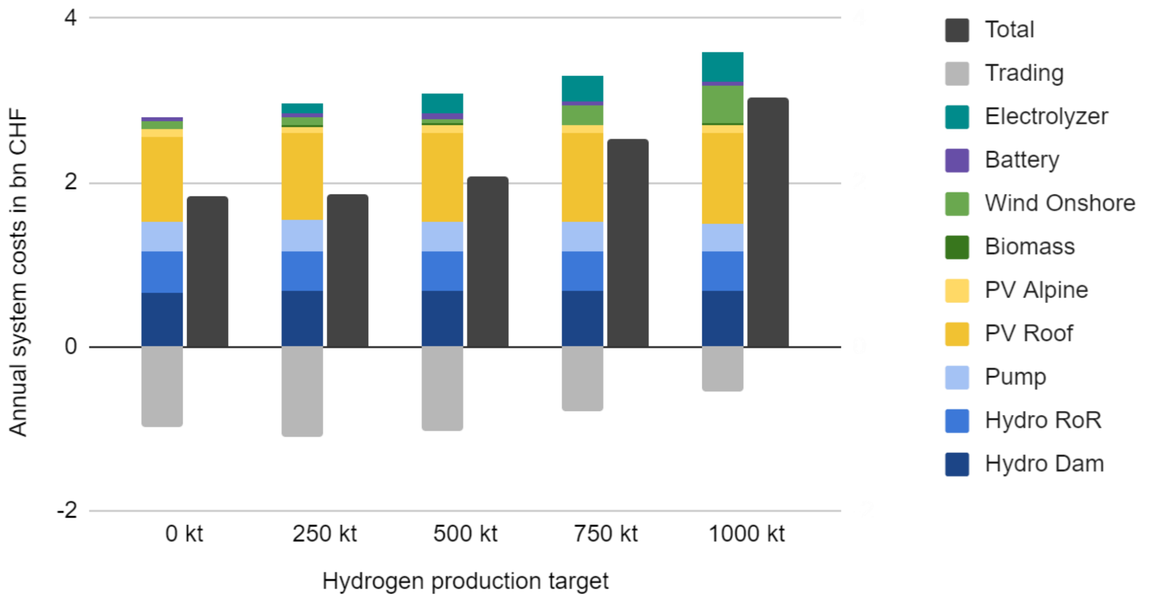

Figure 25: Annual system costs in Switzerland with increasing hydrogen production target.

Figure 26 (left) depicts the resulting LCOH in Switzerland. It is striking that the LCOH is increasing with higher hydrogen production targets from 1 to 2.7 CHF/kg-H2. Electricity purchases are responsible for

[64] Please note that the annual costs in the 0 kt-H2 of 1.8 bn CHF scenario also represent the annual costs of the reference scenario.

the largest share of the LCOH, but this strongly depends on the targeted level. For example, with the 250 kt target, electricity purchase costs are only responsible for around 50% of the LCOH and, instead, the investment and operation and maintenance (O&M) costs weigh in much more. This can be explained by the fact that with a lower production target, electrolyzers can run most of the time in the hours with the lowest electricity market prices. For the sensitivity with less optimistic assumptions on technological and regulatory developments (see section 3.3.4), the LCOH is substantially higher, ranging from 5.5 to 6.7 CHF/kg-H2. The electricity purchase costs remain the same but make up a much smaller share due to higher electrolyzer investment costs and grid fees.

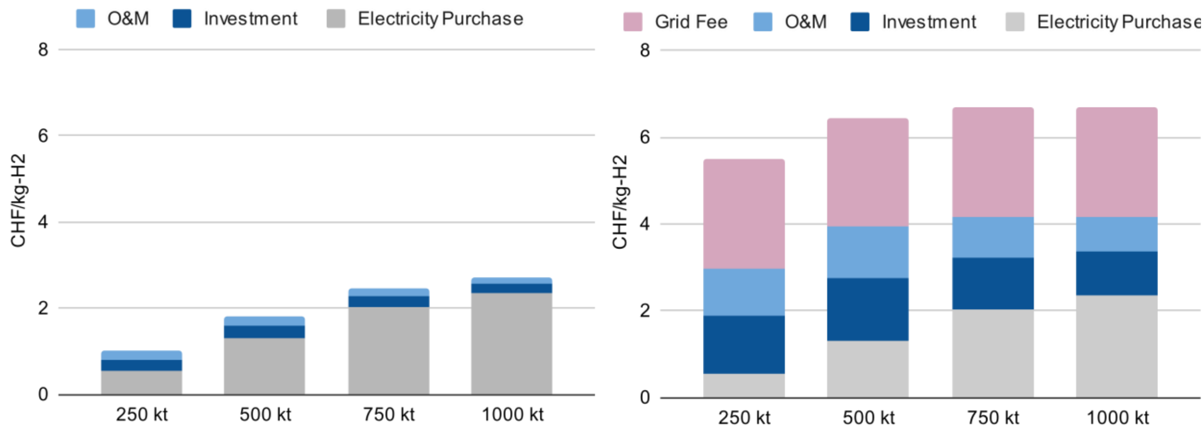

Figure 26: LCOH in Switzerland with the reference (left) and more conservative assumptions on technological and regulatory developments (right).

So why are electricity purchase costs higher with increasing production targets? Figure 27 depicts the hourly electricity price for 2050 and the hourly hydrogen production for the 250 and 1000 kt-H2 production targets. The hours of the year are sorted according to the electricity price level, from high to low, with the respective hydrogen production in that hour. In the 250 kt-H2 scenario, we see that electricity prices (black line) are primarily between 20 and 80 CHF/MWh but can go up to 130 CHF/MWh and down to 0 CHF/MWh. Hydrogen (blue bars) is produced in the hours of the year with the lowest prices (and available electricity). On average, the electrolyzer pays 11 CHF/MWh for electricity (black dotted line). In the 1000 kt-H2 scenario, the electricity price spread decreases as lower prices increase due to an increase in demand in low price hours and most electricity prices are now between 60 and 80 CHF/MWh. While electrolyzers still utilize the low-price hours as much as possible, hydrogen production is also spread out more over the year, meaning that the electrolyzers also run in some high-price hours. This results in an average electricity purchase price of 53 CHF/MWh-el. This is because, with a low production target, the additional demand is mainly covered with surplus electricity that would otherwise be curtailed or exported in very low-price hours. The electrolyzers also make use of some surplus electricity in the neighboring countries. With higher production targets, new renewable capacity has to be installed, making the electrolysis more expensive.

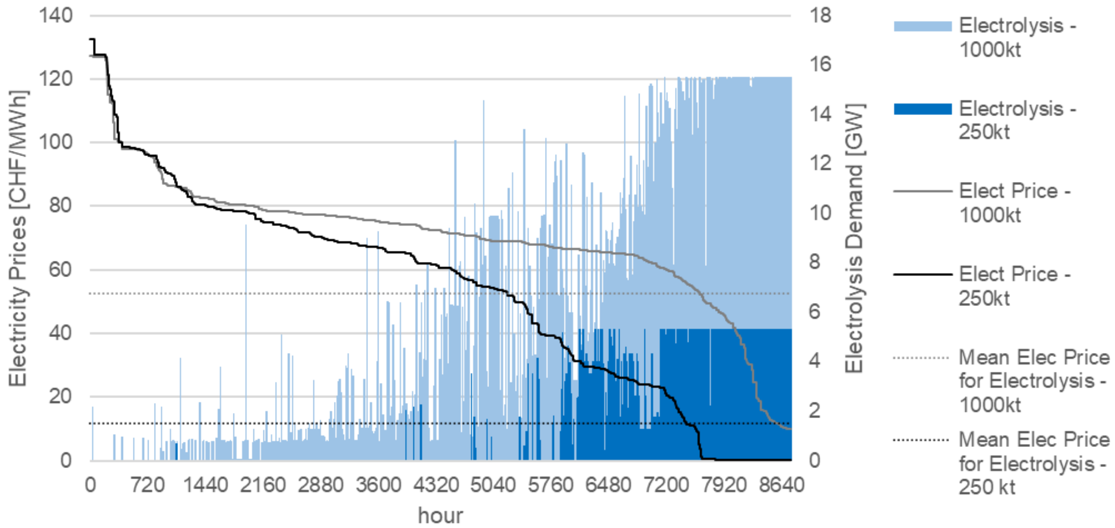

Figure 27: Electricity Prices (sorted) utilized for hydrogen production.

We also derive the hydrogen supply cost (i.e., end-customer prices based on domestic hydrogen production). To account for a more realistic hydrogen demand, we assume in this separate sensitivity that hydrogen has to be provided constantly over the year to end customers such as industry or transport. Figure 28 depicts the resulting hydrogen supply costs in Switzerland for reference and sensitivity assumptions.

The hydrogen supply costs are generally higher than the LCOH, ranging from 2.8 to 3.7 CHF/kg-H2. This is mainly because hydrogen has to be distributed from its production to the demand and must be provided constantly over the year. The model invests in hydrogen storage to avoid running electrolyzers in hours with very high electricity market prices. For example, in the 250 kt scenario, the supply costs are 1.8 CHF/kg higher than the LCOH. We also see that providing hydrogen constantly over the year results in higher electricity purchasing costs, with an average of 37-68 CHF/MWh-el. The reason is that the model has to find a trade-off between running electrolyzers in high price hours and investing into hydrogen storage to balance the supply over the year. In our results, the storage size is rather small, avoiding only hours with very high market prices. With a more pessimistic view, hydrogen supply costs rise to 8-8.6 CHF/kg-H2. Please note that distribution costs and grid fee are exogenous input parameters and are constant for each produced kg-H2 (see section 3.3.4). Also, the distribution costs are assumed to be higher here by 1 CHF/kg-H2.

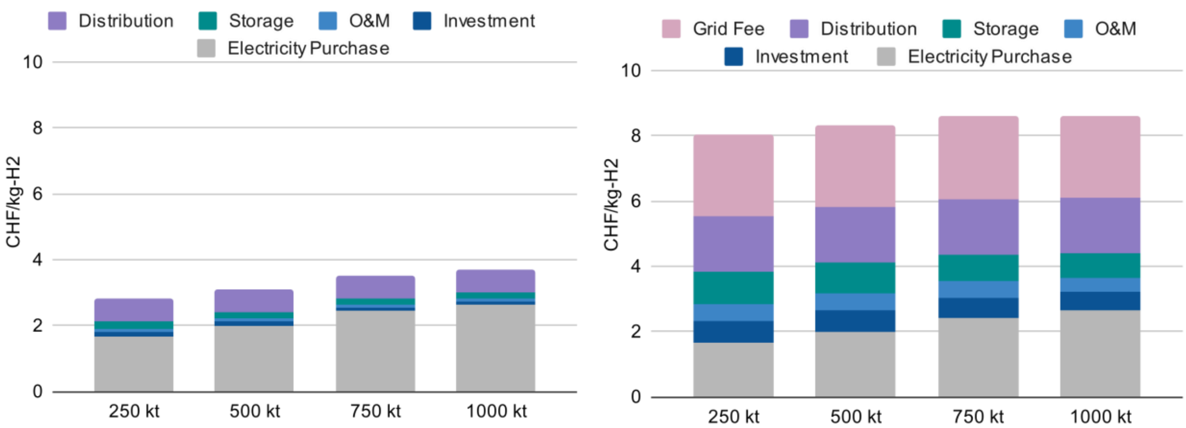

Figure 28: Hydrogen supply costs in Switzerland with the reference (left) and less optimistic assumptions on technological and regulatory developments (right).

Figure 29 shows the electrolyzers' electricity demand, installed capacity, and capacity factor for the scenarios calculating the LCOH and the hydrogen supply cost. Whereas when calculating the LCOH, the utilization of the electrolyzer (top right) is at around 24-33 percent (2100-3200 h), this goes up to 51-57 percent (4400-5600 h) when calculating the hydrogen supply costs (bottom right). The reason is, although hydrogen storage is installed, electrolysers are still running more spread out over the year. Therefore, fewer electrolyzers achieve the production target with higher utilization. Also, Figure 30 illustrates electrolyzers' less pronounced seasonal behavior in the hydrogen supply cost case.

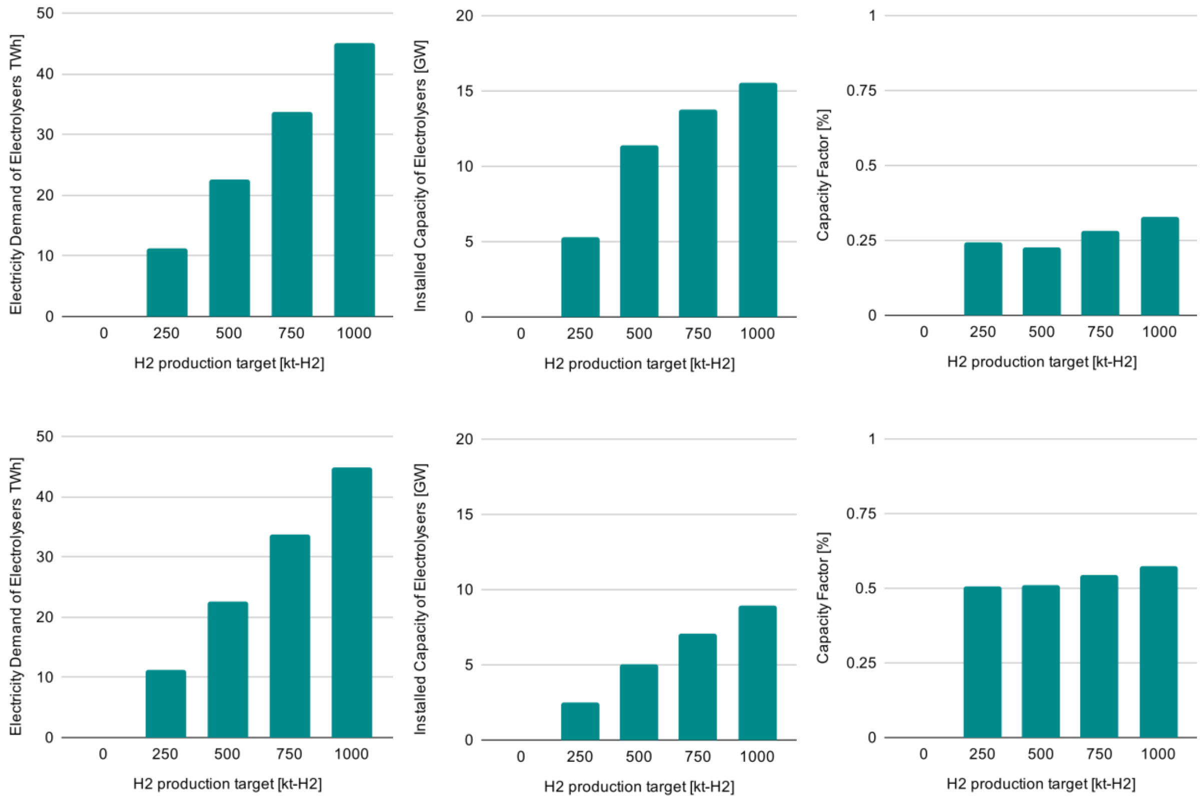

Figure 29: Electricity demand, installed capacity, and capacity factor of electrolyzers for the scenarios calculating the LCOH (upper) and the hydrogen supply costs (lower).

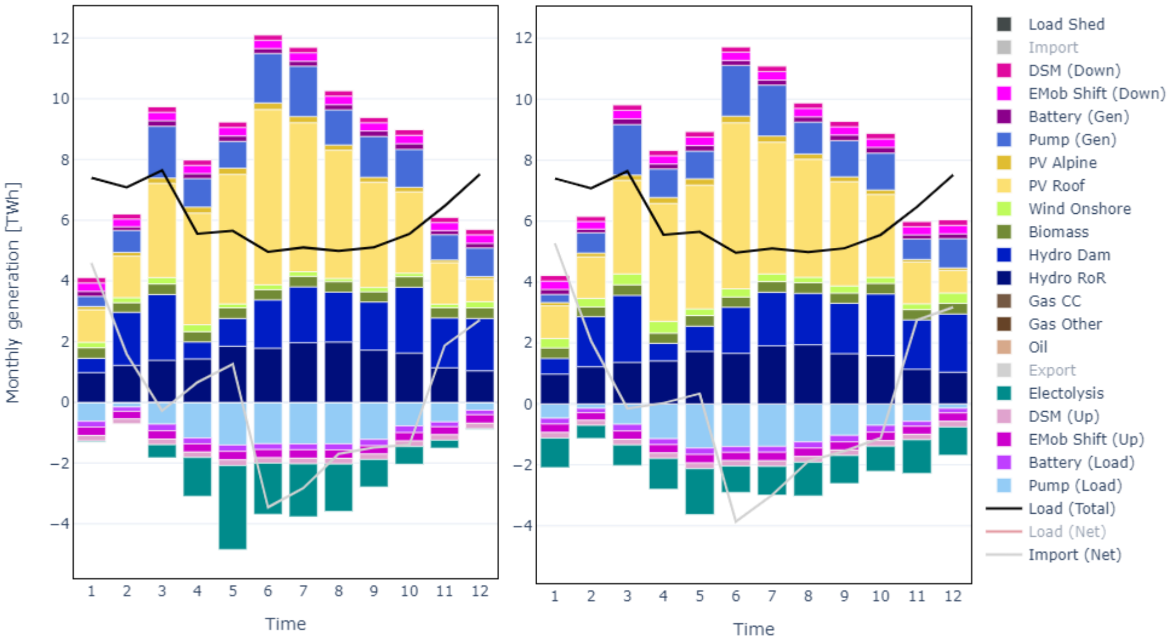

Figure 30: Monthly electricity generation and demand in 2050 with a 250 kt target for the production (left) and supply (right) cost of hydrogen.

Figure 31 depicts the electricity source for the electrolyzer. With lower production targets, electrolyzers use electricity that otherwise would be curtailed, exported in low-price hours, or is available as neighboring countries have excess electricity. Only with higher production targets, new renewables are installed in Switzerland to provide additional electricity for electrolysis.

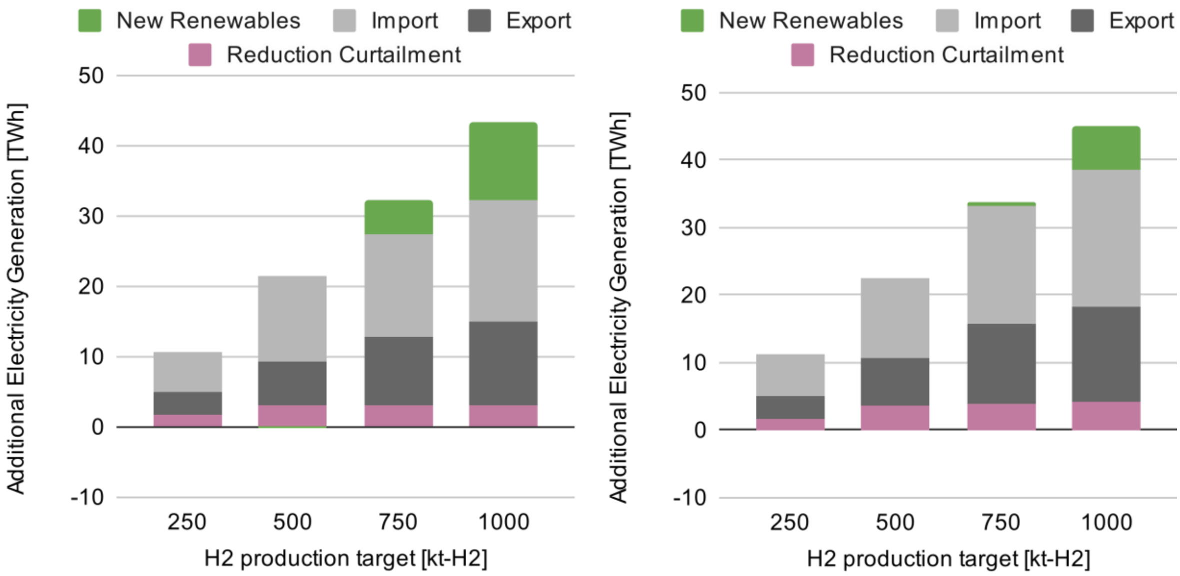

Figure 31: Source of electricity for electrolyzers in the scenarios with the reference (left) and less optimistic assumptions (right) on technological and regulatory developments.

4.4.2. E-methane production targets

For e-methane, we vary the production targets from 0 – 30 TWh-CH4-LHV in steps of 7.5 TWh-CH4. Figure 32 outlines the annual system costs in 2050 to achieve the production targets. Generally, we see that system costs are increasing with a higher production target. To produce, for example, 7.5 TWh of e-methane annually, Swiss annual system costs increase by 0.33 bn CHF from 1.83 bn CHF to 2.16 bn CHF. This is primarily due to the investments into electrolyzers, methanation systems, wind turbines, lower trading revenues, and hydrogen storage. That storage is being built, although e-methane can be provided at any point in time because methanation systems are relatively expensive, and by adding hydrogen storage, the methanation plant can achieve a higher utilization. This allows the electrolyzers to still exploit the lowest-cost hours but provide hydrogen with its storage more constantly to the methanation unit.

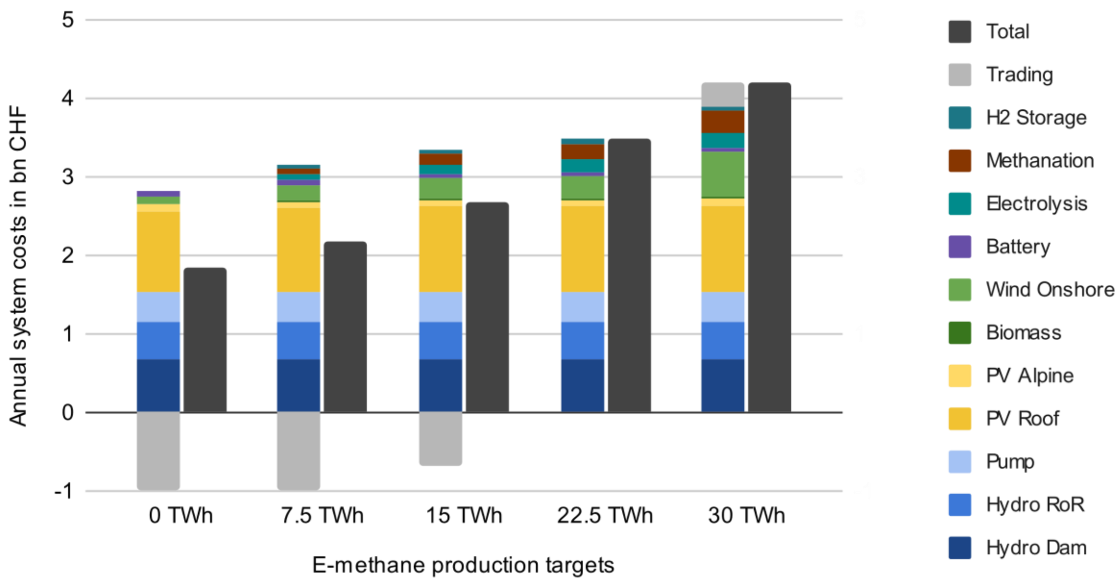

Figure 32: Annual system costs in Switzerland under varying e-methane production target.

Figure 33 (left) outlines the levelized costs of e-methane production (LCOeM) in Switzerland. Similar to the LCOH, the LCOeM also increases with the level of the production target, ranging from 84-124 CHF/MWh-CH4. This is mainly because the electrolyzer runs for more hours of the year, including higher-price hours, to achieve the production targets. Electricity purchases are responsible for the largest share of the production costs, especially with very high production targets. Electrolyzers' and methanation (and DAC) systems' costs similarly contribute to the production costs. With less optimistic assumptions on technological developments (Figure 33, right; see assumptions in section 3.3.4), levelized production costs are substantially higher, ranging from 253-263 CHF/MWh. A large share of the LCOeM in this sensitivity analysis are the hydrogen storage, higher costs for the electrolyzer, and partly also the higher DAC costs, to provide zero-emission CO2 for the methanation. Interestingly, the difference in the LCOeM between the targets becomes minimal.

For supplying e-methane to end-customers constantly over the year, we assume that the energy carrier can be buffered in existing gas infrastructure and, therefore, no investments in e-methane storage are required. Hence, the two scenarios with a flexible or constant supply of e-methane are identical for the model. We expect distribution costs of around 45-50 CHF/MWh-CH4 (see section 2.4). Adding the distribution costs to the e-methane production costs, we derive the resulting supply costs ranging between 129-149 CHF/MWh-CH4 and 303-313 CHF/MWh under reference and sensitivity assumptions, respectively.

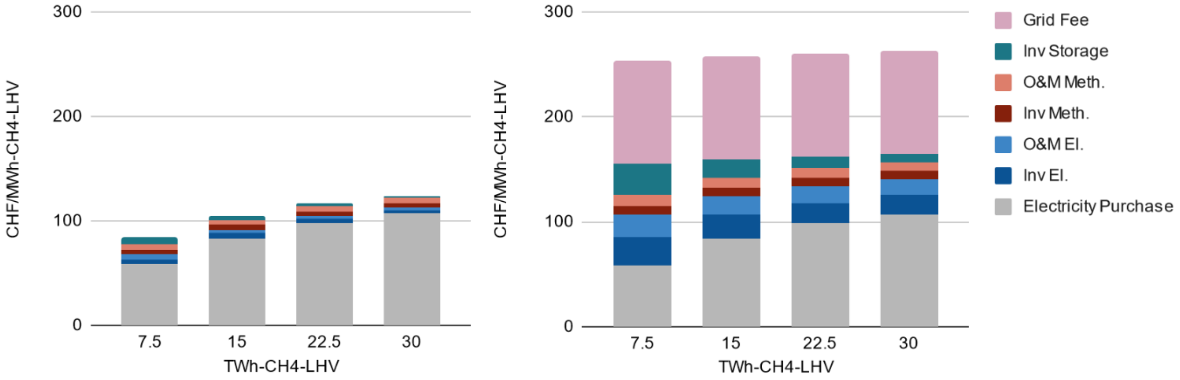

Figure 33: E-methane production costs in Switzerland with the reference (left) and less optimistic (right) assumptions on technological and regulatory developments.

Figure 34 depicts the hourly electricity price for 2050 and the hourly electricity demand for electrolysis and methanation for the 7.5 and 30 TWh-CH4 production target. The hours of the year are sorted according to the electricity price level, from high to low, with the respective electricity demand in that hour. In the 7.5 TWh scenario, electricity prices (black line) are primarily below 80 CHF/MWh but can go up to 130 CHF/MWh. E-methane (red bars) is produced mainly in the hours of the year with the lowest prices. However, some demand is spread throughout the year, indicating that the methanation is taking place over many hours throughout the year. Electricity for the methanation is purchased for an average price of 33 CHF/MWh (compared to 11 CHF/MWh in the 250 kt-H2 scenario). In the 30 TWh-CH4 scenario, we can observe an impact on the electricity prices due to the higher demand but compared to the 1000 kt-H2 scenario, the impact is rather similar across the hours and not focused on low-price hours. This is because electricity demand is also much more evenly spread over the year. The average electricity purchase price is 61 CHF/MWh, which is close to the annual average electricity market price of 71 CHF/MWh.

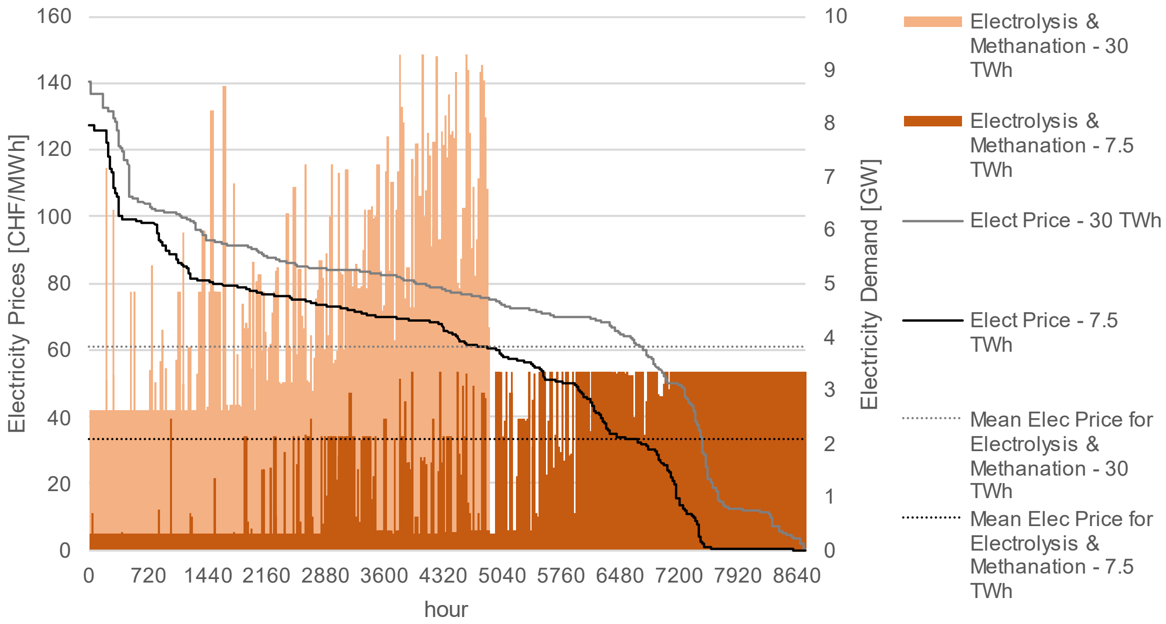

Figure 34: Electricity Prices (sorted) utilized for e-methane production.

Figure 35 shows the electricity demand and capacity factor of the electrolysis and methanation units as well as the required hydrogen and carbon dioxide for the methanation. The additional electricity demand to process hydrogen and carbon dioxide in the methanation unit is relatively small compared to the initial electricity demand for the electrolyzer. The methanation unit's utilization is higher than the electrolyzer, which is enabled by hydrogen storage.

For the methanation, an additional 5 t-CO2 is required for each hydrogen tonne. This means that for 1 TWH-CH4-LHV, around 0.2 mt-CO2 is required. For the targets between 7.5 TWh-CH4-LHV and 30 TWh-CH4-LHV, 1.5 – 5.9 mt-CO2 are required. In our scenarios, the required CO2 is provided with a DAC unit. Alternatives are carbon cycling[65] or the use of domestic biogenic CO2. See Box 3 for CO2 availability in Switzerland.

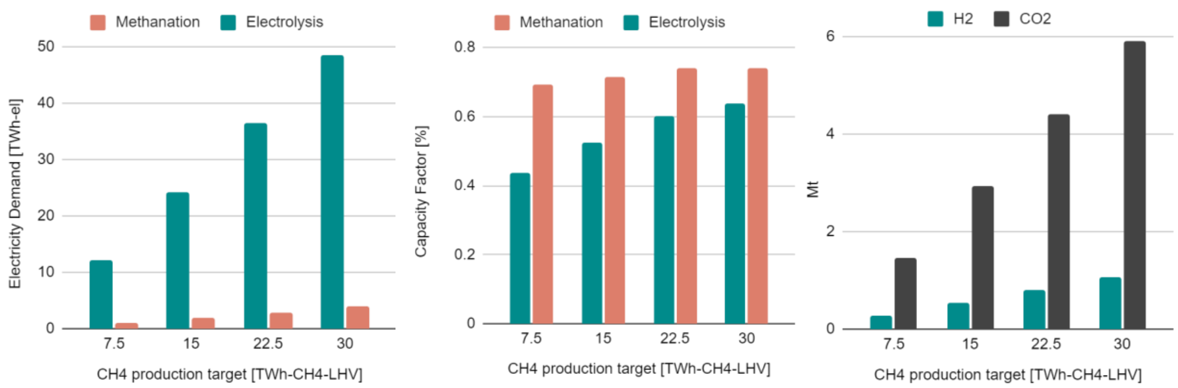

Figure 35: Electricity demand (left) and capacity factor (center) of methanation and electrolysis in the scenarios with the annual CH4 production target. H2 and CO2 requirement for the methanation (right).

Box 3*: CO2 availability in Switzerland*

In 2018, Switzerland emitted 46.4 Mt of CO2-equivalents, with transport being the most emitting sector (15 MtCO$_{2eq}$), followed by industry (12.4 MtCO$_{2eq}$) and buildings (12.3 MtCO$_{2eq}$).[i] For 2050, the Swiss Federal Office of Energy (SFOE) expects the mobility and heating sectors to reduce their emissions entirely, mostly due to electrification. Also, emissions from industry processes are driven down to 7 MtCO$_{2eq}$. Within industry sectors, the largest emitters will stay the waste incineration with 3.6 MtCO$_{2eq}$ and cement production with 2.4 MtCO$_{2eq}$. However, for both sectors, the carbon should be captured and either stored or utilized. As there is biogenic carbon in waste and cement production, capturing the carbon could provide negative emissions. In total, the SFOE expects Switzerland to emit 12 MtCO$_{2eq}$ but capture 7 MtCO$_{2eq}$, including 2 MtCO$_{2eq}$ negative emissions. The remaining emissions are planned to be offset abroad.

Storing a large share of the captured emissions will likely become central for the decarbonization in Switzerland. Whereas the technologies for capturing are already available, one major bottleneck will remain the collection and transport of large volumes of CO2 across Switzerland and Europe. As for the planned amount of captured carbon, conventional transport mode would require an unrealistic amount of daily shipments (≈1000 trucks/day, 11 barges/day, and 450 rail cars/day), the need for a CO2 pipeline network becomes evident. After collecting, the CO2 could

[65] https://doi.org/10.1016/j.apenergy.2019.113594

be transported via pipelines to Rotterdam and further shipped to the Northern Lights Project. Costs for collecting, transporting, and storing CO2 are expected to be around 100 CHF/t-CO2. [iii]

An alternative to transporting the CO2 from Switzerland to Northern Europe would be to utilize the captured carbon (e.g., to produce e-methane) in Switzerland as well as capturing and storing CO2 in Northern Europe (close to a large-scale storage).

i: Energieperspektiven 2050+
ii: Forschungskonzept des Bundesamtes für Energie zu CO2-Entnahme und Speicherung für die Periode 2023 – 2028, 2023, BFE, https://www.bfe.admin.ch/bfe/de/home/forschung-und-cleantech/forschungsprogramme/ccus-net.html
iii: SusLab, https://www.suslab.ch/potential-for-co2-collection-infrastructure

4.4.3.Discussion

Our results outline an LCOH of 1-6.7 CHF/kg-H2 in Switzerland if a certain production target is mandated. This price range matches with what other studies project for LCOH in Switzerland (e.g., 5.3 CHF/kg-H2 in EP2050+, 2.9 CHF/kg-H2 in EZ2050, 3.95 CHF/kg-H2 in Polynomics[66]). The LCOH depends heavily on electricity purchase prices, electrolyzer investment costs, and regulation, especially the grid usage fees. In our scenarios, electrolyzers are operated with average electricity prices of 11-53 CHF/MWh-el. Due to pronounced price variations over the year, our model suggests an optimal utilization of the electrolyzer at 24-33 percent (2100-3200 h). As shown in the less optimistic scenarios, grid fees could heavily affect the economics of electrolyzers. Whether electrolyzers in Switzerland will actually need to pay the grid fee is still open. According to the current interpretation of the "*Mantelerlass*", grid fees are waived in two cases: The first 200 MW (≙10-20 kt-H2) of electrolyzer capacity in Switzerland are exempted from the grid fee, intending to promote the expansion of hydrogen production. Furthermore, operators of electrolyzers get the grid fees reimbursed if they re-convert the produced hydrogen into electricity (for example via a hydrogen power plant) and subsequently feed the electricity into the grid, i.e. if the electrolyzer and the hydrogen power plant are operated as a storage.

The costs to ultimately supply hydrogen to end-customers, e.g., industry or transport, are substantially higher than the LCOH, ranging from 2.8 to 8.6 CHF/kg-H2, adding 1.8-1.9 CHF/kg-H2 to the levelized cost. The higher prices are mainly due to distributing and buffering hydrogen so that it can be provided to the customer when needed. Please note that we assume that distribution costs are independent of how much hydrogen is produced in Switzerland. However, distribution costs might be substantially higher, especially during the potential uptake of hydrogen production in Switzerland or when hydrogen generation generally remains limited. A distribution system for a small amount of hydrogen would likely be based on transportation via lorries rather than pipelines. Companies developing their net-zero plans need to consider the costs of hydrogen supply, not the LCOH. Ultimately, these companies' willingness to pay for hydrogen must be higher than the supply costs.

For e-methane, our results show LCOeM ranging from 84-263 CHF/MWh-CH4, which is in range of what previous studies projected (e.g., 98 CHF/MWh-Ch4 in EZ2050, 40-170 CHF/MWh-CH4 by Gorre et a., 2019[67]). The LCOeM depends – similar to the LCOH – heavily on electricity purchase prices, electrolyzer investment costs, and grid usage fees. On top, however, the type of hydrogen storage available and the type of emission-neutral CO2 sourcing for the methanation are important price drivers.

[66] https://e-bridge.de/portfolio-items/wasserstoff-in-der-schweiz-diese-rahmenbedingungen-braucht-es-jetzt/
[67] https://doi.org/10.1016/j.apenergy.2019.113594

Hydrogen storage is cost-effective for methanation because it allows the expensive methanation plus DAC units to run for more hours of the year and thus achieve a higher utilization – whereas electrolyzers can still run in low-price hours. In our scenarios, DAC units provide the required CO2. Alternatives to DAC could be carbon cycling[68] or the use of domestic biogenic CO2 of which 2 Mt is expected to be available in Switzerland. As producing 1 TWh of e-methane requires roughly 0.2 Mt of CO2, alone with the domestic biogenic CO2 ,10 TWh of e-methane could be produced annually in Switzerland.

E-methane supply costs range from 129-313 CHF/MWh. While we assume that e-methane can be buffered in existing gas infrastructure and thus no e-methane storage is required, distribution costs must also be considered, which have historically been for methane at around 45-50 CHF/MWh-CH4.

Comparing the supply of hydrogen and e-methane based on their LHV, e-methane (129-313 CHF/MWh-LHV) seems more expensive than hydrogen (84.1-258.3 CHF/MWh-LHV). However, the distribution system for methane already exists, whereas the one for hydrogen has to be built up. Without the distribution costs for e-methane, the supply costs for the two energy carriers would be very similar.

[68] https://doi.org/10.1016/j.apenergy.2019.113594