Techno-Economic Assessment of Feedstock and Supply Chain Potential of Power-to-X Fuels in Switzerland

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Executive Summary

As fossil reserves start to dwindle and countries committing to rapidly reducing their carbon emissions to mitigate catastrophic global warming scenarios, finding solutions for the decarbonization of the energy sector has been a top priority for governments, industry, and the scientific community. While electrification will to play a dominant role in the energy transition by decarbonizing large emissions sectors such as personal mobility and residential heating, Power-to-X (PtX) fuels, including green hydrogen (H_2) along with its derivatives ammonia (NH_3), methane (CH_4), methanol (CH_3OH) and *Fischer-Tropsch* fuels ($C_{16}H_{34}$), can provide a scalable solution for the indirect electrification of “hard-to-abate” sectors, for which there is no suitable direct electrification option.

The increasing demand for PtX fuels in the coming decades will necessitate vast amounts of renewable electricity for their production. For countries with a limited potential for domestic renewable energy generation, meeting this rising demand may hinge on the import of such fuels from renewable-rich exporters. To gain an understanding of the role PtX fuels will play in Switzerland’s future energy mix, as well as assessing their available supply options along economic and environmental criteria, the Swiss Federal Office of Energy (SFOE) has commissioned a research project at the Paul Scherrer Institute (PSI) called “Sustainable cHEmicaL Transport fuEls foR SwitzErlanD (SHELTERED)”. This thesis forms part of the SHELTERED project and focuses on identifying the available feedstock and supply chain options for PtX fuel supply in Switzerland, as well as evaluating their economic viability.

The first part of this thesis is dedicated to the identification of the major future exporters of PtX fuels. To achieve this, a comprehensive assessment framework has been developed, which serves as a systematic tool to evaluate countries’ potential of developing significant PtX fuel export capacities. The framework is based on a set of nine key criteria considering environmental, institutional, and industrial aspects. Each criterion is supported by quantitative assessment parameters, providing an objective basis for the determination of a country’s export potential and enabling a direct comparison between different exporters. Data pertaining to these assessment parameters has been gathered for 49 countries across 7 world regions, offering a broad global perspective and establishing a strong foundation for the subsequent identification of PtX fuel exporters. Furthermore, a qualitative perspective is provided through a critical analysis of recent industrial and political advancements within each world region, providing in-depth insights into the current state and future trajectory of the global PtX fuel industry. Based on the results of the quantitative and qualitative assessments, as well as considering the current political and scientific consensus on the topic, one major exporter for each world region has been identified (see *Figure 1*). All identified countries share crucial common traits required for successful PtX fuel export, such as an abundant renewable energy potential, vast open land areas for the realization of large-scale projects, a robust local infrastructure, decent political stability, and strong government support for PtX projects.

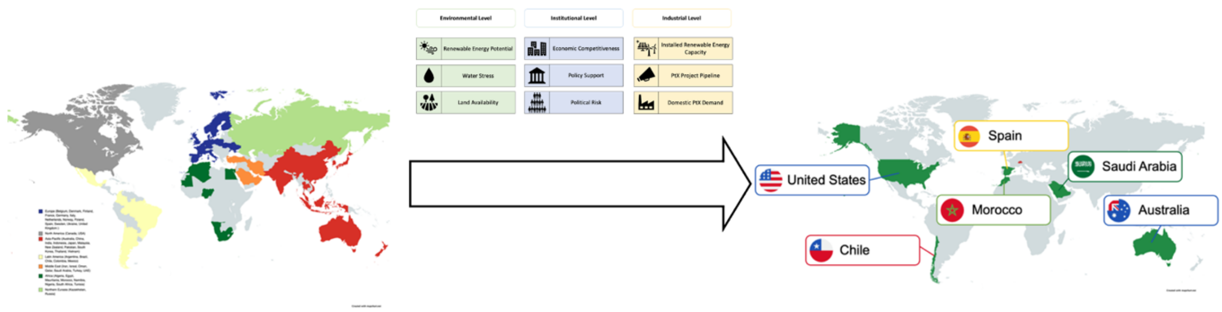

Figure 1: Overview of the conducted PtX fuel exporter assessment.

The second part of this thesis consists of a techno-economic assessment of the PtX fuel supply options available for Switzerland, projecting their cost development up to the year 2050 (see *Figure 2*). To determine the delivered cost of PtX fuels in Switzerland, country-specific production and subsequent import costs have been determined for the identified exporting countries and compared to domestic production in Switzerland.
This assessment entails the modeling a large-scale standalone PtX production facility, encompassing modular simulations for each specific process step. Each process has been comprehensively analyzed to determine the crucial operational and cost parameters, considering country-specific inputs for crucial variables. The electricity model considers standalone solar PV and onshore wind set-ups, as well as a hybrid system consisting of both wind and solar. To bridge the disconnect between a fluctuating power supply and more consistent power demands, battery energy storage capacity is employed to varying degrees. While the fuel production processes are assumed to operate continuously, the electrolyzer systems exhibit varying degrees of operational flexibility. While proton exchange membrane electrolyzers (PEME) can adapt to a flexible electricity supply, consuming electricity as it is generated, alkaline and solid oxide electrolyzers (AE and SOE) only adjust their operation within a limited range, requiring a constant baseload of electricity. To accommodate these differences, three distinct electricity supply scenarios with varying degrees of consistency have been considered. Heat integration is modeled throughout the production facility, with recoverable waste heat from the electrolyzer and fuel production processes being used for feedstock generation.
To determine the supply chain costs of importing PtX fuel from the respective exporting countries to Switzerland, a comprehensive supply chain assessment model has been developed. This model accounts for both maritime transport of fuels to Europe and their subsequent inland transport to Switzerland. For a comprehensive understanding of the available supply chain pathways, all associated conversion steps, available storage options and major transport methods have been considered.

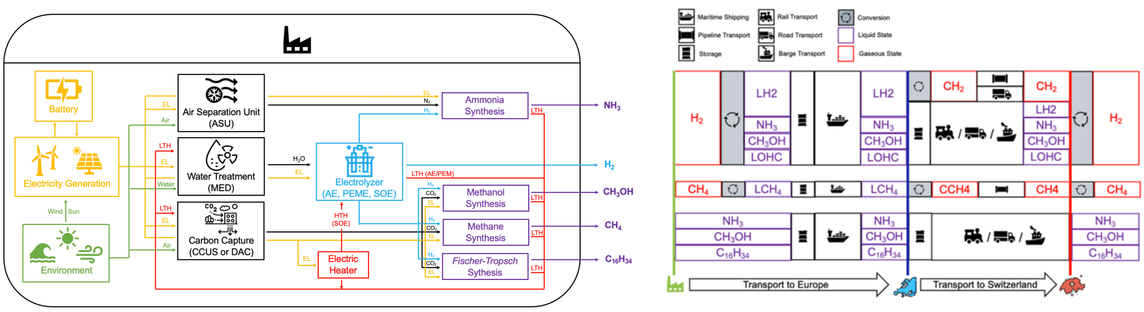

Figure 2: Overview of the techno-economic assessment models for PtX fuel production (left) and their associated supply chains for transport to Switzerland (right).

The determined costs of hydrogen production vary significantly, depending on the regarded electricity generation set-up, electricity supply scenario and electrolyzer technology. The primary cost drivers in the levelized cost of hydrogen (LCoH) are the electricity input and the electrolyzer investment, making a low levelized cost of electricity (LCoE) and a high electrolyzer utilization rate crucial for competitive hydrogen production. Standalone onshore wind systems are able to provide both, making them the premier electricity generation technology for hydrogen production. Standalone solar PV systems are only suitable in fringe cases, as their low-capacity factors lead to suboptimal electrolyzer utilization. The considered hybrid systems were handicapped with lower capacity factors for wind and solar, due to assumed trade-offs in site selection. Nevertheless, they showed to be especially suitable in cases where a constant electricity supply was necessary, making use of complementary feed-ins. Generally, increasing the utilization rate of the electrolyzer by adding battery capacity to the system did not turn out as an economic option, as the resulting increase in the LCoE outweighed the achieved electrolyzer cost reductions. Therefore, PEME systems were able to achieve the lowest LCoH, as their ability to operate on a flexible electricity supply allows them to profit from lower LCoE than AE and SOE systems.

In 2023, optimal production set-ups achieve LCoH between 3.7-5.4 CHF/kgH_2 in the considered exporting countries, while domestic production in Switzerland is more expensive at 6.5 CHF/kgH_2. In the base case scenario, by 2050, LCOH are anticipated to drop to 1.4-2.2 CHF/kgH_2 for exporters and 2.4 CHF/kgH_2 for Switzerland, based on significant decreases in the cost of renewable electricity generation and electrolysis systems. The cost structure of the remaining PtX fuels is largely dominated by their hydrogen input costs, with only minor contributions from additional feedstock generation and fuel production processes. In 2023, production costs of 2.7 CHF/kgCH_4, 0.9 CHF/kgNH_3, 1.1 CHF/kgCH_3OH and 2.5 CHF/kg$C_{16}H_{34}$ can be achieved, with similar reduction potentials as observed for hydrogen. Country-specific variations in production costs stem primarily from differences in the underlying LCoE, which result from differences in the regional renewable energy potentials and investment costs for electricity generation systems. The country-specific cost of capital is another key component in explaining regional variations, as it has a strong influence on the levelized cost of all capital-intensive renewable energy technologies. The lowest PtX fuel production cost is achieved in Australia, closely followed by Chile and the United States, all profiting from extremely favorable wind potentials coupled with favorable financing conditions.

As the transport of ammonia, methane, methanol and *Fischer-Tropsch* fuels is well established, with proven global supply chains, import costs represent only a minor component of the total delivered cost in Switzerland for these fuels. Importing hydrogen is much more expensive, mainly due to the costly conversion processes required to facilitate its transport. Consequently, supply chain costs account for a significant part of its delivered cost in Switzerland. For overseas exporters, shipping hydrogen in the form of ammonia appears to be the most viable option, with transport as methanol or using liquid organic hydrogen carriers (LOHC) being marginally more expensive. Liquid hydrogen shipping is the most expensive option, as in addition to the expensive liquefaction step high transport and storage costs are incurred, caused by handling issues, cooling requirements, and boil-off losses. For regional exporters, pipeline transport emerges as an attractive transport option due to the absence of costly conversion processes.

Considering a scenario where an extensive hydrogen pipeline system equivalent to the proposed European Hydrogen Backbone (EHB) is available in Europe by 2030, hydrogen imports from regional exporters achieve the lowest delivered cost at 3.6 CHF/kgH_2. However, constructing such a system in just a few years will require massive investment and decisive political action, making its realization far from certain. In a scenario without a EHB, imports from overseas exporters become more competitive, as the high fixed cost required for the conversion of hydrogen into a transportable form account for the majority of the overall supply chain costs and are independent of the respective transport distance. In this case, delivered cost of hydrogen would be significantly higher at 4.7 CHF/kgH_2 in 2030. Due to their low transport costs, the other considered PtX fuels are usually cheapest to import from the exporters with the lowest production costs, namely Australia, Chile and the United States.

In conclusion, although significant cost decreases in both production and transport of PtX fuels are expected, it will likely take decades until the achieved delivered costs are competitive with their fossil-based equivalents. Both the scale and pace of the expected cost reductions are closely linked to the rate of adoption and associated demand increase for PtX fuels, around which there currently remains a lot of uncertainty. As renewable electricity will be in short supply over the coming decades and PtX fuels show relatively poor roundtrip efficiencies, it is likely that electrification will be the preferred option for many decarbonization solutions. In cases where PtX fuels are indispensable, imports will likely be necessary for Switzerland due to its limited renewable energy potential and high domestic production costs. Both the ideal exporting countries, as well as the resulting delivered costs of hydrogen, will largely depend on the availability of a European pipeline system for its transport. While Swiss influence on whether such a project materializes will be limited, ensuring the country's access in case it is does get built will be crucial.

Acknowledgements

"If I have seen further, it is by standing on the shoulders of giants"

(Newton, 1675)

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I would like to thank Christian Bauer and Zipeng Liu from the Technology Assessment Group at PSI for their guidance and support while getting introduced to the SHELTERED project and the research field on low-carbon fuels as in general, which allowed me to understand the bigger picture my work is contributing toward. I also want to thank them for their invaluable expertise and constructive feedback which have been instrumental in shaping the direction and quality of this work.

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Abbreviations

Institutions

IEA	International Energy Agency
IRENA	International Renewable Energy Agency
PSI	Paul Scherrer Institute
US DOE	United States Department of Energy
US EIA	United States Energy Information Agency
UZH	University of Zurich
VSE	Verband Schweizerischer Elektrizitätsunternehmen
WEF	World Economic Forum

Financial Parameters

CAPEX	Capital Expenditure
OPEX	Operating Expenditure
REPEX	Replacement Expenditure
WACC	Weighted Average Cost of Capital
CRF	Capital Recovery Factor
LCoE	Levelized Cost of Electricity
LCoW	Levelized Cost of Water
LCoC	Levelized Cost of Carbon Dioxide
LCoN	Levelized Cost of Nitrogen
LCoH	Levelized Cost of Hydrogen
LCoX	Levelized Cost of PtX Fuel

Production Processes & Equipment

AE	Alkaline Electrolysis
SOE	Solid Oxide Electrolysis
PEME	Proton Exchange Membrane Electrolysis
CC	Carbon Capture
DAC	Direct Air Capture
ASU	Air Separation Unit
BESS	Battery Energy Storage System
BtX	Biomass-to-X
PtX	Power-to-X
PtL	Power-to-Liquids

Chemicals

H_2	Hydrogen
N_2	Nitrogen
CO_2	Carbon Dioxide
H_2O	Water
NH_3	Ammonia
CH_4	Methane
CH_3OH	Methanol
$C_{16}H_{34}$	*Fischer-Tropsch* Fuels (based on average carbon chain length)

The "Colors of Hydrogen"

Black	Produced from Coal via Coal Gasification
Grey	Produced from Natural Gas via Steam Methane Reforming
Blue	Produced from Natural Gas via Steam Methane Reforming with Carbon Capture
Turquoise	Produced from Natural Gas via Methane Pyrolysis
Pink	Produced from Nuclear Electricity via Water Electrolysis
Yellow	Produced from Grid Electricity via Water Electrolysis
Green	Produced from Renewable Electricity via Water Electrolysis

Countries & Regions

SAU	Saudi Arabia
ESP	Spain
CHE	Switzerland
USA	United States of America
CHL	Chile
AUS	Australia
MAR	Morocco
EU	European Union
APAC	Asia-Pacific
GCC	Gulf Cooperation Council (Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and the UAE)
CIS	Commonwealth of Independent States (Russia, Belarus, Armenia, Azerbaijan, Kazakhstan, Kyrgyzstan, Uzbekistan, Tajikistan, Turkmenistan)

Other Abbreviations

IRA	Inflation Reduction Act
EHB	European Hydrogen Backbone

1 Introduction

"Energy is the only universal currency."

(Smil, 2018)

The evolution of the human species has been fundamentally shaped by the way we have learned to harness and transform energy, starting with the discovery of fire in the early stone age (Cleveland, 2009). The more recent industrialization and electrification of our society, and the resulting explosion in both population sizes and living standards, would not have been possible without the cheap and abundant supply of fossil energy over the past two centuries. However, due to the finite nature of fossil resources, as well as the increasingly evident climate and environmental impact that their combustion process incurs, our reliance on them will inevitably need to come to an end. Being able to continue satisfying humanity's ever-increasing demand for energy, whilst at the same time replacing 80% of the current energy supply, is shaping up to be one of the greatest challenges of the 21st century.

By signing the Paris Agreement at COP21 in 2015, 195 countries committed to keep global warming well below 2 °C compared to the pre-industrial period, while "pursuing efforts" to keep it below 1.5 °C (UNFCCC, 2023). As illustrated in *Figure 3*, achieving those goals will require a drastic reduction of greenhouse gas emissions over the next decades, in order to prevent cumulative emissions from rising above tolerable levels. Since their commitment in Paris, many governments have proposed or ratified legislation outlining concrete emission reduction pathways, usually involving a commitment to reaching net-zero emissions by a specific date. In 2021, the European Union (EU) adopted the European Climate Law, a key part of its overarching European Green Deal aimed at transforming Europe into a climate neutral continent by 2050 (EC, 2023a). Switzerland similarly saw voters approve the government's proposed climate law, which defines a binding emission reduction pathway to net-zero emissions by 2050.

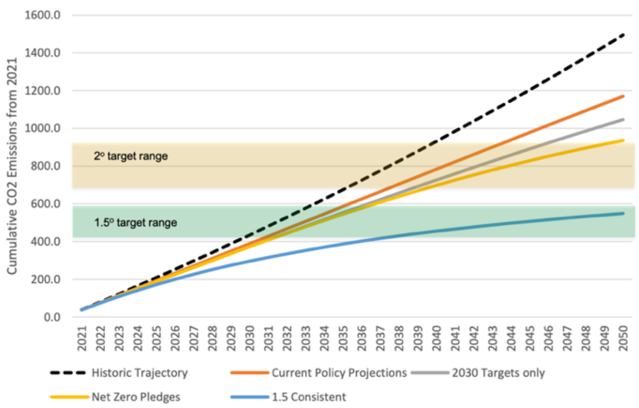


Figure 3: Available carbon budgets to limit global warming to 1.5 or 2 °C, compared to the projected emissions reduction pathways in various scenarios (OIES, 2023).

How such net-zero energy systems are going to be achieved has been subject to intense research and policy discussions in the last decades. While the concrete results of specific studies can vary based on their underlying assumptions or geographic focus, most of them share a few common characteristics, such as a massive rollout of renewable energy capacity combined with intense energy efficiency measures, such as the electrification of personal mobility or residential heating (Azevedo *et al.*, 2021). These trends lead to a significant increase in the share of electricity in the final energy mix, which could rise from the current 20% to over 50% by 2050 (IEA, 2023a). In areas where electrification is challenging given the current technological options, the so called "hard-to-abate" sectors, renewable fuels are expected to play a pivotal role to achieve decarbonization.

Renewable fuels can be either based on biomass (BtX) or renewable electricity (PtX) as their respective feedstock. As biofuels have an inherently limited feedstock base and are subject to intense land use competition (Goldemberg, 2008), PtX fuels have been proposed as a more scalable option. Based on a much more scalable feedstock in the form of renewable electricity, these could provide a convenient solution to indirectly electrify applications in the "hard-to-abate" sectors, such as chemicals production, international shipping or steel manufacturing (see *Figure 4*).

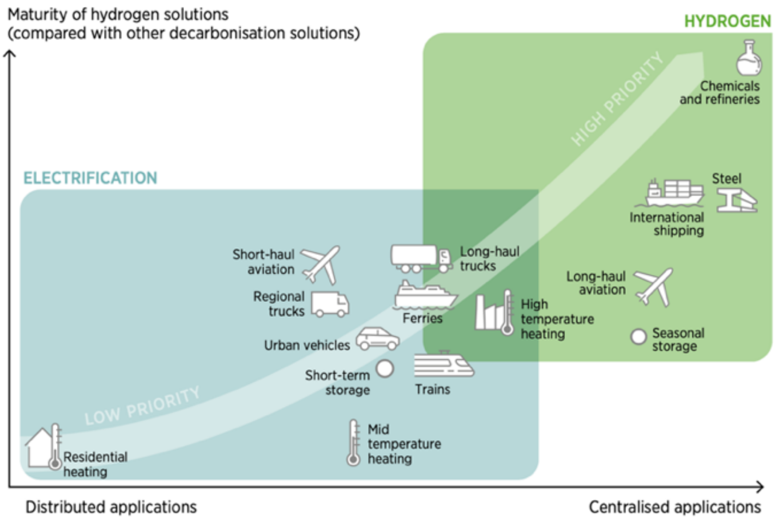


Figure 4: Decarbonization options for different end-use sectors (IRENA, 2022a).

Green hydrogen, which is the most prominent PtX fuel, is produced by the electrolysis of water using electricity from renewable sources, such as solar or wind energy. Through the derivatization of this hydrogen with either nitrogen (N_2) or carbon dioxide (CO_2), other PtX fuels can be synthesized, the most important of which are ammonia (NH_3), methanol (CH_3OH), methane (CH_4) and *Fischer-Tropsch* fuels ($C_{16}H_{34}$)[1]. These provide significant advantages with regard to their handling and storage and can be used as drop-in replacements for their fossil equivalents, enabling a convenient pathway to decarbonize existing assets.

Many studies have tried estimating how big the role of PtX fuels will be in a global net-zero energy system (see *Table 1*). While their resulting projections vary widely, ranging between 300–600 MtH_2, all of them conclude that the future demand will increase significantly from the current levels of 94 MtH_2 (IEA, 2022b). To keep up with such an enormous increase in demand, while also decarbonizing the current production capacities based on natural gas or coal, massive increases in PtX fuel production capacities will be required, along with an even larger increase in renewable energy generation capacity to provide the necessary electricity feedstock.

Virtually every country has access to some form of renewable energy, which has sparked prophecies of a "democratized" energy sector (Casertano, 2012), leaving behind the geopolitical dependencies caused by the asymmetric distribution of fossil fuel reserves around the world. Although a certain regionalization of energy supply is likely (IRENA, 2022a), the significant differences in renewable energy potential between countries, especially when it comes to solar and wind resources, will most likely lead to a new class of energy importers and exporters (Scita *et al.*, 2020). In a decarbonized energy system, PtX fuels have the potential to substitute oil as the medium to facilitate the international flow of energy.

[1] *Fischer-Tropsch* fuels will be abbreviated with $C_{16}H_{34}$ in this study, based on their average carbon chain length (Samsun *et al.*, 2015).

Table 1: Overview of studies on net-zero energy systems and their respective predictions of hydrogen demand in 2050.

Author	**Study**	**Yearly Hydrogen Demand in 2050**	**Share of Final Energy Demand**
(IRENA, 2023a)	World Energy Transitions Outlook 2023 (1.5 °C pathway)	523 Mt	14%
(IEA, 2021a)	Net Zero by 2050	530 Mt	10%
(DNV, 2022)	Hydrogen Forecast to 2050	300 Mt	5%
(Hydrogen Council, 2021)	Hydrogen for Net Zero	660 Mt	22 %
(BNEF, 2023a)	New Energy Outlook 2022 (Net Zero Scenario)	500 Mt	10%

With such monumental changes on the horizon, countries need to figure out how they want to position themselves within the emerging PtX fuel supply chain. With global hydrogen sales projected to be worth up to 600 billion USD by 2050 (FT, 2021), based on a total value chain worth close to 12 trillion USD (Goldman Sachs, 2020), governments are racing to incentivize PtX projects, fighting to attract a slice of this massive developing market, as well as securing supply for their domestic energy demand. While Japan was the only country to have published a national hydrogen strategy in 2017, 36 countries had done so by the end of 2022, with many more expected to follow suit in the coming years (RystadEnergy, 2023a). The focus of such strategies varies significantly, with some countries proclaiming high ambitions with regards to their PtX fuel export potential, while others recognize their resource constraints and focus on securing their supply via imports. Trade talks between such exporters and importers have since started to pick up, with initial plans and agreements starting to reveal a sense of how the future map of energy trade could look like (see *Figure 5*).

In a report analyzing the geopolitical implications of the rise of hydrogen and its derivatives, (IRENA, 2022a) postulates that the shift to a global PtX fuel market is likely to evolve in multiple stages. While the next decade is going to be defined by a race for technology leadership in PtX technologies as well as the achievement of much-needed reductions in production cost, global trading volumes are projected to increase after 2035, once the increased adoption of hydrogen technologies leads to a surge in demand. By 2050, (IRENA, 2022a) expects that one third of the global demand for hydrogen will be transported between countries, either directly via pipeline or shipped in the form of a hydrogen derivative, most likely ammonia.

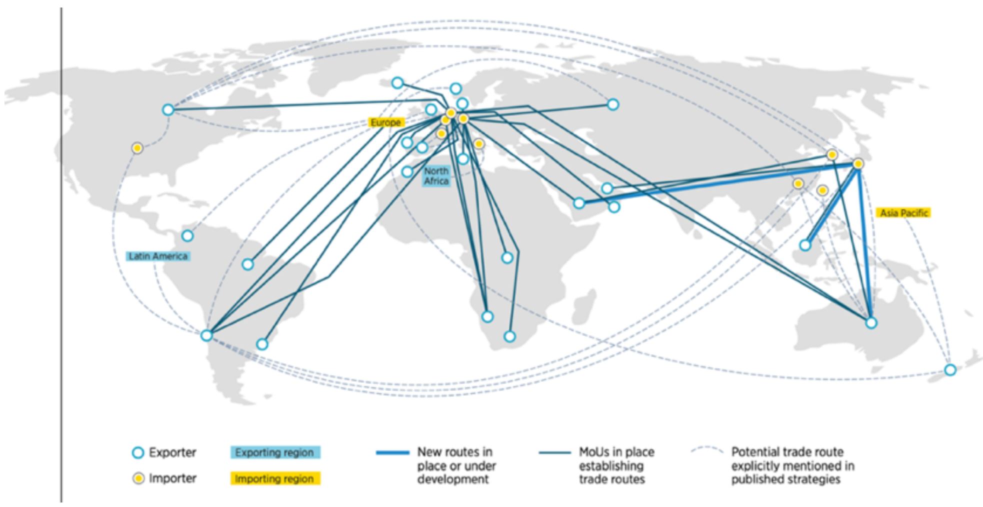


Figure 5: Map showing the developing PtX fuel trade relationships, based on government declarations (IRENA, 2022a).

Switzerland's government has not yet published a PtX fuel strategy, but has promised to follow suit in 2024, as the pressure to do so has increased in recent years (Meier, 2023). A recent study published by the Verband Schweizerischer Elektrizitätsunternehmen (VSE) concludes that hydrogen and its derivatives could provide up to 20% of the Swiss final energy demand by 2050, helping to bridge the energy supply gap during the winter months (VSE, 2022). As the potential for renewable energy generation in Switzerland is limited, and any new capacity additions will likely be needed to substitute the generation capacity that will come off the grid once the remaining nuclear power plants are decommissioned, it is expected that a large part of the required PtX fuels will have to be imported.

To gain a holistic understanding of the role PtX fuels will play in Switzerland's future energy mix, as well as assessing their available supply options along economic and environmental criteria, the Swiss Federal Office of Energy (SFOE) is funding a research project called "Sustainable cHEmicaL Transport fuEls foR SwitzErlanD (SHELTERED)" at the Paul Scherrer Institute (PSI). This thesis is part of the SHELTERED research project and is tasked with determining the available feedstock and supply chain options for PtX fuel supply in Switzerland as well as assessing their economic viability. It aims at doing so by identifying the available import options for Switzerland in a first step, before assessing the levelized cost of such imports, considering both their production and subsequent transport to Switzerland. The varying import options from different exporters will subsequently be analyzed and compared to each other as well as to domestic production in Switzerland. Overall, the comprehensive economic assessment of all available PtX fuel supply options be able to inform policy making decisions on behalf of Switzerland.

In *Chapter 2* of this report, a thorough analysis of potential PtX fuel exporting countries will be conducted and candidates with the highest potential identified. To do this systematically, a comprehensive assessment model will be developed, based on quantifiable assessment criteria considering environmental, institutional, and industrial factors. The developed assessment framework will subsequently be used as a guide to determine the export potential of the major economies around the world. This will be done both quantitatively through the collection of the determined assessment parameters, and qualitatively in the form of a critical analysis of the state of PtX fuel projects and policies in all major world regions. Based on this comprehensive assessment of available candidates, one major exporter per world region will be identified, which will serve as the basis for PtX fuel import modelling in the following chapters.

Chapter 3 will comprise the techno-economic assessment of the determined PtX fuel supply options available to Switzerland, both from imports as well as domestic production. This is achieved through the development of a comprehensive techno-economic assessment model, which can be used to determine the delivered cost of all major PtX fuels produced along various production pathways. This is done by considering different electricity generation technologies, plant electricity supply scenarios, and electrolysis technologies, as well as various supply chain options for the import of these fuels to Switzerland. The results of this analysis are subsequently presented, extracting key takeaways with regards to the most suitable production pathways, important country-specific considerations, and major cost factors, before being comparing the resulting costs to available fossil fuels and outlining some energy efficiency considerations.

Finally, the findings of the techno-economic assessment will be critically analyzed and interpreted in *Chapter 4*, deriving the key conclusions relevant for Switzerland. This section will also discuss how this study aligns with the current field of research and how its scope could be expanded in the future.

2 Assessment of PtX Fuel Exporters

The ongoing shift to a renewable energy system provides immense economic and geopolitical opportunities, especially for countries with abundant renewable energy resources. To capitalize on this potential many countries around the world foster ambitions of becoming the new major energy exporters of the future. As PtX fuels present an opportunity to facilitate this trade and emerge as a new export commodity, many governments have announced bold targets for their domestic PtX fuel production capacity. While some have already followed up those targets with concrete strategies and roadmaps, others have not much more than a nice vision to show for their efforts.

For an energy importing country such as Switzerland, it is crucial to have the capacity to independently assess the viability of potential future exporters, to be able to identify possible trading partners. As recent years have painfully shown, disruptions in energy supply caused by geopolitical events can rapidly lead to energy shortages in energy importing countries, with detrimental effects on their population and industrial development. Therefore, it is crucial that energy exporters are not only assessed based on their available export capacity, but also with regards to various additional criteria to assess their stability and reliability as a potential trading partner.

To provide the tools necessary for a holistic analysis of potential PtX fuel exporters, the following chapter develops a comprehensive assessment framework. It does so by developing a set of assessment criteria along environmental, institutional, and industrial dimensions, defining a set of quantitative parameters along which these can be measured, and collecting these data points for the most important players in the PtX fuel supply chain. In addition to this quantitative assessment, a qualitative analysis provides up to date insights on the current political and industrial trends in every world region.

Based on the developed criteria, the collected data set, and the critical analysis, one major exporter is defined for each world region, and will serve as a model country in the techno-economic assessment of PtX fuel production and transport in subsequent chapters.

2.1 Literature Review

As interest in PtX fuels as important enabling tools for the energy transition has increased significantly over recent years, and the expected reliance of many resource-constrained countries on their import, multiple studies concerned with the identification and assessment of the future exporters have been published. While some of these conduct solely qualitative assessments, others try to compose quantitative methodologies in order to achieve a more objective result. Overall, the general conclusions of such studies are often quite similar, even if the specific countries identified as the best exporters may differ from case to case.

One study by (Pflugmann and Blasio, 2020) analyzed the renewable energy resources, water endowment, and infrastructure potential of different countries to evaluate their suitability for large-scale hydrogen export. They concluded that countries with limited renewable energy resources such as Germany, Japan and South Korea, are likely to remain reliant on significant energy imports, while Canada, Australia, the United States, Indonesia, Mauritania, Mexico, Morocco, Namibia and Norway are deemed ideally positioned to develop into "export champions" (see *Figure 6*). Other countries showing decent export potential include Chile, Colombia, Finland, Spain, Sweden, and Turkey. Many countries in the Middle East and Africa, such as Saudi Arabia, Oman, Egypt and South Africa are held back by their water constraints, even though their renewable energy potential is very favorable. Infrastructure constraints limit the hydrogen export potential in a number of African and South American countries. In addition to the outlined country analysis, the study elaborates on the necessity for potential exporters to establish a favorable policy framework to allow for their emerging hydrogen industry to flourish.

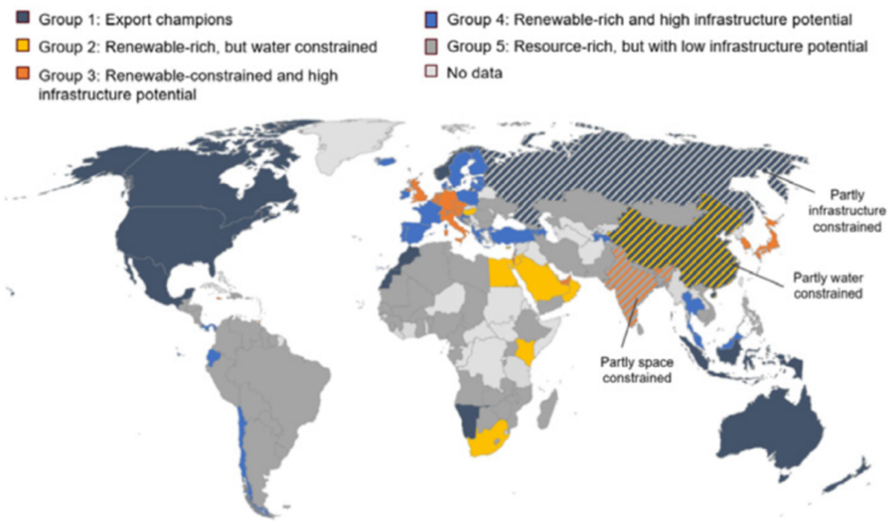


Figure 6: World map showing countries' projected hydrogen export potential (Pflugmann and Blasio, 2020).

A study by *(Anouti et al., 2020)* identified high-yield renewable resources, large areas of barren land, abundant water availability and low domestic hydrogen consumption as the key characteristics of ideal PtX fuel exporters. In their analysis, they identified Argentina, Australia, Canada, Chile and countries around the Persian Gulf, such as Saudi Arabia, Oman and the UAE as the major hydrogen exporters of the future (see *Figure 7*). While they expect major economies such as the US, China and India to significantly ramp up their hydrogen production capacity over the next decades, they also predict the domestic demand in those countries to rise, leading to a self-sufficient supply situation. Similarly to the report by (Pflugmann and Blasio, 2020), countries in Western Europe, as well as Japan and South Korea are identified as the major importers of the future.

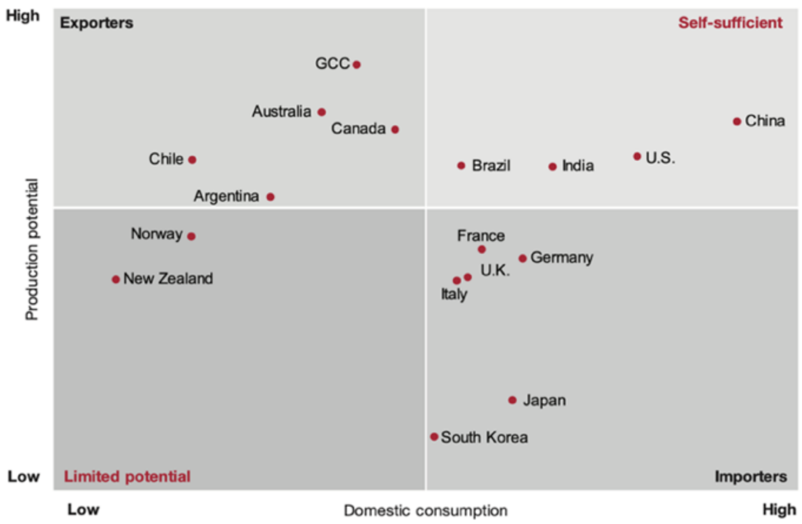


Figure 7: Classification of countries based on their hydrogen export potential (Anouti et al., 2020). GCC stand for Golf Cooperation Council, and includes Bahrain, Kuwait, Oman, Qatar, Saudi Arabia, and the United Arab Emirates.

A report by (Breitschopf *et al.*, 2022) at the Fraunhofer ISI identified future PtX fuel exporters though a quantitative criteria-based assessment, employing a multi-criteria analysis approach. More than 50 indicators were employed, in the categories of natural and technical resources, environmental conditions, infrastructure potential, as well as socio-institutional and economic aspects. Their assessment considered two different time horizons, looking at both the short-to-medium term as well as the long-term perspective. Depending on the time horizon, the mentioned indicators were weighed differently. The quantitative assessment was enhanced by a qualitative, expert-based approach. In conclusion, different groups of potential exporters emerged from the multi-criteria analyses and the expert discussions (see *Figure 8*). Countries that are identified as exporters under all of the utilized approaches are Algeria, Chile, Argentina, Brazil, the UAE, Kazakhstan and South Africa. The multi-criteria analysis approach furthermore identified Australia, China, Saudi Arabia, the US and Egypt as promising candidates for hydrogen export, both in the short- and long-term.

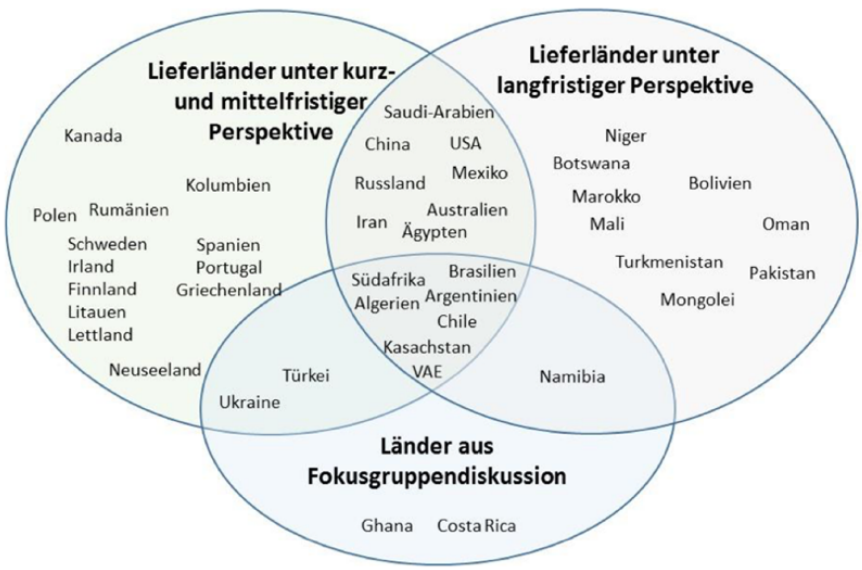


Figure 8: Identification of future hydrogen exporters under different analysis methods (Breitschopf et al., 2022).

In their recent report series on the future of global hydrogen trade, (IRENA, 2022b) modeled emerging hydrogen trade routes assuming an energy demand scenario compliant with limiting global warming to 1.5 °C. Their model focuses solely on technical and economic aspects, although they do mention that "soft" factors, such as energy security considerations, existing trade relationships, and other geopolitical factors will also have a significant impact on the development of hydrogen trade routes. Within their model, they identify Australia, Chile and several North African countries as the main pure exporters of the future (see *Figure 9*). Additional exporters include Italy, Spain, and Colombia. The US, China, India, and countries in the Middle East are expected to be self-sufficient, with the largest importers being similar to those of the previously discussed studies.

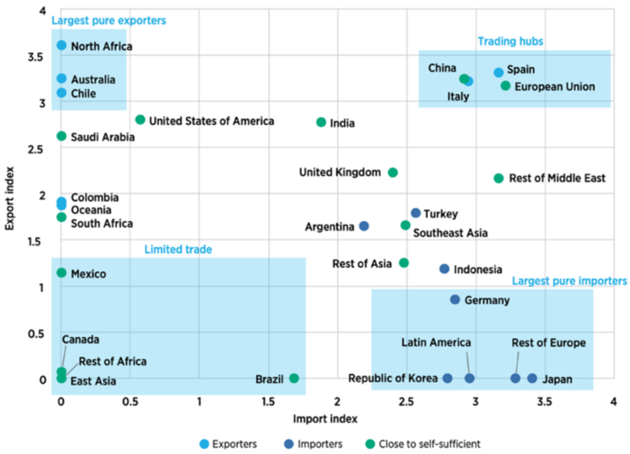


Figure 9: Volumes of hydrogen export and import for world regions in 2050, considering an optimistic scenario with 1.5 °C global warming (IRENA, 2022b).

Although all these studies vary in their approach, the considered assessment criteria, and the specific countries identified as future exporters, several common themes can be identified between them. First and foremost, for a country to become a successful producer and exporter of PtX fuels, a certain number of environmental prerequisites, such as an abundant supply of renewable energy, a water source and vast areas of buildable land, need to be available. Furthermore, a robust economy and well-functioning infrastructure need to be in place to provide the necessary framework within which PtX producers can operate effectively. Finally, a strong policy framework supporting the development of PtX production capacities is vital to support a favorable business case for potential producers, at least in the early stages of the industry's development. When evaluating the countries that were identified as potential future exporters, Australia and Chile are leading many of the rankings, closely followed by Middle Eastern countries, such as Saudi Arabia, the UAE, and Oman, despite water constraints that need to be considered in this region. North America is also expected to emerge as a major exporting region. While Canada was usually preferred in assessments conducted prior to the recent changes in United States' climate policy, the significant impact of recent climate laws has skewed the balance in favor of the US. Africa and South America are generally considered promising regions, most notably Egypt, Morocco, Argentina and Colombia, however their infrastructure competitiveness still needs to catch up. European countries are generally predicted to emerge as PtX importers, although certain exceptions such as Spain and Italy do exist. Of the big economies in Asia, China and India are expected to be largely self-sufficient, while Japan and South Korea will need to rely on imports to satisfy their demands.

It is important to note that while such results can provide valuable insights, they merely provide a static snapshot of a rapidly evolving environment. Factors such as policy developments, technological advancements, as well as geopolitical changes can significantly affect the attractiveness of different countries for developers of PtX projects. It is therefore crucial to continually update the assumptions to ensure that the drawn conclusions remain current and relevant.

2.2 Methodology

Based on the systematic review of exporter analyses found in literature as well as expert inputs from senior researchers in this field at PSI, a set of nine key criteria has been developed which provide a holistic framework for the analysis of potential PtX fuel exporters along environmental, institutional and industrial dimensions (see *Figure 10*). The following section elaborates on these criteria and defines quantitative assessment parameters for each of them, providing a solid foundation for the exporter analysis in the following chapter.

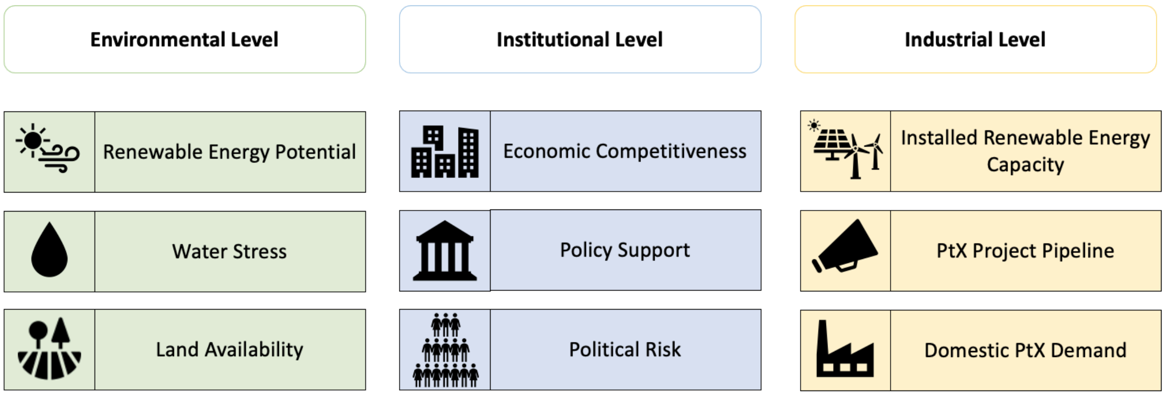


Figure 10: Identified assessment criteria for the evaluation of potential PtX fuel exporters.

2.2.1 Environmental Criteria

Several environmental prerequisites are crucial to enable the successful production of PtX fuels. Being the two major feedstocks for the production of hydrogen, both electricity and water need to be available at the production site, ideally in large quantitates and at low prices. Therefore, the potential for large-scale renewable energy generation as well as a suitable water source are vital criteria to determine a country's suitability for becoming a PtX fuel exporter. Since large-scale PtX production plants, and especially the associated electricity generation facilities, have a large land footprint, the availability of abundant land serves as the third criterion to be considered in the environmental category.

The renewable energy potential of countries can vary significantly and is mainly based on geographic factors such as their latitude, topography, and climate patterns. This study will focus solely on wind and solar energy, as they are the most well established and scalable forms of renewable electricity generation.[2] To determine the solar and wind energy potential of a country, the long-term yearly average global horizontal irradiance and mean wind speed at a height of 100 m were used. As any PtX production facility will most likely be built in an area with favorable renewable energy potential, only the land area in the top 25% of their respective category have been considered. The corresponding data was retrieved from the World Bank's Global Solar Atlas and Global Wind Atlas respectively (Global Solar Atlas, 2023; Global Wind Atlas, 2023).[3]

[2] *Chapter 3.3.1.1* will further elaborate on why this constraint has been implemented.
[3] Only solar irradiance data, below the 60^{th} north parallel is available in the Global Solar Atlas. Therefore, certain areas of Canada, Norway, Sweden and Russia have not been included in the reported data. For Finland, which lies almost exclusively above the 60^{th} parallel, no data was available. As the solar potential in this region is very limited anyway, this lack of data was deemed acceptable.

To determine the water availability in each country, an overview of water stress levels by (IRENA, 2022a) was utilized (see *Figure 11*). This data focuses on freshwater stress, therefore high water stress levels do not automatically disqualify a region from large-scale PtX fuel production. If the country has access to seawater, desalination serves as a suitable alternative to provide a water feedstock, as this process only contributes around 2% of the final production cost of green hydrogen (Blanco, 2021).

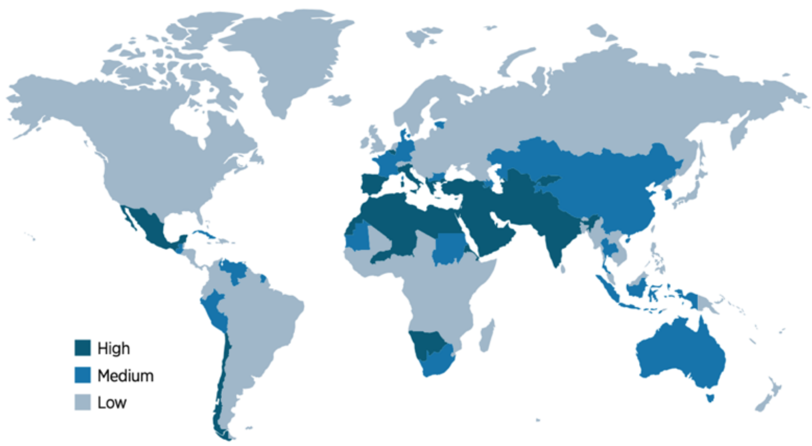


Figure 11: Overview of worldwide water stress levels (IRENA, 2022a).

The large-scale rollout of renewable energy generation will likely result in increased land use competition, a trend that has previously been seen with the utilization of biomass as an energy resource (van de Ven *et al.*, 2021). In order to prevent such negative externalities with regards to the PtX fuel production, the required facilities should ideally be built on barren or sparsely vegetated areas, as to minimize impact on food security and disruption of ecosystems. The availability of such areas has been assessed by using land cover statistics published by the United Nation's Food and Agriculture Organization (FAOSTAT, 2023). Although the focus was chosen intentionally narrow when considering the types of land area deemed acceptable for the construction of PtX facilities, it will likely also be possible for such facilities to be built on areas with existing vegetation or previous usage. Furthermore, it is important to consider that not all barren or sparsely vegetated areas will be suitable for such projects, due to terrain requirements or lacking renewable energy potential.

2.2.2 Institutional Criteria

For an emerging industry such as the production of PtX fuels to flourish, a favorable institutional framework is indispensable. To determine whether such an environment is given in a potential exporting country, the competitiveness of their domestic economy will be analyzed, together with the available policy support measures for PtX fuel projects, and the intrinsic political risks associated with doing business in those countries.

Economic competitiveness is a criterion intended to measure the ease of doing business in a country, referring to the overall simplicity and efficiency with which a business can establish and operate in the given economic environment. There are several indices measuring the competitiveness of economies around the world, such as the World Bank's "Doing Business" report series, IMD Business School's "World Competitiveness Ranking" and the "Global Competitiveness Index" published by the World Economic Forum (WEF). Such rankings analyze countries along several economic indicators, such as macroeconomic factors, governmental and institutional efficiency, as well as the availability of talent and infrastructure. Although such rankings can provide a good starting point to assess a country's economic competitiveness, it is important to keep in mind that the choice and weighting of specific indicators can significantly influence the outcome of the result, opening the door for subjectivity and bias. Additionally, as data availability varies greatly among different countries, making comparisons between them can prove to be difficult. As both the Global Competitiveness Index and Doing Business Report series were discontinued after 2019 and 2020 respectively, IMD's ranking published in 2023 provides the most up-to-date data for this category (IMD, 2023). Since the IMD Ranking only includes 64 countries, lacking data on many Middle Eastern and African countries relevant to this study, the Global Competitiveness Index of 2019 was additionally considered (WEF, 2019). With a few minor exceptions, the scores of the two reports are quite complementary, further increasing the validity of the obtained results.

Policy support plays a crucial role in the development and growth of the PtX industry, especially in its nascent stages. Demand creation and direct subsidization of supply are powerful levers with which governments can foster its development. For this study, the availability of a hydrogen or PtX strategy in a specific country, as well as the ambition of the stated production capacity goals are regarded as a proxy for the level of governmental support for such initiatives. Data on the availability of a hydrogen strategy as well as its declared goals is obtained either from (IRENA, 2022b), (RystadEnergy, 2023) or (BNEF, 2023b), and adjusted where necessary by consulting published hydrogen strategies directly (see *Figure 12*).

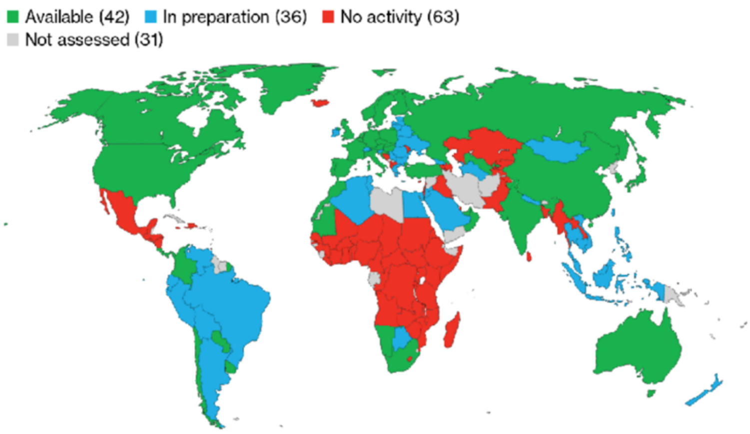


Figure 12: Published or announced hydrogen strategies as of February 2023 (BNEF, 2023b).

As strategies and roadmaps are more easily published than executed, the creation of an ambitious targets alone does not ensure governments will actually follow up with concrete actions to reach them. To get a measure of government's willingness to "put their money where their mouth is" when it comes to the clean energy transition, the level of historic subsidies for green energy projects must be considered. As the actual value of subsidies can be rather difficult to estimate, normalized data from the Energy Policy Tracker was consulted for this purpose (Welker *et al.*, 2023). This data can serve as a representative measure of the funding available for clean energy projects in a specific country, however certain limitations must be considered. First, only policies that were newly passed or updated between 2020–2021 are included in the data, omitting already existing measures and support programs. Furthermore, as the data collection only reaches until the end of 2021, key pieces of legislation that have passed since, such as the Inflation Reduction Act, are not included. Finally, only 38 economies were analyzed, resulting in a lack of data for the rest of the countries considered for the exporter analysis. However, as all the G20 countries and other major economies are considered, it can be expected that the major sources of subsidies available for green energy projects were included.

As the final criteria in the institutional category, the political risks associated with importing PtX fuels from specific exporters need to be examined. As events in recent years have shown, geopolitical factors have a growing influence on global supply chains. From Russia's invasion of Ukraine to the increasing tensions and associated trade restrictions between the United States and China, the global market has become more uncertain than in previous decades (The Economist, 2022). In a time when the "de-coupling" and "de-risking" of critical supply chains are at the top of Western government's minds, selecting trading partners that share similar political systems and values has become more important. To account for this development, the level of democracy of potential exporters is considered in this study. For a reliable measure of this, the Economist's 2022 Democracy Index was consulted, which determines the level of democracy of countries' regimes based on categories such as their electoral process, government functioning, political participation, and civil liberties (see *Figure 13*).

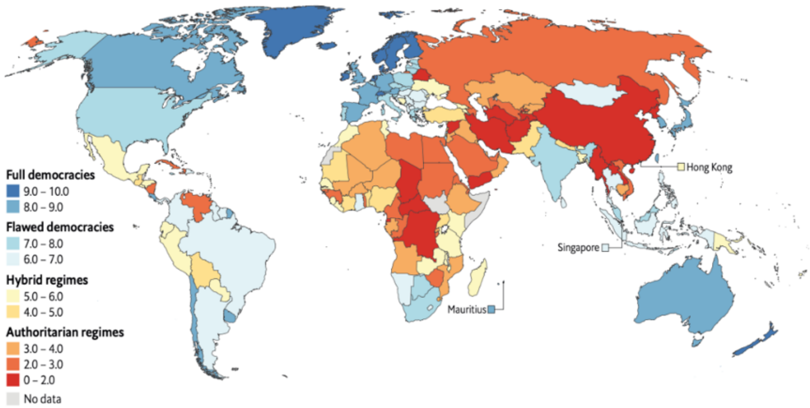


Figure 13: Map of the different regimes around the world (Economist Intelligence, 2023).

A second indicator to determine the level of political risk associated with an exporting country is its level of peacefulness. A low possibility of conflict increases the reliability of an exporter, and is more successful in attracting investment. The Global Peace Index 2023 serves as a measure to determine the peacefulness of the analyzed countries. It is developed by the Institute for Economics and Peace (IEP) and uses qualitative as well as quantitative indicators to measure the "state of peace" along the domains of societal safety and security, ongoing domestic and international conflicts, and the degree of militarization in the country (IEP, 2023).

2.2.3 Industrial Criteria

On an industrial level, the state of a country's pre-existing clean energy sector is closely examined, to determine whether the industrial prerequisites are favorable to clean energy development as well as the country's previous success in attracting investment in this area. To determine this, the level of current and projected installed renewable energy capacity as well as the current pipeline of announced PtX projects are regarded. To determine whether a country will be able to achieve an excess production capacity in addition to its local demand, the projected PtX fuel demand in its region will be analyzed.

The installed renewable energy capacity and its projected development is an important measure to determine how far along countries are in developing their clean energy sector. As most governments have ambitious targets for the decarbonization of their electricity mix in the medium, and the whole energy system in the long term, it is unlikely that existing renewable energy generation infrastructure can be accessed to produce PtX fuels. More likely, dedicated renewable energy generation will have to be constructed for PtX projects. This assumption falls in line with the European Commission's additionality principle (EC, 2023d), according to which PtX projects are only considered renewable if they are connected to newly constructed renewable power generation capacity. Nevertheless, the amount of previously installed renewable energy generation indicates the industry's maturity and therefore how efficiently such projects can be carried out in the future. Data for the installed renewable energy capacity in each country was obtained via IRENA's 'Renewable Energy Statistics 2023' report (IRENA, 2023b), and the projected renewable energy capacity in 2027 is based on the IEA's 'Renewables 2022' report (IEA, 2023b).

The existing pipeline of PtX fuel projects in a country is an important indicator to evaluate how attractive PtX developers and investors currently deem a specific country. Furthermore, successfully established projects might catalyze further investment, as the local industry and infrastructure will already be established, and successful use cases will strengthen investor confidence. The IEA keeps a database of the PtX project pipeline at all stages of development, from the concept stage to operational facilities (IEA, 2022c), which will be used in this assessment. As announcements of gigawatt scale projects, which are often far away from a final investment decision, can inflate the projections for certain countries, the reported totals should be taken with a grain of salt, and the specific project announcements might need to be considered for an in depth understanding.

As a last criterion, the projected regional demand for PtX fuels is taken into consideration. Only countries with significant excess production capacity compared to domestic demand can consider exporting them. The demand is analyzed on a regional basis, as potential exporters will likely prioritize importers in their geographic proximity, to cut down on transport costs and complexity. To determine the regional PtX fuel demand in 2050, a Rystad Energy analysis is used, which predicts a global hydrogen demand of 300 Mt in 2050, with the main demand centers being Asia, followed by Europe and America (see *Figure 14*).

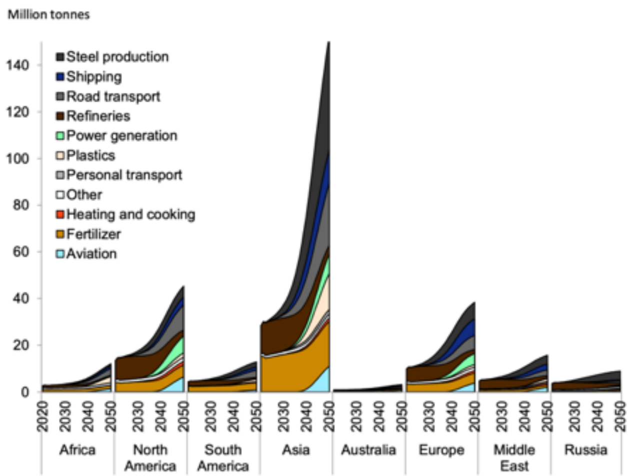


Figure 14: Projected hydrogen demand in 2050 by world region and industry (RystadEnergy, 2023a).

2.3 Exporter Analysis

The developed assessment criteria now serve as the basis for the analysis of the PtX fuel export potential of 49 countries distributed across seven world regions (see *Figure 15*). This assessment has been divided into a quantitative and a qualitative section, both approaching the topic from a different angle to achieve a comprehensive overview of the current state and future trajectory of global PtX fuel export potentials.

Quantitative data was gathered for each of the previously defined assessment parameters, and the outcomes of this analysis are presented in *Tables 2–8*. The collected data serves as a solid quantitative foundation to inform the subsequent exporter identification. Furthermore, it provides a valuable data resource for future research in this field, such as a weighted analysis of the assessed countries, aggregating the data points into a single score system to yield a global ranking of exporters. Such an analysis has not been pursued within this thesis, as it would come at the expense of work on the techno-economic assessment model.

The acquired raw data is subsequently complemented by a qualitative analysis focused on providing a snapshot of the current state and possible future developments of the PtX fuel industry around the world. This analysis is focused on the main players in the future of the global PtX trade, giving a detailed insight into their recent industrial and political developments in this regard and analyzing how these might affect their future position in the emerging PtX fuel supply chain.

Based on the results from the quantitative and qualitative assessments, as well as the current consensus in literature and policy-making circles, one main exporter from each of the considered regions will be selected to serve as a model country for the techno-economic assessment of PtX fuel production and supply chains in the following chapter. This geographic distribution criteria has been implemented in order to gain a generalizable understanding of the regional differences that need to be considered with regards to PtX fuel production as well as their subsequent import to Switzerland. This approach allows for the resulting techno-economic assessment model to be continually expanded to more countries of interest.

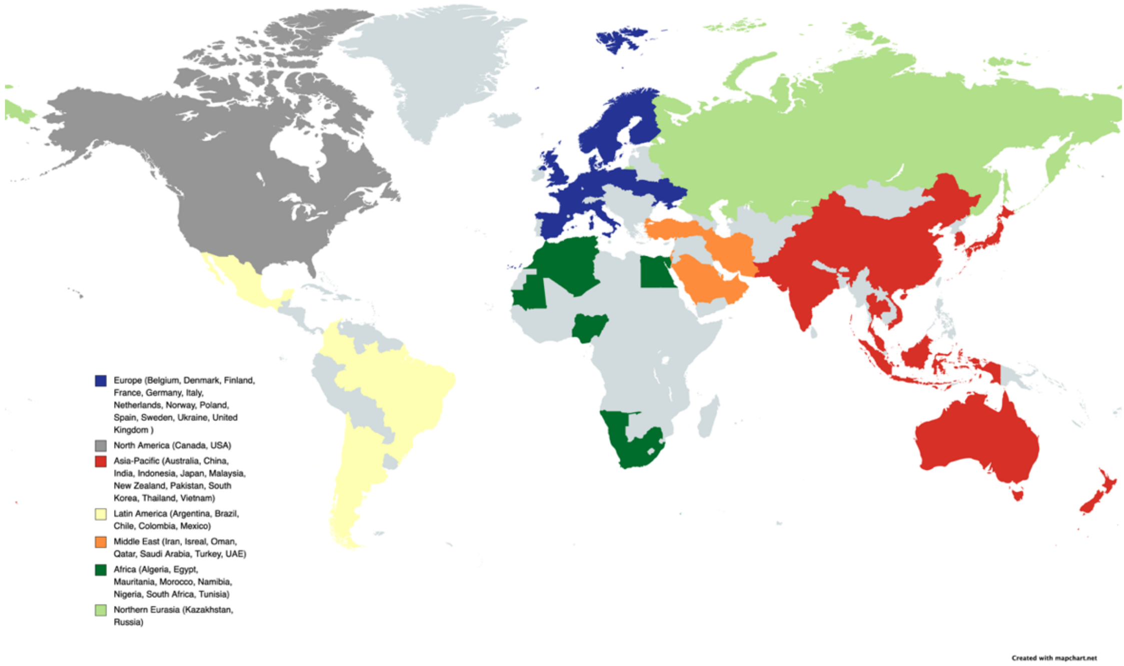


Figure 15: Map of countries assessed as part of the exporter analysis.

2.3.1 Quantitative Assessment Parameters

The quantitative exporter analysis consisted of the collection of data according to the defined assessment framework. In total, 13 data points along the 9 defined assessment criteria were collected for each country and are summarized in the following tables. As previously mentioned, the collected data could be weighted and used to determine a normalized score, providing a quantitative measure for a country's export potential. Due to time constraints, such an analysis has not been included in this thesis.

Table 2: Exporter Analysis data for Europe sorted by environmental (green), institutional (blue) and industrial (yellow) criteria.

Country	**Barren and sparsely vegetated land area [km^2]**	**Average Global Horizontal Irradiance [W/m^2]**	**Mean Wind Speed [m/s]**	**Freshwater stress**	**Sea Access**	**Global Competitiveness Rating**	**National Hydrogen Strategy (2030 Goal)**	**Public Money support for clean energy in 2020/ 2021 [billion USD]**	**Regime Type**	**Level of Peace**	**Installed Renewable Energy Capacity (Solar, Wind, Hydro) [GW_{el}]**	**PtX Project Pipeline (H_2, NH_3, Other) [GW_{el}]**	**Hydrogen Demand 2050 [Mt]**
Belgium	10	124	7.8	High	Yes	IMD: 90 WEF: 76	Yes	n.a.	Flawed Democracy	High	2022: 13 (6.9, 5.3, 0.1) 2027: 20 (10, 6.7, 1.5)	2.6 (1.9, 0, 0.7	40
Denmark	31	117	9.0	Medium	Yes	IMD: 100 WEF: 81	Yes (5 GW)	n.a.	Full Democracy	Very High	2022: 12 (2.5, 7.1, 0) 2027: 19 (6.1, 10, 0)	12.4 (8.7, 1.0, 2.7)	
Finland	5154	n.a.	7.2	Low	Yes	IMD: 90 WEF: 80	Yes (10 GW)	2.01	Full Democracy	Very High	2022: 12 (0.6, 5.6, 3.2) 2027: n.a.	0.5 (0.5, 0, 0.02)	
France	4708	153	7.7	Medium	Yes	IMD: 71 WEF: 79	Yes (6.5 GW)	22.78	Full Democracy	Medium	2022: 65 (17, 21, 25) 2027: 93 (32, 32, 26)	9.4 (8.9, 0.03, 0.5)	
Germany	346	129	8.0	Medium	Yes	IMD: 80 WEF:82	Yes (10 GW)	41.7	Full Democracy	High	2022: 148 (67, 66, 5.6) 2027: 242 (127, 92, 11)	22.9 (22, 0.5, 0.4)	
Italy	8815	182	6.5	High	Yes	IMD: 63 WEF: 72	Yes (5 GW)	49.1	Flawed Democracy	High	2022: 57 (25, 12, 19) 2027: 86 (42, 16, 23)	2.1 (2.1, 0, 0.02)	
Kazakhstan	952383	172	8.2	Medium	Yes	IMD: 66 WEF: 63	No	n.a.	Authoritarian Regime	Medium	2022: 5.9 (2.0, 1.1, 2.8) 2027: n.a.	20 (20, 0, 0)	
Netherlands	65	121	8.6	Low	Yes	IMD: 96 WEF: 82	Yes (3.5 GW)	4.99	Full Democracy	High	2022: 33 (23, 9.3, 0) 2027: 53 (36, 15, 0)	26.1 (20, 5.9, 0.2)	
Norway	98966	111	9.0	Low	Yes	IMD: 88 WEF: 78	Yes	0	Full Democracy	High	2022: 40 (0.3, 5.1, 34) 2027: n.a.	4.5 (0.5, 1.3, 2.7)	
Poland	118	127	7.6	Low	Yes	IMD: 60 WEF: 69	Yes (2 GW)	8.29	Flawed Democracy	High	2022: 21 (11, 8.0, 1.0) 2027: 49 (32, 14, 2.5)	1.5 (1.5, 0, 0)	
Russia	1481907	139	7.8	Low	Yes	IMD: n.a. WEF: 67	Yes	0	Authoritarian Regime	Very Low	2022: 57 (1.8, 2.2, 51) 2027: 61 (2.8, 3.2, 53)	0 (0, 0, 0)	
Spain	14414	204	7.0	High	Yes	IMD: 67 WEF: 75	Yes (4 GW)	21.29	Full Democracy	High	2022: 68 (20, 29, 17) 2027: 125 (61, 39, 20)	77.1 (76, 0.9, 0.2)	
Sweden	16697	120	7.7	Low	Yes	IMD: 92 WEF: 81	Yes (5 GW)	4.29	Full Democracy	High	2022: 38 (2.6, 15, 16) 2027: 47 (5.0, 21, 16)	4.4 (2.5, 0.6, 1.3)	
Switzerland	4001	146	7.0	Low	No	IMD: 99 WEF: 82	In preparation	n.a.	Full Democracy	Very High	2022: 20 (4.1, 0.1, 15) 2027: n.a.	0.03 (0.03, 0, 0.003)	
Ukraine	594	145	7.4	Low	Yes	IMD: n.a. WEF: 57	In preparation	0	Hybrid Regime	Very Low	2022: 15 (8.1, 1.8, 4.8) 2027: 21 (10, 3.2, 6.9)	3.2 (3, 0.3, 0)	
United Kingdom	5655	116	9.6	Low	Yes	IMD: 75 WEF: 81	Yes (7.5 GW)	33.03	Full Democracy	High	2022: 52 (14, 28, 2.2) 2027: 88 (26, 48, 4.8)	7.8 (7.8, 0.01, 0.03)	

Table 3: Exporter Analysis results for North America sorted by environmental (green), institutional (blue) and industrial (yellow) criteria.

Country	Barren and sparsely vegetated land area [km^2]	Average Global Horizontal Irradiance [W/m^2]	Mean Wind Speed [m/s]	Freshwater stress	Sea Access	Global Competitiveness Rating	National Hydrogen Strategy (2030 Goal)	Public Money support for clean energy in 2020/ 2021 [billion USD]	Regime Type	Level of Peace	Installed Renewable Energy Capacity (Solar, Wind, Hydro) [GW_{el}]	PtX Project Pipeline (H_2, NH_3, Other) [GW_{el}]	Hydrogen Demand 2050 [Mt]
Canada	1457248	142	8.2	Low	Yes	IMD: 88 WEF: 80	Yes	41.9	Full Democracy	Very High	2022: 106 (4.4, 15, 83) 2027: 115 (8.1, 20, 84)	1 (0.8, 0.2, 0)	45
USA	378722	205	8.3	Low	Yes	IMD: 91 WEF: 84	Yes (10 Mt)	144.6	Flawed Democracy	Low	2022: 352 (113, 141, 84) 2027: 653 (316, 216, 103)	29.9 (23, 1.7, 5.2)	

Table 4: Exporter Analysis results for Asia-Pacific sorted by environmental (green), institutional (blue) and industrial (yellow) criteria.

Country	Barren and sparsely vegetated land area [km^2]	Average Global Horizontal Irradiance [W/m^2]	Mean Wind Speed [m/s]	Freshwater stress	Sea Access	Global Competitiveness Rating	National Hydrogen Strategy (2030 Goal)	Public Money support for clean energy in 2020/ 2021 [billion USD]	Regime Type	Level of Peace	Installed Renewable Energy Capacity (Solar, Wind, Hydro) [GW_{el}]	PtX Project Pipeline (H_2, NH_3, Other) [GW_{el}]	Hydrogen Demand 2050 [Mt]
Australia	3055635	256	7.7	Medium	Yes	IMD: 83 WEF: 79	Yes	4.58	Full Democracy	High	2022: 46 (27, 10, 7.7) 2027: 83 (53, 19, 10)	85 (46, 28, 11)	155
China	1893851	189	8.1	Medium	Yes	IMD: 82 WEF: 74	Yes (0.2 GW by 2025)	20.51	Authoritarian Regime	Medium	2022: 1160 (393, 366, 368) 2027: 2139 (915, 691, 455)	15.1 (15, 0, 0.1)	
India	17809	223	5.9	High	Yes	IMD: 65 WEF: 61	Yes (80 GW)	41.26	Flawed Democracy	Medium	2022: 163 (63, 42, 47) 2027: 300 (161, 62, 65)	6.1 (2.8, 3.3, 0.005)	
Indonesia	21405	199	4.2	Medium	Yes	IMD: 71 WEF: 65	In preparation	0	Flawed Democracy	High	2022: 12 (0.3, 0.2, 6.7) 2027: 21 (5.2, 0.8, 9.3)	0 (0, 0, 0)	
Japan	69	161	7.0	Low	Yes	IMD: 68 WEF: 82	Yes	19.75	Full Democracy	Very High	2022: 118 (79, 4.5, 28) 2027: 183 (111, 13, 50)	0.02 (0.02, 0, 0)	
Malaysia	286	203	3.7	Low	Yes	IMD: 76 WEF: 75	In preparation	n.a.	Flawed Democracy	High	2022: 9.0 (1.9, 0, 6.2) 2027: n.a.	1.54 (0.04, 0.7, 0.8)	
New Zealand	12146	159	10.1	Low	Yes	IMD: 73 WEF: 77	In preparation	1.4	Full Democracy	Very High	2022: 8.1 (0.3, 0.9, 5.4) 2027: n.a.	4.8 (4.8, 0, 0)	
Pakistan	245145	242	7.0	High	Yes	IMD: n.a. WEF: 51	No	n.a.	Hybrid Regime	Low	2022: 14 (1.2, 1.4, 11) 2027: 27 (8.2, 2.9, 14)	0.4 (0.4, 0, 0)	
South Korea	532	169	6.8	Medium	Yes	IMD: 76 WEF: 80	Yes	1.24	Full Democracy	High	2022: 27 (21, 1.9, 1.8) 2027: 62 (45, 5.5, 6.5)	1.4 (1.4, 0, 0)	
Thailand	317	213	5.7	Medium	Yes	IMD: 75 WEF: 68	In preparation	n.a.	Flawed Democracy	Medium	2022: 12 (3.0, 1.5, 3.1) 2027: 17 (6.7, 1.8, 4.0)	0.001 (0.001, 0, 0)	
Vietnam	247	203	6.4	Low	Yes	IMD: n.a. WEF: 62	In preparation	0	Authoritarian Regime	High	2022: 45 (18, 4.6, 22) 2027: 65 (29, 13, 22)	0.7 (0.7, 0, 0)	

Table 5: Exporter Analysis results for Latin America sorted by environmental (green), institutional (blue) and industrial (yellow) criteria.

Country	Barren and sparsely vegetated land area [km^2]	Average Global Horizontal Irradiance [W/m^2]	Mean Wind Speed [m/s]	Freshwater stress	Sea Access	Global Competitiveness Rating	National Hydrogen Strategy (2030 Goal)	Public Money support for clean energy in 2020/ 2021 [billion USD]	Regime Type	Level of Peace	Installed Renewable Energy Capacity (Solar, Wind, Hydro) [GW_{el}]	PtX Project Pipeline (H_2, NH_3, Other) [GW_{el}]	Hydrogen Demand 2050 [Mt]
Argentina	597119	214	9.9	Low	Yes	IMD: 34 WEF: 57	Yes	0.04	Flawed Democracy	High	2022: 14 (1.1, 3.3, 10) 2027: 22 (2.0, 4.7, 14)	15 (15, 0, 0)	
Brazil	5362	229	6.2	Low	Yes	IMD: 42 WEF: 61	Yes	0.92	Flawed Democracy	Low	2022: 175 (24, 24, 110) 2027: 233 (66, 36, 112)	4.8 (4.3, 0.5, 0)	
Chile	256990	295	11.9	High	Yes	IMD: 60 WEF: 71	Yes (25 GW)	0.51	Full Democracy	High	2022: 18 (6.2, 3.8, 7.3) 2027: 46 (17, 18, 8.1)	19.6 (0.9, 14, 4.7)	15
Colombia	5678	215	4.9	Low	Yes	IMD: 46 WEF: 63	Yes (2 GW)	0	Flawed Democracy	Low	2022: 13 (0.5, 0, 12) 2027: n.a.	0.1 (0.1, 0, 0)	
Mexico	28398	251	6.3	High	Yes	IMD: 48 WEF: 65	No	1.93	Hybrid Regime	Low	2022: 32 (9.0, 7.3, 13) 2027: 37 (12, 8.7, 13)	0.1 (0.06, 0, 0)	

Table 6: Exporter Analysis results for the Middle East sorted by environmental (green), institutional (blue) and industrial (yellow) criteria.

Country	Barren and sparsely vegetated land area [km^2]	Average Global Horizontal Irradiance [W/m^2]	Mean Wind Speed [m/s]	Freshwater stress	Sea Access	Global Competitiveness Rating	National Hydrogen Strategy (2030 Goal)	Public Money support for clean energy in 2020/ 2021 [billion USD]	Regime Type	Level of Peace	Installed Renewable Energy Capacity (Solar, Wind, Hydro) [GW_{el}]	PtX Project Pipeline (H_2, NH_3, Other) [GW_{el}]	Hydrogen Demand 2050 [Mt]
Iran	1175300	244	7.6	High	Yes	IMD: n.a. WEF: 53	No	n.a.	Authoritarian Regime	Low	2022: 12 (0.5, 0.3, 11) 2027: 16 (0.5, 0.4, 15)	0 (0, 0, 0)	
Israel	12490	248	6.4	High	Yes	IMD: 79 WEF: 77	No	n.a.	Flawed Democracy	Low	2022: 4.5 (4.4, 0, 0) 2027: 10 (8.8, 0.3, 0.3)	0 (0, 0, 0)	
Oman	305096	267	7.9	High	Yes	IMD: n.a. WEF: 64	Yes (1 Mt)	n.a.	Authoritarian Regime	High	2022: 0.7 (0.6, 0.1, 0) 2027: n.a.	18.1 (15, 2.6, 0.5)	
Qatar	10543	248	7.1	High	Yes	IMD: 90 WEF: 64	No	n.a.	Authoritarian Regime	High	2022: 0.8 (0.8, 0, 0) 2027: n.a.	0 (0, 0, 0)	20
Saudi Arabia	1895805	265	7.5	High	Yes	IMD: 86 WEF: 70	In preparation	0.91	Authoritarian Regime	Medium	2022: 0.4 (0.4, 0, 0) 2027: 11 (9.1, 1.8, 0)	2.2 (0, 2.2, 0)	
Turkey	45989	204	6.6	High	Yes	IMD: 56 WEF: 62	Yes (2 GW)	0	Hybrid Regime	Low	2022: 56 (9.4, 11, 32) 2027: 87 (25, 18, 35)	0 (0, 0, 0)	
UAE	65734	255	6.8	High	Yes	IMD: 91 WEF: 75	Yes (1 Mt by 2031)	n.a.	Authoritarian Regime	Medium	2022: 3.0 (3, 0, 0) 2027: 13 (11, 0, 0.3)	3.7 (3.3, 0.4, 0.007)	

Table 7: Exporter Analysis results for Africa sorted by environmental (green), institutional (blue) and industrial (yellow) criteria.

Country	Barren and sparsely vegetated land area [km^2]	Average Global Horizontal Irradiance [W/m^2]	Mean Wind Speed [m/s]	Freshwater stress	Sea Access	Global Competitiveness Rating	National Hydrogen Strategy (2030 Goal)	Public Money support for clean energy in 2020/ 2021 [billion USD]	Regime Type	Level of Peace	Installed Renewable Energy Capacity (Solar, Wind, Hydro) [GW_{el}]	PtX Project Pipeline (H_2, NH_3, Other) [GW_{el}]	Hydrogen Demand 2050 [Mt]
Algeria	2169440	256	8.3	High	Yes	IMD: n.a. WEF: 56	In preparation	n.a.	Authoritarian Regime	Medium	2022: 0.6 (0.5, 0, 0.1) 2027: n.a.	0 (0, 0, 0)	15
Egypt	915252	269	8.7	High	Yes	IMD: n.a. WEF: 55	No	0	Authoritarian Regime	Medium	2022: 6.3 (1.7, 1.6, 2.8) 2027: 10 (3.6, 3.8, 2.9)	9.9 (1.3, 8.5, 0.1)	
Mauritania	900476	254	9.1	Medium	Yes	IMD: n.a. WEF: 41	Yes	n.a.	Hybrid Regime	Medium	2022: 0.1 (0, 0.1, 0) 2027: n.a.	20 (20, 0, 0)	
Morocco	282514	243	7.9	High	Yes	IMD: n.a. WEF: 60	Yes	n.a.	Hybrid Regime	Medium	2022: 3.7 (0.8, 1.5, 1.3) 2027: 8.4 (2.3, 3.2, 2.2)	0.3 (0.1, 0.2, 0)[4]	
Namibia	175677	273	6.8	High	Yes	IMD: n.a. WEF: 55	Yes	n.a.	Flawed Democracy	High	2022: 0.5 (0.2, 0, 0) 2027: n.a.	7.1 (6.2, 0.9, 0)	
Nigeria	992	246	6.4	Low	Yes	IMD: n.a. WEF: 48	No	0.36	Hybrid Regime	Low	2022: 3.5 (0.8, 0, 2.1) 2027: n.a.	0 (0, 0, 0)	
South Africa	98279	250	7.1	Medium	Yes	IMD: 40 WEF: 62	Yes (14.2 GW)	0	Flawed Democracy	Low	2022: 10 (6.3, 3.1, 0.8) 2027: 24 (12, 6.2, 3.6)	13.5 (5.1, 0.9, 7.5)	
Tunisia	102408	232	8.3	High	Yes	IMD: n.a. WEF: 56	In preparation	n.a.	Hybrid Regime	Medium	2022: 0.5 (0.2, 0.2, 0) 2027: n.a.	0 (0, 0, 0)	

Table 8: Exporter Analysis results for North East Eurasia sorted by environmental (green), institutional (blue) and industrial (yellow) criteria.

Country	Barren and sparsely vegetated land area [km^2]	Average Global Horizontal Irradiance [W/m^2]	Mean Wind Speed [m/s]	Freshwater stress	Sea Access	Global Competitiveness Rating	National Hydrogen Strategy (2030 Goal)	Public Money support for clean energy in 2020/ 2021 [billion USD]	Regime Type	Level of Peace	Installed Renewable Energy Capacity (Solar, Wind, Hydro) [GW_{el}]	PtX Project Pipeline (H_2, NH_3, Other) [GW_{el}]	Hydrogen Demand 2050 [Mt]
Kazakhstan	952383	172	8.2	Medium	Yes	IMD: 66 WEF: 63	No	n.a.	Authoritarian Regime	Medium	2022: 5.9 (2.0, 1.1, 2.8) 2027: n.a.	20 (20, 0, 0)	10
Russia	1481907	139	7.8	Low	Yes	IMD: n.a. WEF: 67	Yes	0	Authoritarian Regime	Very Low	2022: 57 (1.8, 2.2, 51) 2027: 61 (2.8, 3.2, 53)	0 (0, 0, 0)	

[4] Not included in the IEA numbers is the AMUN project, which is set to produce 1 Mt of hydrogen per year once completed, the equivalent to roughly 10 GW of electrolyzer capacity (RystadEnergy, 2023b).

2.3.2 Qualitative Regional Assessment

2.3.2.1 Europe

With an annual demand of around 8 Mt H_2 in 2021, mainly from its refining activities and the domestic chemical industry, Europe is currently the fourth largest consumer of hydrogen in the world (IEA, 2022b). This demand is supplied by a production capacity of 11.5 Mt H_2, largely based on natural gas reforming (see *Figure 16*). Although Europe as a whole will most likely continue to remain dependent on energy imports in a decarbonized energy system, certain regions are well suited to produce PtX fuels on a large scale and have the potential to emerge as regional exporters. Such clusters will be concentrated in regions with an abundant renewable energy potential, such as wind in the northern part of the continent and solar in the south. Many European countries can attract PtX fuel producers with attractive subsidies, high economic competitiveness, and political stability. With an increasingly attractive business case to be made for the production of green hydrogen and its derivatives, new projects are being announced at a rapid pace. According to the European Clean Hydrogen Alliance, the current project pipeline consists of 840 announced projects (see *Figure 17*), while the capacity pipeline for green hydrogen production stands at 9.2 Mt (RystadEnergy, 2023a).

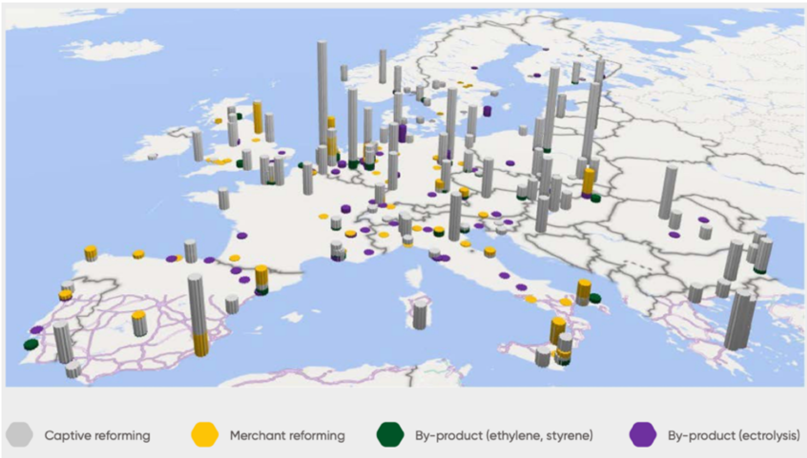


Figure 16: European hydrogen production capacity in 2020 (Hydrogen Europe, 2022).

The European Union (EU) has always been one of the frontrunners when it comes to policymaking in the sustainability and renewable energy space, and it had published its first hydrogen strategy as part of the EU Green Deal back in 2020 (EC, 2020). At the time, the strategy envisaged an increase in the demand for clean hydrogen to 10 Mt by 2030, half of which would be supplied by domestic production (DNV, 2023). It also specified that green hydrogen ought to be the main hydrogen source of the future, with blue hydrogen regarded as a temporary solution in the medium term (Noussan *et al.*, 2021). As a result of the Russian invasion of Ukraine, along with its dramatic implications for the European energy sector, the European Commission introduced the REPowerEU plan in 2022, which increases the demand goals to 20 MtH_2 by 2030 (EC, 2022). Most long-term estimates predict European demand to reach at least 40 MtH_2 by 2050 (DNV, 2023).

In response to the US' Inflation Reduction Act (IRA), the European Commission published the Net Zero Industry Act (NZIA), with the aim of regaining control of critical renewable energy supply chains, such as wind, solar, and PtX fuel technologies (Schmutz, 2023). Europe currently holds a strong position in the manufacturing of electrolyzers, building on its historical dominance in the sector (Fraunhofer ISE, 2020). The key will be to defend this market share against the rapidly expanding Chinese manufacturers, who are already dramatically undercutting European competitors with regards to pricing (BNEF, 2021).

In addition to the policies introduced by the European Commission, several EU member states have released their own PtX strategies and roadmaps. Pioneering these efforts, the Union's economic powerhouses Germany and France have both set ambitious targets with regard to their installed electrolysis capacity and have invested a combined 16 billion EUR towards the achievement of these goals (BMWi, 2020; Strockl, 2021). As might be expected, the two countries follow different approaches when it comes to their hydrogen color of choice. While Germany champions green hydrogen, France is largely banking on pink hydrogen, which it hopes to produce by leveraging its leading position in the nuclear energy sector. The country is also lobbying heavily on the European level, to get pink hydrogen classified as sustainable (Lee, 2021). Despite their efforts, it is unlikely that the domestic production capacity in these countries will be able to satisfy the growing domestic demand for PtX fuels, making it crucial to secure import capacity. Especially Germany has been following an aggressive import strategy, and has already signed bilateral agreements with a number of potential hydrogen exporters, such as Morocco, Chile, and Australia (IRENA, 2022a).

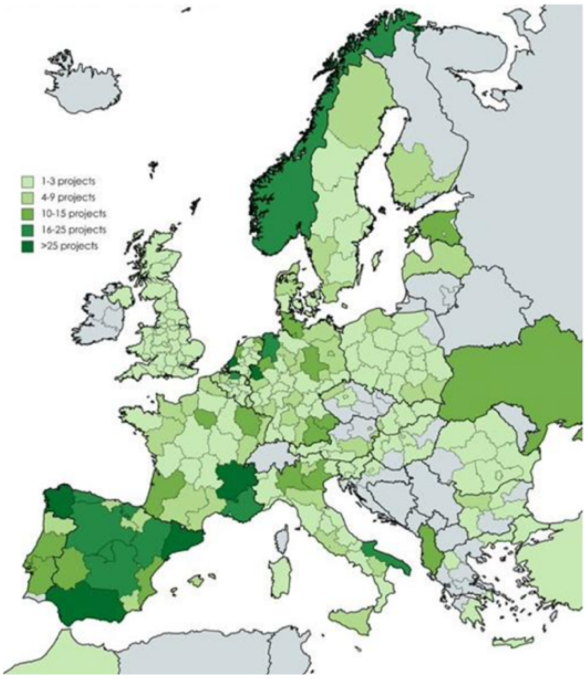


Figure 17: Mapping of European clean hydrogen projects in 2022 (EC, 2023b).

Many countries situated along the North Sea, such as the United Kingdom, Denmark, the Netherlands, Norway and Belgium, hope to capitalize on the vast wind energy potential in the region to power their PtX industries. Most of them have published some sort of hydrogen strategy, and are cooperating in the development of offshore wind projects in the North Sea. These efforts have started bearing fruit, exemplified by the recent signing of the Esbjerg declaration, a 135 billion EUR package with the goal of installing 65 GW of offshore wind capacity by 2030, increasing to 150 GW by 2050 (IEA, 2023c). Of the countries in this region, Denmark and Norway are the most likely to be able to export some of their excess capacity to the European heartland. Denmark, currently accounting for 9% of the European renewable energy capacity specifically dedicated to green hydrogen production (IEA, 2023c), has even signed an export agreement with its neighbor Germany, which includes the construction of a hydrogen pipeline between the two countries by 2028 (Schreiber, 2023). Norway on the other hand will focus on the production of blue hydrogen, at least for the short and medium term (Klevstrand, 2022c), capitalizing on its vast natural gas reserves as well as its existing strengths in the oil & gas industry. In early 2023, the state-run energy company Equinor announced a partnership with German utility company RWE, to construct a hydrogen pipeline between the two countries (Smith, 2023).

Countries with access to the Baltic Sea, such as Poland, Sweden and Finland, have similar goals regarding the development of offshore wind power (see *Figure 18*). Specifically the two Nordic countries have taken ambitious steps in developing green hydrogen projects (Energy Connects, 2022). In early 2023, Finland’s government adopted a resolution to further support green hydrogen developments, claiming the country might supply up to 10% of Europe’s total green hydrogen demand (Finnish Ministry of Economic Affairs and Employment, 2023). Both countries are also actively investing in the development of green hydrogen’s downstream industries, such as green steel manufacturing (Lulea, 2023), which will likely lead to an increase in local demand.

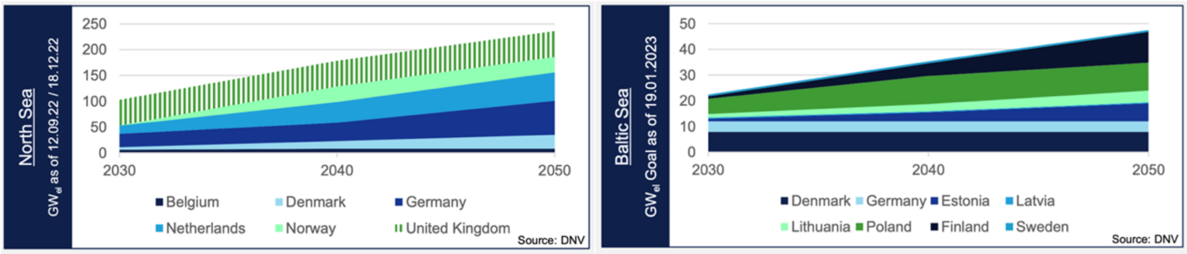


Figure 18: Wind energy development in the North and Baltic Sea, based on countries’ declared targets (DNV, 2023).

Unlike their northern counterparts, countries in southern Europe, such as Spain and Italy, do not rely solely on wind for their renewable energy generation, as they are also blessed with abundant solar resources. Both countries are also strategically positioned to emerge as hubs for cheap renewable energy imports from North Africa (ITA, 2021). With an abundance of sparsely populated territory, which is both windswept and receives more than 2500 hours of sunshine per year, Spain is positioning itself to become a European leader in the production of PtX fuels (Symons, 2023). According to the (IEA, 2023c), the country is expected to account for half of Europe’s growth in renewable energy capacity dedicated to hydrogen electrolysis over the next decade. Taking into account the pipeline of announced projects, the government’s capacity target of 4 GW already seems modest. One project alone, namely HyDeal España, is set to have an installed electrolyzer capacity of 7.4 GW by 2030 (Enagás, 2022).

Overall, it is unlikely that Europe will manage to satisfy its increasing demand for PtX fuels with domestic production, prompting many countries to start looking for suppliers across the Mediterranean Sea and beyond. It is likely however, that certain regional exporters will emerge. While Norway will focus on blue, and France on pink hydrogen, Spain is ideally positioned to emerge as a major exporter of green hydrogen. Its combination of wind and solar energy potential, abundant available land area, rapid renewable energy rollout and attractive policy support make for an ideal investing environment for green hydrogen producers. Due to these factors, that the Spain’s pipeline of hydrogen projects currently far outmatches that of any other European country.

2.3.2.2 North America

North America has all the environmental prerequisites necessary for the successful production of PtX fuels, including a vast renewable energy potential and the abundant availability of suitable land area. Additionally, its high economic competitiveness, strong institutions, and policy support for clean energy projects, make the region extremely attractive for an emerging PtX industry.

The United States have been involved in the hydrogen economy since the term was first coined at American universities during the oil crisis in the 1970s (Noussan *et al.*, 2021). Since that shock, energy security has played a big role in US energy policy (Wemer, 2020). The shale gas boom of the 2010s has made the country one of the top worldwide producers and a leading exporter of energy (IEA, 2019b), a position it looks to defend as the global energy system decarbonizes. In 2021, the US was the second-largest hydrogen consumer with around 12 MtH_2 (IEA, 2019a, 2022b), which it currently produces from fossil feedstocks, mainly natural gas (Calma, 2022). The country is home to an impressive hydrogen infrastructure, including 1,600 miles of pipelines, 90 percent of which are located along the Gulf coast (Salinas *et al.*, 2021). Many clean hydrogen projects have been announced in recent years, with the total project pipeline capacity currently standing at approximately about 12 MtH_2, the majority of which stems from blue hydrogen projects (see *Figure 19*).

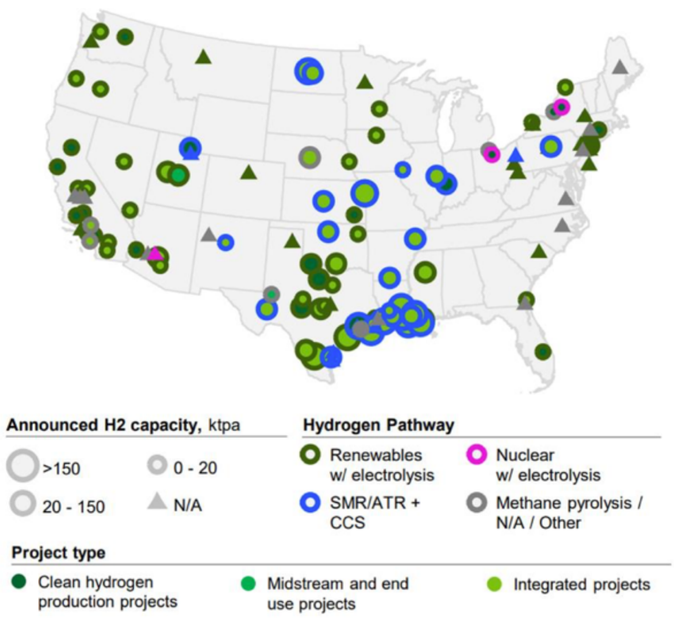


Figure 19: Clean hydrogen projects in the United States (DOE, 2023b).

There have been several government programs initiated to foster domestic hydrogen production, although political support for clean technologies has fluctuated over time. In 2016, the Department of Energy (DOE) released the H2@Scale initiative, to support the industrial production and use of hydrogen (DOE, 2016). Those efforts were increased in 2021, with the introduction of the "Hydrogen Shot", an initiative which aims to reduce the cost of clean hydrogen production to 1 USD/kgH_2 within the next decade (DOE, 2021). The massive influx of subsidies brought on by the signing of the Bipartisan Infrastructure Law (BIL) in November 2021 and the Inflation Reduction Act (IRA) in August 2022, is expected to lead to a substantial boost in the development of renewable energy technologies (see *Figure 20*). The influence of these packages, which contain subsidies of up to 3 USD per kg of produced green hydrogen, is expected to lead to an explosion of such projects over the next years.

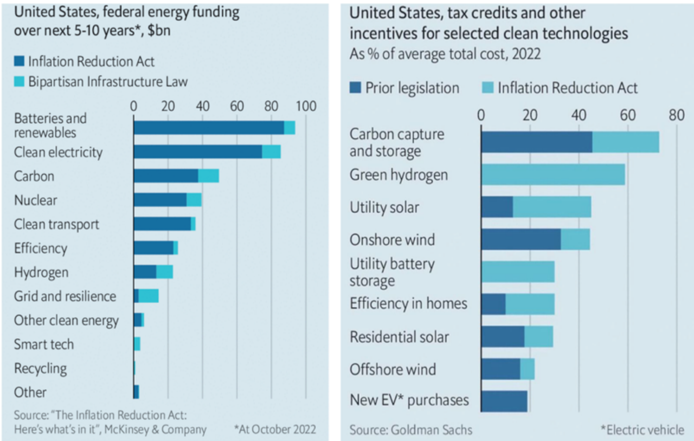


Figure 20: Quantified impact of the BIL and IRA on the clean energy sector, both in absolute values (left) and as a percentage of total cost (right) (The Economist, 2023).

To coordinate all these government efforts, the DOE released a national hydrogen strategy in 2023, which targets 10 Mt of clean hydrogen production by 2030, increasing to 20 Mt by 2040 and 50 Mt by 2050 (DOE, 2023b). The strategy explicitly mentions the goal of developing a dedicated exporting capacity, in order to support US allies in their energy security.

Like many other fossil fuel exporters, Canada sees hydrogen as a natural pivot for its energy industry. The country believes it is well-positioned to become a leading exporter of clean fuels and is supporting industry efforts for the development of clean hydrogen production capacity (Government of Canada, 2020). It is expected that blue hydrogen will be the dominant production method in the medium term, given the country's abundant hydrocarbon resources. However, the country's significant hydropower capacity and still largely untapped wind potential also provide the possibility for green hydrogen production in the future (IRENA, 2022a). Although Canada seems well positioned to achieve its target of becoming a hydrogen exporter, the recently announced projects have been rather small in scale. As a reaction to the US IRA, the Canadian government has announced plans to introduce a tax credit of up to 40% for clean hydrogen production, to avoid investors moving over the border (Klevstrand, 2022b). In 2022, the government signed its first export agreement with Germany, with the goal of jointly developing a transatlantic supply chain for PtX fuels (Radowitz, 2022).

In conclusion, North America has the potential of becoming a major exporting region for PtX fuels, much of which will likely be headed for consumption in Europe. While both Canada and the US show a clear political will to make a push in production capacity and provide the financial means to get the ball rolling, the magnitude of the IRA is expected to propel the US to the forefront of PtX fuel developments worldwide, making it an ideal candidate to become one of the leading global exporters.

2.3.2.3 Asia-Pacific

The emergence of the PtX industry is an exciting prospect for the Asia-Pacific (APAC) region. Not only does it have the potential to help supplying the increasing energy demand of its rapidly growing population and industry, but it also provides opportunities for economic growth and increased energy sovereignty. Many countries in the region have the renewable energy potential to become energy exporters and hope their economies will be able to capitalize on this opportunity.

China is by far the most important player in APAC's renewable energy transition. As part of its goal of becoming carbon neutral by 2060, the Chinese government has identified hydrogen as one of six "industries of the future" in its most recent Five-Year Plan (Yujie *et al.*, 2021). Today, the country accounts for roughly a third of global hydrogen demand, which it produces mainly from coal (IEA, 2022b; Nakano, 2022b). Domestic demand is expected to continue to grow, and might reach up to 100 MtH_2 by 2060 (China Hydrogen Alliance, 2018). Considering the country is home to the world's largest installed renewable energy capacity, and currently dominates key renewable energy supply chains such as solar panel and battery manufacturing (Hutchinson and Zhao, 2023; IEA, 2022d), the government's green hydrogen production goal of just 0.2 Mt by 2025 seems notably modest (Xinhua, 2022). Chinese energy companies on the other hand are leading a major push, hoping to replicate their success in the wind and solar industry within the PtX value chain. Those efforts are starting to bear fruits, as China was projected to account for 60% of newly installed electrolyzer capacity in 2022 (BBN Bloomberg, 2021) and is currently home to the world's largest electrolyzer facility with a capacity of 150 MW in Ningxia (FuelCellsWorks, 2022), a record that it is bound to break itself in 2023, once Sinopec finishes construction of a 260 MW electrolyzer in Xinjiang (Xin, 2021). The development of PtX infrastructure is also progressing rapidly. There are currently more than 1000 km of hydrogen pipeline under construction, including two long distance pipelines connecting the wind energy rich Inner Mongolia to industrial hubs such as Huhehot and Beijing (Wu, 2023). Finally, Chinese electrolyzer manufacturers have been rapidly gaining ground on their Western competitors, accounting for 40% of global capacity by 2022 (IEA, 2023d). Although China is sure to be a major player throughout the PtX value chain, it is unlikely to emerge as an exporter of the fuels themselves since its domestic consumption is projected to rise alongside its increasing production capacity. Furthermore, water constraints in some of its renewable-rich regions might make large scale hydrogen production for export unfeasible (Pflugmann and Blasio, 2020). Therefore, China is most likely going to be a self-sufficient country concerning hydrogen production (Anouti *et al.*, 2020).

Another rising star in APAC's renewable energy transition is India. The nation surpassed China as the most populous country this year (Fischer, 2023), a development that has led to enormous challenges for the domestic energy sector (Ghani, 2021). In an effort to meet its growing energy demand, while simultaneously reducing the emissions intensity of the energy mix, the government has set a target to install 500 GW of renewable energy capacity by 2030 (ET, 2023). The same level of ambition can also be seen in the development of the PtX industry. According to India's National Hydrogen Mission, the country aims to produce at least 10 Mt of green hydrogen by 2030, based on an installed electrolyzer capacity of 60–100 GW being powered by 125 GW of dedicated renewable energy capacity (Ministry of New & Renewable Energy, 2022). Prime minister Narendra Modi mentioned in a speech that he plans to make India a "global hub for green hydrogen production and export" (Rajshekhar, 2021). Accordingly, business activity in the sector has started to pick up in recent years, the most notable example being Total Energies' partnership with the Adani group, which intends to invest 50 billion USD over the next 10 years (Palmer, 2023). Nevertheless, due to existing infrastructure challenges, combined with the projected growth in domestic demand, the country will most likely fail in its goal of becoming a leading exporter of PtX fuels (Anouti *et al.*, 2020; Pflugmann and Blasio, 2020), and is more likely to remain self-reliant in this sector.

While both China and India are on a stable path to self-reliance in the PtX sector, other major economies in the region have little hope of achieving significant domestic production capacities. Due to its limited renewable energy potential, Japan's hydrogen strategy has mainly focused on the applications of PtX fuels rather than their production. The country aims to be the world's first "hydrogen society" (Akimoto, 2023), and has become a global leader in hydrogen research, currently holding more patents in the field than any other country (IRENA, 2022a). Its ambitions include plans to build 1000 hydrogen refueling stations for fuel cell electric vehicles (FCEV) by 2030 (Hydrogen Central, 2021), representing a ten-fold increase from current numbers (see *Figure 21*). To satisfy its growing demand, imports play a critical role in the country's energy strategy. To strengthen supply chains, the government has been pursuing bilateral agreements with potential PtX fuel exporters, most notably Saudi Arabia, Brunei and Australia (Nakano, 2021a). South Korea is another country expected to become a major importer of PtX fuels. While the country has become a global leader in the deployment of fuel cell electric vehicles, fundamental constraints in its renewable energy potential and land availability make it unfeasible for the country to satisfy its demand with domestic production. The country has therefore been investing in infrastructure for receiving and distributing PtX imports (Nakano, 2021b), and has engaged in trade talks with future exporters such as Australia and Saudi Arabia (IRENA, 2022a).

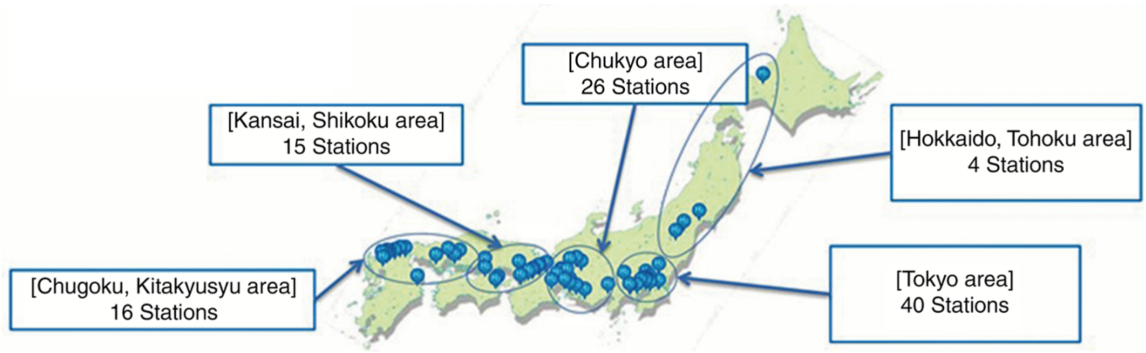


Figure 21: Overview of hydrogen refueling stations across Japan (Iida and Sakata, 2019).

Australia has announced that it wants to be a major player in clean hydrogen supply chain, and considers the fuel its "next big export" (IRENA, 2022a). With abundant land area and significant renewable energy potential in both wind and solar, the nation is indeed well positioned for such an undertaking. The government has recently released a national hydrogen strategy and has invested over 1 billion USD in the development of seven prospective green hydrogen hubs (Australian Department of Industry, Science and Resources, 2021) (see *Figure 22*). This policy has shown to bear fruits, with 118 projects currently in the pipeline (CSIRO, 2023), estimated to produce 2 Mt of green hydrogen by 2030 (RystadEnergy, 2023a). The rollout of green hydrogen projects has also met a few roadblocks, however. This is best exemplified by the Asian Renewable Energy Hub, a mega-project which had aimed at producing 26 GW of electricity for the generation of green hydrogen, before being rejected by the government due to its potential impact on wetlands and migratory birds (Smyth, 2021). Despite such setbacks, the country seems to be in a prime position to become one of the leading exporters of hydrogen, especially to the Asian market.

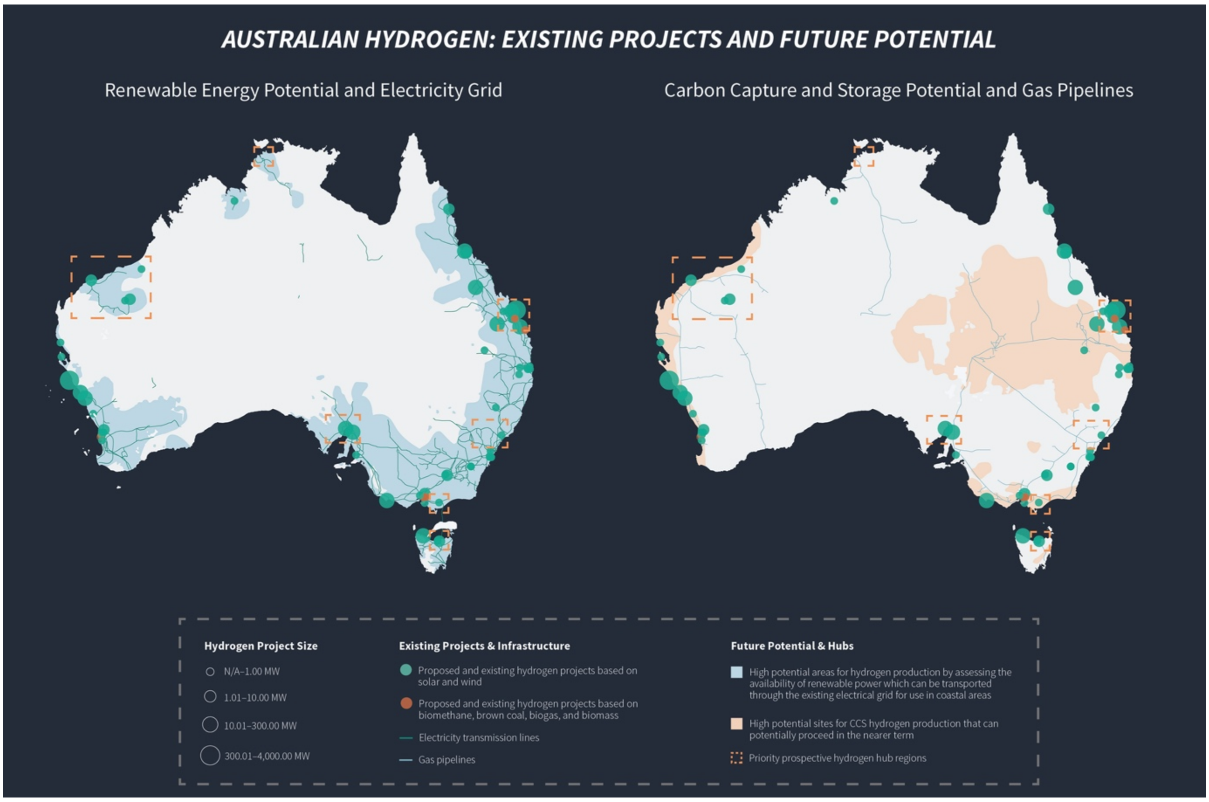


Figure 22: Overview of Australia's hydrogen projects and prospective hydrogen hubs (Carey, 2021).

Other countries in South East Asia, such as Thailand, Vietnam, Malaysia and Indonesia, have a large potential for renewable energy generation, although the development of specific PtX projects has not gained much traction (S&P Global, 2021). As infrastructure development starts picking up, these countries have the potential to become self-sufficient in their PtX consumption, although some might prefer imports due to cost considerations (Pflugmann and Blasio, 2020).

With the projected surge in PtX fuel demand in the APAC region, driven primarily by China, India and Japan, it is anticipated that the region will emerge as a net importer of the fuels, likely coming from the Middle East and South America. The exception to this trend is Australia, which is believed to become one of the world’s major exporters. Due to its proximity to the Asian demand centers, it remains to be seen how much of the country’s export capacity will actually be available for European demand.

2.3.2.4 Latin America

With most of its countries having a high solar irradiance and a strong potential for offshore wind development, Latin America has the potential to become a global leader in the deployment of renewable energy technologies. The region currently has 320 GW of renewable energy capacity in development and is expected to quadruple its current capacity by 2030 (see *Figure 23*). Many countries have recognized the economic opportunities emerging from the energy transition and are racing to capitalize on them. As the region has a low domestic demand for hydrogen of only 4 Mt (IEA, 2021b), overseas export of surplus production capacity is expected to be a lucrative option.

Figure 23: Projected solar and wind energy capacity in Latin America by 2030 (Global Energy Monitor, 2023).

Brazil is currently the region's renewable energy front-runner with 27 GW of operational wind and solar capacity, a lead it is expected to extend even further, considering the 217 GW of planned capacity in the pipeline by 2030 (Global Energy Monitor, 2023). The country is also actively promoting the adoption of renewable fuels, concentrating on biofuels which are projected to account for almost 20% of its energy mix by 2030 (CIF, 2021). The government has not yet published any specific PtX production targets, but a McKinsey analysis concludes that an export volume of up to 2 MtH_2 by 2030 and 4 MtH_2 by 2040 could be feasible (McKinsey, 2021). In recent years, the government has signed several Memoranda of Understanding (MoU) with private sector companies regarding the construction of green hydrogen plants (BNamericas, 2023). In April of 2023, China Energy announced investments of over 10 billion USD in the country, with a particular focus on green hydrogen development (Economist, 2023).

Although Colombia currently does not produce significant amounts of wind or solar energy, their development is expected to pick up over the next years. Following COP27, Colombia signed an agreement with the European Union to develop green hydrogen production capacity dedicated for export to Europe (BNamericas, 2022). With plans to dramatically decrease its fossil fuel extraction over the next decades, the country is urgently looking for alternatives to replace those revenues, which currently account for approximately half of its total exports (Rubiano, 2022). In 2021, the country released a hydrogen strategy, including a goal of 1 GW of installed electrolyzer capacity by 2030 (Garcia-Navarro, 2021). In 2022, the country's state-owned energy company Ecopetrol announced a green hydrogen pilot plant in Cartagena, along with a plan to invest some 2.5 billion USD into clean hydrogen production through 2040 (Reuters, 2022).

Mexico also has significant potential for renewable energy generation, particularly when it comes to solar and wind power. Although the country had been a regional front runner in wind and solar installations in the 2010s, this growth has dramatically slowed down due to restrictive policies by its current pro-fossil government (Global Energy Monitor, 2023). Although private initiatives are trying to drive the development of hydrogen production and applications in the country, political adversity will make it difficult for them to compete with the highly subsidized production of its neighbors. The effects of these issues are evident in the number of PtX fuel projects being developed, which are close to zero. Even if the political tides were to shift, the medium-term potential seems limited. A recent report estimated that with the necessary policy support and favorable conditions for industry adoption, electrolyzer capacity would only reach 670 MW by 2030 (GIZ, 2021).

Argentina is hoping for a green miracle to propel itself out of its economic misery of the past years, consisting of unsustainable debt and sky-high inflation. The country is home to abundant renewable energy resources but has not yet been able to capitalize on them so far (Global Energy Monitor, 2023). The government's hydrogen strategy aims to install 5 GW of electrolyzer capacity by 2030 and estimates that its PtX fuel exports could be worth as much as 15 billion USD by 2050 (GH2, 2022). These hopes have been starting to materialize as Australian company Fortescue announced an 8 billion USD investment plan in 2021, to construct a green hydrogen production facility in Rio Negro (Misculin and Geist, 2021). Nevertheless, economic uncertainty will continue to pose a problem for the nascent PtX fuel industry in the country.

Historically a net importer of fossil fuels, Chile is striving to have a 100% renewable energy system by 2030 (Global Energy Monitor, 2023). With extremely high solar irradiation in the North combined with strong winds throughout the country, particularly in Patagonia, Chile possess the ideal conditions to become a renewable energy powerhouse (en:former, 2021). Its government has published one of the most ambitious hydrogen strategies of any country, hoping to become a world leader in the export of PtX fuels. By 2030, it aims to have an installed electrolyzer capacity of 25 GW, more than half of which could be dedicated to export (Chilean Ministry of Energy, 2020). It has even more ambitious goals in the long term, hoping that the hydrogen industry will grow to become a significant pillar in the country's economy. The government's efforts in this regard have been yielding promising results, with major companies such as Enel, Linde and AirLiquide announcing projects in the country (Imagen de Chile, 2022). In 2022, Porsche started production in the first commercial eFuel plant in Punta Arenas (Braitinger, 2022).

While many Latin American countries have big hopes for the energy transition and its associated economic opportunities, the implementation of such a shift will entail major challenges, as infrastructure constraints could hold back the development of PtX projects (Pflugmann and Blasio, 2020). Nevertheless, initial signs are looking promising, as the region currently has the largest share of green hydrogen projects dedicated specifically for export (Economist, 2023). With an abundance of renewable energy and strong policy support, Chile seems to be the country most equipped to become a major exporter within the next decades (Anouti *et al.*, 2020).

2.3.2.5 Middle East

Historically, many Middle Eastern countries have relied heavily on the export of fossil fuels as a central pillar of their economy. Realizing that this model has an inevitable expiry date, these countries are now looking to reposition themselves and shift towards the green energy sector. To achieve this, governments have started investing heavily in the development of renewable energy projects, specifically in the production of blue and green hydrogen and their derivatives (Kourkejian *et al.*, 2023). By leveraging the region's vast renewable energy potential and the existing energy infrastructure, they hope to defend their leading position in the energy sector.

Saudi Arabia, the world's top exporter of crude oil, is facing a major shift in its economic structure in the next decades. Consequently, the Saudi government has identified the diversification of exports and the development of new industrial sectors as two key mandates in its 2030 vision (Nakano, 2022a). The projected worldwide demand for PtX fuels offers a unique opportunity for the country to achieve these goals. Fittingly, energy minister Prince Abdulaziz bin Salman al-Saud announced the ambition to become the top supplier of hydrogen in the world (Reuters, 2021). For the foreseeable future, clean hydrogen exports will be largely produced from natural gas with associated carbon capture, however there are also green hydrogen projects under development, profiting from the country's vast areas of flat land ideally positioned in the sun belt (Casey, 2021). Saudi Aramco, the national oil company, has made some major investments in clean ammonia production, and in 2020 it delivered the first shipment of blue ammonia to Japan (Nakano, 2022a).

Oman is another country in the region hoping to reduce its dependence on fossil fuels, which currently account for up to 85% of the government's revenue (Abouzzohour, 2021). With reserves dwindling and becoming increasingly costly to extract, efforts to shift away from this dependency have increased over the last years. The government released a hydrogen strategy in 2022, targeting a green hydrogen production capacity of 1 Mt by 2030 (Ministry of Energy and Minerals, 2022). Multiple large-scale PtX projects have been announced in recent years (see *Figure 24*), capitalizing on the abundant renewable energy potential in the region and the excellent connection to global trade networks via the Arabian sea port of Duqm (IRENA, 2022a).

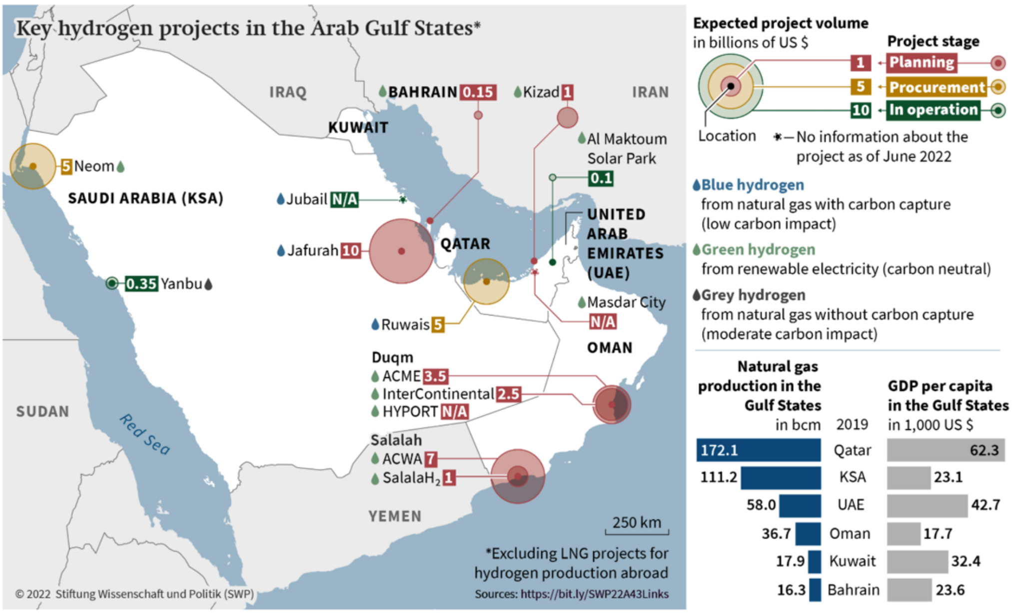


Figure 24: Overview of key hydrogen projects in the Middle East (Ansari, 2022).

The economy of the UAE is one of the strongest and most diversified in the Middle East (Seric and Tong, 2019). While it is still driven by its oil and gas industry, significant progress has been made when concerning diversification into new sectors, such as finance, real estate, manufacturing, and tourism (Nair, 2022). The government has also announced massive investments in renewable energy technologies, as part of its effort to achieve climate neutrality by 2050 (Arabian Business, 2021). The country has ambitions to become a leading exporter of blue and green hydrogen and is set to release its hydrogen strategy in 2023 (Chandak, 2023), which is expected to provide a further boost to its project pipeline, which is already sizeable at 28 projects (Benny, 2023).

Turkey is another important player in the Middle East, both economically and politically. As a result of the country's rapidly increasing energy demand, its dependence on energy imports has been increasing over the past decade (Kalehsar, 2019). Ensuring energy security has become one of the government's main priorities, and the ramp up of domestic renewable energy generation plays a key role in these efforts, along with the planned exploitation of several new gas fields in the Red Sea (IEA, 2021e). In early 2023, the country released a hydrogen roadmap specifying the goal of installing 2 GW of electrolyzer capacity by 2030 (Hydrogen Central, 2023). It has also been engaged in talks with Germany, to discuss potential hydrogen exports into the EU (Mihm, 2023). Whether such ambitious targets can materialize will depend in large part on how fast Turkey can recover from its recent inflation crisis, which will be crucial to attracting foreign investment.

Overall, the Middle East seems predestined to become an exporter of PtX fuels in the future. In addition to strong existing energy infrastructure, great renewable energy potential and vast areas of desert land, the need to escape the dependence on fossil fuel exports poses a great incentive for governments to support developments in this area. Of several suitable candidates, Saudi Arabia and Oman stand out as the countries with the greatest potential of becoming significant PtX fuel exporters.

2.3.2.6 Africa

Africa is widely considered as the continent of the future, with an average age demographic of just 19 years old and a population that is bound to triple by 2050 (Hajjar, 2020). Despite facing significant challenges such as limited infrastructure potential and financial hardship, many African countries are actively pursuing the developments of PtX fuel projects and have set ambitious targets for their deployment (see *Figure 25*). The energy transition has the potential to transform the continent's energy landscape, improving energy access, and contribute to global efforts to combat climate change. Africa's vast renewable energy potential provides it with unique tools to tackle this challenge. While 8% of the Sahara desert covered with solar panels would be enough to supply the entire world's energy demand (van Wijk *et al.*, 2017), wind speeds in countries such as Morocco, Egypt and Algeria are comparable to those measured in the North and Baltic Seas (Samir *et al.*, 2023).

Morocco is considered an African pioneer in the field of renewable energy (Boutaleb, 2022). As the only North African country with no fossil fuel resources, it largely depends on imports for its energy supply (Oxford Business Group, 2015). Therefore, there is a strong incentive to support domestic renewable energy production to ensure energy independence and possibly create an export market. The country possesses a solid infrastructure, and is already connected to Europe via electric links and gas pipelines (Samir *et al.*, 2023). PtX fuel production presents an attractive growth opportunity for the country's economy, and the government has published a hydrogen roadmap back in 2021 to support developments in this area (GH2, 2021). In the meantime, there are already several large-scale projects underway, most notably the Amun project which is set to have an annual capacity of almost 1 MtH_2 by the time of its completion (RystadEnergy, 2023b).

Egypt's prime geographical location at the crossroads of Africa, Europe and Asia, combined with its control of the Suez Canal, give the country an excellent position to become a global renewable energy hub (RystadEnergy, 2023b). At COP27 in Sharm el-Sheikh, the government signed eight framework agreements to further accelerate the development of several PtX projects (Lewis, 2022). It has also earmarked an area of 7,000 km^2 for renewable energy production, which is estimated to be large enough to produce up to 90 GW of clean power (Abu Zaid, 2021). Unfortunately, the country has been experiencing economic hardships in recent years, including the devaluation of its currency and soaring inflation, which have been detrimental to foreign investment and industrial development (Lewis, 2023).

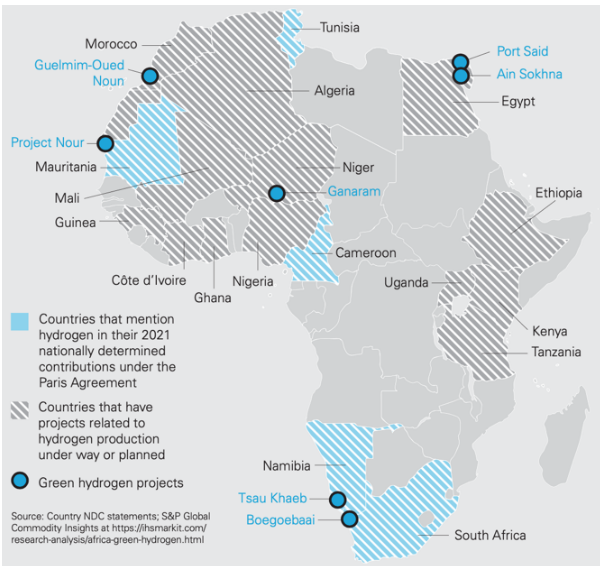


Figure 25: Overview of hydrogen policies and projects in Africa (White & Case, 2022).

Mauritania has the biggest hydrogen project pipelines of any African country, which is mainly driven by three enormous projects, namely the Aman project, with a planned production capacity of 1.7 MtH_2, the Nour Electrolyzer project (1.2 MtH_2), and the recently announced Masdar-Infinity-Conjuncta project (1.36 MtH_2) (RystadEnergy, 2023b). One of its main selling points for such projects is the geographical proximity to the deepwater port of Nouadhibou, which provides excellent export opportunities (RystadEnergy, 2023b). To facilitate exports, there have also been discussion about the possibility of constructing a hydrogen pipeline destined for Europe, although no concrete plans have been put into motion (Reed, 2022). As a large producer of iron and copper, Mauritania also has the potential to create a domestic market for its green hydrogen, for example in the production of green steel (Ackermann and Contensou, 2023). Given the concentration of the announced capacity to only three projects, a failure of these to materialize could seriously dampen the country's ambitions.

Namibia is hoping that the development of PtX fuel projects can help its ambition to become an industrialized nation (GH2 Namibia, 2022), and its government has recently created a national Green Hydrogen Council to support this mission (IRENA, 2022a). The recent project announcement by Hyphen Hydrogen Energy impressively demonstrates the immense economic opportunity this sector can entail, with the announced investment volume of 9.4 billion USD being roughly equivalent to the countries annual GDP (Creamer, 2021). The government has also started looking for potential export partners, signing first agreements with Germany, Belgium and the Netherlands (Schutz, 2021).

South Africa's clean energy ambitions are driven both by its decarbonization goals and the desire to support economic growth and increase exports (Salma and Tsafos, 2022). The country has a large and diversified economy, as well as a comparably advanced infrastructure, which provide it with a good starting point for the development of a PtX fuel industry (Salma and Tsafos, 2022). As the dominant exporter of Platinum and Iridium (Minke *et al.*, 2021) and an already well established *Fischer-Tropsch* production capacity (NETL, 2023), the country has shown that it is capable of being a major player in the clean energy supply chain. This optimism is shown in the government's "Hydrogen Society Roadmap", which was released in 2021 and sets a goal of developing 14.2 GW of installed electrolyzer capacity by 2030 (IRENA, 2022e). Several structural challenges remain however, including limited economic growth and persisting electricity supply shortages leading to rolling blackouts throughout the country (World Bank, 2023), which potentially hinders the use of electricity for purposes such as fuel export.

Overall, the African continent has great potential to export significant amounts of PtX fuels. Europe is the most likely destination for such exports, as such an arrangement could prove to be mutually beneficial for both regions. For Europe, these imports would provide significant assistance in the fulfillment of its decarbonization objectives and enhance its energy security, while Africa could profit from the associated industrialization efforts, job creation, and overall economic growth (van Wijk and Wouters, 2021). High uncertainty remains however, as political and economic crises are still a regular occurrence on the continent. Additionally, only 13 out of the 114 GW in the project pipeline have reached a final investment decision (RystadEnergy, 2023b).

2.3.2.7 Northern Eurasia

The region of Northern Eurasia includes Russia and many of its immediate neighbors in Eastern Europe and Central Asia, jointly forming the Commonwealth of Independent States (CIS) (see *Figure 26*). Many of its members are heavily reliant on the extraction and export of natural resources, especially fossil fuels. Like previously discussed regions that have a similar economic structure, the adjustment to a decarbonized energy system comes with great challenges but also provides opportunities. The region's vast desert areas and the far-reaching Eurasian steppe, provide abundant potential for the generation of wind power. Additionally, due to its fossil history, the region is home to a robust energy infrastructure which could serve as the basis for the development of a renewable energy industry.

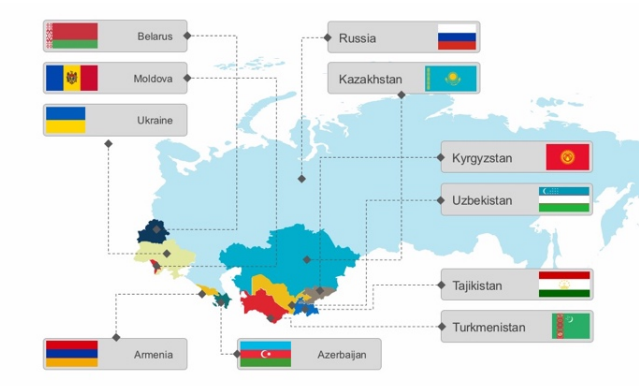


Figure 26: Overview of states associated with the Commonwealth of Independent States (CIS).[5]

One country that has gained attention as a potential PtX exporter in recent years is Kazakhstan. Currently a major fossil fuel exporter, the country has set goals to transition away from these and increase renewable energy deployment (Zholdayakova *et al.*, 2022). To achieve this shift, the Kazakh government signed an investment agreement with European company Svevind in 2022, detailing plans for a 20 GW green hydrogen plant, which hopes to produce green hydrogen for export to Europe by 2032 (Klevstrand, 2022a). Despite such promising signs, there have not been many other projects announced since, leading to a considerable concentration risk in the country's PtX project pipeline. It also remains to be seen, whether president Kassym-Jomart Tokayev can keep the peace after bloody mass protests shook the country early last year (Mirovalev, 2022).

While Russia had ambitious plans with regard to the production of blue hydrogen, announcing the goal to export 2 MtH_2 by 2035 (Barlow and Tsafos, 2021), recent geopolitical developments will make the achievement of such goals close to impossible. After its invasion of Ukraine, the major demand centers in Europe have imposed strict sanctions on the country, and although these sanctions may be lifted at some point in the coming decades, many of the PtX supply chains will have been established by then. Additionally, green hydrogen will likely be preferred by then over Russia's blue equivalent.

In conclusion, while there are some fringe candidates that might have a chance of developing into PtX exporters in the long-term, none of the countries in Northern Eurasia appear to be feasible candidates at the moment, especially when comparing their prospects to some of the other emerging export champions around the world.

[5] Both the Ukraine and Moldova have distanced themselves from the cooperation in the past decade as a response to Russian interference and aggression, which is why there were regarded as part of Europe for this analysis.

2.4 Results & Discussion

The combination of the obtained quantitative data with the subsequent qualitative insights provides a comprehensive overview of the present status and expected trajectory of countries' PtX fuel export potential. The environmental potential for large-scale PtX fuel production varies significantly across the world. Regions such as Africa, North and South America, the Middle East, and certain parts of APAC provide the best environmental conditions for the low-cost production of such fuels. Conversely, many European and Eurasian countries face limitations in their renewable energy potential. Considering institutional and industrial constraints further narrows down the number of countries realistically expected to emerge as major PtX exporters, although some promising candidates remain.

Based on the results of the quantitative and qualitative assessments, and considering the current political and scientific consensus, six major PtX fuel exporters have been identified to serve as model countries in the following techno-economic assessment of PtX fuel production and transport (see *Figure 27*). While certain regions have clear frontrunners, such as Spain in Europe, Australia in APAC, and Chile in Latin America, there are several viable candidates for others. Particularly in the Middle East, several countries display realistic potential for PtX fuel export, such as Oman, Saudi Arabia and the UAE. Although Saudi Arabia is currently slightly lagging behind its regional competitors in PtX projects under development, it has been chosen as the major exporter due to its ambitious goals and the enormous financial resources the country can mobilize. For North America, the United States are selected as the main future PtX fuel exporter, largely influenced by the significant impact of the IRA. While there are several potential exporters in Africa, much more uncertainty remains in this region due to economic and political instability. Morocco is chosen as the major African exporter for this analysis due to its relative political stability, serviceable infrastructure and geographic proximity to demand centers in Europe. Given the limited export potential in Northern Eurasia, no exporter from this region has been considered.

The conducted exporter analysis provides a comprehensive snapshot of the current PtX fuel export potential around the world. As long-term projections inherently carry uncertainties, and unforeseen events will always have the potential to disrupt the current trends, it is important to keep updating the underlying assumptions. Thanks to the established assessment framework such future developments can be taken into account, allowing it to remain responsive to evolving circumstances.

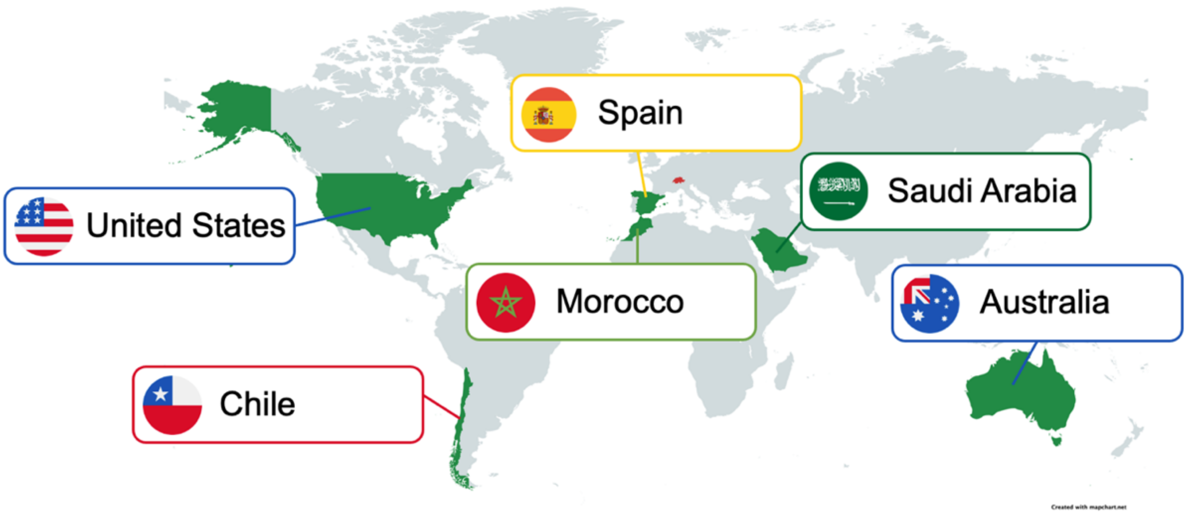


Figure 27: The major PtX fuel exporters identified in this study.

3 Techno-Economic Assessment of PtX Fuel Supply Options

The following techno-economic assessment will focus on determining the delivered cost of different PtX fuel supply options, including import options from the identified exporter countries as well as domestic production in Switzerland.

The chapter will start off with an overview of prior studies in the field of techno-economic assessment of PtX fuel production and transport. Numerous studies have been published in recent years, displaying significant variations in their chosen system boundaries, geographical and temporal scopes, and methodological approaches. The literature review aims to extract the key insights from these different types of studies, to inform the methodology of the following techno-economic assessment. Furthermore, it provides a comprehensive and structured overview of the relevant studies in this field, acting as a reference point for future research.

Subsequently, a coherent techno-economic assessment model for the production of PtX fuels is developed, consolidating the methodologies and insights from the aforementioned studies within a unified framework. To achieve this, the model aggregates the various process steps into a holistic production facility, considering the dynamic interactions between them. Literature research is conducted to determine crucial cost and operational parameters, providing the data foundation of this assessment and ensuring the validity of its results. Certain input parameters are determined on a country-specific level to identify regional differences and their impact on PtX fuel production costs. Overall, this assessment provides comparable results across different fuel types, production technologies and geographic locations, which are crucial to gain a comprehensive understanding of available supply options for Switzerland.

To assess and compare the delivered cost of PtX fuel supply options in Switzerland, it is essential to account for the supply chain costs associated with importing PtX fuels from exporting countries to Switzerland. For this purpose, an assessment model for the analysis of required supply chains is created. This model considers various available transport methods, whose associated costs are determined based on literature input data. Supply chains from exporting countries to Switzerland are modelled considering several scenarios with regards to the development of the future available supply chain infrastructure. Consequently, the analysis will establish the delivered cost of all feasible supply options for PtX fuels, encompassing both imports and domestic production within Switzerland.

In a last step, the determined delivered costs will be analyzed and interpreted, elucidating the cost structures of electricity generation, hydrogen electrolysis as well as PtX fuel production. Emphasis will be placed on evaluating the production cost differences between distinct regions to elucidate disparities among various exporters. Furthermore, important considerations with regards to PtX fuel import from regional and overseas exporters will be discussed, considering different infrastructure development scenarios. The results of this analysis will serve as the starting point for a final conclusion and provide the basis for future policy making decisions.

3.1 Literature Review

Due to the growing interest in PtX fuels as the solution to various decarbonization challenges, research in this field has been plentiful over the last decade. As economic considerations are key drivers of any widespread PtX adoption, a substantial portion of this research has been focused on the economic feasibility of PtX production and their supply chains. While they are all interested in the same end result, determining the levelized cost of the considered PtX fuel, the scopes of such studies vary widely, ranging from detailed process simulations of specific PtX production plants to global studies aimed at determining the localized cost of PtX fuel production all around the world.

Process level studies employ a very narrow scope and are usually focused on determining the optimal cost and operational parameters of a specific fuel production process. These studies usually work with process modelling software such as Aspen Plus to model and optimized different processes and determine their economic performance. A prominent example of such a study was published by (Schemme *et al.*, 2020), who conducted a comprehensive process-oriented techno-economic assessment for various Power-to-Liquid (PtL) fuels. Other studies are more specialized, focusing on a specific electrolysis technology (Olivier *et al.*, 2016; Sánchez *et al.*, 2020) or the production of a specific type of fuel such as ammonia (Zhang *et al.*, 2020), methanol (Sollai *et al.*, 2023) or methane (Choe *et al.*, 2021). The results of such research can vary depending on the employed methodology and determined system boundaries, however there are some commonly identified cost reduction measures, such as heat integration throughout the plant and scaling the production to achieve cost benefits (Campion *et al.*, 2023).

Expanding the scope from a mere focus on a specific production process, system level studies focus on integrating the fuel production process with its associated power supply set-up. This allows to explore how variable electricity generation technologies can be coupled to fuel production processes with limited flexibility in their operation, and how power storage technologies or grid integration set-ups can help in facilitating this. Such studies usually work with location-specific weather data to perform temporal optimization calculations and determine ideal production set-ups. A nice example of such as study has recently been published by (Terlouw *et al.*, 2022), who compared large-scale hydrogen production in grid-connected, hybrid and autonomous constellations on geographical islands. Many other studies are available with varying scopes regarding their geographic location, type of underlying electricity supply and the type of produced fuel. To name a few, (Nayak-Luke *et al.*, 2018) published a study on the production of green ammonia based on different renewable energy generation systems in the United Kingdom, (Olateju *et al.*, 2016) investigated an integrated hydrogen production plant based on wind power in Western Canada, and (Hou *et al.*, 2021) simulated green methanol production based on hybrid renewable energy systems in China. Many system level studies find that increasing the operational flexibility of a fuel production facility can lead to an overall reduction in costs, and that employing a combination of different electricity sources can have a complementary effect on energy supply (Campion *et al.*, 2023).

Due to the significant differences in utilized methodologies, system boundaries, and the location-specific weather data, results of such studies are difficult to compare, and their conclusions are often not generalizable. To improve the comparability between different studies, efforts have been made to standardize such assessment models (see *Figure 28*). In cases where such principles are followed and transparency regarding the underlying assumptions of the models is given, process and system level studies can provide valuable insights into optimal production set-ups, such as electrolyzer sizing, system efficiencies and other operational parameters.

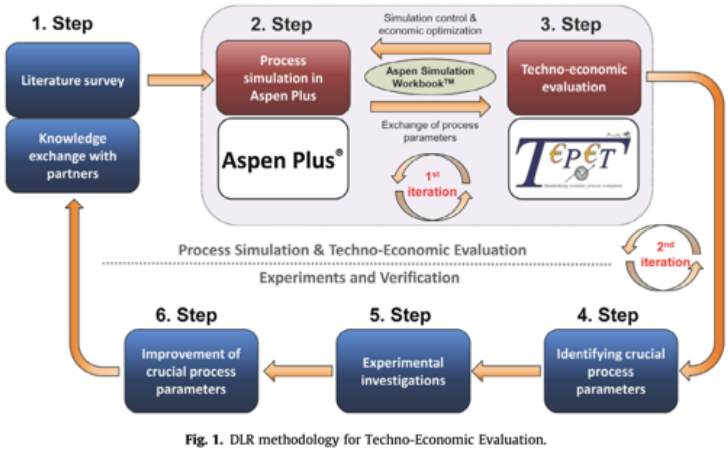


Figure 28: A standardized methodology for the techno-economic evaluation of PtX fuel production (Albrecht et al., 2017).

Building on the insights of process and system level studies, high-level techno-economic analyses utilize generalized operational and cost parameters to determine fuel production costs within a certain country, region or even on a global scale (see *Figure 29*). To achieve this, they often employ dedicated Geographic Information System (GIS) analysis tools to determine location specific input data sets, such as weather patterns, land use restrictions or water availability. An overview of the most relevant studies in this context has been compiled in *Table 9*. As demonstrated in this overview, next to the geographic variations ,these studies are also very heterogeneous with respect to their chosen scopes. While some provide a snapshot of the current PtX production costs, others model cost for a certain point in the future or even look at entire cost development pathways from today to 2050. When observing the considered technologies, most studies include solar photovoltaics (PV), wind turbines, or a combination of the two as their power supply. Other forms of renewable energy, such as hydropower, geothermal energy or concentrated solar power (CSP) are considered to a lesser extent. Only a few studies specifically include the option of employing a battery to increase the operational flexibility of the system. Considering the electrolyzers employed, AE and PEME systems are regarded in most studies, while some also include SOE. Finally, the available studies also vary widely in the type of PtX fuels that are analyzed. While most studies regard the cost of hydrogen production, some also include other PtX fuels, such as ammonia, methanol, methane and *Fischer-Tropsch* fuels.

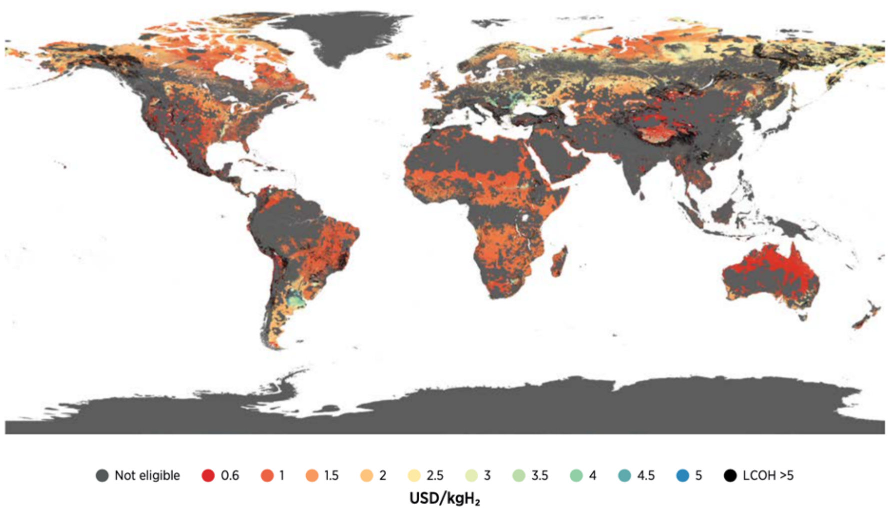


Figure 29: Overview of global hydrogen production costs in 2050 (IRENA, 2022d).

In addition to determining the production costs of PtX fuels, many of the regarded studies also include a techno-economic assessment of the associated supply chain required to transport the fuels to importing countries (see *Figure 30*). In this context, the most considered importing region is Europe, with the majority of studies looking specifically at Germany. Certain studies also focus on Japan as a potential importing nation. No techno-economic assessments of the supply chain associated with PtX imports to Switzerland have been found in literature.

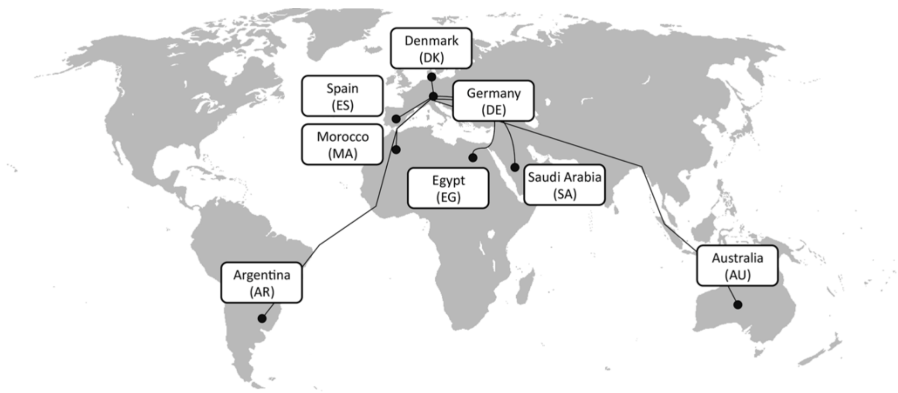


Figure 30: Import of renewable energy carriers to Germany (Hampp et al., 2023).

The previously outlined methodological heterogeneity of current literature studies, make their results difficult to compare, not allowing for a wholistic global view of all available PtX supply options. Additionally, there remains a research gap regarding the supply chain options and costs associated with importing PtX fuels to Switzerland.

To provide a unified framework, the techno economic assessment model in this study aims to integrate the research findings from all types of discussed studies, from process- and system-level studies up to global techno-economic assessments. This will allow for the identification of key variables that need to be considered when modelling production cost for various production pathways and system set-ups in different regions around the world. The resulting assessment framework allows for the integration of all relevant PtX fuels, production pathways, system set-ups and exporting countries as well as all their respective transport to Switzerland, under one harmonized framework, providing a comprehensive overview of the available supply options in Switzerland.

In the final stages of the preparation of this report, two studies with very similar scopes to the one defined here have been published by (Hank *et al.*, 2023) and (Pfennig *et al.*, 2023) which looked at the import of PtX fuels to Germany. As the methodologies of this study has not been influenced by the work conducted by these authors, the respective results provide an interesting comparison, which will be discussed in *Chapter 4*.

Table 9: Chronological literature overview, adapted and expanded from similar reviews by (Brändle et al., 2021) and (Pfennig et al., 2023).

Study	**Time Period**	**Production Region**	**Electricity Generation**	**Electrolyzer**	**PtX Fuels**	**Supply Chain**
(Fasihi *et al.*, 2017)	2030, 2040	Maghreb region	PV, Wind	AE	CH_4, $C_{16}H_{34}$	Ship to Finland
(Brynolf *et al.*, 2018)	2015, 2030	Not defined	Not defined	AE, SOE, PEME	H_2, CH_4, CH_3OH, CH_3OCH_3, $C_{16}H_{34}$	Not considered
(Perner *et al.*, 2018)	2020, 2030, 2050	Northern Europe, Iceland, MENA	PV, On- and Offshore Wind, Geothermal, Hydropower	low temperature electrolysis	CH_4, CH_3OH, $C_{16}H_{34}$	Ship or Pipeline to Germany
(IEA, 2019a)	"Near term" "Long term"	Global	PV, Onshore Wind	AE, PEME, SOE	H_2, CH_4, NH_3, $C_{16}H_{34}$	Ship, Truck, Pipeline to Japan and Europe
(Kober *et al.*, 2019)	2015	Switzerland	PV, Wind, Grid	AE, PEME, SOE	H_2, CH_4, CH_3OH, $CH_{16}H_{34}$	Not considered
(Timmerberg and Kaltschmitt, 2019)	2020	North Africa	PV, Wind, Battery	PEME	H_2	Pipeline to Central Europe
(Heuser *et al.*, 2019)	not mentioned	Argentina	Wind	PEME	H_2	Pipeline to Export Port, Ship to Japan
(Jensterle *et al.*, 2019)	2030, 2050	30 non-EU countries around the world	PV, Wind, Battery	not mentioned	H_2	Ship and Pipeline to Germany
(Fasihi and Breyer, 2020)	2020, 2030, 2040, 2050	Global	PV, Wind, Battery	not mentioned	H_2	Not considered
(Gerhardt *et al.*, 2020)	2050	Morocco, Tunisia	PV, Wind, Battery	PEME	H_2	Ship and Pipeline to Germany
(Kreidelmeyer *et al.*, 2020)	2020, 2030, 2040, 2050	MENA	PV, Wind	AE, PEME, SOE	H_2, CH_4, CH_3OH, $C_{16}H_{34}$	Pipeline to Germany
(Heuser *et al.*, 2020)	2050	Regions with strong wind and solar potential	PV, Wind	not specified	H_2	Global transport model based on supply and demand simulations

Table 9 (cont.): Chronological literature overview, adapted and expanded from similar reviews by (Brändle et al., 2021) and (Pfennig et al., 2023).

Study	**Time Period**	**Production Region**	**Electricity Generation**	**Electrolyzer**	**PtX Fuels**	**Supply Chain**
(Runge *et al.*, 2020)	2035	Argentina, Australia, Canada, Chile, Egypt, Iceland, Namibia	PV, Wind, Geothermal, Hydropower	AE, PEME	H_2, CH_3OH, $C_{16}H_{34}$	Ship to Germany, local distribution by Truck
(Hank *et al.*, 2020)	2020, 2030	Morocco, Western Sahara	PV, wind	PEME	H_2, CH_4, CH_3OH, NH_3	Ship to Europe
(Liebich *et al.*, 2021)	2015, 2050	MENA, Europe	PV, Wind, Geothermal, Hydropower, CSP	AE, PEME, SOE	CH_4, CH_3OH, $C_{16}H_{34}$	Ship, Truck, Pipeline to Germany
(Lux *et al.*, 2021)	2030, 2050	MENA	PV, On- and Offshore Wind, CSP	PEME, SOE	H_2, CH_4	Ship and Pipeline to Europe
(Brändle *et al.*, 2021)	2020 to 2050	94 Countries on 6 Continents	PV, On- and Offshore Wind	low and high temperature electrolysis	H_2	Ship or Pipeline to Germany and Japan
(Sens *et al.*, 2022)	2020, 2030, 2040, 2050	Europe, North Africa, Middle East	PV, Onshore Wind, Battery	PEME	H_2	Pipeline to Germany
(IRENA, 2022b, 2022c, 2022d)	2030, 2050	Whole World	PV, On- and Offshore Wind	AE	H_2	Global Transport Model based on supply and demand simulations
(Janssen *et al.*, 2022)	2020, 2030, 2040, 2050	30 European Countries	PV, On- and Offshore Wind	AE	H_2	Not considered
(DNV, 2022)	2020 to 2050	Whole world, divided into 10 regions	PV, Wind, Nuclear, Grid	AE, PEME	H_2, CH_3OH, NH_3	Global Transport Model based on supply and demand simulations
(Bauer *et al.*, 2022)	2020 to 2050	Switzerland	PV, Grid	AE, PEME, SOE	H_2	Literature review of Transport and Storage
(Hampp *et al.*, 2023)	2030, 2040, 2050	Argentina, Australia, Denmark, Egypt, Germany, Morocco, Saudi Arabia, Spain	PV, On- and Offshore Wind	AE	H_2, CH_4, CH_3OH, NH_3, $C_{16}H_{34}$	Ship and Pipeline to Germany

3.2 Methodology

The following techno-economic assessment includes an evaluation of the state of the art and future developments of the key technologies required for the production, storage and transport of PtX fuels. Key process parameters with regards to material and energy balances have been compiled along with cost data and have been integrated into a comprehensive calculation model to determine the delivered cost of various PtX fuel supply options in Switzerland.

3.2.1 Data Collection

Input data for the calculation model was collected from scientific articles as well as "grey" literature, such as reports by the International Energy Agency (IEA), the International Renewable Energy Agency (IRENA), the US Department of Energy (US DOE) and Energy Information Agency (US EIA), as well as reports that were published by established research institutions such as the Fraunhofer-Gesellschaft and the Paul Scherrer Institute (PSI). To verify their validity, the collected data points were critically analyzed and compared. To account for the regional differences in production cost data, key input parameters such as the installation cost of renewable energy generation, capacity factors of both power generation and the associated electrolyzer operation, financing condition, and the required water treatment steps were determined on a country-specific basis. For certain input parameters, additional expert input was considered to confirm the validity of the data. Due to the rapid pace of innovation with regards to underlying technologies and the corresponding cost reductions, more recent literature data is generally favored to older ones. In cases where older data was used, expected learning rates have been applied to get reasonable estimates of their current state.

As the considered time horizon for this study extends decades into the future (2020–2050), it is in large part based on assumptions and projections with regard to the cost and technological development of the considered technologies. Furthermore, as many of the regarded technologies are not commercially standardized yet, even reports on current cost data can be subject to wide variations. To account for the large uncertainties resulting through these limitations, three distinct scenarios have been considered, providing a range of possible future cost developments. While the pessimistic scenario reflects a conservative stance, incorporating factors that could potentially lead to less favorable results, the optimistic scenario encompasses best-case conditions, highlighting the potential of highly favorable outcomes. The considered base case strikes a balance between these extremes and is grounded in the most realistic assumptions based on the available data trends. By exploring all three scenarios, this study tries to offer insights that include the whole spectrum of possible developments, enabling a more nuanced interpretation of the research findings.

Part of the collected input parameters for the techno-economic assessment involves data on energy values, such as the energy content of fuels or the energy balances of production processes. While the SI unit of energy is the Joule (J), there are several possible alternatives that are commonly used in literature. To ensure uniformity in this study, energy values are denoted Wh or their respective factors of magnitude (kWh, MWh, GWh or TWh). In the case where literature values were given in any other unit, the general conversion factors were applied (see *Table 10*).

Table 10: General conversion factors for energy units (IEA, 2022e).

		Multiplier to convert to:					
		EJ	Gcal	Mtoe	MBtu	bcme	GWh
Convert from:	EJ	1	2.388×10^{8}	23.88	9.478×10^{8}	27.78	2.778×10^{5}
	Gcal	4.1868×10^{-9}	1	10^{-7}	3.968	1.163×10^{-7}	1.163×10^{-3}
	Mtoe	4.1868×10^{-2}	10^{7}	1	3.968×10^{7}	1.163	11 630
	MBtu	1.0551×10^{-9}	0.252	2.52×10^{-8}	1	2.932×10^{-8}	2.931×10^{-4}
	bcme	0.036	8.60×10^{6}	0.86	3.41×10^{7}	1	9 999
	GWh	3.6×10^{-6}	860	8.6×10^{-5}	3 412	1×10^{-4}	1

The energy content of a fuel can be measured using its lower or higher heating value (LHV or HHV), both of which represent the amount of energy released during the complete combustion of the fuel. They differ in whether they account for the energy required to vaporize the water in the combustion products. The LHV takes this energy requirement into account, which is why it is the relevant value with regards to fuels that are going to be used for the production of energy, be that through conversion to mechanical, electrical or thermal energy (Lettenmeier, 2019). In cases where the fuel is regarded as a chemical product, that is destined for use in the chemical industry, the HHV can be considered. For the purpose of this study, the LHV is considered in all calculations and the utilized values for the analyzed fuels are summarized in *Table 11*.

Table 11: LHV for all PtX fuels considered in this study, obtained from (Valera-Medina et al., 2018), (Schemme et al., 2020) and (Engineering Toolbox, 2023).

Fuel	**LHV [kWh/kg]**
Hydrogen (H_2)	33.33
Ammonia (NH_3)	5.22
Methanol (CH_3OH)	5.54
Methane (CH_4)	13.89
Fischer-Tropsch Fuels ($C_{16}H_{34}$)	12.21

All collected cost data was converted to Swiss Francs (CHF) using the average conversion factors summarized in *Table 12*. Some techno-economic assessments adjust cost data from older literature sources for inflation, however since both the Swiss and European inflation rate has been very low during the regarded time period (BFS, 2023; Eurostat, 2021), the inflationary impact on the reported numbers was considered to be negligible compared to the intrinsic uncertainties of the overall cost calculation.

Table 12: Conversion factors employed for the harmonization of literature cost values to CHF, based on the average currency exchange rate over the past 5 years (OFX, 2023).

Currency	**Swiss Franc (CHF) Equivalent**
1 Euro (EUR)	1.05 CHF
1 United States Dollar (USD)	0.94 CHF
1 Pound Sterling (GBP)	1.21 CHF
1 Australian Dollar (AUD)	0.66 CHF
1 Canadian Dollar (CAD)	0.72 CHF

As this study is dedicated specifically for policy recommendation, no financial policy incentives have been considered for the cost analysis, since these could artificially distort the calculated cost and potentially lead to misinterpretation and misguided measures (Christensen, 2020).

3.2.2 Cost of Capital

Many renewable energy assets are characterized by their high upfront investment cost, whereas their operating costs are generally much lower compared to conventional fossil fuel power generation. This phenomenon is especially pronounced in wind and solar power generation, where around 80% of the generated electricity cost can be attributed to investment and financing (OIES, 2023).

Due to this capital intensive cost structure of renewable energy technologies, the financing cost of the employed capital has a significant impact on the final levelized cost of fuel (Egli *et al.*, 2019). Financing conditions can vary significantly between countries, with capital costs reaching levels up to seven times higher in emerging economies compared to developed economies (IEA, 2021d). Failing to take these differences into account can lead to distorted results and flawed conclusions with regard to the global differences in PtX fuel production (IRENA, 2022a).

Fundamentally, the cost of capital is composed of a certain base rate, representing the interest rate of an investment with virtually no default risk, and a risk premium, representing the additional financial compensation for taking on the project specific risk, which can vary depending on the specific country and technology combination of a project (EY, 2022). As projects are usually financed by a combination of debt (D) and equity (E), the financing costs for the project are determined as the weighted average cost of capital ($WACC$), which represents a weighted average of the cost of debt (r_d) and the cost of equity (r_e) (see *Equation 1*).

Equation 1

$$WACC = \frac{D}{D+E} * r_d + \frac{E}{D+E} * r_e$$

Estimating the cost of capital for a specific renewable energy project can be a challenging task. The cost of debt is more attainable as it can be estimated through publicly available data on central bank rates, lending rates of commercial banks, and typical risk premiums for similar types of projects. The cost of equity is more difficult to estimate, given the confidentiality around company internal project finances and return expectations (IEA, 2021d). To obtain reasonable estimates despite the limited data availability, several calculation models such as the capital asset pricing model (CAPM) can be employed in combination with publicly available financial reporting data.

The WACC values used for calculations in this study are based on a publicly available dataset published by (IRENA, 2023c), which is based on a comprehensive analysis conducted in collaboration with ETH Zurich and includes country-specific WACC values for solar PV and onshore wind projects. Because PtX installations are subject to a higher risk premium than the more established solar and wind projects (Schelo, 2022), a third WACC value is calculated which is used for plant investments such as the electrolyzers, batteries, feedstock generation and fuel synthesis plants. This general WACC is assumed to be 5% higher than the average WACC for wind and solar projects in the respective country.

As the IRENA dataset is based on data collected in 2021, recent inflationary pressures and the resulting rise in interest rates around the world have not been included. These data points are therefore used in the optimistic scenario, assuming a quick taming of inflation and a return to a low interest rate environment. For the pessimistic scenario, inflation is assumed to stay at the current elevated levels, assuming an increased period of higher interest rates. In this scenario, the reported WACC's of the optimistic scenario are increased by the interest rate hikes of each country's central bank between 01.01.2022 to 31.07.2023, which are published by the bank of international settlements (BIS, 2023).

In the base case scenario, it is assumed that inflationary easing will lead to a moderate drop of the current interest rates, however the long-term interest rate will stabilize at a higher rate than during the low interest rate environment of the 2010s. The WACC's for this scenario are obtained by taking the average of the optimistic and the pessimistic scenario. All of the resulting WACC's by country, technology and scenario are listed in *Table 13*.

Table 13: Cost of capital for different technologies, by country and scenario.

Scenario	Country	Solar	Wind	General
Optimistic	CHE	1.70%	4.70%	8.20%
	USA	4.30%	3.00%	8.65%
	AUS	2.90%	2.90%	7.90%
	CHL	3.50%	4.50%	9.00%
	MAR	6.70%	6.10%	11.40%
	SAU	6.20%	6.20%	11.20%
	ESP	3.60%	3.10%	8.35%
Base Case	CHE	2.95%	5.95%	9.45%
	USA	6.93%	5.63%	11.28%
	AUS	4.90%	4.90%	9.90%
	CHL	6.63%	7.63%	12.13%
	MAR	7.45%	6.85%	12.15%
	SAU	8.70%	8.70%	13.70%
	ESP	5.60%	5.10%	10.35%
Pessimistic	CHE	4.20%	7.20%	10.70%
	USA	9.55%	8.25%	13.90%
	AUS	6.90%	6.90%	11.90%
	CHL	9.75%	10.75%	15.25%
	MAR	8.20%	7.60%	12.90%
	SAU	11.20%	11.20%	16.20%
	ESP	7.60%	7.10%	12.35%

3.2.3 PtX Fuel Production

To evaluate the production of PtX fuels on an industrial scale, operational and cost parameters for a large-scale facility have been modeled as part of this study, including the associated electricity generation, feedstock generation units, electrolysis system and fuel production facilities. The scale of the facility is based on an industrial scale electrolyzer with a capacity of 1 GW. Detailed studies on the feasibility of such a gigawatt scale hydrogen projects have been conducted, underlining the obtainable benefits of operating at such a scale (ISPT, 2022) (see *Figure 31*). Today, the largest electrolyzer facilities in operation are usually in the range of a few hundred MW but are assumed to quickly scale up to the assumed levels. A standalone electricity generation and supply setting is assumed for the facility, with no grid connection available.

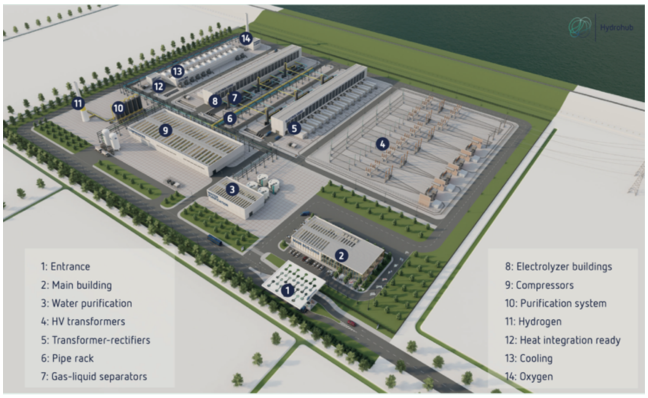


Figure 31: Visualization of a 1 GW green-hydrogen plant, based on an advanced design by (ISPT, 2022).

To be able to coherently calculate and compare the production cost of PtX fuels achieved using varying production technologies with different cost structures, uniform economic performance indicators have to be employed (Bauer *et al.*, 2022). The calculation of the levelized cost of a fuel, also called "Life Cycle Costing" or LCC, has been widely accepted in the scientific community for this purpose, improving the comparability of different studies across the field (Burgherr *et al.*, 2021). This method considers all life-cycle costs of the production facility, such as investment, operation, and end-of-life costs, while also considering the associated capital cost and the time value of money. The levelized costs are evenly distributed over the lifetime of the plant to provide a yearly average (see *Figure 32*).

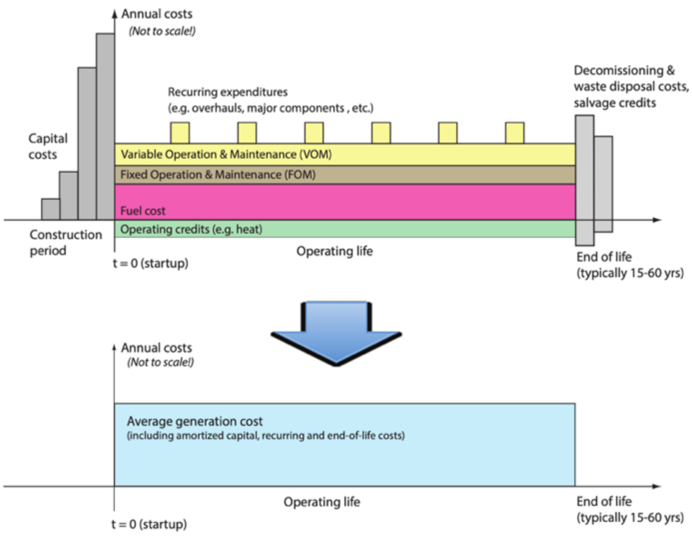


Figure 32: Schematic representation of the methodology for levelized cost calculations (Burgherr et al., 2021).

To achieve this even distribution of one-time investments over the whole lifetime (n) of the plant, the capital recovery factor (CRF) is required. It can be calculated according to *Equation 2*, and is strongly dependent on the corresponding WACC.

Equation 2

$$CRF = \frac{WACC * (1 + WACC)^n}{(1 + WACC)^n - 1}$$

Total investment and replacement cost can be annualized according to *Equations 3 & 4*. While the investment cost (C_{inv}) represents the capital expenditure (CAPEX) required for the initial installation of the plant, replacement costs (C_{rep}) include any replacement expenditure (REPEX) in cases where the lifetime of a specific system component, in this study specifically the electrolyzer or the battery, is shorter than the 30 years of assumed plant lifetime. Generally, these costs are lower than the initial CAPEX for the component, as certain parts can be reused (Christensen, 2020). To account for this, the initial investment cost is multiplied by a technology specific replacement factor (F_{rep}<1). As the replacement cost is incurred at a certain point in the future, certain studies further discount the replacement cost to its present value, however this step has been omitted in this study.

Equations 3 & 4

$$C_{inv,a} = CRF * C_{inv} \qquad\qquad C_{rep,a} = CRF * F_{rep} * C_{inv}$$

To calculate the levelized fuel production cost, the annualized investment and replacement costs ($C_{inv,a}$ & $C_{rep,a}$), as well as the yearly operating expenditure (OPEX) ($C_{O\&M}$) are divided by the amount of fuel produced per year (M_a) (see *Equation 5*). Although there might be some minor revenue streams available for PtX production facilities, such as the sale of purified oxygen or excess waste heat, those are generally not commercialized in present facilities and will therefore not be considered in this analysis.

Equation 5

$$Levelized\ Cost = \frac{C_{inv,a} + C_{rep,a} + C_{O\&M}}{M_a}$$

In this study, the levelized cost of electricity (LCoE), levelized cost of water (LCoW), levelized cost of carbon dioxide (LCOC), levelized cost of nitrogen (LCON), levelized cost of hydrogen (LCoH) and levelized cost of PtX fuels (LCoX) will be calculated, based on the compiled cost and operational parameters. *Figure 33* provides an overview of the LCOX calculation, based on general and country-specific input parameters, as well as the separately calculated LCOE and LCOH. Detailed formulas on the calculation steps required for each of each these can be found in Annex in *Chapter 6.1*.

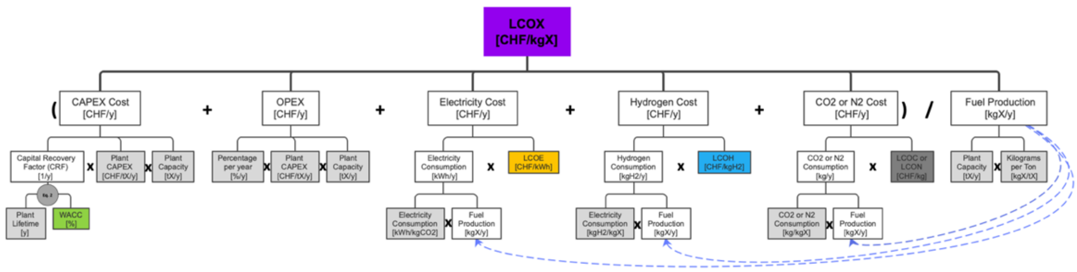


Figure 33: Calculation of the levelized cost of PtX fuels (LCOX). General input parameters are marked in light grey, country-specific input parameters in light green.

3.2.4 PtX Fuel Supply Chain

The second part of the techno-economic assessment is concerned with determining the costs of the available supply chain set-ups required to transport the produced PtX fuels to Switzerland for consumption. To obtain a holistic perspective and take into account all costs along the supply chain, in addition to transport costs the model also considers any conversion and reconversion steps that might be necessary to convert the fuel into its transportable form, as well as intermediate storage prior to transport (see *Figure 34*).

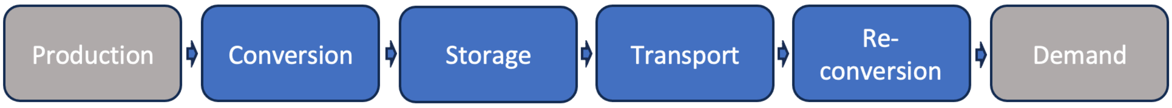


Figure 34: Schematic overview of the PtX fuel supply chain model.

The transport model is divided into two separate parts, evaluating first the transport of PtX fuels from overseas exporters to Europe, considering maritime shipping from the major industrial ports of exporting countries to the port of Rotterdam. The respective ports of origin were chosen based on multiple criteria, such as their proximity to PtX projects and their ability to handle large volumes of bulk fuels. The Port of Rotterdam was chosen as the import port in Europe, being the busiest port in Europe with excellent infrastructure for receiving and distributing fuels (van der Meulen *et al.*, 2020). The respective shipping routes are calculated using the ShipAtlas Tool developed by Maritime Optima and are illustrated in *Figure 35*, with route details summarized in *Table 14*. While there are discussions around utilizing PtX fuels as propulsion fuel for shipping, this study only considers shipping powered by heavy fuel oil (HFO).

Table 14: Route details for maritime shipping from PtX fuel exporters to Europe.

Exporter	Port of Origin	Port of Destination	Distance [km]	Travel Time
Australia	Melbourne		20’579	33 days
Chile	San Antonio		13’870	23 days
Morocco	Casablanca	Rotterdam	2’572	4 days
Saudi Arabia	Jeddah		7’389	12 days
United States	Houston		9’267	15 days

Figure 35: Shipping routes from overseas PtX fuel exporters to Europe.

Once the fuels have reached Europe, inland transport to Switzerland is modelled considering all available transport methods. The European continent is connected via a well-established transport system of roads, railroads, and canals, all of which can be used for large-scale fuel transports (see *Figure 36*). Transport distances for road transport were determined by the usage of Google Maps, while those for rail and barge transport were determined via Routescanner.

Figure 36: Overview of the Rail, Truck and Barge transport routes in Europe, provided by (Wikimedia, 2023), (EC, 2023c) and (CCNR, 2023).

In addition to the overland transport methods mentioned above, Europe also contains an extensive natural gas pipeline system, which can be used for methane transport. As there are currently many hydrogen pipeline projects within Europe being discussed, and a comprehensive hydrogen pipeline network might be available for hydrogen transport in the future, such a possibility will be considered in the transport model. Such a hydrogen pipeline system is adopted from the network proposed by the European Hydrogen Backbone (EHB). Both the natural gas and hydrogen pipeline systems considered in this study can be found in *Figure 37*.

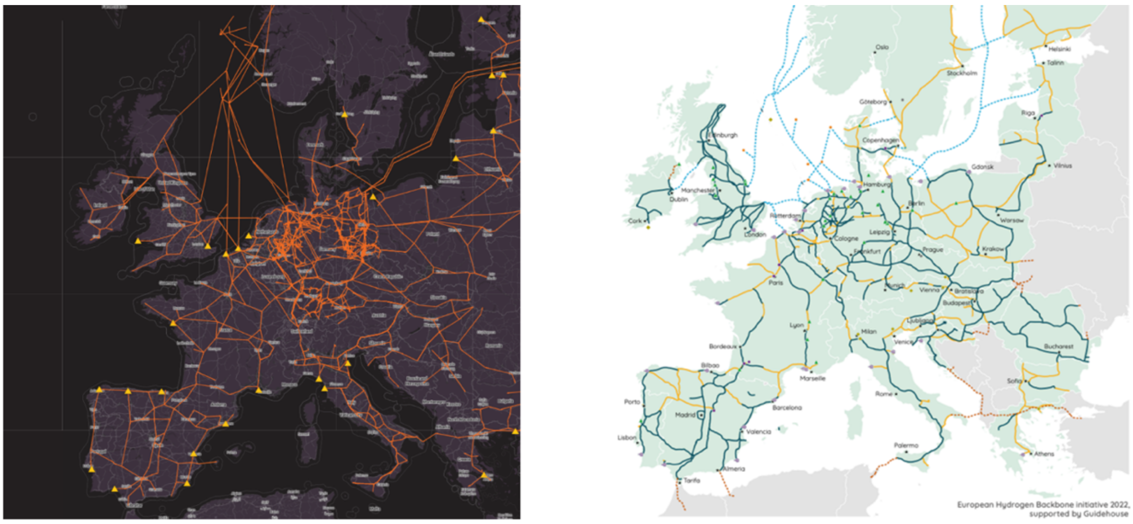


Figure 37: Overview pipeline transport networks within Europe, including the existing natural gas pipeline system on the left (Sacaric, 2022) and the proposed European Hydrogen Backbone (EHB) on the right (EHB, 2022).

To account for the storage requirements along the supply chain, a transport method specific storage period is considered prior to each journey leg, including 15 days prior to maritime shipping, 5 days prior to barge transport, 3.5 days prior to truck and rail transport, 0 days prior to pipeline transport.

The determined cost parameters for the transport (given in CHF/kg/km) and storage (given in CHF/kg/d) were subsequently multiplied with the calculated transported distances and total storage time, to determine the supply chain costs.

3.3 PtX Fuel Production

To determine the production cost of PtX fuels, a comprehensive techno-economic assessment model of a large-scale standalone production facility is developed. The model considers all associated process steps from the generation, storage and supply of electricity and other input feedstocks to the electrolysis system and subsequent fuel production processes (see *Figure 38*). The upcoming section elaborates each of these process steps, explores how they interact with each other, and determines operation and cost parameters for each of them.

First off, the available options for electricity generation and storage are analyzed. Further analysis is dedicated to gaining deeper insights into effectively integrating a variable electricity generation output with industrial loads possessing limited operational flexibility, such as electrolysis systems and fuel production processes. To achieve this, different electricity supply scenarios are developed, employing various amounts of storage capacity to provide varying degrees of consistency in electricity supply. Subsequently, further feedstock generation processes such as the generation of nitrogen, treatment of input water to the electrolyzer and different carbon supply options discussed and modelled.

Building upon these inputs, a thorough analysis of the electrolysis system is conducted. This system holds a pivotal position at the core of the PtX production facility, bridging the electricity supply with subsequent fuel production processes. To understand this dynamic interconnection, the various types of electrolyzer technologies that are commercially available today or expected to be so in the near future are closely examined and their respective cost and operational parameters determined.

Finally, the various PtX fuel production processes required for the synthesis of ammonia, methane, methanol and *Fischer-Tropsch* fuels will be extensively analyzed. For this purpose, the mass and energy balances of the underlying processes are established, and their corresponding costs parameters identified. A specific focus is placed on integrating the recoverable heat from the fuel production processes with the rest of the facility, as it can be effectively reused in the feedstock generation steps. Such an integration provides a substantial opportunity for enhancing the energy efficiency of the PtX production facility, as well as providing cost benefits.

The results of the techno-economic assessment of PtX fuel production will be discussed together with the results of the subsequent techno-economic assessment in PtX fuel supply chains in *Chapter 3.5*.

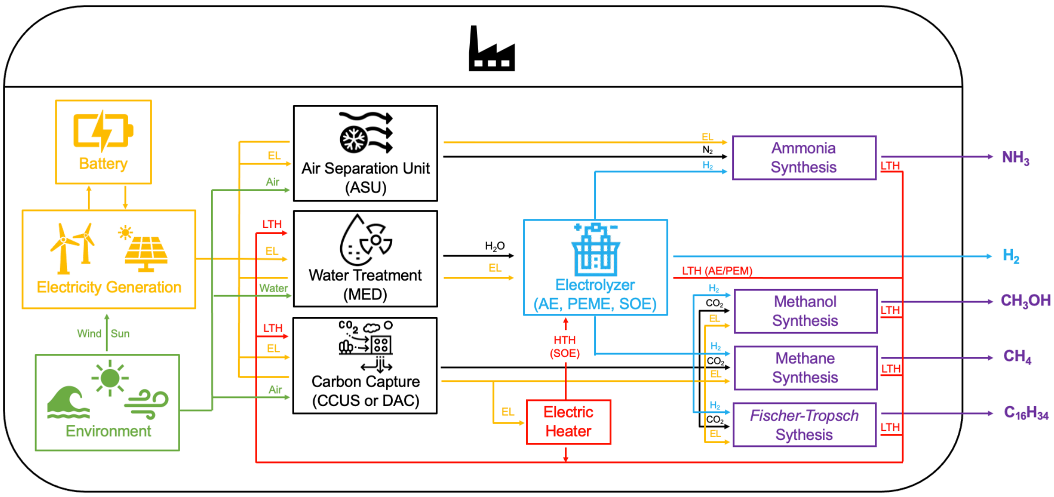


Figure 38: Schematic overview of the PtX fuel production facility modeled in this study.

3.3.1 Feedstocks

3.3.1.1. Electricity

As their name suggests, electricity is the primary feedstock for the energy content contained in PtX fuels. Additionally, PtX production plants also require large amounts of electricity to power the feedstock generation processes, fuel synthesis as well as all the required auxiliary equipment. Consequently, the availability of an affordable, scalable, and sustainable electricity source is of paramount importance for the successful operation of such a facility.

There are several sources of renewable energy that could be considered for this purpose, namely solar, wind, hydro, geothermal and biomass (see *Figure 39)*. To satisfy a global demand of 500 Mt of hydrogen, an annual electricity supply of 25'000 TWh would be required[6], which is roughly equivalent to the total global electricity consumption in 2022 (Ember, 2023). The only renewable energy sources with the theoretical potential to scale to such an extent, are solar, wind, and geothermal. While hydropower accounts for around half of the renewable electricity today (IRENA, 2023d), its potential for further expansion is limited, as many countries have already exhausted their most suitable locations (Fendt, 2021). Biomass energy is intrinsically limited due to its feedstock availability, and can be directly converted to biofuels, avoiding the detour via electricity. Although geothermal energy has a significant theoretical potential, its limited employment for electricity generation and geographical limitations also exclude it as a viable candidate for the purposes of this study (Lund *et al.*, 2022).

Therefore, the focus of this study remains on wind and solar as the renewable energy feedstock for PtX fuel production. Considering the previously outlined capacity criteria, producing 500 Mt of hydrogen would require an installed capacity of around 14 TW of solar panels or 8 TW of installed wind turbines[7], which lies well within the theoretical limit of those energy sources.

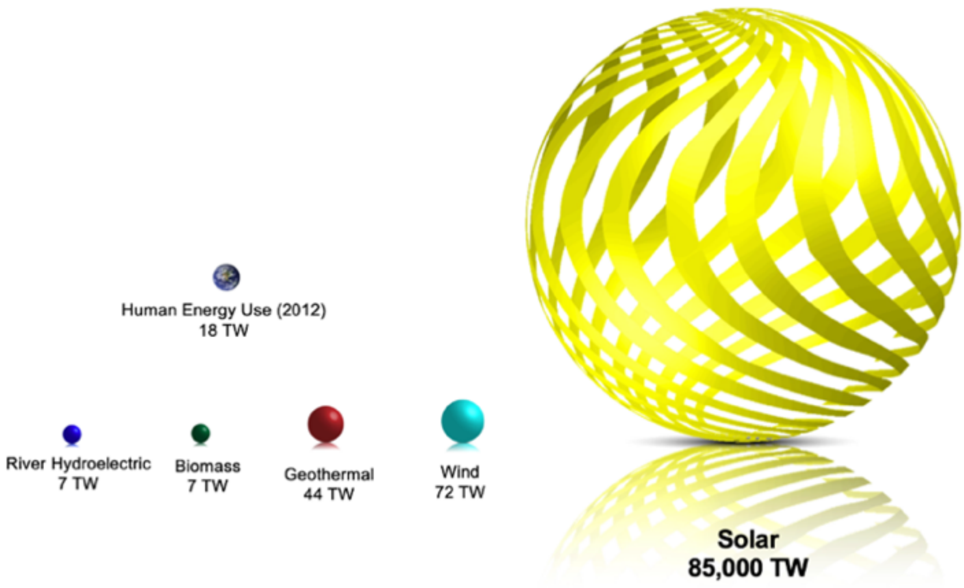


Figure 39: Overview of the theoretical potentials of renewable energy resources by (Tilley, 2022) based on calculations done by (Abbott, 2010).

[6] Assuming 50 kWh of electricity is needed to produce one kg of hydrogen.
[7] Assuming a capacity factor of 20% for solar and 35% for wind.

The sun and wind are resources that will hardly ever cease and are available free of charge all over the world, although considerable regional variations do exist with regard to their abundance (see *Figure 40*). In 2022, power generation from solar and wind accounted for 12% of global electricity generation, which is up from just 3% a decade earlier (Ember, 2023). Combined, they are expected to account for three quarters of the growth in renewable energy over the next decades (IEA, 2022e). The dominant forms of generating electricity from wind and solar are onshore wind turbines and solar PV systems, both of which have experienced a tremendous boom in recent years. While offshore wind deployment has also gained momentum recently, it will not be considered in this study due to its geographical constraints.

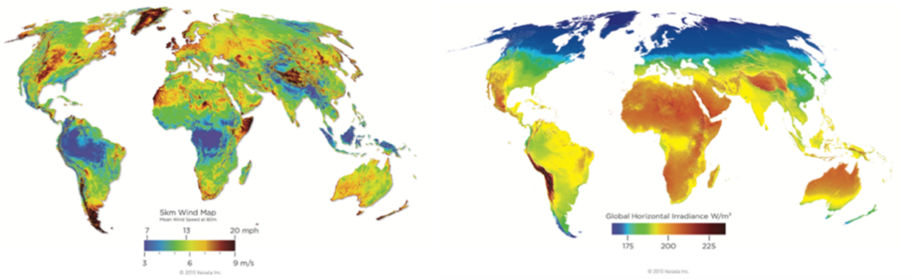


Figure 40: Global horizontal irradiance (right) and a wind map (left) (Vaisala, 2015).

The large-scale rollout of onshore wind and solar PV over the last decades was accompanied by a dramatic fall in the installation cost of such systems. According to IRENA, their average global LCoE has fallen by 68% for onshore wind and 88% for solar PV over the last decade, averaging 33 and 48 USD/MWh respectively in 2021 (IRENA, 2022f). Both technologies are highly capital-intensive forms of energy generation, with the majority of the final cost of electricity being determined by the initial CAPEX and the associated capital cost (IEA, 2021c). A breakdown of the installation cost can be found in *Figure 41*. While the foundation, tower and nacelle account for the majority of the installed cost in the case of onshore wind, the modules and associated racking equipment make up a smaller part of the overall cost in the case of solar, with bigger portions coming from electrical equipment and installation costs.

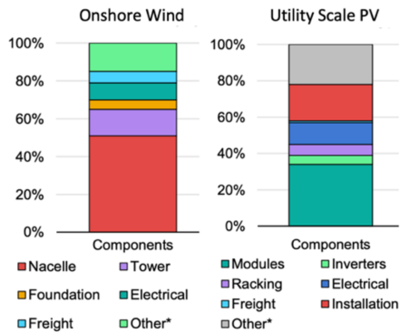


Figure 41: Installation cost breakdown for onshore wind (left) and utility scale solar PV (IEA, 2021c). Other costs include project development, management and financing.

According to the "Renewable Power Generation Cost 2021" report by (IRENA, 2022f), the global average in CAPEX was 1325 USD/kWp for onshore wind and 857 USD/kWp for utility-scale solar PV, although significant regional differences exist. As the chosen installed cost has a significant impact on the resulting levelized cost of electricity, country-specific costs have been considered for this study. The mentioned IRENA report provides such granular data, based on a comprehensive analysis of inputs by IRENA members, industry associations, governments as well as specific cost data from auctions and tenders. Sourcing this data from the same report ensures uniform system boundaries and direct comparability between countries. As the report does not provide data for solar PV in Switzerland and Morocco, these CAPEX values were obtained from country-specific analyses conducted by (Gupta *et al.*, 2020) and (Bouramdane *et al.*, 2021). For onshore wind, reported CAPEX values for Morocco were exceptionally low, with no indication in the text to explain such an anomaly. As no corroborating reports to justify such a low value could be found in literature, a more conservative estimate by (Touili *et al.*, 2020) was considered for this study. Further data gaps for Switzerland were filled using data from (Gupta *et al.*, 2020). As there is no literature data available on the installed cost of onshore wind in Saudi Arabia, the global average cost was employed. The resulting country-specific input CAPEX values that have been used in this report vary between 1081–2109 CHF/kWp for onshore wind and 767–1252 CHF/kWp.

Future cost developments of renewable energy technologies can be challenging to predict, especially against the backdrop of current supply chain disruptions, geopolitical uncertainties, and high inflationary pressures. As these factors might lead to a stagnation or even a slight increase of CAPEX values in the coming years, the overarching trends of efficiency improvements in production processes along with the further scaling of the associated value chains are expected to lead to further cost reductions in the long term (IRENA, 2022f). Due to the high uncertainties associated with predicting price developments decades into the future, reported values in literature vary widely (see *Table 15*). To account for these variations, three different cost reduction scenarios were considered in this study, assuming yearly CAPEX reduction rates of 2, 3 and 4% for solar PV and 0.5%, 1% and 1.5% for onshore wind.

Table 15: Literature CAPEX projections for solar PV and onshore Wind by 2050.

Source	Solar PV	Onshore Wind
(IRENA, 2019a) / (IRENA, 2019b)	165–481 USD/kWp	650–1000 USD/kWp
(Perner *et al.*, 2018)	306–667 EUR/kWp	780–1478 EUR/kWp
(BNEF, 2022a)	290–400 USD/kWp	1012–1262 USD/kWp
(Bauer *et al.*, 2019)	240–495 CHF/kWp	

OPEX only accounts for a small portion of the overall cost of solar PV plants and is mainly composed of preventive maintenance and module cleaning (IRENA, 2022f). In the case of onshore wind power, OPEX is higher and can compose up to a third of the final levelized cost of electricity (Stehly and Duffy, 2022). For the purpose of this study, a yearly OPEX of 1.5% of total CAPEX was considered in the case of solar PV and 2.5% for onshore wind, as proposed by (Perner *et al.*, 2018). A lifetime of 30 years was assumed for all power generation installations.

Due to the capital-intensive nature of renewable energy generation technologies, their economic performance is crucially dependent on their capacity factor, indicating how much electricity is produced compared to the total installed capacity. It is calculated by dividing the actual electricity output by the output that could be achieved if the system operated at full capacity (see *Equation 6*). To account for the significant regional differences in solar irradiation and wind speeds around the world, this study considers country-specific capacity factors. The respective data was extracted from the World Bank's "Global Solar Atlas" and "Global Wind Atlas" respectively. The provided GIS data layers were filtered to identify the most suitable areas for power generation for both onshore wind and solar PV and to determine respective country-specific capacity factors.

Equation 6

$$Capacity\ Factor = \frac{Annual\ power\ generation\ [kWh]}{Installed\ Capacity\ [kW] * 8760\ [h]}$$

An overview of the collected input parameters for electricity generation via onshore wind and solar PV can be found in *Table 16* and *Table 17*. In addition to the standalone electricity generation systems, a hybrid system consisting of 70% onshore wind and 30% solar PV has been considered. As there might be trade-offs necessary when searching for locations that are suitable for both wind and solar resources, the capacity factors of the top 25% of land mass were considered for hybrid systems, while the top 10% were used for standalone systems. The respective values with regards to CAPEX and OPEX were calculated proportionally.

Table 16: Calculation input parameters for onshore wind electricity generation.

Country	**CAPEX (2021) [CHF/kWp]**	**Yearly CAPEX Reduction**	**Annual OPEX**	**Capacity Factor (Top 10%)**	**Capacity Factor (Top 25%)**
Australia	1102	0.5% (pes) 1% (bas) 1.5% (opt)	2.5% of CAPEX	47.56%	43.03%
Chile	1480			65.19%	52.23%
Morocco	1081			43.89%	35.28%
Saudi Arabia	1246			43.05%	38.78%
Spain	1168			38.00%	31.12%
Switzerland	2109			34.20%	26.54%
United States	1299			50.88%	44.94%

Table 17: Calculation input parameters for solar PV electricity generation.

Country	**CAPEX (2021) [CHF/kWp]**	**Yearly CAPEX Reduction**	**Annual OPEX**	**Capacity Factor (Top 10%)**	**Capacity Factor (Top 25%)**
Australia	767	2% (pes) 3% (bas) 4% (opt)	1.5% of CAPEX	21.83%	21.63%
Chile	999			26.08%	25.21%
Morocco	1029			22.17%	21.75%
Saudi Arabia	876			22.50%	21.96%
Spain	962			19.42%	19.13%
Switzerland	1252			15.79%	13.79%
United States	1019			21.29%	19.38%

By their very nature, power output generated from wind and solar resources will be subject to variations, ranging from short term fluctuations within a timespan of seconds or minutes up to long-term intermittencies that occur within a year or even between different years. While such longer-term variations are considered insofar as the average yearly capacity factor has been used, the power output variations occurring within a single day warrant a closer look, as they can have significant impacts on the associated PtX fuel production.

When powering industrial equipment, such as electrolyzers or fuel synthesis plants, with variable electricity generation, their operational flexibility needs to be considered. Many industrial loads will be subject to certain limitations when it comes to ramping their rate of production up and down as energy generation fluctuates. In such cases, the variable electricity generation needs to be combined with a battery energy storage system (BESS) in order to smooth the electricity generation curve and provide a more stable electricity supply. Utility-scale BESS are usually composed of lithium-ion batteries (LIB), which have experienced a rapid surge in deployment over recent decades, accompanied by a drastic decrease in price. There are many different variations with regard to the battery chemistries of LIB, with the ideal solution usually depending on the application. For utility-scale BESS, lithium iron phosphate (LFP) batteries, are projected to be the dominant technology (Wood Mackenzie, 2020), due to their low price, long lifetime and high safety (Fallah and Fitzpatrick, 2023).

The main cost component of a LIB storage system is the battery pack itself, which is reported per kWh of storage, and the cost for the associated power unit, which is reported per kW. Due to the association economies of scale, the price of a battery decreases significantly in larger installations. For this study, current CAPEX data as well as future developments were based on a literature review by (Bauer *et al.*, 2022). Of the projected future cost ranges, the more conservative values have been chosen, considering the fact that possible battery supply bottlenecks will slow down the incredible price decreases that have been achieved in previous decades.

A general OPEX of 2.5% of CAPEX was assumed (Breyer *et al.*, 2018), as well as a battery lifetime of 15 years, after which the battery pack needs to be replaced (Armand *et al.*, 2020). As large scale BESS will likely consist of LFP batteries, a state of charge constraint between 10–90% was considered, meaning that 20% of the battery capacity is not available for charge cycling (Adeyemo and Amusan, 2022). Furthermore, a roundtrip efficiency of 90% is considered, in line with reported literature values (Mongird *et al.*, 2020; Terlouw *et al.*, 2022). An overview of all calculation input parameters can be found in *Table 18*.

Table 18: Calculation input parameters for the considered BESS.

Parameter	2020	2050
Battery pack CAPEX [CHF/kWh]	200	100
Power unit CAPEX [CHF/kW]	159	75
OPEX	2.5% of CAPEX	
State of Charge (SOC)	10–90%	
Roundtrip Efficiency	90%	
Lifetime [y]	15	
Replacement Factor	0.7	

To cover the range of possibilities of how variable electricity generation technologies can be coupled to industrial loads with varying degrees of flexibility, three distinct electricity supply scenarios were modeled for the purpose of this study, with increasing employment of BESS to achieve higher degrees of consistency with regards to power supply, namely Flexible, Variable, and Continuous.

In the flexible electricity supply scenario, the industrial load utilizes electricity as it is produced. This set-up can only be employed for loads with large flexibilities with regards to their operation, such as proton exchange membrane electrolyzers. For loads that can adjust their operation withing a certain limited range, a variable electricity supply scenario is constructed, which employs a BESS to ensure that a certain baseload of 20% of the installed load capacity is provided at all times, with the remaining operation remaining flexible. This option is employed for alkaline and solid oxide electrolyzers, which have a certain flexibility when it comes to ramping their operation, however idling time can lead to damage of the electrolyzer stacks. The third electricity supply model is called a continuous supply, which uses a BESS to smooth any variation in electricity generation and provides a constant supply of electricity. This option can be employed for all electrolyzers, as well as the rest of the feedstock generation and fuel production plants. An overview of which types of loads can be powered with which electricity supply can be found in *Table 19*.

Table 19: Overview of electricity demand profiles of loads.

Load	Flexible Electricity Supply	Variable Electricity Supply	Continuous Electricity Supply
PEME	x	x	x
SOE		x	x
AE		x	x
Feedstock Generation			x
PtX Fuel Synthesis			x

Electricity generation data from the three considered power generation set-ups (onshore wind, solar PV and hybrid) was modeled after literature datasets by (Zhang *et al.*, 2015), (Tiong *et al.*, 2015), (Teleke *et al.*, 2010), *(SPA, 2019)* and (Agrawal *et al.*, 2016) (see *Figure 42*). One important assumption that was made in this context, is that the daily solar and wind power output curves show a complementary behavior, manifesting as a slight drop in wind production during the day and an increase in power output at night. While such patterns are common in many parts of the world (Gerlach *et al.*, 2011), wind patterns can vary significantly based on geographic factors.

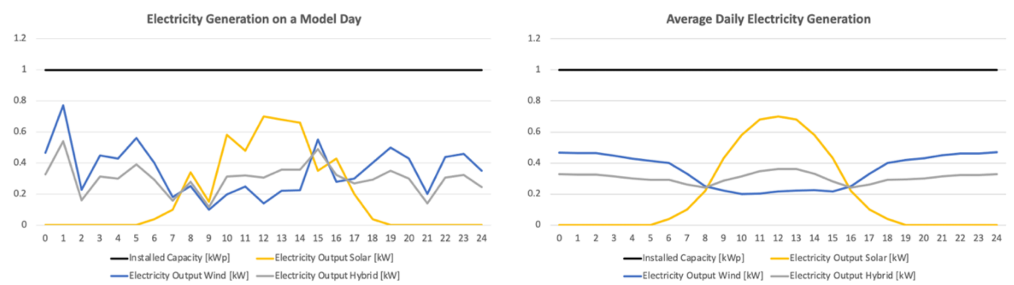


Figure 42: Output of the considered electricity generation technologies on a model day (left) and their average daily output throughout the year (right).

The results of the modelled electricity supply scenarios are illustrated in *Figure 43*, *Figure 44* and *Figure 45* respectively, while the determined operational parameters with regards to the relative sizing of power generation and consumption capacity, the size of the employed BESS and the resulting capacity factors are summarized in *Table 20*.

In the flexible electricity supply scenario, only a small battery of 0.2 kWh per kWp of installed wind and solar capacity needs to be employed to cover short-term fluctuations and avoid extreme ramping of the load (Teleke *et al.*, 2010). As hybrid systems can make use of complementary feed-ins from wind and solar (Gerlach *et al.*, 2011), 0.1 kWh/kWp of battery capacity suffice. To optimize the usage of the corresponding load, power generation capacity needs to be oversized. A DNV study found that when operating on an intermittent solar power supply, sizing electrolyzers at 70% of the energy generation capacity led to the lowest overall hydrogen cost (DNV, 2022). As load hours with an electricity output above this threshold are limited in the case of solar, resulting curtailing losses are negligible and will therefore not be accounted for in this study. Because load hours close to maximum capacity are much more common for wind energy, the optimal size of the electrolyzer is selected at 95% of the installed power generation capacity. For hybrid systems, a weighted average of 87.5% of energy generation capacity is employed. The described setup results in electrolyzer capacity factors of 29% in the case of solar, 37% in the case of wind and 35% for hybrid, assuming capacity factors of 20%, 35% and 30% of the respective power generation technologies.

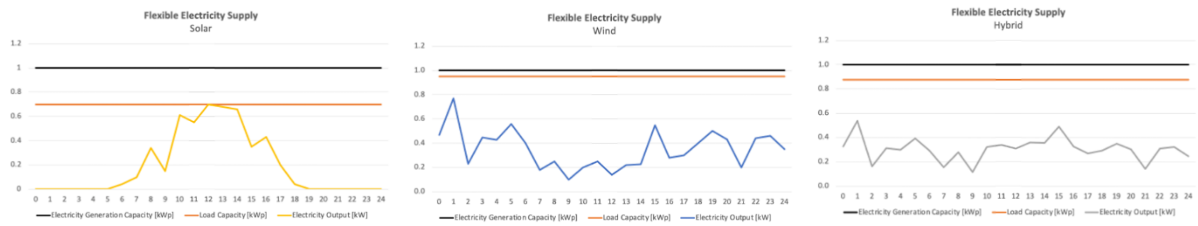


Figure 43: Overview of the installed power generation capacities, their corresponding power output and the load sizing in the flexible electricity supply scenario.

In the case of a variable electricity supply, larger battery capacities are employed to bridge the hourly variations in power generation and provide a smoothed power output curve. The battery sizing depends on the volatility of the respective power generation technology. In the case of standalone solar, (Hund *et al.*, 2010) estimate that 2.2 kWh per kWp of energy generation capacity is required. While solar power output only needs to be smoothed while the sun is shining, wind power output is subject to continuous fluctuations. Subsequently, the amount of required battery capacity increases to around 3.7 kWh per kWp of installed wind power (Zareifard and Savkin, 2016). In the hybrid system, the complementarity of wind and solar electricity generation reduce the volatility in their combined power output. Because this effect can only be exploited during daytime hours however, a battery capacity of 2.2 kWh per kWp of installed capacity is assumed. Standalone solar PV systems require an additional battery capacity of 1.43 kWh to bridge its diurnal cycle and ensure a baseload power supply during the night, while this is already achieved by the smoothed power supply curves in the case of wind and hybrid systems. The ability to spread out the generated power allows for increased oversizing of power generation, leading to much higher capacity factors of the connected loads.

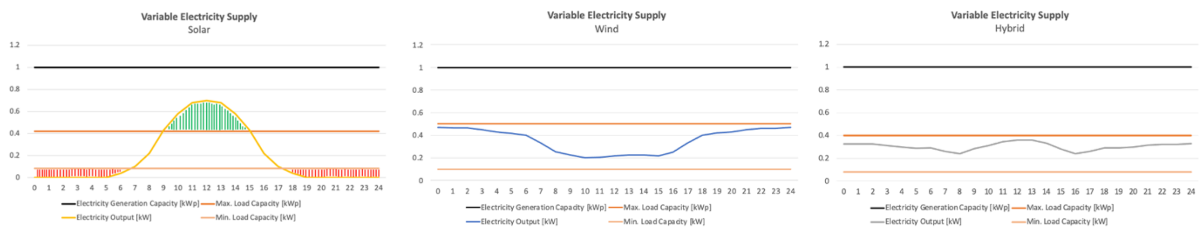


Figure 44: Overview of the installed power generation capacities, their smoothed power supply curves and the power demand range of the installed load in the variable electricity supply scenario. The shaded areas mark the charging (green) and discharging (red) process of the battery.

In the continuous electricity supply scenario, a constant supply of electricity is supplied to the associated loads. To achieve this, in addition to the battery capacity necessary to smooth the power supply to a daily average, additional battery capacity is added to evenly distribute the generated electricity throughout the day. The load is sized in a way that the excess electricity produced during periods of high power output is sufficient to cover demand in times of low or absent generation, taking into account battery roundtrip efficiencies and state of charge constraints. In total, a battery capacity of 5.77 kWh/kWp is necessary in the case of solar and 5.43 kWh/kWp in the case of wind. These results correspond nicely with literature values for optimization calculations in standalone solar and wind systems (Belouda *et al.*, 2016; Bortolini *et al.*, 2014). For a hybrid electricity supply, a smaller battery capacity of 2.95 kWh per kWp is sufficient, due to the complementarity of solar and wind electricity generation. A similar reduction in necessary battery capacity when switching from standalone solar or wind to hybrid systems have been reported in literature (Elsayed *et al.*, 2017).

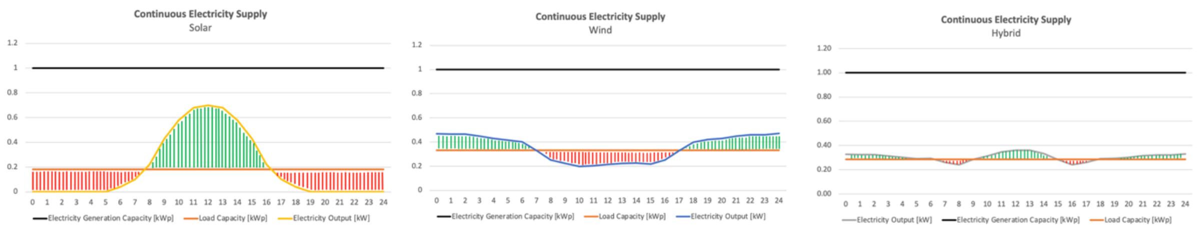


Figure 45: Overview of the installed power generation capacity, their average daily power supply and the electricity demand of the installed loads in the continuous electricity supply scenario. The shaded areas mark the charging (green) and discharging (red) process of the battery.

The determined operational parameters for the discussed set-ups are summarized in Table 20. In the following techno-economic analysis, they are combined with cost input parameters to determine the levelized costs of electricity (LCoE) for the various power generation technologies and power supply scenarios. The load capacity factors were further used to determine of the levelized cost of hydrogen (LCoH) and other PtX fuels (LCoX). It should be mentioned here that weather conditions, the resulting power generation curves and optimal fuel production set-ups can vary significantly depending on local conditions. This model aims to extract some generalizable insights, recognizing that doing so will inevitably require simplifications that reduce its accuracy in certain regions. In the cases where such considerations are crucial, location specific analyses should be additionally considered.

Table 20: Overview of the determined operational parameters for different electricity generation technologies and electricity supply scenarios. The determined parameters include the sizing of the load with respect to electricity generation capacity, the employed battery capacity and the achieved load capacity factor. Values are presented here for standardized capacity factors of 20% for solar, 35% for wind and 30% for hybrid, but adjusted for country-specific values in the calculation model.

Power Generation	**Flexible Power Supply**	**Variable Power Supply**	**Continuous Power Supply**
1 kWp Solar (CF=20%)	0.70 kW Load CF= 29% 0.20 kWh Battery	0.42 kW Load CF= 46% 3.63 kWh Battery	0.19 kW Load CF= 95% 5.77 kWh Battery
1 kWp Wind (CF=35%)	0.95 kW Load CF= 37% 0.20 kWh Battery	0.5 kW Load CF= 70% 3.70 kWh Battery	0.35kW Load CF= 95% 5.43 kWh Battery
1 kWp Hybrid (CF=30%)	0.88 kW Load CF= 35% 0.20 kWh Battery	0.4 kW Load CF= 76% 2.20 kWh Battery	0.30 kW Load CF= 95% 2.95 kWh Battery

3.3.1.2 Water (H_2O)

Water is another key feedstock for the production of PtX fuels, serving as the basis for hydrogen production through electrolysis. Large-scale PtX production facilities have a significant water demand. Stoichiometrically, approximately 9 liters of water are required to produce one kg of hydrogen (Shi *et al.*, 2020). After accounting for losses through evaporation, leaks, cleaning demands and a safety buffer, the number is closer to 13.5 liters (Simoes *et al.*, 2021). Subsequently, a 1 GW electrolyzer facility can consume up to 1.7 million m^3 of water per year (Madsen, 2022), which amounts to approximately 3% of the total consumption of the entire city of Zurich (Stadt Zürich, 2023). To accommodate such a demand dedicated water treatment facilities are required, which can use groundwater, treated waste water, surface water from rivers and lakes as well as seawater as their feedstock and convert it to ultrapure water ready for electrolysis (Madsen, 2022).

Ultrapure water needs to meet certain purity criteria to ensure optimal efficiency of the equipment and prevent damage to the electrolyzer (Ellersdorfer *et al.*, 2023). The type of required water treatment necessary to achieve these specifications depends on both the water feedstock used as well as the type of electrolyzer. One key parameter for assessing the water purity is its conductivity, which can indicate the presence of troublesome ions and molecules. Alkaline electrolyzers are less sensitive and can function well with water conductivity below 5 µS/cm, while PEM electrolyzers demand a higher purity, requiring a conductivity below 0.1 µS/cm (Madsen, 2022). To achieve these levels, the water needs to be deionized, which is usually done using Ion-Exchange (IX) systems, that replace unwanted ions with hydrogen or hydroxyl ions (Atlas Scientific, 2022).

In cases where seawater is chosen as a feedstock, desalination is necessary as a first step. Seawater desalination is a well-established technology, with over 20'000 desalination plants operating around the world (Ginsberg *et al.*, 2022). There are two main approaches to desalinating seawater, namely thermal and membrane-based processes. Today, reverse osmosis (RO) is the dominant membrane based technology on the market, accounting for more than half of global desalination capacity (Burn *et al.*, 2015). Considering thermal processes, multi-effect distillation (MED) is the most suitable technology for large scale applications (Ginsberg *et al.*, 2022). Due to its high energy demand, MED is usually more expensive than RO for drinking water applications, but the technology offers several advantages in the production of PtX fuels. Firstly, waste heat from the electrolyzer and fuel production processes can be re-used, dramatically reducing the associated energy cost. Furthermore, MED directly produces water that is pure enough for the less sensible electrolyzers, while water desalinated using RO has to undergo a further deionization step (Ginsberg *et al.*, 2022). Therefore, MED is starting to be regarded as the superior desalination technology for PtX fuel production (Ellersdorfer *et al.*, 2023). There has also been some research in the field of direct electrolysis of sweater, although since the energy required for desalination is diminishingly low compared to the electrolysis process, the efficiency losses of directly using seawater currently far outweigh the benefits of skipping the desalination step (see *Figure 46*).

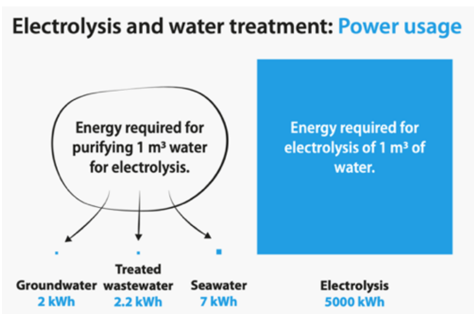


Figure 46: Comparison of the energy consumption for water desalination to that of water electrolysis (Madsen, 2022).

This study used seawater feedstock in countries with a high water stress. After MED desalination is completed, the water can be directly used as input for AE and SOE, while a further deionization step is necessary in the case of PEME. In countries that have abundant freshwater available, only a deionization step will be considered. The complete water purification scheme can be found in *Figure 47*.

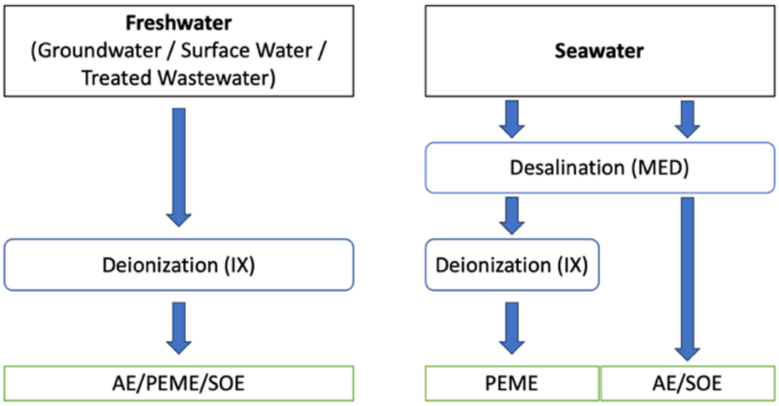


Figure 47: Overview of Water purification options depending on the type of water feedstock and electrolysis.

Installation cost for water treatment systems can vary widely, as regional factors such as water salinity, necessary pre- and post-treatment and local environmental regulations have a large impact on the plant requirements (Advasian, 2023). As a regional analysis into the local conditions in each considered country is beyond the scope of this study, a standardized assessment is necessary. A techno-economic assessment by *(*Ginsberg *et al., 2022)* determined the cost data of both desalination and deionization systems based on industry data provided by the Global Water Intelligence database. Although their reported values for MED are rather at the high end of cost data in literature *(*Ghaffour *et al., 2013)*, they are adopted for this report, due to the high credibility of the source and to ensure consistency between the technologies.

With regard to their energy demand, MED requires both thermal energy for the distillation process and electrical energy for circulatory pumping. The thermal energy consumption values reported in literature vary substantially. While a literature review conducted by *(*Ghaffour *et al., 2013)* resulted in values between 4–7 kWh_{th}/m^3, another one by (Al-Karaghouli and Kazmerski, 2013) reported values between 12–19 kWh_{th}/m^3 and *(*Ginsberg *et al., 2022)* had even higher values between 50–120 kWh_{th}/m^3. For purpose of this study, a medium value of 50 kWh_{th}/m^3 was assumed. The reported values with regards to the necessary electrical energy are more in alignment, usually between 1.5-2.5 kWh_{el}/m^3. Water deionization via IX only requires electricity, with a demand of 0.5 kWh_{el}/m^3 reported by *(*Hank *et al., 2020)*.

A lifetime of 30 years was assumed for the desalination plant *(*Caldera *et al., 2016)*. The expansion of the water desalination market in recent decades has led to immense decreases in its costs *(*Ghaffour *et al., 2013)*. However, in recent years, this trend seems to have stabilized. Therefore, the CAPEX and OPEX values are kept constant over the considered time frame. An overview of the operation and cost parameters used for the modelling of the water treatment can be found in *Table 21*.

Table 21: Input parameters for water treatment facilities.

Technology	**CAPEX [$CHF/m^3/d$]**	**OPEX [CHF/m^3]**	**Electricity Demand [kWh_{el}/m^3]**	**Heat Demand [kWh_{th}/m^3]**
Desalination (MED)	2092	0.19	2	50
Deionization (IX)	303	0.13	0.5	0

3.3.1.3 Carbon Dioxide (CO_2)

For the production of carbon based PtX fuels, such as methane, methanol and *Fischer-Tropsch* fuels, a sustainable feedstock of CO_2 is required. Carbon capture technologies are currently attracting a lot of interest from governments and industry alike, as it is becoming evident that reaching climate goals without them will be next to impossible (IEA, 2020). CO_2 can be filtered directly from flue gases of power generation plants and industrial processes through carbon capture (CC) or filtered out of the atmosphere using direct air capture (DAC). Both technologies are still in early stages of their commercialization, so there remains a lot of uncertainty about how far they can scale and how their costs might be reduced over the next decades.

The idea of capturing carbon emissions directly at their source has been around for a long time, although its concrete implementation only started to ramp up in recent years. Until September 2022, there were 197 carbon capture projects worldwide, 30 of which are in operation at an industrial level, with a combined annual capture capacity of 42.5 Mt of CO_2 per year (Global CCS Institute, 2022). *Figure 48* gives an overview of the different carbon sources, capture approaches, and capture processes, which will be briefly outlined in the following paragraphs.

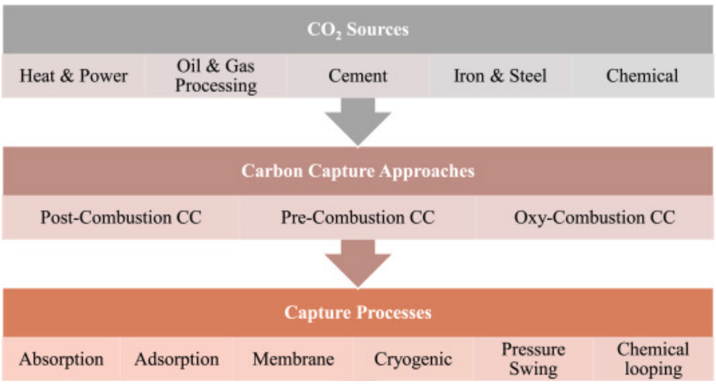


Figure 48: Processes involved in carbon capture from point sources (Olabi et al., 2022).

Carbon emissions can be captured from various point sources, which vary widely in their capture potential and waste stream compositions. Of the total 36.1 Gt of CO_2 emissions in 2022, 39.3% were emitted by the power sector, and 28.9% from industrial processes, such as steel, cement or chemicals production (Liu *et al.*, 2023). Both sectors consist to a large part of large scale, centralized plants, making them good candidates for point capture. Of the three main approaches to capture CO_2, only post-combustion capture is considered in this study, as the others require complex adjustments to existing processes, limiting their potential (Gaurina-Međimurec *et al.*, 2018). The effective CO_2 capture process can be achieved through a wide array of technologies including physical and chemical processes such as ad- and absorption, cryogenic separation, membrane separation, pressure swing absorption and chemical looping. The specific set-up of a carbon capture plant can vary greatly depending on flue gas composition and the industry process in which it is integrated.

Next to capturing CO_2 from industrial flue gases using CC, the feedstock can also be filtered directly from ambient air, using DAC technology. Unlike many of the industrial carbon sources, the acquired CO_2 feedstock is truly carbon neutral, as it removes all the carbon from the atmosphere that will be re-emitted upon combustion of any fuels that are produced from it. Another advantage of DAC is its geographic flexibility eliminating the need for a PtX fuel production site, to set up near industrial carbon sources. However, DAC is still less advanced in terms of its deployment compared to CC. By the end of 2022, there were only 18 direct air capture plants in operation worldwide, cumulatively capturing approximately 0.01 Mt CO_2 per year (IEA, 2022a).

The DAC technologies that are applicable on an industrial level today can be classified into two main approaches, namely the liquid and solid sorbent technologies (Chauvy and Dubois, 2022).

In the liquid sorbent approach, ambient air passes through an air contactor wetted by a liquid sorbent, usually a strong base such as KOH, that can dissolve CO_2 (McQueen *et al.*, 2021). The CO_2 depleted air is released, and the dissolved CO_2 is further processed over several reaction loops to regenerate the sorbent and recover pure CO_2. One main drawback of this capture technology is the high temperatures of up to 900 °C which are required for sorbent regeneration. If this heating step is achieved by combustion of natural gas, as is the case in several proposed projects, 0.5 tons of CO_2 will be released per ton of captured CO_2 for this step alone (Fasihi *et al.*, 2019).

Due to these significant drawbacks with regards to their sustainability, the solid sorbent approach is often favored, especially when producing carbon feedstocks in PtX production facilities. This process only requires low-temperature heat, which can be re-used process heat from the fuel production steps. This provides the technology with an economic advantage, in addition to the mentioned sustainability benefits. The technology works by making use of interactions between the CO_2 molecules in the air, and a solid sorbent material. Depending on the type of sorbent, these interactions can be weak intramolecular forces (physisorption) or strong covalent bonding (chemisorption) (McQueen *et al.*, 2021). As schematically represented in *Figure 49*, while the air flows through the contactor, the sorbent material progressively saturates itself with CO_2. Once saturated, the contactor is closed and the CO_2 is released by means of either a temperature or pressure adjustment and a pure CO_2 stream is recovered (Chauvy and Dubois, 2022). Although this system is a discontinuous process, a constant CO_2 stream can be achieved by running multiple units in parallel (Hank *et al.*, 2020).

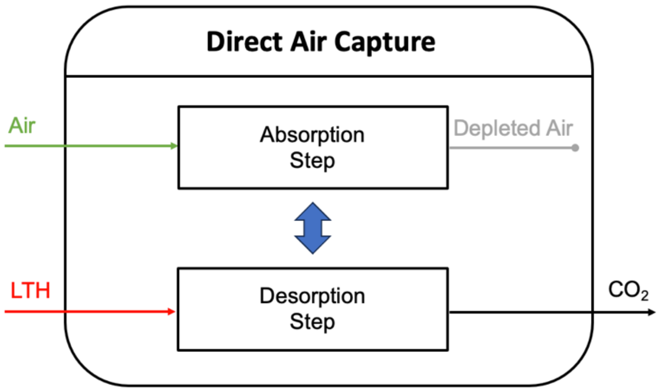


Figure 49: Simplified process flow diagram of direct air capture process, adapted from (Chauvy and Dubois, 2022).

Considering the cost of capturing carbon, the CO_2 concentration in the respective environment is the crucial factor. Some carbon waste streams, including those from natural gas processing, steam methane reforming, and other chemical production processes such as ammonia or bioethanol production, can contain up to 50–90% CO_2 and are therefore the cheapest to capture (IEA, 2021f). Unfortunately, these make up only around 5% of the total emission volume (McKinsey, 2023). The vast majority of carbon emissions come from lower-concentration sources, such as heat and power plants, cement production, or iron and steel mills. Here the CO_2 concentration in the flue gases is around 5–15%, making it significantly costlier to capture (IEA, 2021f). Capturing carbon from ambient air is much more challenging and therefore expensive, considering the CO_2 content of only around 400 ppm (Goeppert *et al.*, 2012). Another factor that needs to be considered for carbon capture from flue gases is the need to further to remove lingering impurities such as Sulphur, which could poison catalysts in subsequent PtX-fuel production (Götz *et al.*, 2016).

Extensive literature reviews on the cost of capturing carbon from point sources have been conducted by (Leeson *et al.*, 2017), (Brynolf *et al.*, 2018), (van Leeuwen and Zauner, 2018) and the (IEA, 2021f). An overview of the compiled data is shown in *Figure 50*. As the high concentration carbon sources only account for a small part of the total carbon emissions, they cannot reasonably be assumed to be available as the feedstock for the modelled PtX fuel production. Therefore, a rather conservative purchase price for carbon of 100 CHF per ton of CO_2 is assumed in the calculation model. As carbon capture expands, technology improvements and economies of scale are assumed to decrease linearly over the next decades, down to 50 CHF per ton in 2050.

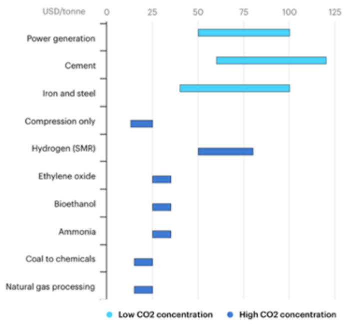


Figure 50: Levelized cost of CO2 capture by sector and CO2 concentration in the waste stream, adapted from (IEA, 2021f).

There is significantly more uncertainty when evaluating the current and projected costs of DAC. The Swiss company Climeworks, which operates DAC plants in Switzerland and Iceland with capacities of 900 and 4000 tons of CO2 per year respectively, claims that capturing a ton of CO_2 at its Swiss plant costs about 600 USD, a number that they expect to drop below $100 per ton in 5–10 years, as operations ramp up (Tollefson, 2018). Similar claims are being made by other companies in the field, for example Global Thermostat (Ping *et al.*, 2018). Literature reviews report a rather wide range of values such as 150–360 EUR/tCO_2 (van Leeuwen and Zauner, 2018) and 134–342 USD/tCO_2 (IEA, 2021f). There are also more critical reports, that estimate current costs to lie much higher, between 600–1100 USD/tCO_2 (Liebreich, 2023a).

For the purpose of this study, a DAC plant is modelled after cost and operational specifications reported by (Fasihi *et al.*, 2019), who combined an extensive literature review as well as sophisticated modelling of future technology and cost developments. As their resulting costs of carbon are rather low at 222 EUR/tCO_2 in 2020, their parameters are utilized for the optimistic scenario. To provide more reasonable base case and a pessimistic scenario, CAPEX values were adjusted so that the resulting carbon cost represents a wider array of reported literature values (see *Table 22*). Waste heat from the fuel production processes will be utilized in cases where it is available. If that is not or only partly the case, the remaining heat demand is supplied using electric heaters. A lifetime of 30 years is assumed for the DAC plant.

Table 22: Cost specifications for the modelled direct air capture plant

Technology	**Year**	**CAPEX (opt/bas/pes) [CHF/tCO_2/y]**	**Annual OPEX**	**Electricity [kWh_{el}/tCO_2]**	**Heat [kWh_{th}/tCO_2]**
DAC	2020	767, 1384, 2000	4% of CAPEX	250	1750
	2030	355, 928, 1500		225	1500
	2050	209, 605, 1000		182	1102

3.3.1.4 Nitrogen (N_2)

Nitrogen is required as a feedstock for the production of ammonia and can be obtained from ambient air by the use of an Air Separation Unit (ASU). There are several available technologies to separate ambient air into its components, of which cryogenic air separation is the most established for applications entailing high volume and purity requirements (Frattini *et al.*, 2016). The method makes use of the different boiling points of nitrogen (80 K at 1 atm) and oxygen (90 K at 1 atm) to separate them (Klein *et al.*, 2021).

After a compression step, further contaminants, such as water, CO_2 and hydrocarbons are removed in a pretreatment step (Klein *et al.*, 2021). The air is then cooled to cryogenic temperatures and can be distilled into pure oxygen, nitrogen, and argon streams. To conserve refrigeration, the product streams are warmed against the incoming air feed (see *Figure 51*). The product gases usually leave the unit slightly above atmospheric pressure and near ambient temperature (Smith and Klosek, 2001).

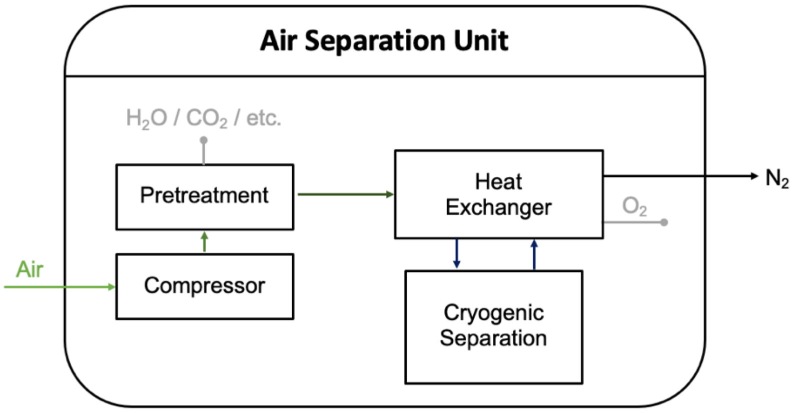


Figure 51: Schematic overview of a cryogenic air separation unit adapted from (Smith and Klosek, 2001) and (Klein et al., 2021).

ASU setups can vary widely, depending on the number and purity of product stream that are required, leading to large differences in associated capital cost and energy consumption (Smith and Klosek, 2001). As PtX production plants only require a nitrogen product feed, a less specialized unit that does not isolate argon can be employed. The electricity demand is the main cost driver of cryogenic air separation, and varies between 0.15–0.25 kWh/kgN_2 (Dey, 2022). Reliable CAPEX values were difficult to obtain, as in cost calculation this value is often integrated within the total CAPEX of Haber-Bosch plants. (Hank *et al.*, 2020) specified a CAPEX of 54 EUR/tN_2/y specifically for cryogenic air separation which was adopted for this study. An OPEX of 2% and a lifetime of 30 years is assumed, as are the values usually used for such combined Haber Bosch /ASU systems (Nayak-Luke and Bañares-Alcántara, 2020; Salmon and Bañares-Alcántara, 2022). An overview of the operation and cost parameters used for the modelling of the nitrogen feedstock generation can be found in *Table 23*.

Table 23: Input parameters for the calculation of nitrogen production cost.

Technology	**CAPEX [CHF/tN2/y]**	**Annual OPEX**	**Electricity [kWh_{el}/kgN_2]**
Cryogenic Air Distillation	57	2% of CAPEX	0.2

3.3.2 Electrolysis

During the process of hydrogen electrolysis, electrical energy is converted into chemical energy stored in hydrogen bonds. Discovered in 1800, electrolysis had been the primary technology for the production of hydrogen, before being displaced by steam methane reforming (SMR) which became more attractive due to the increasing availability of cheap natural gas (Lettenmeier, 2019). As calls for the phasing out of fossil fuels are increasing, electrolysis is now regaining its popularity. Although hydrogen production via electrolysis only makes up a tiny fraction of total hydrogen production today (IEA, 2022b), studies estimate that this share will dramatically increase over the next decades (BNEF, 2022c).

Fundamentally, an electrolyzer consists of a cathode and an anode, which are being separated by an electrolyte responsible for transporting charge carriers between the two. As the electrolysis is taking place, hydrogen gas is produced through a reduction reaction at the cathode, while oxidation takes place at the anode to evolve oxygen. The electrochemical reaction of splitting water into hydrogen and oxygen has a reduction potential of –1.23 Volt (see *Equation 7*), although higher voltages are required to drive the process in practice to overcome kinetic barriers as well as the ohmic resistance of the electrolyte (Lim *et al.*, 2021).

Equation 7

$$2H_2O \rightarrow 2H_2 + O_2$$

$$E_{cell} = -1.23\ V$$

In addition to the electrolyzer stacks, several system components are necessary to facilitate the entire process, such as electrical equipment, water supply and thermal management systems (see *Figure 52*). The required set-ups and operational parameters can vary significantly depending on the type of electrolyzer employed.

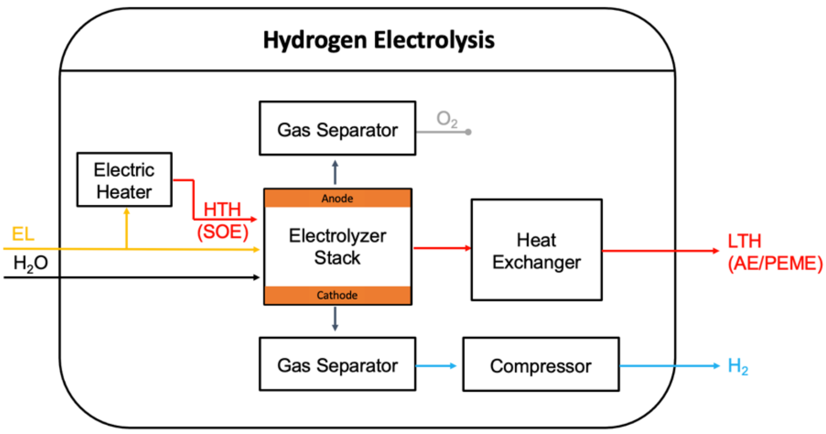


Figure 52: Simplified process flow diagram for electrolysis, based on (IRENA, 2020).

There are currently three major electrolysis technologies being regarded as viable options to produce hydrogen at a large scale within the next decades, namely alkaline electrolysis (AE), proton exchange membrane electrolysis (PEME) and solid oxide electrolysis (SOE) (see *Figure 53*). All of these systems are characterized by distinct advantages and disadvantages, which can make a direct comparison difficult (see *Figure 54*). The following paragraphs will focus on elaborating the intricacies that these technologies entail, before assessing their techno-economic and operational parameters in order to accurately model the cost of hydrogen production.

3.3.2.1 Alkaline electrolysis (AE)

Alkaline electrolyzers are by far the most mature electrolyzer technology, as they have been industrially employed for almost a century (Santos *et al.*, 2013). The system consists of nickel coated stainless steel electrodes separated by an aqueous KOH electrolyte and operates at temperatures between 70–90 °C and pressures below 30 bars (BNEF, 2023b). AE systems are currently the first choice for industrial-scale applications, due to their comparably low price and long lifetime. Consequently, (BNEF, 2023b) estimates that they account for around three quarters of the worldwide electrolyzer manufacturing capacity today. However, the technology also faces some challenges, including limited current densities due to the moderate mobility of hydroxide ions as well as corrosion issues arising from the KOH electrolyte (Kumar and Lim, 2022). AE also faces constraints concerning its operational flexibility, as frequent stops and starts can lead to a decreasing stack efficiency over time (Pieper, 2019). The diaphragms making up the physical barrier between the two electrodes are not able to completely prevent gas crossovers between the half-cells, which can give rise to safety concerns and leads to lower purity hydrogen (99.9%) (Kumar and Lim, 2022). There is ongoing research aimed at mitigating some of these issues, for example the development of anion exchange membranes (López-Fernández *et al.*, 2021), however such designs are still limited to the laboratory scale (Bauer *et al.*, 2022).

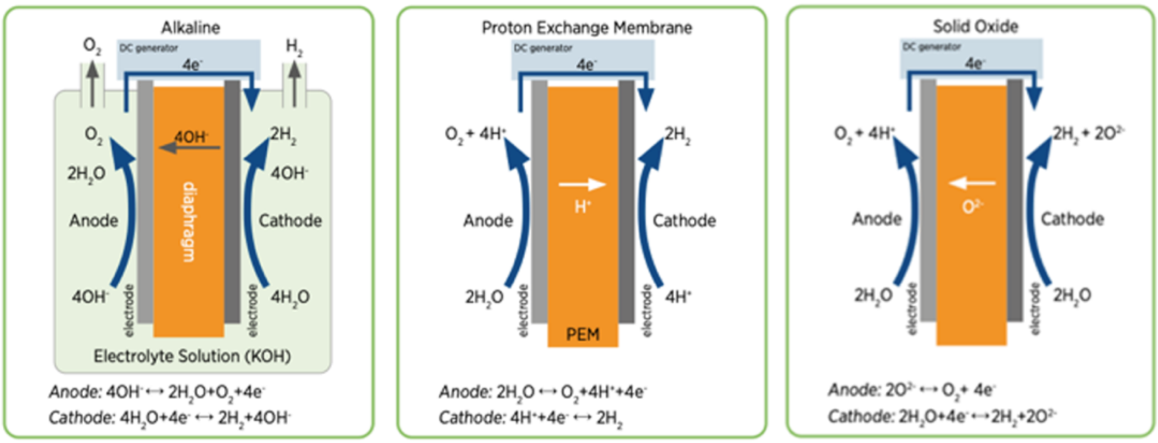


Figure 53: Schematic overview of the reactions taking place in AE, PEME and SOE (IRENA, 2020).

3.3.2.2 Proton Exchange Membrane electrolysis (PEME)

Proton exchange membrane electrolyzers use protons as their charge carriers, which travel between the electrodes through a sulfonated polymer membrane, allowing for higher current densities and producing hydrogen at much higher purity (99.999%) (Kumar and Lim, 2022). Another key advantage of this technology is the possibility for flexible operation, which makes it easy to couple to an intermittent electricity supply such as wind and solar (Pieper, 2019). Typical PEME systems operate at comparable conditions to their AE counterparts, with temperatures between 40–60 °C and pressures of up to 70 bar (Kumar and Himabindu, 2019). The acidic environment and high voltages lead to a harsh environment in the electrolyzer, which requires the employment of titanium based materials, protective coatings and electrodes made from expensive and scarce platinum and iridium metals (IRENA, 2020). Such requirements make current PEME systems more expensive than AE, although their potential for cost reduction through technological innovation as well as economies of scale remain substantial.

3.3.2.3 Solid oxide electrolysis (SOE)

Solid oxide electrolysis is a high temperature process, splitting water in the form of steam at temperatures of around 800 °C. Switching to high temperatures provides a favorable kinetic environment, leading to drastic improvements in the electrical efficiency of the electrolysis process, while allowing for the usage of relatively cheap nickel electrodes (IRENA, 2020). The electrodes in a SOE system are separated by a solid electrolyte, usually yttrium stabilized zirconium dioxide (von Hepperger, 2021). The high temperatures employed also open up innovative uses of this technology, such as the reversibility of the electrochemical reactions taking place, allowing it to switch between electrolysis and fuel cell operation as well as applications involving the co-electrolysis water with CO_2 to directly produce carbon based fuels (IRENA, 2020). The high temperatures also have a downside however, taking a high toll on the materials and leading to the relatively short lifetimes of this technology (Pieper, 2019). Additionally, as the employed materials are sensitive to high temperature gradients, some baseload operation needs to be guaranteed at all times, limiting the flexibility of such systems (Fogel *et al.*, 2019). Due to the early stages of the development that this technology is in, substantial cost reductions and lifetime improvements are expected, giving it the potential of becoming a true competitor to AE and PEME.

Electrolysis technology	Advantages	Disadvantages
Alkaline water electrolysis	• Well established Technology • Commercialized for industrial applications • Noble metal-free electrocatalysts • Relatively low cost • Long-term stability	• Limited current densities • Crossover of the gasses • High concentrated (5M KOH) liquid electrolyte
PEM water electrolysis	• Commercialized technology • Operates higher current densities • High purity of the gases • Compact system design • Quick response	• Cost of the cell components • Noble metal electrocatalysts • Acidic electrolyte
Solid oxide water electrolysis	• High working temperature • High efficiency	• Limited stability • Under development

Figure 54: Overview of advantages and disadvantages of the regarded electrolysis technologies (Kumar and Lim, 2022).

3.3.2.4 Operating Parameters

As the electrolyzer system is one of the key components of the PtX fuel production facility, its main operational parameters, such as efficiency, durability and flexibility need to be closely understood in order to obtain a reliable model for PtX fuel production. In the following paragraphs, these key variables are investigated. The determined operational parameters used for this study are summarized in *Table 24* at the end of this chapter.

As electricity consumption is one of the major cost factors in the production of green hydrogen, the efficiency is one of the most crucial performance parameters of an electrolyzer system (Lettenmeier, 2019). When analyzing data regarding the efficiency of any system, it is important to have clarity with regards to the boundaries of said system. In the context of electrolysis, efficiency values are usually reported either for a specific electrolyzer stack or for the whole electrolyzer system (van Leeuwen and Zauner, 2018). In both cases, the efficiency can be calculated by dividing the energy content of the produced hydrogen, which is the product of its mass (m_{H_2}) and lower heating value (LHV_{H_2}), by the electrical energy that was required for its production (P_{el}) (see *Equation 8*).

Equation 8

$$\eta_{LHV} = \frac{m_{H_2} \cdot LHV_{H_2}}{P_{el}}$$

While the system boundaries regarding the stack efficiency are quite clear, definitions with regards to the system efficiency have not been universally agreed upon, leading to large variations in reported literature values (van Leeuwen and Zauner, 2018). The situation is further complicated by the fact that system performance can vary depending on the operating load. While electrolyzer stacks show an increased efficiency at partial loads, the efficiency of some auxiliary equipment shows the opposite effect (see *Figure 55*). These factors make the comparison of reported efficiency values quite challenging, especially since the exact system boundaries and operation conditions are often not disclosed by literature sources.

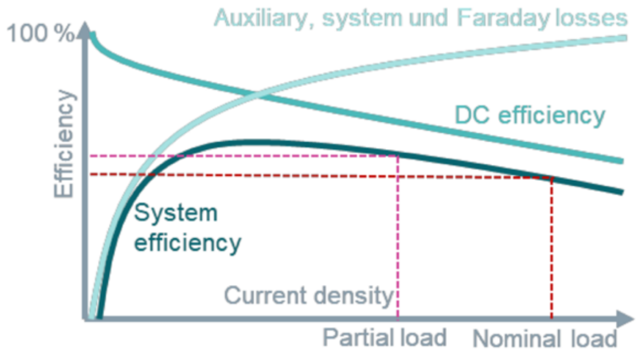


Figure 55: Components affecting electrolyzer system efficiency at a varying electrical load (Lettenmeier, 2019).

Consequently, compiled efficiency values in literature reviews have a very broad range, demonstrated by an (IRENA, 2020) study reporting electrolyzer efficiencies between 50–78% for AE and 50–83% for PEME. Another literature review by (van Leeuwen and Zauner, 2018) was able to slightly narrow these values down for AE (66–72%) although their ranges for PEME were still rather broad (59–77%). Efficiencies reported for SOE systems are associated with even higher uncertainty, as there are no industrially operational examples that might give an indication to their validity. A review by (Buttler and Spliethoff, 2018) estimate the range to be somewhere between 76–81%, including the energy demand for heat in their calculation. To account for the large variations and uncertainties with regards to literature values, three different efficiency scenarios were considered for the purpose of this study, modelled after a report by *(*Bauer *et al.,* 2022*)*, who compiled a comprehensive overview of efficiency variations between technologies and their development over time. A few minor adjustments to their values were made for this work, specifically the reduction of the optimistic AE scenario in 2050 from 80% to 75% and the increase of the optimistic PEM scenario in 2050 from 73% to 75%, as it seems unreasonable that AE will maintain such a large efficiency advantage in the future, especially once PEM electrolyzer systems scale up to larger systems.

Expanding the view from electrical efficiency to the total energy efficiency, the generation and consumption of heat in electrolyzer systems is an important component to be considered (see *Figure 56*). Due to voltage losses in the electrolyzer stack, AE and PEME release heat in their operation, which can partly be recovered and utilized to satisfy low temperature heat demand in the rest of the PtX production facility (Ginsberg *et al.*, 2022). A comprehensive heat management analysis for PEME systems found that around 17.1% of the initial power input to the electrolyzer can be recovered as usable heat (Tiktak, 2019). This number is lower for AE systems, due to the lower current densities employed. Simulations by (Holst, 2017) determined the share of reusable heat at 15.8 % of initial power input.

SOE on the other hand requires additional heat input for its high temperature operation. Thermal energy inputs account for around 20% of total energy demand in these systems (Liu *et al.*, 2022). Because this heat demand partly consists of high temperature heat, which is necessary to heat the inlet gases to stack operating temperatures (Min *et al.*, 2022), it cannot be supplied by the process heat from other fuel synthesis, and needs to be provided by electric heaters. For the purpose of this study, full conversion efficiency of electricity to heat was assumed, which allowed for the heat demand to be provided by the same electricity supply utilized for electrolysis.

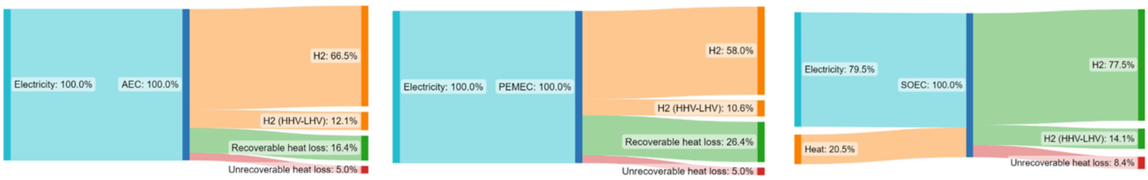


Figure 56: Schematic Overview of energy flows in AE, PEM and SOEC (left to right) electrolyzer systems (Liu et al., 2022).

Over time, continual voltage degradation leads to decreasing efficiency of the electrolyzer stacks, to the point where replacing them becomes economically beneficial (Bertuccioli *et al.*, 2014). As electrolyzer lifetimes are usually shorter than those of PtX production plants, they need to be replaced throughout its operation. Due to the fact much of the auxiliary equipment can be reused, replacement costs (REPEX) are usually only a fraction of the initial CAPEX. For this study, a replacement factor of 0.5 is assumed for all electrolyzer technologies (Bauer *et al.*, 2022).

Alkaline electrolyzer stacks currently have the longest lifetime of all regarded technologies. While (Bertuccioli *et al.*, 2014) reported in 2014, that leading electrolyzer manufacturers were able to achieve lifetimes of up to 90’000 hours, later reports by (IRENA, 2020) or the (IEA, 2019a) reported conservative estimates of 60’000 and 75’000 hours respectively. Such variations in reported data about an established technology seem surprising, however this might be explained by the varying definitions in operating conditions and the acceptable efficiency drop before replacement. Indeed, when (Felgenhauer and Hamacher, 2015) received quotes from 11 different commercial AE producers, the quoted system lifetimes ranged between 55’000 and 96’000 hours. To account for the large spread in lifetime values of AE systems, three different scenarios of 60’000, 75’000 and 90’000 hours are considered in this study. For PEM electrolyzers, both (Bertuccioli *et al.*, 2014) and the (IEA, 2019a) report a lifetime of 60’000 hours, with (IRENA, 2020) giving a range between 50’000–80’000 hours. A manufacturer survey by (Buttler and Spliethoff, 2018) returned an even larger spread of 60’000–100’000 hours. Considering these ranges, scenarios of 60’000, 70’000 and 80’000 hours are considered for the present study. For solid oxide electrolyzers, current lifetimes are much shorter than the low temperature technologies, both because of their early stages of development and the high heat stress under which they operate. Both the (IEA, 2019a) and (IRENA, 2020) report a lifetime of 20’000 hours in 2020. These values have been adopted for several techno-economic analyses of hydrogen production via SOE, such as (Bauer *et al.*, 2022) and (Christensen, 2020).

With regards to future estimated lifetimes for 2050, estimates for both PEM and AE range between 100’000 to 125’000 hours in the consulted studies. To account for this spread, scenarios of 100’000, 110’000 and 125’000 hours were assigned, with the lifetime values increasing linearly between 2020 and 2050. For SOE systems, estimates vary between 80’000 and 90’000 hours, whereby 80’000, 85’000 and 90’000 hours were considered as possible scenarios for 2050.

As previously discussed in *Chapter 3.3.1.1*, the type of power supply needs to be carefully considered for electrolyzer operation, as different technologies have varying limitations with regards to their flexibility in this aspect. Alkaline electrolyzers require a minimum operating capacity, usually defined at 20% of the nominal capacity, as frequent stops and starts in operation cause the stack to progressively degrade (Abdel Haleem *et al.*, 2022). While there have not been many studies on the dynamic operation of solid oxide electrolyzers (Kojima *et al.*, 2023), it is expected that due to the sensitivity of the employed materials to high temperature gradients, as well as the hour-long cold-start times, some baseload operation needs to be guaranteed at all times (Fogel *et al.*, 2019). Due to these limitations present in both AE and SOE, these technologies can only operate with a variable or continuous electricity supply. PEM electrolyzers on the other hand have been shown to operate well under a fluctuating electricity supply (Carmo *et al.*, 2013). With system responses within milliseconds (Smolinka *et al.*, 2011), and cold-start times of only a few minutes (Buttler and Spliethoff, 2018), they are ideally equipped to deal with fluctuations and intermittencies in power supply. Furthermore, flexible operation does not seem to lead to significant degradation in these systems (Kojima *et al.*, 2023). Therefore, PEME is the only technology that can operate in all three of the proposed power supply scenarios.

3.3.2.5 Cost Parameters

As with parameters concerning the operational performance of electrolyzer systems, literature data on their cost are subject to large variations. The reasons for these deviations are manifold, including the rapid pace of technological innovation, heterogeneity with regards to the considered plant sizes and chosen system boundaries, as well as industry secrecy around the topic. The latter reason leads to a lack of reliable up-to date data that is publicly available and forces many studies to reference cost data collected between 2014 and 2018 (Corbeau and Merz, 2023). Considering the rapid pace of industry innovation that has happened since, this leads to a high degree of uncertainty around the state of current costs.

Investment costs for electrolysis systems can be separated into costs for the electrolyzer stack and balance of plant (BoP) costs, which include auxiliary equipment such as power electronics and cooling systems. While BoP can be responsible for more than half of the total investment cost for smaller installations that share significantly reduces as plant sizes increase (Böhm *et al.*, 2020; Mayyas *et al.*, 2019). Costs for the electrolyzer stacks increases linearly with the overall system size, due to their modular nature (see *Figure 57*). As the PtX production facility considered for this study is a large-scale operation, cost data for maximally scaled systems will be considered.

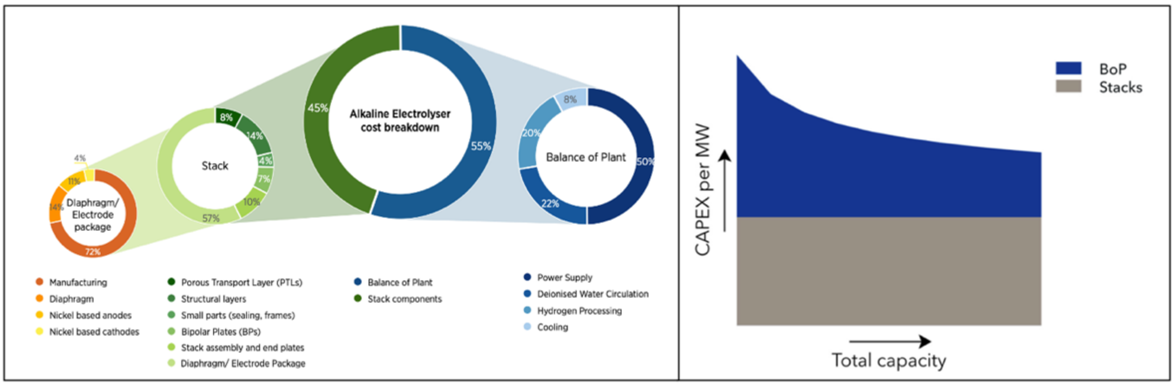


Figure 57: Investment cost breakdown for a 1 MW alkaline electrolysis system (IRENA, 2020), and how this distribution changes as systems scale (DNV, 2022).

Several reports reviewing installation costs of electrolyzer systems have been published in recent years, an overview of which is provided in *Figure 58*. These figures were combined with additional literature sources including (BNEF, 2022b), (Böhm *et al.*, 2018), (Bauer *et al.*, 2022), (Christensen, 2020), (Brynolf *et al.*, 2018), (Perner *et al.*, 2018) and (van Leeuwen and Zauner, 2018). Due to the large variation in reported data, three different scenarios were considered in the calculation model.

Present		2030	2050	Source
Alkaline				
700	2017	450	450	Fraunhofer, 2018
500 to 1,400	2019	400 to 850	200 to 700	IEA, 2019
500 to 1,000	2020			IRENA, 2020
540 to 900	2022			OIES, 2022
600 to 1,100	2022			Goldman Sachs, 2022
610	2022	344		DOE, 2022
Proton exchange membrane (PEM)				
1,460	2017	810	510	Fraunhofer, 2018
1,100 to 1,800	2019	650 to 1,800	200 to 900	IEA, 2019
700 to 1,400	2020			IRENA, 2020
667 to 1,450	2022			OIES, 2022
800 to 1,250	2022			Goldman Sachs, 2022
Solid oxide				
1,410	2017	800	500	Fraunhofer, 2018
2,800 to 5,600	2019	800 to 2,800	500 to 1,000	IEA, 2019
-	2020		<300	IRENA, 2020
2,300 to 6,667	2022			OIES, 2022
>1,850	2022			Goldman Sachs, 2022

Figure 58: Overview of system investment cost for electrolysis compiled by (Corbeau and Merz, 2023) based on data by (Smolinka et al., 2018), (IEA, 2019a), (IRENA, 2020), (Patonia and Poudineh, 2022), (Clarke and Della Vigna, 2022) and (DOE, 2023b).

AE systems are currently the most cost competitive option, due to their technological maturity and the low-cost materials employed (Miller *et al.*, 2020). Cost estimations reported in literature range between 500–1100 USD/kW$_{el}$, although some outliers do exist. Recently, (BNEF, 2022b) published an analysis highlighting the large variations in the production costs of Chinese manufacturers (400 USD/kW$_{el}$), compared to Western alternatives (1200 USD/kW$_{el}$). Such price discounts are usually accompanied by reduced quality parameters however, specifically with regards to efficiency and lifetime (Kumar, 2022). For the present study, 500 CHF/kW$_{el}$, 800 CHF/kW$_{el}$ and 1100 CHF/kW$_{el}$ were considered as reference installation costs in 2020. With significant economies of scale benefits expected in the coming years, especially European manufacturers should be able to rapidly reduce their costs, while cost reductions of Chinese manufacturers are expected to slow down (BNEF, 2022b). This will lead to a decreased cost range between the considered scenarios by 2030 of 300 CHF/kW$_{el}$, 500 CHF/kW$_{el}$ and 700 CHF/kW$_{el}$ respectively. By 2050, some studies projects global costs sinking to as low as 100 USD/kW$_{el}$ (BNEF, 2022b), although there are also much more conservative estimates (Christensen, 2020; Smolinka *et al.*, 2018). To accommodate this range of possibilities, scenarios of 200 CHF/kW$_{el}$, 350 CHF/kW$_{el}$, 500 CHF/kW$_{el}$ are considered.

PEM electrolysis system require higher upfront investments, due to their need for noble metal electrodes as well as other materials able to withstand its harsh operating conditions (IRENA, 2020). Current literature values usually range between 800 to 1500 CHF/kW$_{el}$. Recently, (BNEF, 2022b) increased their short-term cost estimations to 1500 CHF/kW$_{el}$, citing lingering supply chain issues as well as high commodity prices as the reason for doing so. They expect these effects to normalize over the next years however, with costs sinking to 500 USD/kW$_{el}$ by 2030 and around 100 USD/kW$_{el}$ by 2050. Generally, PEM systems are expected to have a higher CAPEX reduction potential than AE systems, as the technology is still set to profit from further innovation and system scaling effects. Considering these factors, 900 CHF/kW$_{el}$, 1200 CHF/kW$_{el}$, and 1500 CHF/kW$_{el}$ were set as baseline costs in 2020, decreasing to 500 CHF/kW$_{el}$, 700 CHF/kW$_{el}$, 1000 CHF/kW$_{el}$ by 2030 and 200 CHF/kW$_{el}$, 350 CHF/kW$_{el}$, 500 CHF/kW$_{el}$ by 2050.

Because SOE systems are still in the early stages of their development and their production encompasses a complex manufacturing process, current investment costs are much higher than those of the already commercialized technologies (Hauch *et al.*, 2020). Due to the larger uncertainties with this technology, the reported cost ranges also have a higher spread. While some reports suggest CAPEX values of as low as 1400 EUR/kW_{el} (Smolinka *et al.*, 2018), others report values of up to 6000 USD/kW_{el} (IEA, 2019a). For the calculation in this study, such outliers were avoided, and cost scenarios of 2000 CHF/kW_{el}, 2500 CHF/kW_{el}, and 3000 CHF/kW_{el} were assumed for 2020. Because of the massive technical improvements and economies of scale to be exploited, costs are expected to decrease rapidly, reaching 1000 CHF/kW_{el}, 1500 CHF/kW_{el}, 2000 CHF/kW_{el} in 2030 and 500 CHF/kW_{el}, 750 CHF/kW_{el}, 1000 CHF/kW_{el} in 2050.

Data on the OPEX of electrolysis systems are generally reported as a percentage of the system CAPEX, and ranges between 2–5% depending on the system in question (Brynolf *et al.*, 2018). These values include any additional operation and maintenance cost, that is not covered by the stack replacement cost discussed previously. AE systems have a comparably high maintenance cost due to the corrosive nature of the employed electrolyte, while PEM systems are usually quite robust and therefore cheaper in operation (Makhsoos *et al.*, 2023). Detailed OPEX data on SOE systems are quite scarce, although the high heat stress on system components will likely lead to an operating cost comparable to AE systems. Depending on the further usage of the produced hydrogen, the product stream needs to be further compressed. For further fuel synthesis considered in this study, compression to 40 bar is considered. As PEME systems already operate at such pressures, no additional costs are incurred in their case, while the cost of 0.05 CHF/kgH_2 and 0.1 CHF/kgH_2 are incurred for additional compression in the case of AE and SOE respectively (Christensen, 2020).

Table 24: Overview of the most important operating and economic parameters for the calculation model.

Parameter		**AE**	**PEME**	**SOE**
CAPEX (opt / bas / pes) [CHF/kW]	2020	500 / 800 /1100	900 / 1200 / 1500	2000 / 2500 / 3000
	2030	300 / 500 / 700	500 / 700 / 1000	1000 / 1500 / 2000
	2050	200 / 350 / 500	200 / 350 / 500	500 / 750 /1000
Annual OPEX		5% of CAPEX	3% of CAPEX	5% of CAPEX
Compression Cost [CHF/kgH_2]		0.05	0	0.10
Lifetime (opt / bas / pes) [1000 h]	2020	90 / 75 / 60	80 / 70 / 60	20 / 20 / 20
	2050	125 / 110 / 100	125 / 110 / 100	90 / 85 / 80
Replacement Factor		0.5		
Efficiency (opt / bas / pes) [%]	2020	70 / 67 / 58	65 / 61 / 58	83 / 82 / 81
	2050	75 / 71 / 61	75 / 73 / 70	90 / 90 / 88
Heat Balance [% of Power Input]		15.8%	17.1%	–20%
Water input [kgH_2O/kgH_2]		13.5		

3.3.3 Fuel Production

3.3.3.1 Ammonia (NH_3)

Ammonia is one of the largest-volume synthetically produced chemicals globally, as it plays a pivotal role in fertilizer production (Pattabathula and Richardson, 2016). Consequently, its production process has been thoroughly established and refined over decades. Current production of ammonia primarily relies on natural gas based hydrogen feedstock, a fact that makes it responsible for 1.4% of global CO_2 emissions (Capdevila-Cortada, 2019). To produce green ammonia, hydrogen produced via water electrolysis based on renewable energy is substituted as feedstock. In addition to its use in fertilizer production, renewable ammonia has also received increasing attention as a potential energy carrier and fuel to be used in sectors such as electricity generation, transport, or heating (Nayak-Luke *et al.*, 2018).

Industrial ammonia production employs the well-known *Haber-Bosch* process, wherein hydrogen and nitrogen gas react catalytically on an iron-based catalyst (see *Equation 9*). The process is characterized by a decrease in entropy, favoring lower temperatures and higher pressures. Due to the slow kinetics of the reaction however, high temperatures of around 500 °C at 200 bar are still necessary to drive the reaction (Giddey *et al.*, 2017). Given the exothermic nature of the reaction, waste heat of approximately 0.75 $kWh_{th}/kgNH_3$ can be reclaimed from the process (Smith *et al.*, 2020)

Equation 9

$$N_{2(g)} + 3N_{2(g)} \rightarrow 2NH_{3(g)}$$

$$\Delta H^0 = -91.8\ kJ$$

As per the findings of (Hank *et al.*, 2020), the production of 1 $kgNH_3$ involves the consumption of 0.18 kgH_2 and 0.84 kgN_2, resulting in a LHV efficiency of 87%. Additionally, the process demands approximately 0.5 $kWh_{el}/kg\ NH_3$, which is mainly used for the pressurization of the input gas feeds (Hank *et al.*, 2020; Nayak-Luke and Bañares-Alcántara, 2020). The NH_3 output is directly liquefied at –33 °C, facilitated by cooling obtained from the evaporation of N_2 feed. A simplified overview of the production process can be found in *Figure 59*.

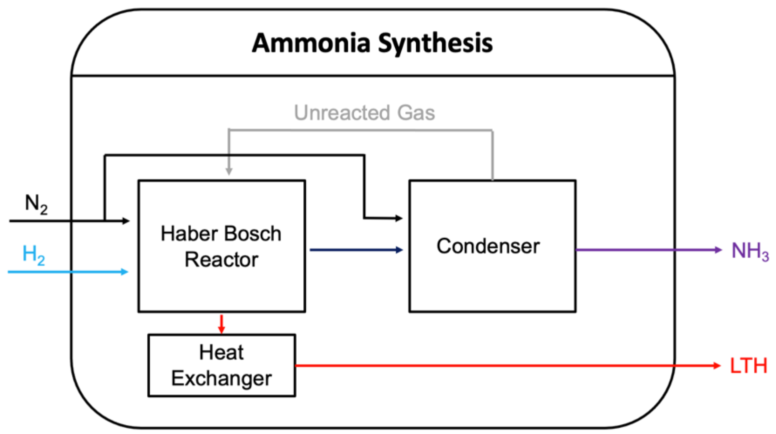


Figure 59: Simplified process flow diagram for ammonia synthesis based on (Ghadban et al., 2021).

Extensive literature reviews have been conducted regarding the installation and operating cost of ammonia synthesis plants (see *Figure 60*). The CAPEX of such plants decreases rapidly as their size increases, profiting from significant economies of scale. For the purpose of this study, CAPEX values for a large-scale operation have been utilized.[8] Accordingly, 600 USD/kW_{NH3} are chosen for the calculation model, which corresponds to 354 CHF/tNH_3/y assuming a capacity factor of 95%.

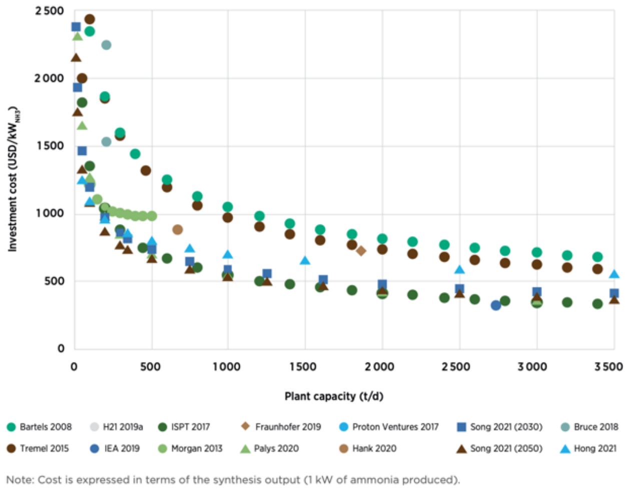


Figure 60: Overview of the reported investment cost for an ammonia synthesis plant as reported by several studies (IRENA, 2022c).

As the ammonia production process is extremely mature, its cost is expected to remain constant over the regarded time period (Nayak-Luke and Bañares-Alcántara, 2020). Literature data on yearly operational costs for the ammonia synthesis plant range between 1.5% and 4% of initial CAPEX values (IRENA, 2022c). For the present study, an average of 3% has been selected. An overview of the operation and cost parameters used for the modelling of the ammonia production process can be found in *Table 25*.

Table 25: Input parameters for the calculation of ammonia production cost.

	Ammonia Synthesis
CAPEX [CHF/tNH_3/y]	336
Annual OPEX	3% of CAPEX
Electricity [kWh_{el}/kgNH_3]	0.5
Heat [kWh_{th}/kgNH_3]	−0.75
Hydrogen [kgH_2/kgNH_3]	0.18
Nitrogen [kgN_2/kgNH_3]	0.84

[8] A 1 GW electrolyzer running at an average 50% capacity would deliver enough hydrogen to produce 2000 tNH_3 per day.

3.3.3.2 Methane (CH_4)

The process of producing methane from hydrogen and carbon dioxide is the reverse of the transformation taking place during the steam methane reforming (SMR), which is the dominant method for hydrogen production from natural gas feedstock today. The catalytic methanation process was first published in 1902 by French chemist Paul Sabatier, and has been historically utilized to remove CO and CO_2 from hydrogen rich gas streams, for example in the fertilizer industry (Vogt *et al.*, 2019). There has also been significant research in the field of biological methanation in recent years, a process that employs microorganisms which produce methane from hydrogen and CO_2 as part of their metabolism (Bauer *et al.*, 2022). As such projects are still largely on the pilot and demonstration level (Thema *et al.*, 2019), and might only be applicable for small-scale production plants (Perner *et al.*, 2018), this process will not be considered in this study.

Catalytic methanation is carried out at approximately 300–400 °C with a nickel-based catalyst (Bauer *et al.*, 2022), and is the reverse transformation which takes place during SMR (see *Equation 10*). The exact catalytic reaction pathways have not been universally agreed upon (Miao *et al.*, 2016), although it is believed that in total up to 11 reactions are taking place in the methanation reactor (Zoss *et al.*, 2016).

Equation 10

$$CO_2 + 3H_2 \rightarrow CH_4 + 2\,H_2O$$

$$\Delta H^0 = -165\ kJ$$

Process simulations conducted by (Brynolf *et al.*, 2018) and (Hank *et al.*, 2020) have determined that the production of one $kgCH_4$ requires on average 0.53 kgH_2 and 2.8 $kgCO_2$ as well as 0.14 kWh_{el}. This translates to a LHV conversion efficiency of 79% from hydrogen, which is in good agreement with other literature values (Perner *et al.*, 2018). Due to the exothermic nature of the reaction, waste heat of approximately 2.8 $kWh_{th}/kgCH_4$ can be recovered (Brynolf *et al.*, 2018; Hank *et al.*, 2020) (see *Figure 61*).

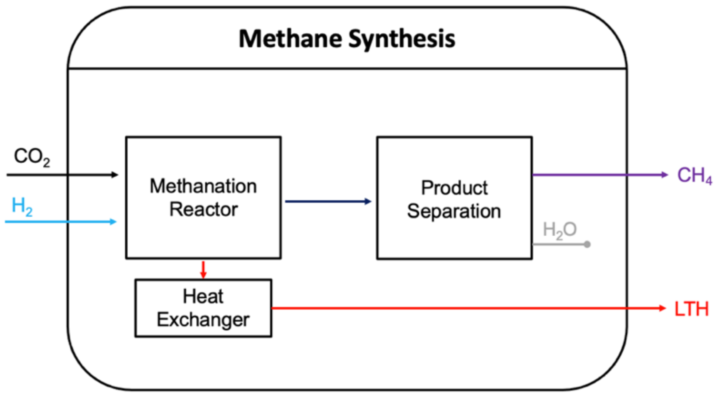


Figure 61: Simplified process flow diagram for methane synthesis based on (Castellani et al., 2017) and (Vogt et al., 2019).

The investment costs for methanation plants reported in literature vary widely. A review of techno-economic assessments by (Götz *et al.*, 2016) found values ranging from 130 – 1,500 EUR/kW_{CH4}. A later review with more data points by (van Leeuwen and Zauner, 2018) found an even wider range, between 107–2000 EUR/kW_{CH4}, with the most reasonable estimates ranging between 300–700 EUR/kW_{CH4}. A review by (Brynolf *et al.*, 2018) looking specifically at larger scale plants of 200 MW or above, found CAPEX values between 30–300 EUR/kW_{CH4}. Considering the plant regarded in this study will also be large scale, 300 EUR/kW_{CH4} are assumed as CAPEX for 2020, which is equivalent to 527 CHF/tCH_4/y when operating at a capacity factor of 95%. As methanation is already a reasonably well-established technology, future cost decreases are expected to be moderate, and mainly due to economies of scale (Perner *et al.*, 2018). Taking this into account, a CAPEX reduction to 330 CHF/tCH_4/y by 2050 has been assumed.

Data with regard to the operating cost of methanation reactors is not as widely available as investment cost data (van Leeuwen and Zauner, 2018). A number that is often cited in techno-economic analyses is 10% which had been initially reported by (Grond *et al.*, 2013). Although there are also studies that use lower numbers, such as (Perner *et al.*, 2018) with 3%, the more conservative value has been adopted for this study. An overview of the operation and cost parameters used for the modelling of the methane production process can be found in *Table 26*.

Table 26: Input parameters for the calculation of methane production cost.

	Methane Synthesis
CAPEX [CHF/tCH_4/y]	2020: 527 2050: 330
Annual OPEX	10% of CAPEX
Electricity [$kWh_{el}/kgCH_4$]	0.14
Heat [$kWh_{th}/kgCH_4$]	−2.80
Hydrogen [$kgH_2/kgCH_4$]	0.53
Carbon Dioxide [$kgCO_2/kgCH_4$]	2.80

3.3.3.3 Methanol (CH_3OH)

Conventionally, methanol is produced from syngas (CO and H_2), which is generally produced via steam methane reforming of natural gas (Ott *et al.*, 2012). To produce methanol in a carbon neutral way, captured CO_2 and green hydrogen can be used as alternative feedstocks. Today, there are few operational production plants producing green methanol, although several pilot plants are in development, ranging in production capacity between 60–2000 tCH_3OH per year. Comparing this to conventional methanol synthesis plants, which have production capacities of up to 2500 tCH_3OH per day (Alvarez, 2023), there is still a lot of scale to be achieved.

There are two possible reaction pathways for methanol synthesis, either the direct hydrogenation of CO_2 (see *Equation 11*), or via a reverse water gas shift reaction to produce syngas followed by conventional methanol synthesis (Battaglia *et al.*, 2021). Both of these processes have a high technological readiness level (Schemme *et al.*, 2018), but the direct hydrogenation pathway seems to be the technology with the largest commercial development perspective (Kotowicz *et al.*, 2021; Wilk *et al.*, 2016) and will therefore be employed in this assessment.

Equation 11

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$$

$$\Delta H^0 = -49.5\ kJ$$

CO_2 hydrogenation usually takes place in a fixed-bed reactor at approximately 250–300 °C, by employing a Cu-based catalyst (Sollai *et al.*, 2023). The reaction takes place at around 50–100 bar, as lower pressures would favor the formation of CO by water gas shift reaction (Battaglia *et al.*, 2021). Since only around 20–40% of CO_2 gets converted to methanol in a single pass, recycling the unreacted gases is critical for good conversion rates (Urakawa and Sá, 2014) (see Figure 62). The product stream is cooled to condense methanol and water and subsequently sent to the distillation column (Sollai *et al.*, 2023). The produced liquid methanol can be stored and shipped at atmospheric pressure (Marquez and Deign, 2023).

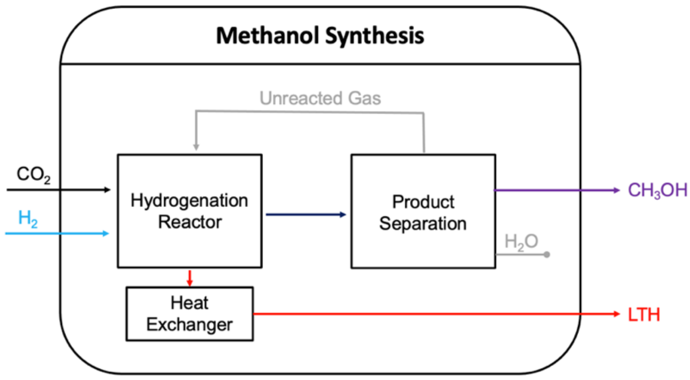


Figure 62: Simplified process flow diagram for methanol synthesis based on (Dieterich et al., 2020) and (Bowker, 2019).

Several process simulations and literature reviews have been conducted to determine required in- and outputs of the methanol synthesis process, including (Schemme *et al.*, 2020), (Hank *et al.*, 2020), (Bongartz *et al.*, 2019) and (Brynolf *et al.*, 2018). The reported data was in good agreement with regards to the required hydrogen input feed, at 0.19 kgH_2/kgCH_3OH, indicating a LHV efficiency of 87%. Data with regard to the CO_2 requirements had a broader range, averaging around 1.45 kgCO_2/kgCH_3OH. The process also requires around 0.25 kW_{el}/kgCH_3OH and releases 0.45 kW_{th}/kgCH_3OH of recoverable heat during fuel synthesis.

Compared to the widely analyzed electrolysis and methanation processes, fewer studies focus on the techno-economic analysis of methanol synthesis (Perner *et al.*, 2018). Available literature CAPEX values for large scale plants range between 200–400 EUR/kW_{CH3OH}, as reported by (Schemme *et al.*, 2020), (Brynolf *et al.*, 2018) and (Arnaiz del Pozo *et al.*, 2022). Assuming a capacity factor of 95%, an average investment cost of 300 EUR/kW_{CH3OH} translates to 210 CHF/tCH_3OH/y, which is chosen as the CAPEX value for 2020. As methanol synthesis is already a well-established technology, less cost reductions induced by technological innovation are expected. Nevertheless, standardization and scaling up of plant design has the potential to decrease investment cost, which are assumed at 140 CHF/tCH_3OH/y in 2050. OPEX values are adopted from a techno-economic assessment conducted by (Perner *et al.*, 2018) and were set at 3% of CAPEX. An overview of the operation and cost parameters used for the modelling of the methanol production process can be found in *Table 27*.

Table 27: Input parameters for the calculation of methanol production cost.

	Methanol Synthesis
CAPEX [CHF/t/y]	2020: 210 2050: 140
Annual OPEX	3% of CAPEX
Electricity [$kWh_{el}/kgCH_4$]	0.25
Heat [$kWh_{th}/kgCH_4$]	−0.45
Hydrogen [$kgH_2/kgCH_4$]	0.19
Carbon Dioxide [$kgCO_2/kgCH_4$]	1.45

3.3.3.4 Fischer-Tropsch Fuels ($C_{16}H_{34}$)

Longer-chain hydrocarbon fuels such as gasoline or diesel can be produced via the *Fischer-Tropsch* synthesis, a process which was invented in 1926 by Franz Fischer and Hans Tropsch, in an effort to turn coal into liquid hydrocarbons (Mahmoudi *et al.*, 2017).

The process is a catalytic polymerization reaction, turning syngas into longer chain-hydrocarbons by reacting it over a Fe or Co catalyst (Sayed Ahmed, 2022) (see *Equation 12*). Temperature conditions can be adjusted to alter the distribution of product chain length and usually range between 150–300 °C. Lower temperatures favor longer chains, producing diesel, naphtha and wax, while higher temperatures are used to produce gasoline and chemicals (Loosdrecht *et al.*, 2013). The resulting products are separated by distillation and absorption columns. To maximize fuel output, additional diesel product can be achieved from hydrocracking of wax and olefin oligomerization, while naphtha can be upgraded to gasoline in a refining step (Dieterich *et al.*, 2020). The resulting hydrocarbon fuels are often superior to their fossil counterparts, as they have low aromatics and no Sulphur content, resulting in cleaner combustion (Steynberg and Dry, 2004).

Equation 12

$$(2n+1)\ H_2 + n\ CO \rightarrow C_nH_{2n+2} + n\ H_2O$$

$$\Delta H^0 = n(-165\ kJ)$$

To produce carbon neutral *Fischer-Tropsch* fuels, captured CO_2 and green hydrogen need to be converted to syngas by means of a reverse water gas shift (RWGS) reaction. This is usually done prior to the *Fischer-Tropsch* reactor (see *Figure 63*), although some ongoing research exists which relies on the direct hydrogenation of CO_2 (He *et al.*, 2019). For the present study, the two-step process will be considered, as it is the commercially more mature option.

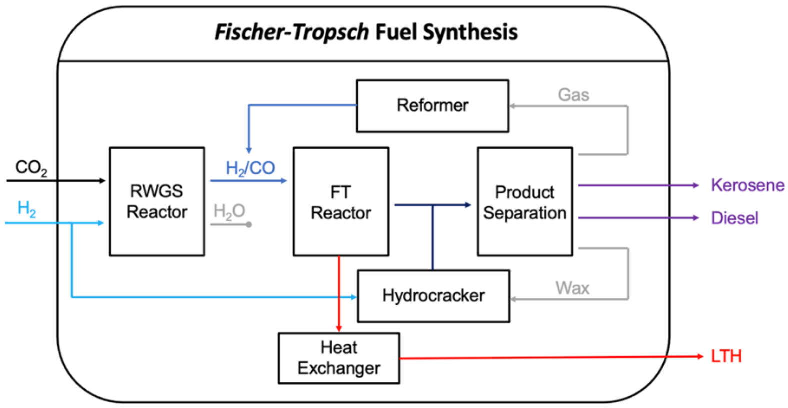


Figure 63: Simplified process flow diagram for the synthesis of Fischer Tropsch Fuels, based on (Schemme et al., 2020).

For this study, *Fischer-Tropsch* fuels are represented as $C_{16}H_{34}$, which represents an average product chain length and amounts to a LHV of 12.21 kWh/kg (Samsun *et al.*, 2015). Process simulations by (Schemme *et al.*, 2020) concluded that approximately 0.48 kgH_2 and 3.06 $kgCO_2$ are required to produce 1 $kgC_{16}H_{34}$, indicating a LHV efficiency of 76%. Similar values were reported in a literature review by (Brynolf *et al.*, 2018). Furthermore, the process consumes 0.30 $kW_{el}/kgC_{16}H_{34}$ and releases 5.6 $kW_{th}/kgC_{16}H_{34}$ usable process heat (Schemme *et al.*, 2020).

Literature data on the investment cost for large-scale *Fischer-Tropsch* synthesis plants, including a RWGS reactor and additional facilities for product upgrading, range between 300–700 EUR/kWh$_{C16H34}$ (Brynolf *et al.*, 2018). (Schemme *et al.*, 2020) utilized 666 EUR/kW$_{C16H34}$ for their process simulation study and (Perner *et al.*, 2018) used 788 EUR/kW$_{C16H34}$ in their techno-economic assessment. For this study, 600 EUR/kW$_{C16H34}$ were assumed for 2020, which corresponds to 925 CHF/t$C_{16}H_{34}$/y at a capacity factor of 95%. *Fischer-Tropsch* synthesis and upgrading is a mature technology (Varone and Ferrari, 2015), whereas the RWGS reaction is still less developed. Therefore, a moderate cost reduction down to 700 CHF/t$C_{16}H_{34}$/y until 2050 is considered. Both (Perner *et al.*, 2018) and (Fasihi *et al.*, 2016) assumed an operating cost of 3% of CAPEX per year, which will be adopted for this study. An overview of the operation and cost parameters used for the modelling of *Fischer-Tropsch* fuel production process can be found in *Table 28*.

Table 28: Input parameters for the calculation of Fischer-Tropsch fuel production cost.

	Fischer-Tropsch **Fuel Synthesis**
CAPEX [CHF/t$C_{16}H_{34}$/y]	2020: 925 2050: 700
Annual OPEX	3% of CAPEX
Electricity [kWh$_{el}$/kg$C_{16}H_{34}$]	0.30
Heat [kWh$_{th}$/kg$C_{16}H_{34}$]	−5.60
Hydrogen [kgH_2/kg$C_{16}H_{34}$]	0.48
Carbon Dioxide [kgCO_2/kg$C_{16}H_{34}$]	3.06

3.4 PtX Fuel Supply Chain

While most hydrogen is produced at the point of demand today (FCHO, 2021), the other PtX fuels considered in this study are already globally transported along well-established supply chains. To develop a comprehensive understanding of the available import options, the developed techno-economic assessment model takes into account all relevant supply chain costs. In addition to the cost of all major transport methods, this includes costs for any conversion and reconversion steps that might be necessary to convert the fuels into a transportable form, as well as costs for intermediate storage prior to transport (see *Figure 64*).

While liquid fuels can be transported with relative ease, those inhabiting a gaseous state at standard conditions need to be converted prior to transport, in order to achieve a better energy density. Such a transformation can consist of compression, liquification or even the conversion to another chemical substance. While the liquefaction of ammonia and natural gas is already well established, the optimal transport medium for hydrogen remains undecided. Potential candidates include compression, liquefaction, conversion to ammonia or methanol, as well as binding it to a carrier molecule such as a liquid organic hydrogen carrier (LOHC). All of these options are regarded in this assessment, to compare their performance and derive conclusion regarding their suitability for facilitating future hydrogen transports.

In the context of PtX fuel transport, shipping is the only viable option for transporting fuels from overseas exporters to Europe, with the exception of exporters that are close enough for the connection to a European pipeline system. For the further transportation within Europe and onward to Switzerland the options are more varied, including rail, truck, barge and pipeline transport. All of these options are evaluated within the supply chain model, together with the available options for PtX fuel storage prior to transport.

An overview of all determined supply chain cost parameters can be found in *Table 29* at the end of this section. The results of the supply chain assessment and the resulting delivered cost of PtX fuels in Switzerland are discussed in *Chapter 3.5*.

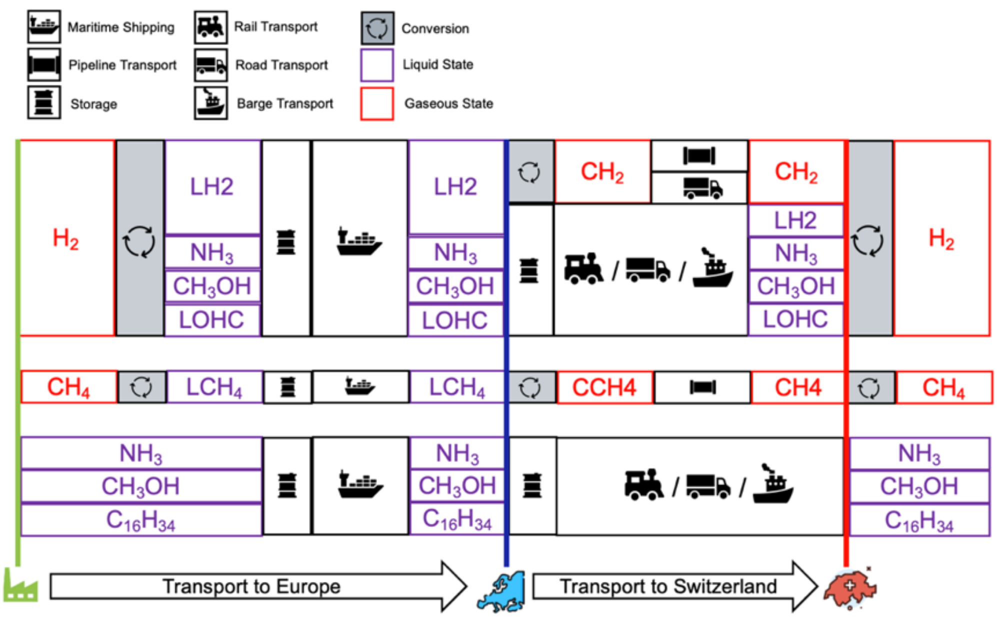


Figure 64: Schematic overview of the PtX fuel supply chain pathways available for their import to Switzerland.

3.4.1 Conversions

While some PtX fuels, such as methanol and *Fischer-Tropsch* fuels, are already liquid at room temperature and can be directly transported, others require prior conversion steps to ensure their efficient transportability.

While hydrogen has the highest gravimetric energy density of any energy carrier, its low volumetric energy density poses several challenges to its transport (Allendorf *et al.*, 2022). To mitigate this issue, hydrogen is converted either physically or chemically, both to increase its volumetric density but also to make its handling easier. An overview of the hydrogen densities in some of its most common transport forms can be found in *Figure 65*.

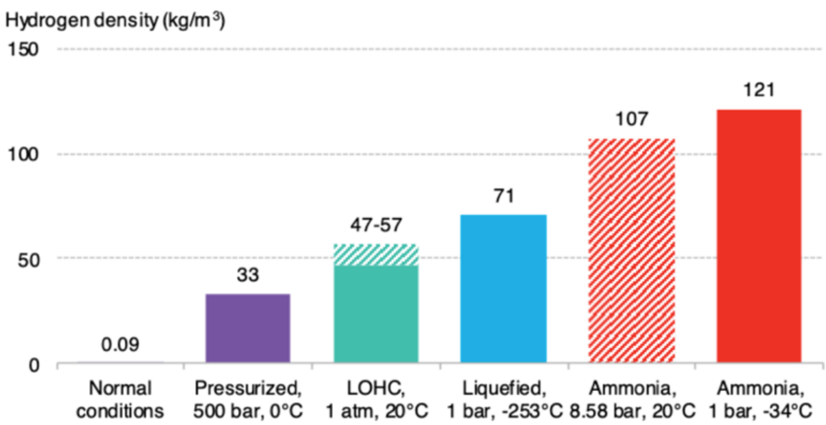


Figure 65: Hydrogen densities in different types of transport media (BNEF, 2019b). Liquid methanol has a hydrogen density of around 100 kg/m³.

The most straightforward methods to increase hydrogen's volumetric density are physical conversions, namely its compression or liquefaction. Hydrogen compression is a well-established technology, and possible up to pressures of 1000 bar, although for practical transport and storage uses 500 bar are common (BNEF, 2019b). Compressing hydrogen to 500 bar consumes around 3.9 kWh/kgH_2, more than 10% of hydrogen's LHV, and increases its density by a factor of 350. Hydrogen compression costs of 0.25 CHF/kgH_2 are assumed for this report based on numbers reported by (BNEF, 2019b) and the (IEA, 2019a).

Hydrogen liquefaction is achieved at cryogenic temperatures of −253 °C, and reduces its volume 800-fold (Kawasaki, 2019). This process is very energy intensive, requiring energy for pre-cooling, condensation, as well as to facilitate the ortho-para nuclear conversion that takes place during the liquefaction process. The physical minimum energy required to facilitate this process is 3.90 kWh/kgH_2 (Kamiya *et al.*, 2015), although in practice this number is often much higher at around 10 kWh/kgH_2 of hydrogen. Considering technology improvements, projections assume that this number will drop to around 6 kWh/kgH_2 over the next decades (Hank *et al.*, 2023). Liquefaction infrastructure does exist today, although it would need to be scaled up tremendously to facilitate global liquid hydrogen supply chains (d'Amore-Domenech *et al.*, 2021). Cost estimation for the liquefaction process range from 1 USD/kgH_2 (IEA, 2019a) to 3.95 USD/kgH_2 (BNEF, 2019b). A literature review by (Bauer *et al.*, 2022) reported costs between 1.07 to 1.59 CHF/kgH_2, which are in line with calculations by (Meca *et al.*, 2022) which assume the availability of a widespread hydrogen infrastructure and calculated cost of 1.68 USD/kgH_2. Taking these findings into account, this study assumes liquefaction cost of 2.5 CHF/kgH_2 in 2020, dropping to 1 CHF/kgH_2 in 2050. The cost for the re-conversion of liquefied hydrogen to its gaseous form is assumed at 0.018 CHF/kgH_2, based on the equivalent regasification cost of natural gas (Molnar, 2022).

Although physical conversion methods can significantly increase the energy density of hydrogen, the achieved values are still less than half the energy density of liquefied natural gas (LNG) and only a fifth of oil (Sano, 2009). Additionally, supply chains transporting molecular hydrogen are confronted with added challenges, such as leakage (Fan *et al.*, 2022) and embrittlement of materials exposed to the hydrogen (Moradi and Groth, 2019). To circumvent these challenges, the option of chemically transforming hydrogen to energy carriers with a higher energy density and easier handling have been proposed. The most discussed candidates are fuels such as ammonia and methanol, but also LOHCs such as toluene. To satisfy a respective demand at their destination, the fuels need to be re-converted back to hydrogen after transport.

The conversion of hydrogen to ammonia and methanol has been elaborated as part of the PtX fuel production model in *Chapter 3.3*. The determined conversion cost will be directly utilized for the transport model. Reconversion processes of these fuels are less technologically mature, as there have not been many commercial applications for such transformations.

Reconverting ammonia back to hydrogen requires a process called ammonia cracking (see *Equation 13).* This process has not been commercialized, and dedicated catalysts are still under development (Makhloufi *et al.*, 2019). Current catalysts require high temperatures between 500–900 °C and the process is therefore characterized by a high energy demand of around 7.9 kWh/kgH_2 (Bauer *et al.*, 2022; IRENA, 2022c).

Equation 13

$$NH_3 \rightarrow \frac{3}{2}H_2 + \frac{1}{2}N_2$$

$$\Delta H^0 = 45.9\ kJ$$

To achieve a pure hydrogen stream, further purification steps such as membrane separation or cryogenic distillation are required after the cracking step (Makhloufi *et al.*, 2019). For the overall process, the energy losses are at least 15% of the total energy contained in the converted hydrogen, reaching up to 30% when accounting for leakage and thermal losses (IRENA, 2022c). Literature values on the costs for this reconversion process vary widely, ranging from more conservative estimations of 2.35 USD/kgH_2 (Lee *et al.*, 2022) to much lower values of 0.8 USD/kgH_2 (IEA, 2019a). Several assessments fall somewhere in between, such as (BNEF, 2019b) at 1.44 USD/kgH_2 and (Makhloufi and Kezibri, 2021) at 1.71 EUR/kgH_2. For this study, a value of 1.50 CHF/kgH_2 was chosen, dropping linearly to 1.00 CHF/kgH_2 by 2050, accounting for expected cost savings from technological progress and economies of scale.

When considering the conversion of methanol back to hydrogen, steam reforming is currently the option with the highest technical maturity (Lee *et al.*, 2022) (see *Equation 14*). This process takes place at temperatures of up to 400 °C, and requires an energy input of approximately 5 kWh/kgH_2 (Meca *et al.*, 2022). Current research is focused on developing better catalysts that would allow for operation at lower temperatures (Schwarz *et al.*, 2020), as well as developing entirely new approaches, such as the electrochemical splitting of methanol (Pethaiah *et al.*, 2020).

Equation 14

$$CH_3OH + H_2O \rightarrow 3H_2 + CO_2$$

$$\Delta H^0 = 49.2\ kJ$$

Due to the early stages of such new approaches, the present study will focus on the well-established methanol steam reforming. Reliable cost data is rather rare in literature and varies significantly, with reported values ranging from only 0.54 USD/kgH_2 (Meca *et al.*, 2022) to 2.14 USD/kgH_2 (Lee *et al.*, 2022). A specialized analysis on methanol reforming conducted by (Byun *et al.*, 2020) found conversion costs of 1.13 USD/kgH_2, with significant cost reductions being expected in the next decades. Based on this data, a reconversion cost of 1.30 CHF/kgH_2 was assumed for 2020, dropping linearly to 0.75 CHF/kgH_2 by 2050.

While there is a plethora of available options for liquid organic hydrogen carrier systems, the present study will focus on the toluene-methylcyclohexane system as it most technologically mature (Bárkányi *et al.*, 2023). During hydrogenation, the aromatic ring of toluene is saturated, resulting in the stable methylcyclohexane, which is easy to transport (Niermann *et al.*, 2019). Unlike ammonia or methanol, whose feedstocks are entirely turned to gas during the reconversion process, LOHC molecules can be re-used for several transport cycles, implying that they need to be returned to the production plant after dehydrogenation, which adds transport cost. On the flipside, the initial investment for the carrier molecule, which is in the range of approximately 0.30 CHF/kg for toluene (Hurskainen and Ihonen, 2020), can be depreciated over several trips.

The hydrogenation reaction of toluene is shown in *Equation 15* and takes place at temperatures between 100–200 °C utilizing either a Pt or Ni based catalyst (Niermann *et al.*, 2019). Cost estimates reported in literature for these conversion steps are in rather good alignment, between 0.30–0.40 USD/kgH_2 (IEA, 2019a; Lee *et al.*, 2022). In this study, an average value of 0.35 CHF/kgH_2 is adopted.

Equation 15

$$C_7H_8 + 3H_2 \rightarrow C_7H_{14}$$

$$\Delta H^0 = -204.9\ kJ$$

The endothermic dehydrogenation reaction of methylcyclohexane, requires higher temperatures of around 400 °C (Niermann *et al.*, 2019), leading to high energy consumption driving up reconversion costs, which are currently estimated at around 2.20 USD/kgH_2 (Lee *et al.*, 2022). For this report, 2.15 CHF/kgH_2 are chosen for 2020, including a linear reduction to 1.00 CHF/kgH_2 by 2050, an assumption that is based on cost projections by the (IEA, 2019a) and (BNEF, 2019b).

Hydrogen is not the only fuel that requires conversion steps prior to transport. As both ammonia and methane are not liquids at room temperature, they need to be liquefied prior to transport. The conversion of ammonia into its liquid state is already considered as part of the production model, as this step can be directly achieved by utilizing thermal integration with the associated air separation unit. Similar to hydrogen, methane needs to be cryogenically liquefied at −162 °C to enable its transport, a process which reduces its volume by a factor of 600. The infrastructure for the large scale liquefaction and regasification of natural gas is already in place all around the world, which is why this process is already highly efficient and involves costs of 0.108 CHF/kgCH_4 and 0.018 CHF/kgCH_4 respectively (Molnar, 2022).

3.4.2 Transport

To evaluate the supply chains for PtX fuels in Switzerland, the available transport options for each fuel are elaborated in the following paragraphs, and their respective cost parameters are determined.

Although hydrogen is not transported on a large scale today, several transport technologies have been shown to be reliable, such as regional pipeline networks as well as trucking hydrogen in its gaseous or liquid form (DOE, 2023a). Liquefied hydrogen trailers consist of steel tanks and currently have a capacity between 2.6–5 tH_2 (BNEF, 2019b). Although the tanks are well insulated, boil-off losses can reach 0.3–0.6% per day (Bauer *et al.*, 2022). Gaseous hydrogen on the other hand is usually transported in tube or container trailers, with capacities between 200–1100 tH_2, depending on their pressure level (BNEF, 2019b). Due to the high material cost and low capacity, compressed hydrogen transport is only suitable for short distances, with liquefaction being the superior option for longer journeys (see *Figure 66*). Although all the considered transport distances in this study consist of longer journeys, both liquefied and compressed hydrogen transport will be modelled, to achieve a comprehensive overview of the available possibilities. The cost of transporting liquid hydrogen by truck are has been estimated to remain constant over the considered time frame at 0.0006 $CHF/kgH_2/km$, based on data by (BNEF, 2019b) and the (IEA, 2019a), while transport costs for compressed hydrogen are likely to drop as transport capacities increase, from an estimated 0.003 $CHF/kgH_2/km$ in 2020 to 0.002 $CHF/kgH_2/km$ by 2050 (BNEF, 2019b).

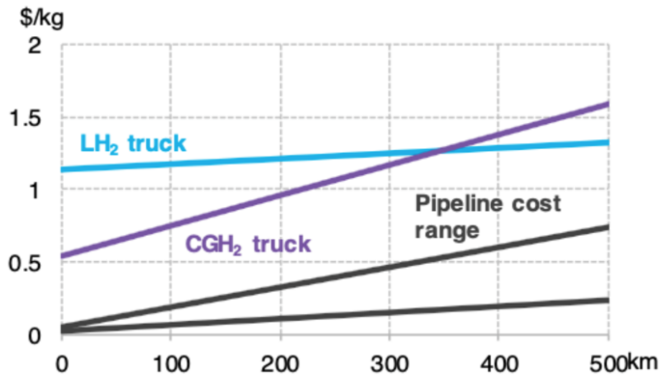


Figure 66: Cost of hydrogen by distance (IEA, 2019a).

For large volumes, pipelines are the cheapest way of transporting hydrogen over land (BNEF, 2019b), however they require significant upfront investment as well as extensive permitting and route planning. Today, there are only regional pipeline networks connecting industrial clusters in operation, although larger projects have been proposed. The European Hydrogen Backbone (EHB) initiative, spearheaded by 31 energy infrastructure companies, proposes the construction of an extensive 50’000 km pipeline network across Europe, to facilitate efficient and affordable hydrogen transport within the continent (see *Figure 67*). The project, requiring an initial investment of around 80–140 billion EUR, will consist of both dedicated hydrogen pipelines as well as repurposed natural gas pipelines, which have been shown to provide economic benefits (Cerniauskas *et al.*, 2020). The EHB project claims pipeline transport costs between 0.0001–0.0002 $EUR/kgH_2/km$ as realistic cost estimates within its network (EHB, 2022). As this estimate is likely biased, and studies by the (IEA, 2019a) and (BNEF, 2019b) of smaller scale networks reported higher estimates of 0.0006 $USD/kgH_2/km$, the present study will utilize 0.0003 $CHF/kgH_2/km$ as the estimate.

Figure 67: Build-up of a hydrogen pipeline system across Europe by 2040 as proposed by the European Hydrogen Backbone (EHB, 2022).

Next to the established technologies for the inland transport of hydrogen, other possibilities have emerged, such as transport by rail or barge. DB Cargo recently announced that they are working on a project to make the transport of liquid hydrogen via rail a viable alternative to road transport (Batrak, 2022), although setbacks with regard to vapor loss and venting issues are challenging such applications (Bauer *et al.*, 2022). Hydrogen barges have also been proposed as a possible transport option, and the concept has been proven to work by NASA, which currently employs 3 hydrogen barges to transport its fuel (LR, 2020). Due to the uncertain implementation timelines and requirements, cost data for these transport technologies vary significantly and are rather scarce. Assuming a fully implemented rail freight system, rail transport cost will likely be cheaper than road transport but more expensive than pipeline, leading to the assumption of 0.0005 CHF/kgH_2/km in 2020, falling linearly to 0.0003 CHF/kgH_2/km in 2050. For barge transport, a similar cost premium to LH_2 shipping has been assumed, leading to costs of 0.00056 CHF/kgH_2/km in 2020, declining linearly to 0.00042 CHF/kgH_2/km in 2050.

To transport hydrogen between continents and across oceans, none of the mentioned possibilities will due, which is why there has been high interest in the development of LH_2 carrier ships. While only demonstration projects with capacitates of up to 90 tons of hydrogen exist today (Hank *et al.*, 2023), large-scale liquid hydrogen carriers with transport capacities of up to 11'000 tons have been envisioned (Kamiya *et al.*, 2015). CAPEX cost for such tankers are assumed between 400–500 million USD (BNEF, 2019b; Heuser *et al.*, 2019; Kamiya *et al.*, 2015), which is more than double the cost of comparably sized LNG carriers (Molnar, 2022). During transport, liquid hydrogen cargo suffers from boil of losses of around 0.2% per day (Oyama, 2013), although there are plans to utilize these for propulsion of the vessel (Meca *et al.*, 2022). Specific transport cost data for LH_2 shipping range from optimistic assumptions of 0.000075 EUR/kgH_2/km (Roland Berger, 2021) to much higher estimates at 0.0025 USD/kgH_2/km (Lee *et al.*, 2022). A literature review by (Bauer *et al.*, 2022) found cost data between 0.000060–0.00014 CHF/kgH_2/km. (BNEF, 2019b) estimates the cost of shipping liquid hydrogen at 0.000112 USD/kgH_2/km today, with a reduction potential to 0.000076 USD/kgH_2/km. For this study, shipping cost of 0.0001 CHF/kgH_2/km are assumed for 2020, linearly reducing to 0.000075 CHF/kgH_2/km by 2050.

As natural gas has been part of the legacy energy mix for decades, there is already an extensive infrastructure in place to facilitate its transport around the globe. Internationally traded natural gas is either transported in its gaseous state via pipelines or as LNG on dedicated LNG carriers. Natural gas pipelines are made of steel and can span distances of several thousand kilometers. Depending on their usage, their diameter and operating pressure can vary significantly (Molnar, 2022). *Figure 68* shows the extensive network of natural gas pipelines across Europe, which have long served as the main import routes from Russia, Norway and Algeria (Sacaric, 2022). Since the Russian invasion of Ukraine, European states have been racing to add LNG import capacities to diversify their import options (Aitken *et al.*, 2022).

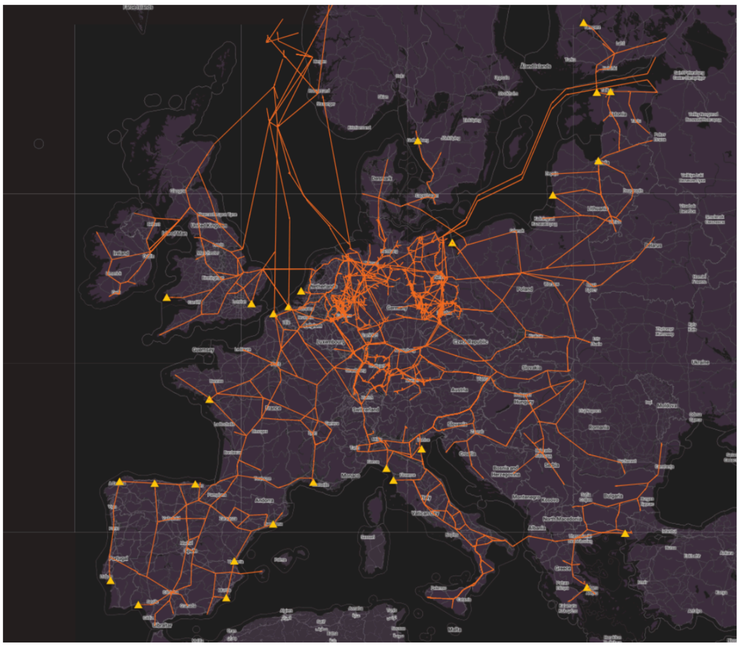


Figure 68: Overview of Europe's natural gas network, including pipelines (orange lines) and LNG terminals (yellow triangles) (Sacaric, 2022).

For the purpose of this study, an in-depth cost analysis by (Molnar, 2022) served as the basis for estimating the cost of transporting methane via pipeline and LNG carriers. It reports a pipeline transport cost range 0.5–0.1 USD/mmbtu/1000 km, which corresponds to 0.000022–0.000044 CHF/kgCH_4/km. For this report, an average value of 0.000033 CHF/kgCH_4/km was employed. Due to the maturity of natural gas pipeline transport, no further cost reductions are considered for the considered time horizon. LNG shipping rates were reported at 0.0000018 CHF/kgCH_4/km by (Molnar, 2022), for a carrier with 160’000 m^3 capacity chartered at 80’000 USD/day. Because this value is significantly higher in other literature sources, such as 0.0000048 CHF/kgCH_4/km (Raj *et al.*, 2016) even 0.000011 CHF/kgCH_4/km (Johnston *et al.*, 2022), for this report an average value of 0.000005 CHF/kgCH_4/km was used. Due to the widespread employment of natural gas shipping, no cost reductions are considered.

Similar to natural gas, the global supply chain for ammonia is already well established. It is usually shipped using liquefied petroleum gas (LPG) carriers, that have transport capacities of up to 90’000 m^3 (Hank *et al.*, 2023). Today, there are around 170 ships with the capacity to transport large volumes of ammonia, 40 of which are dedicated especially for this purpose (Egerer *et al.*, 2023). Ammonia is usually transported at temperatures below its boiling point of −33 °C, so that the tanks don’t need to be pressurized (Hassan *et al.*, 2010). In many cost assessments, transport of ammonia is slightly more expensive than transport of other fuels such as methanol and bulk chemicals (Al-Breiki and Bicer, 2020; Hank *et al.*, 2023). Literature values on the topic are in decent agreement, with the (IEA, 2019a) on the lower end reporting 0.0000037 USD/kgNH_3/km and (Lee *et al.*, 2022) reporting 0.0000094 USD/kgNH_3/km on the higher end. Further reports found values of 0.0000057 USD/kgNH_3/km (BNEF, 2019b) and 0.0000051 USD/kgNH_3/km (Cui and Aziz, 2023). In this study, a shipping cost of 0.0000060 CHF/kgNH_3/km is assumed, with no cost reductions over time.

Inland transport of ammonia can be achieved via rail, road or barge. Rail and truck transport are usually conducted at ambient temperatures, resulting in the need for pressurization of the vessels to around 8 bar (Junior *et al.*, 2012). Freight trains transport ammonia in chemical freight tanks, which can hold up to 110 tNH_3 each, while ammonia trucks are limited to approximately 36 tNH_3 per journey (Nayak-Luke *et al.*, 2021). Barges use refrigeration compressors to cool the transported ammonia (Hutchison, 2005). Freight cost for bulk liquid fuels within Europe have been based on an extensive report on European transport cost by (van der Meulen *et al.*, 2020). Due to the pressurization requirements needed for ammonia transport, a 30% premium to regular liquid bulk freight is considered. The resulting transport costs of 0.000021 CHF/kgNH_3/km for rail, 0.000173 CHF/kgNH_3/km for truck and 0.000036 CHF/kgNH_3/km for barge align nicely with other literature data, such as (BNEF, 2019b), (IEA, 2019a) and (Cui and Aziz, 2023). Ammonia could also be transported by use of dedicated pipelines (Egerer *et al.*, 2023). While there is such a pipeline system in place across the United States, connecting the Gulf of Mexico to demand centers in the Midwest (Acker, 2021), none is available in Europe, which is why this option will be disregarded for the present study.

The remaining carbon-based PtX fuels, namely methanol, *Fischer-Tropsch* fuels and LOHC, are considered as equivalent with regard to their transport, due to their comparable properties and handling. All of them are industrial chemicals with a global supply chain, and their respective transport has been well established for decades. They exist in a liquid state at ambient temperatures, which simplifies their handling. They can be transported using all types of conventional transportation methods, such as ships, trucks, rail, and barges. Pipelines are also currently feasible, however they are only employed in regions with a high concentration of producers and consumers, such as methanol pipelines along the US Gulf Coast (Williams, 2023). Liquid chemicals are transported across oceans using chemical tankers, which usually have transport capacities around 50'000 m^3 (Hank *et al.*, 2023). Depending on the type of chemical, varying safety requirements need to be considered. Maritime shipping costs are taken from the previously mentioned report by (van der Meulen *et al.*, 2020), and amount to 0.000005 CHF/kgX/km. These cost figures are in alignment with those of other PtX fuel transport studies such as (Lee *et al.*, 2022) and (Johnston *et al.*, 2022). For inland transportation, chemicals can be transported in dedicated liquid bulk rail carts, or by use of liquid bulk trucks. Cost data for European rail and road transport are taken from (van der Meulen *et al.*, 2020), and amount to 0.000133 CHF/kgX/km for truck and 0.000016 CHF/kgX/km for rail respectively. Barge transport is also an option for liquid chemicals, costing 0.000028 CHF/kgX/km. As LOHC have to be returned to their point of origin to be re-used, their transport costs need to be considered twice.

3.4.3 Storage

Storage plays a pivotal role within global supply chains, providing much needed flexibility and buffer capacity to ensure seamless operations. To account for such storage requirement, this study considers a storage period prior to transport, including 15 days for maritime shipping, 5 days for barge transport, 3.5 days for truck and rail transport and 0 days for pipeline transport. In general, obtaining reliable cost data with regards to storage of these fuels has proven to be quite challenging. The data presented here is based on the limited sources that could be found, combined with some extrapolation where no other option was available. As storage costs don't usually comprise large shares of the final supply chain cost, except in the case of hydrogen, where the data availability is sufficient, this uncertainty in data was deemed as acceptable.

Pure hydrogen can be stored in both its compressed and liquefied form. While liquid hydrogen is mainly stored in dedicated storage tanks, its gaseous counterpart can also be injected into geological formations such as salt caverns, depleted oil and gas fields or aquifers. Pressurized hydrogen tanks made of metal and or fiber composites are one of the most widely used forms of storage today, although high capital cost for the tanks as well as the lackluster storage density lead to high costs (BNEF, 2019a). Solid state storage methods, such as metal hydrides are also under development, although such systems are far from commercialization and usually involve high material costs (Bauer *et al.*, 2022). For the supply chain model in this study, pressurized and liquified tank storage are considered, depending on the type of subsequent transport. Storage tanks for liquid hydrogen have a fast discharge rate and a roundtrip efficiency of approximately 99%, making them a suitable solution for short-term storage applications (IEA, 2019a). To minimize boil-off, these tanks are spherical in shape and equipped with advanced insulation, to minimize heat transfer from the environment (Andersson and Grönkvist, 2019). Storage costs are based on the Economics of Hydrogen Storage report by (BNEF, 2019a) and amount to 0.082 CHF/kgH_2/d in 2020 for liquid hydrogen, dropping to 0.027 CHF/kgH_2/d by 2050. Storage costs for gaseous hydrogen are higher, at 0.179 CHF/kgH_2/d in 2020, with the potential of dropping to 0.160 CHF/kgH_2/d in 2050 (BNEF, 2019a). These assumptions lead to significant storage costs along the supply chain, as results of previous studies by the (IEA, 2019a) and (Abdin *et al.*, 2022) have concluded.

Similar to hydrogen, natural gas can either be stored in its gaseous form in geological formations or as LNG in storage tanks (MET, 2023). For logistics storage around ports, LNG storage tanks are the most practical option. These tanks account for a high fraction of LNG transport cost. Cost of LNG storage are based on (Dias *et al.*, 2020) and amount to 0.0045 CHF/kgCH_4/d.

Large scale ammonia storage is done in refrigerated carbon steel tanks, with capacities ranging from 5000-50'000 tNH_3 (Hale, 1984). Assuming an average 25'000 ton storage tank, (Nayak-Luke *et al.*, 2021) estimated storage costs of 0.00052 CHF/kgNH_3/d, considering an energy consumption of 0.0378 kWh/kgNH_3 and boil-off losses between 0.03% to 0.1% per day.

Carbon-based liquid fuels can be stored comparably easy in steel tanks at atmospheric pressure (Methanol Institute, 2016). As these fuels are all flammable liquids, fire prevention safeguards need to be in place, the specifics of which can vary depending on the substance in question. Storage cost for carbon-based fuels were assumed to be at 0.0001 CHF/kgX/d for the purpose of this study.

Table 29: Overview of PtX fuel supply chain costs.

	H_2 (as LH_2)	H_2 (as CH_2)	H_2 (as NH_3)	H_2 (as CH_3OH)	H_2 (as LCOH)	NH_3	CH_4	CH_3OH	$C_{16}H_{34}$
Conversion [CHF/kg]	2020: 2.50 2050: 1.50	0.25	2020: 0.75 2050: 0.55	2020: 1.20 2050: 0.65	2020: 0.35 2050: 0.20	n.a.	0.108	n.a.	n.a.
Ship Transport [CHF/kg/km]	2020: 0.000100 2050: 0.000075	n.a.	see NH_3	see CH_3OH	0.000005	0.000006	0.000005	0.000005	0.000005
Truck Transport [CHF/kg/km]	0.0006	2020: 0.003 2050: 0.002	see NH_3	see CH_3OH	0.00013	0.00017	n.a.	0.00013	0.00013
Rail Transport [CHF/kg/km]	2020: 0.0005 2050: 0.0003	n.a.	see NH_3	see CH_3OH	0.000016	0.000021	n.a.	0.000016	0.000016
Barge Transport [CHF/kg/km]	2020: 0.00056 2050: 0.00042	n.a.	see NH_3	see CH_3OH	0.000028	0.000036	n.a.	0.000028	0.000028
Pipeline Transport [CHF/kg/km]	n.a.	0.0003	see NH_3	see CH_3OH	n.a.	n.a.	0.000033	n.a.	n.a.
Storage [CHF/kg/d]	2020: 0.082 2050: 0.027	2020: 0.18 2050: 0.16	see NH_3	see CH_3OH	0.0001	0.0005	0.0045	0.0001	0.0001
Reconversion [CHF/kg]	0.018	0	2020: 1.5 2050: 0.75	2020: 1.30 2050: 0.75	2020: 2.15 2050: 1.00	n.a.	0.018	n.a.	n.a.

3.5 Results & Discussion

This section presents the results of the techno-economic assessment for both the production of PtX fuels as well as the supply chains associated with their import. The objective is to provide a comprehensive understanding of the underlying cost structures inherent in these processes, in order to enable informed conclusions on the optimal supply options available for Switzerland. To gain a deeper understanding of how the derived values are influenced by specific input parameters, and how their implicit uncertainties can impact future cost developments, sensitivity analyses and scenario comparisons are performed throughout this section.

As electricity generation forms the basis of every PtX production plant and PtX fuel costs are significantly influenced by their electricity input costs, the determined levelized cost of electricity (LCoE) are presented in a first step. This examination delves into the distinctions among various forms of electricity generation and electricity supply scenarios, as well as highlighting country-specific considerations. Following this, the results obtained for the levelized cost of hydrogen (LCoH) across all considered countries are discussed, detailing the superior production setups and their associated cost structures. Subsequently, the levelized cost of the remaining PtX fuels (LCoX) are presented and compared to the costs of their fossil fuel alternatives. Finally, the supply chain costs associated with importing PtX fuels to Switzerland are discussed, exploring the implications of various conceivable transport infrastructure scenarios. These findings are integral in determining the delivered cost of PtX fuels in Switzerland, enabling a comparative discussion of different import options as well as domestic production. The cost analysis is complemented by an energy efficiency analysis of both the production and subsequent supply chain conversions, offering another important perspective to consider when evaluation PtX fuel supply options.

The conducted techno-economic assessment encompasses data for many different production pathways, including various options for power generation, different power supply scenarios and several electrolyzer technologies. These production pathways are assessed in multiple countries under the consideration of three different assumption scenarios (see *Figure 69*). As a result, the multitude of potential cost outcomes is substantial, including 189 different LCOE as well as 441 different LCoX. When considering all the available transport options, the spectrum of potential delivered costs expands even further. In the following chapter, the key insights derived from this extensive array of results are presented, often highlighting specific examples in order to elucidate overarching results. For a comprehensive understanding of the entire dataset, the reader is encouraged to utilize the dashboard integrated into the excel calculation model that has been developed as part of this thesis.

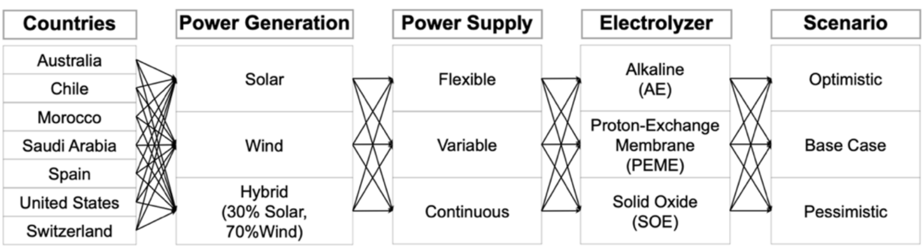


Figure 69: Varying input parameters leading to a multitude of results.

The results showcased in this section serve as the groundwork for important take-away messages that can inform policy making decisions on behalf of Switzerland. However, it is important to recognize that they constitute only a small piece of the entire puzzle and need to be integrated into a larger body of research on low-carbon fuels and energy system analyses, to obtain a holistic perspective. Such conclusions and the perspective for further research in this field will be discussed in *Chapter 4*.

3.5.1 Levelized Cost of Electricity (LCoE)

The determined costs for electricity generation amount to a global average of 44 CHF/MWh for solar PV and 36 CHF/MWh for onshore wind in 2023, aligning nicely with comprehensive studies on current electricity generation costs by (IRENA, 2022f) and (BNEF, 2022a). CAPEX costs are the dominant cost factor for both technologies, accounting for an average of 83% in the case of solar PV and 75% for onshore wind. These findings underline the importance of the initial installation cost and their associated capital costs on the overall electricity generation costs (see *Figure 70*). Another key variable is the capacity factor, as it determines how many kWh the initial CAPEX can be distributed over. While onshore wind is the cheapest form of electricity generation in most countries today, the high cost reduction potential of solar PV enable it to outperform over the next decades, with its average electricity generation costs dropping to just 19 CHF/MWh by 2050, compared to 28 CHF/MWh for onshore wind. These cost reductions are subject to significant uncertainties however, represented in large variations between the optimistic and pessimistic scenarios (12–31 CHF/MWh).

CAPEX [CHF/kWp]	WACC 2%	4%	6%	8%	10%
800	28	34	41	49	57
900	32	39	46	55	64
1000	35	43	52	61	71
1100	39	47	57	67	78
1200	42	51	62	73	85

CAPEX [CHF/kWp]	WACC 2%	4%	6%	8%	10%
1000	23	27	32	37	43
1200	28	33	39	45	52
1400	32	38	45	52	60
1600	37	44	51	60	69
1800	41	49	58	67	78

Figure 70: Sensitivity analysis for the electricity generation cost [CHF/MWh] of solar PV (left) and onshore wind (right), assuming standardized capacity factors of 20% and 35% respectively.

There are also important country-specific differences to consider (see *Figure 71*). As Switzerland is subject to low capacity factors for both wind and solar, its resulting electricity generation costs are the most expensive of all regarded countries. This cost premium is especially pronounced for onshore wind, due to the disproportionally high local CAPEX, which can only partly be compensated by its low cost of capital. The cheapest electricity generation is found in Australia, which profits from a combination of strong capacity factors, low CAPEX in both technologies, and the lowest cost of capital of any exporting country. Chile, which has the best capacity factors for both wind and solar, only lands in second place due to higher CAPEX requirements and the higher cost of capital in the country. The other exporting countries all fall somewhere in the middle of the pack, usually due to limitations in one of the major cost factors. Despite their excellent wind and solar potential, Morocco and Saudi Arabia suffer from high capital costs, which materially increase the final cost. Conversely, Spain is subject to comparably low-capacity factors, while the United States faces higher CAPEX than its global competitors.

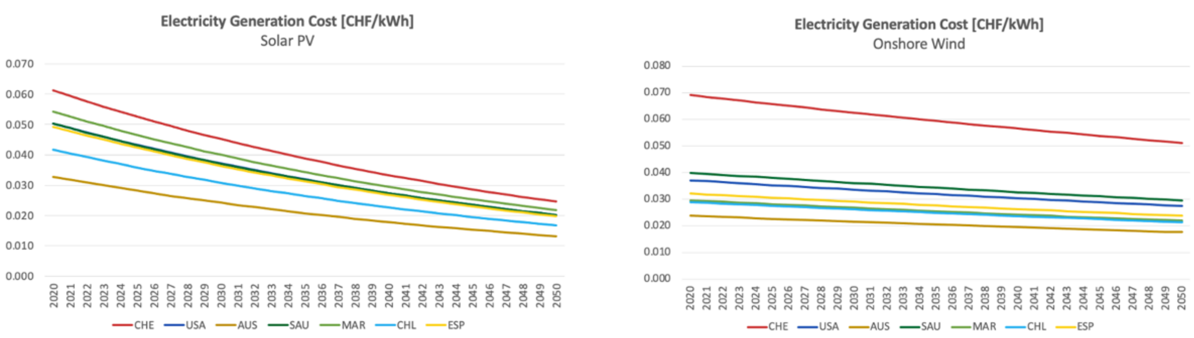


Figure 71: Country-specific electricity generation cost for solar PV and onshore wind in the base case.

To determine the final LCoE which are subsequently considered as input factors for the PtX fuel production facility, the electricity generation costs need to be expanded by the associated electricity storage costs required to provide a certain electricity supply. While these costs remain low in case of a flexible electricity supply, their share increases significantly in when considering variable and continuous electricity supplies (see *Figure 72*). This effect is most pronounced in the case of standalone solar PV systems, which require significant battery capacities in order to provide consistent electricity profiles. The share of battery costs is lower for onshore wind systems, as they do not need to bridge the diurnal cycle of solar. Hybrid systems require the lowest amount of battery capacity, as they can profit from complementary feed-ins of wind and solar.

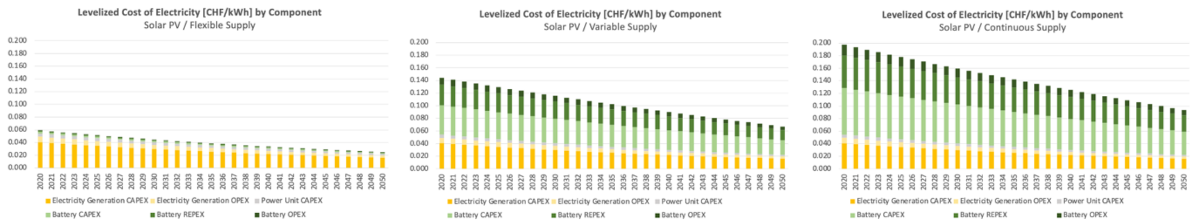


Figure 72: Disaggregated LCoE of solar PV systems in Spain, considering different power supply scenarios.

The resulting LCoE vary significantly based on the regarded electricity generation technology and electricity supply scenario. There also remain large differences in country-specific results, due to the varying local conditions. The resulting average LCoE values are summarized in *Table 30*, with country-specific cost ranges mentioned in brackets.

Table 30: Average LCoE in 2023 for various electricity generation and supply scenarios, with country-specific cost ranges.

	Flexible	Variable	Continuous
Solar PV [CHF/MWh]	54 (38–67)	134 (108–160)	183 (151–218)
Onshore Wind [CHF/MWh]	39 (27–72)	78 (59–116)	96 (73–138)
Hybrid [CHF/MWh]	49 (41–88)	79 (55–125)	90 (64–139)

For variable or continuous electricity supplies, standalone onshore wind or hybrid systems are superior in all cases, with only minor cost differences between the two. With regard to flexible electricity supplies, onshore wind is currently the cheapest electricity generation technology in all countries except Switzerland, although solar PV is projected take its place throughout the 2030s and 2040s in most of them (see *Figure 73*). For some wind-rich countries, such as the United States and Morocco, onshore wind systems will remain the dominant option throughout the regarded time period.

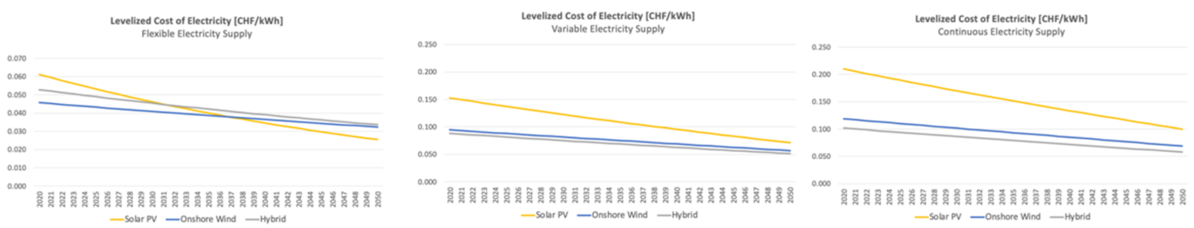


Figure 73: LCoE development in Saudi Arabia for different electricity supplies (scaling of y-axis varies for better resolution).

3.5.2 Levelized Cost of Hydrogen (LCoH)

Considering the available combinations of electricity generation setups, electricity supply scenarios and electrolyzer systems, the calculated LCoH vary significantly. In Switzerland alone, current production costs for the various technology combinations range between 6.5–14.9 CHF/kgH_2, decreasing to 2.4–5.6 CHF/kgH_2 by 2050 (see *Figure 74*). From this plethora of results, a few general trends can be identified. First and foremost, the results show that electrolysis based on a flexible electricity supply achieves the lowest LCoH, with production costs increasing in the variable and continuous supply scenarios. This is due to the significantly higher LCoE in those scenarios, which outweighs the benefits of the higher electrolyzer capacity factor.

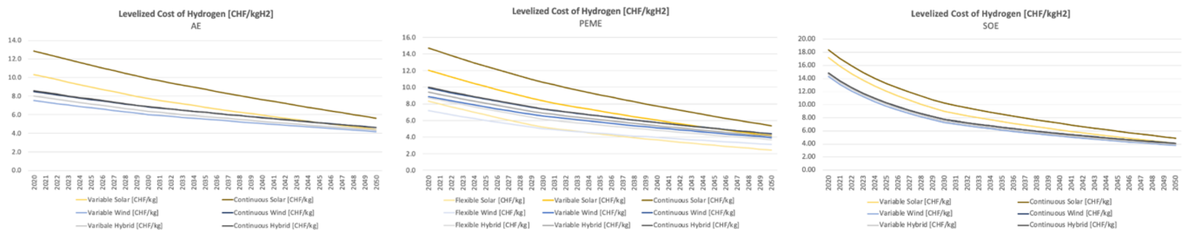


Figure 74: LCoH development in Switzerland for different technology combinations (y-axis scaling varies for better resolution).

As neither AE nor SOE systems can be operated on a flexible electricity supply, their hydrogen production is handicapped with a relatively high input electricity cost. As AE is a well-established technology, it currently holds certain advantages with regards to CAPEX and system lifetimes, which allows it to produce at relatively competitive costs. However, its potential for further cost reductions is limited, causing it to lose ground to upcoming technologies (see *Figure 75*). SOE systems are currently the most expensive electrolysis option available, as their high CAPEX and especially the low lifetimes lead to high electrolyzer costs. Assuming these can be reduced over the coming decades, SOE will become more competitive than AE, as its high efficiency can reduce the incurred electricity costs. Base case domestic production costs in Switzerland are 7.05 CHF/kgH_2 for AE and 11.21 CHF/kgH_2 for SOE in 2023, dropping to 4.16 CHF/kgH_2 and 3.80 CHF/kgH_2 respectively by 2050.

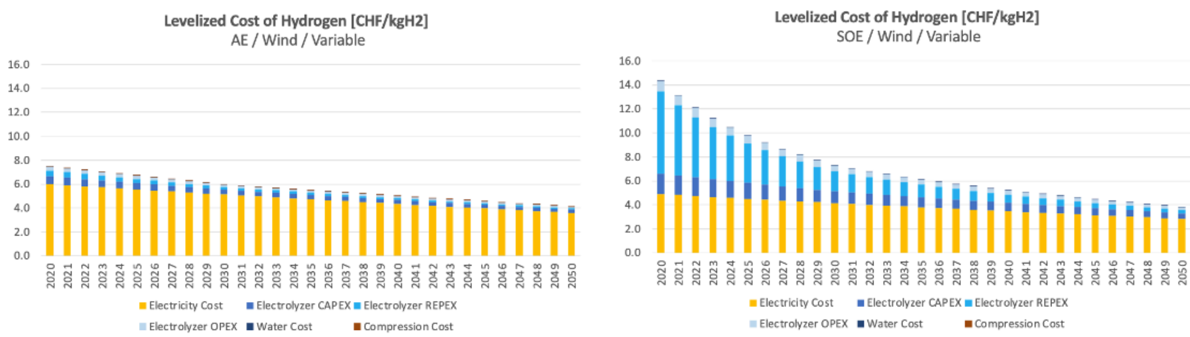
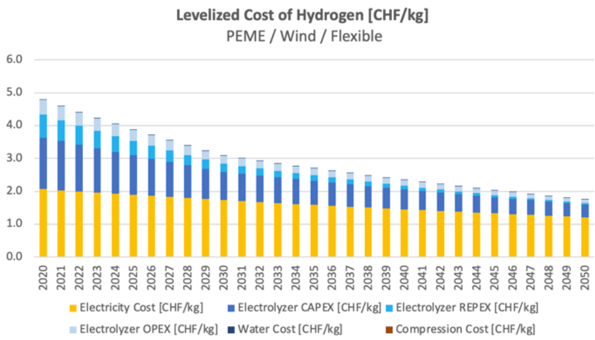


Figure 75: LCoH of AE and SOE systems by component in Switzerland's base case.

As PEME systems are able to operate on a flexible power supply, they achieve the lowest hydrogen production cost of all regarded technologies, profiting from the exceptionally low electricity cost that can be achieved in such a scenario. As electricity generation from standalone onshore wind systems can provide decent electrolyzer utilization rates even in a flexible supply scenario, it is currently the preferred electricity feedstock in all countries. If the projected cost reductions for solar PV systems materialize, standalone solar PV setups are projected to become the preferred electricity source in countries with comparatively high wind power costs, such as Switzerland and Saudi Arabia.

Due to the lower electrolyzer utilization rates achieved when operating on a flexible electricity supply, the CAPEX cost for the electrolysis system accounts for a larger part of final LCoH, leading to a larger influence of the underlying assumptions for the installation cost (see *Figure 76*). Its influence is projected to decrease however, as the projected cost reduction for PEME systems start to materialize.



		LCOE [CHF/MWh]				
		25	50	75	100	125
Electrolyzer CAPEX [CHF/kW]	600	2.8	4.2	5.5	6.8	8.2
	800	3.3	4.7	6.0	7.3	8.7
	1000	3.8	5.2	6.5	7.8	9.2
	1200	4.3	5.6	7.0	8.3	9.7
	1400	4.8	6.1	7.5	8.8	10.2

Figure 76: LCoH of PEME systems by component in Switzerland's base case (left) and its sensitivity regarding CAPEX and LCoE assumptions (right).[9]

Country-specific hydrogen production costs are subject to significant variations. As expected, domestic production in Switzerland is subject to a significant premium compared to the regarded exporting countries (see *Figure 77*). Australia achieves the lowest hydrogen production costs, with a LCoH of 3.7 CHF/kgH_2 in 2023, dropping to 1.4 CHF/kgH_2 by 2050. The country profits from both cheap wind power as well as a low capital cost. Chile and the United States face slightly higher capital costs, but their exceptionally high wind power capacity factors allow them to produce hydrogen competitively. Spain and Morocco achieve similar hydrogen production costs, although based on different underlying cost structures. While Morocco has a decent supply of cheap wind power, its high cost of capital drives up electrolyzer costs, while Spain has better financing conditions but suffers from comparably low wind capacity factors. As Saudi Arabia is plagued by both high wind energy costs and a high cost of capital it represents the most expensive exporting country.

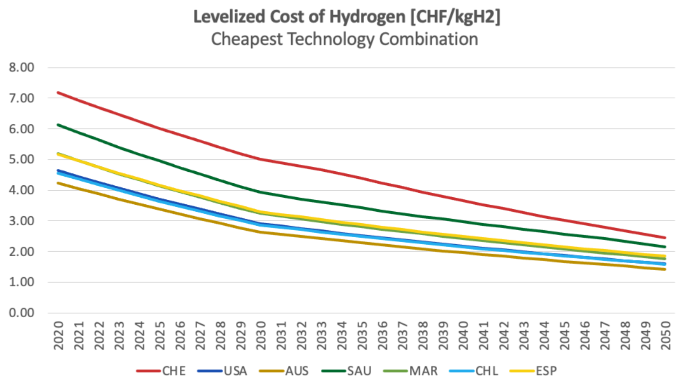


Figure 77: Country-specific LCOH developments in the base case.

Considering a fossil hydrogen price of 2 CHF/kgH_2, cost parity of green hydrogen production can be achieved by 2040 in the base case and already by 2030 in an optimistic scenario. Further cost reductions are increasingly difficult to achieve, as the underlying technologies start to mature. Achieving production costs of 1 CHF/kgH_2, an often-cited benchmark for widespread hydrogen adoption, is only possible in the optimistic scenario, and even there only towards the end of the 2040s.

[9] Sensitivity analysis was performed assuming an electrolyzer capacity factor of 36%, system efficiency of 62%, and an electrolyzer lifetime of 74'000 hours.

Given the capital-intensive nature of both the electricity input and electrolyzer costs, the WACC becomes an important variable with a significant impact on the resulting LCoH, especially since it is subject to large country-specific variations. To illustrate this, Figure 78 shows the country-specific hydrogen production costs, assuming an average uniform WACC in all countries.[10] While such an assumption would make production in Switzerland even more expensive, the differences in production costs between exporting countries decrease. While countries with high financing cost, such as Saudi Arabia and Morocco, are now able to produce more competitively, Australia's cost advantage vanishes, making Chile the cheapest exporter in this scenario. These results show that it is crucial to consider country-specific capital costs when conducting such analyses, an important detail that is overlooked by many studies in this space.

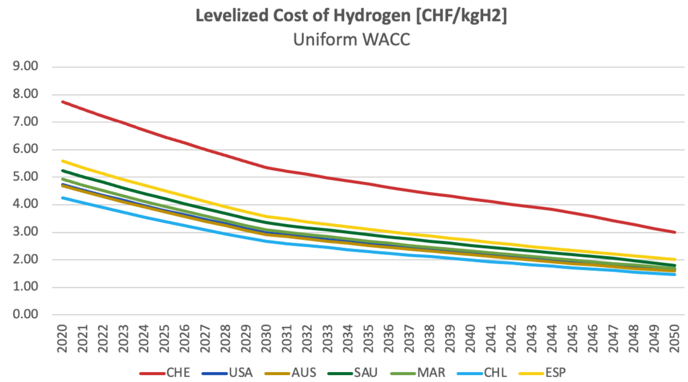


Figure 78: Country-specific LCoH developments considering a uniform WACC.

As previously noted for the LCoE, the determined LCoH values are also subject to significant variations in the different considered cost scenarios (see *Figure 79*). While the uncertainties with regards to electricity generation are mostly associated with the assumed future cost developments, hydrogen production technologies also contain large uncertainties in their current cost and operational parameters, specifically with regard to its CAPEX, efficiency and lifetime. These uncertainties need to be kept in mind when drawing conclusions from such analyses.

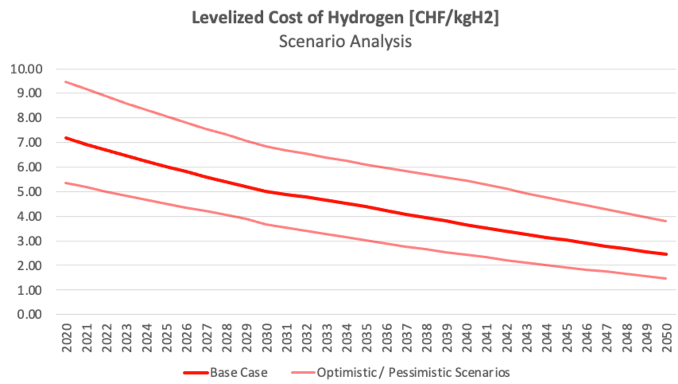


Figure 79: LCoH development in Switzerland for different cost scenarios.

[10] The uniform WACC represent the average of the country-specific WACCs, resulting in 6.16% for solar, 6.39% for wind and 11.28% for general.

3.5.3 Levelized Cost of PtX Fuels (LCoX)

As *Figure 80* impressively illustrates, the cost structures of hydrogen derived PtX fuels are dominated to a large part by the cost of producing their hydrogen feedstock. This cost structure is most extreme for ammonia production, where hydrogen costs currently amount to 88% of the total cost. This cost structure can be explained by both the high cost of hydrogen, as well as the low cost of the further required feedstock. Nitrogen generation costs are approximately 34 CHF/tN_2, a fraction of the cost of green hydrogen production. For carbon-based fuels the share of hydrogen input is slightly lower, due to the higher contribution of carbon feedstock generation to the total cost. Assuming CO_2 is captured in a DAC facility connected to the fuels production plant, carbon input costs of 209 CHF/tCO_2 are achieved, accounting for 17% of the total production cost in the case of methane, 23% for methanol and 25% for *Fischer-Tropsch* fuels. These carbon capture costs are rather low compared to cost data on current carbon capture facilities. This is due to the considered heat integration, which allows for the heat demand of the carbon capture process to be fully covered by recoverable waste heat from the electrolysis and fuel synthesis processes.[11] Assuming no heat integration, carbon capture costs of 440 CHF/tCO_2 would be achieved in the base case, accounting for 25–33% of total fuel production cost.

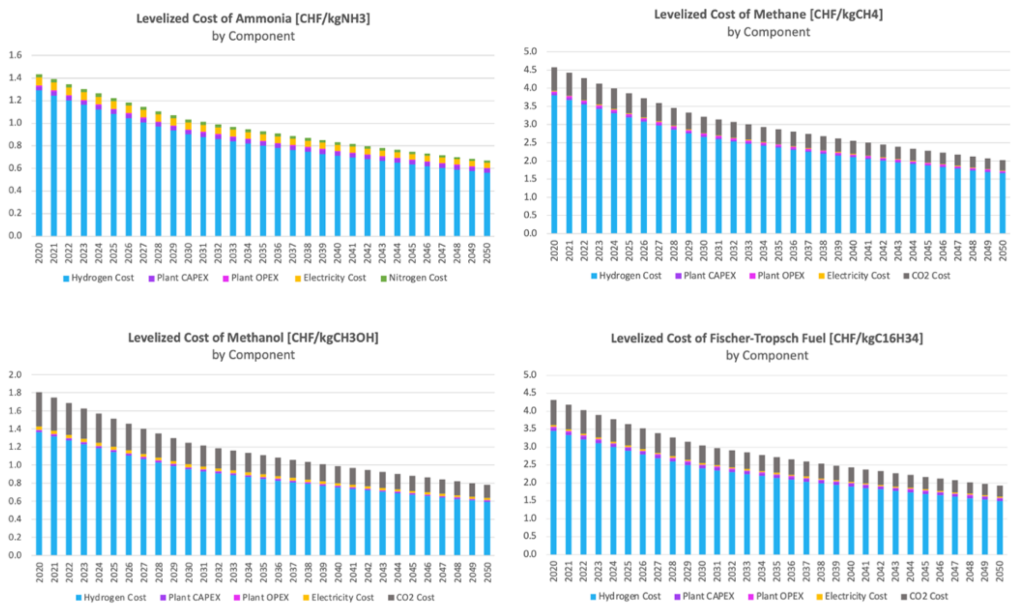


Figure 80: LCoX by component in the Swiss base case, considering DAC as CO_2 feedstock.

Even when accounting for its significant cost reductions over the next decades, hydrogen will remain the major cost factor in the case of ammonia production. In the case of carbon-based fuels, the share of hydrogen input costs will strongly depend on how the cost of carbon capture develops. According to the cost developments for direct air capture regarded in the base case, CO_2 prices will drop alongside the hydrogen production costs, down to 96 CHF/tCO_2 by 2050 with heat integration and 146 CHF/tCO_2 without. Therefore, its share of the overall cost would only slightly increase throughout the considered time frame. Should this cost reduction not materialize however, carbon capture could develop into the major cost component for carbon-based PtX fuels. Assuming a cost of 300 CHF/tCO_2 and a hydrogen cost of 1 CHF/kgH_2, carbon feedstock would emerge as the new bottleneck, now accounting for the majority of the overall fuel production cost.

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[11] Exceptions include fuels based on hydrogen produced by SOE, and in some cases of methanol production. Even in those cases significant parts of the carbon capture heat demand were covered, with the rest being provided by electric heaters.

Due to the fact that all cost structures of PtX fuel production are dominated by their hydrogen input costs, the country-specific fuel production curves all look very similar to those of hydrogen production (see *Figure 81*). Therefore, the observed country-specific differences in production costs can in large part be explained by the cost differences in their respective hydrogen production, in addition to some minor influence of their differences in LCoE.

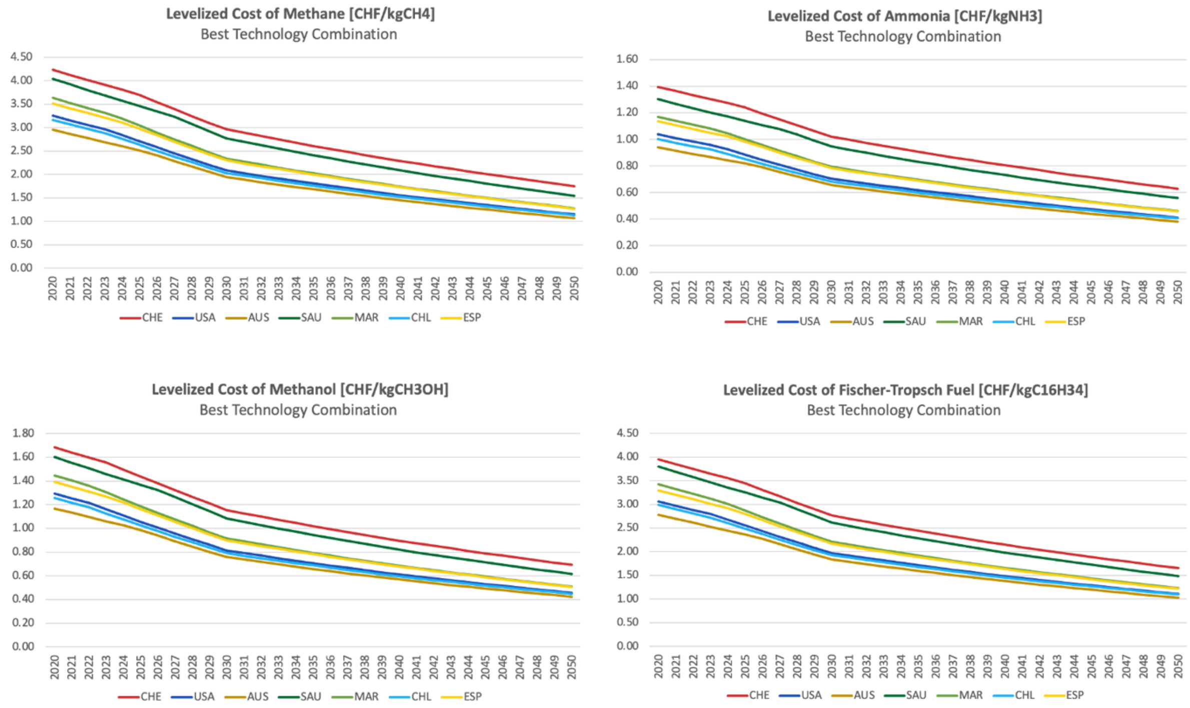

Figure 81: Country-specific LCoX developments in the base case.

Table 31 provides an overview of PtX fuel production cost ranges in the considered exporting countries and compares them to the lowest achievable domestic production cost in Switzerland. The results underline the significant cost advantages that can be realized by producing in exporting countries.

Table 31: PtX fuel production costs in exporting countries compared to domestic production in Switzerland.

	Production Cost Exporters [CHF/kgX]	**Production Cost Switzerland [CHF/kgX]**
H_2	2023: 3.7–5.4 2050: 1.4–2.2	2023: 6.5 2050: 2.4
CH_4	2023: 2.7–3.7 2050: 1.1–1.6	2023: 3.9 2050: 1.8
NH_3	2023: 0.9–1.2 2050: 0.4–0.6	2023: 1.3 2050: 0.6
CH_3OH	2023: 1.1–1.5 2050: 0.4–0.6	2023: 1.6 2050: 0.7
$C_{16}H_{34}$	2023: 2.5–3.5 2050: 1.0–1.5	2023: 3.7 2050: 1.7

As in the case of hydrogen, fossil-based fuels are currently still significantly cheaper than their electricity-based alternatives (see *Figure 82*). As the price of fossil fuels is strongly linked to the underlying prices of natural gas and oil however, the observed market prices for these fuels can vary widely. With the exception of methanol, which is subject to less volatility, all of the fuels considered in this study have been subject to market prices significantly higher than the production cost of their green alternative, mostly during the European energy crisis in 2022. Although such high prices are the exception and not the rule, increasing pressures on fossil fuel prices, both due to mounting geopolitical tensions as well as increasing regulation and carbon emissions pricing, will likely increase in volatility making their green alternatives more attractive.

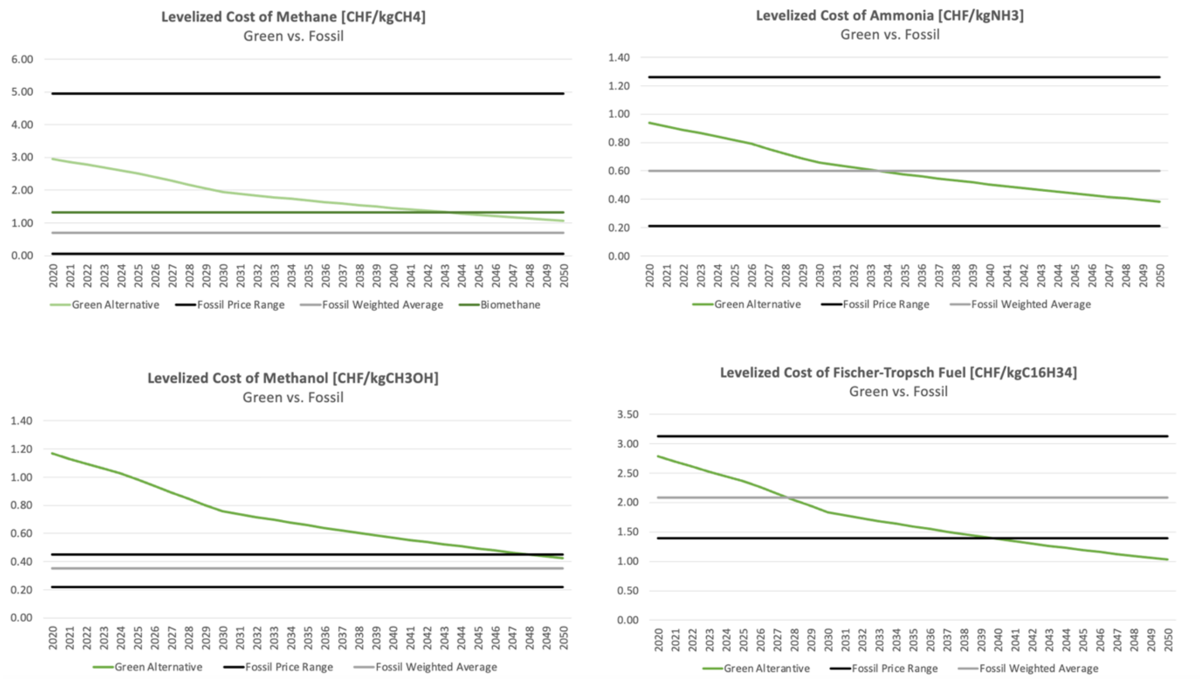

Figure 82: Comparison of the lowest achieved LCoX to their fossil alternatives.[12]

The low average price of natural gas, which is achieved due to its immense extraction volumes and highly optimized processing facilities, makes it difficult for green methane to compete, even when considering the cost reduction achieved by 2050. In this case biomethane might prove to be a more technologically mature option to provide a renewable alternative. Replacing fossil alternatives seems more achievable in the case of diesel and ammonia, where price parity might be reached by the late 20s or early 30s. Fossil methanol prices are still significantly lower than their green alternatives, which may take until 2050 or beyond to catch up.

[12] Determination of fossil fuel alternative is based on publicly available European market price data for ammonia (Business AnalytIQ, 2023a), methanol (Business AnalytIQ, 2023b), natural gas (Trading Economics, 2023), biogas (Simon, 2019) and diesel (Business Insider, 2023), over the last 5 years.

3.5.4 Delivered Cost of PtX Fuels in Switzerland

To be able to compare the delivered cost of PtX fuels for consumption in Switzerland, their previously presented production costs need to be expanded by the supply chain costs associated with importing these fuels from their respective exporting countries.

Shipping costs for hydrogen are by far the most expensive out of all the considered fuels, due to the costly conversion processes required to facilitate its transport. Subsequently, its import can account for a sizeable part of the overall delivered costs. While the production of hydrogen costs 3.7 CHF/kgH_2 in Australia today, the cheapest way of transporting it to Switzerland, in this case shipping it as ammonia, adds another 2.4 CHF/kgH_2 to the overall costs, 90% of which are incurred for the ammonia synthesis and cracking processes (see *Figure 83*). Other transport options, such as converting hydrogen to methanol or binding it to a LOHC, are even more expensive at 2.6 and 2.8 CHF/kgH_2 respectively. As with ammonia, the associated conversion processes also account for the majority of the overall supply chain costs. Shipping hydrogen in its liquid form is by far the most expensive option at 6.3 CHF/kgH_2, as in addition to the expensive liquefaction step, high transport and storage costs are incurred due to the difficult handling of liquid hydrogen, the associated cooling requirements, and boil-off losses.

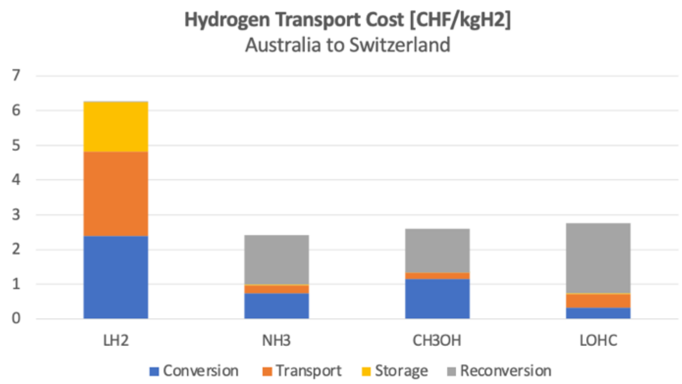

Figure 83: Costs of different hydrogen import options from Australia to Switzerland in 2023.

Although significant cost reductions are expected for all these technologies, these will be outperformed by the reductions in hydrogen production costs, causing the share of transport in the total delivered cost to further increase. By 2050, importing Australian hydrogen produced for 1.4 CHF/kgH_2 will cost 1.5 CHF/kgH_2 for transport as ammonia, 1.6 CHF/kgH_2 for transport as methanol or LOHC and 4.0 CHF/kgH_2 for transport as liquid hydrogen. However, as much of the hydrogen projects are focused on production rather than transport, it is conceivable that future cost reductions might outperform expectations, as increasing production volumes and transport demand catalyzes the development of more innovative solutions.

When it comes to the inland transport of hydrogen from more regional exporters, the cost structures of transportation as NH_3, CH_3OH and LOHC remains comparable to those of overseas exporters, with only slightly lower total transport costs, as the costly conversions are still necessary regardless of the transport distance (see *Figure 84*). Subsequently, it also makes little difference for the overall costs whether such transport is facilitated by truck, rail, or barge. Transport costs for liquid hydrogen are significantly reduced compared to overseas exporters, although it remains the most expensive option. While regional transport in the form of compressed hydrogen (CH_2) trucks is suitable over short distances due to the lower associated conversion costs, the low hydrogen densities drive up the transport cost, making this option unsuitable the longer transport distances regarded in this study.

On the other hand, transporting CH_2 via a pipeline is very cost effective, and represents the cheapest transport option given the required infrastructure is available. The costs for importing hydrogen via pipeline from Spain to Switzerland are estimated at only 0.3 CHF/kgH_2, almost ten times cheaper than the next best alternative. For Morocco, which could also be connected to a European pipeline system, import costs would amount to 0.90 CHF/kgH_2.

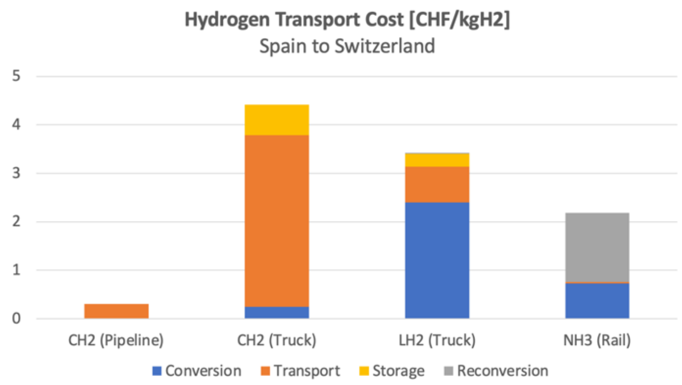

Figure 84: Costs of different hydrogen import options from Spain to Switzerland in 2023.

Such low transport costs would be a major competitive advantage for regional exporters and make them the cheapest import options for Switzerland. However, the realization of such a pipeline system is far from certain and would require massive upfront investments and decisive political action. To account for this uncertainty, the delivered costs of hydrogen have been modelled for two distinct scenarios, one based an operational pipeline system equivalent to the European Hydrogen Backbone (EHB), while the other excludes this option (see *Figure 85*). If such a system were to be built, hydrogen imports from regional exporters, namely Spain and Morocco, would provide the cheapest option for hydrogen supply in Switzerland, amounting to 3.60 CHF/kgH_2 by 2030. Without it, hydrogen import from overseas exporters will be the most suitable supply option, however at a significantly higher cost of 4.71 CHF/kgH_2 by 2030. In such a scenario, domestic production in Switzerland might even become the cheapest option for hydrogen supply by the late 2030s.

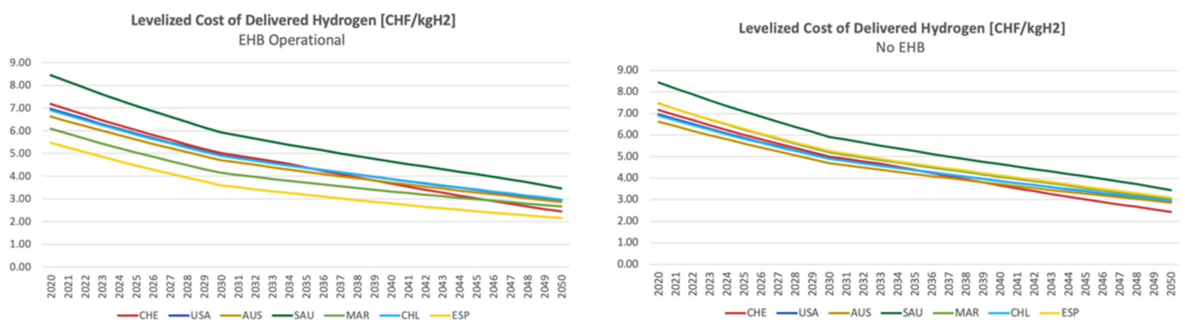

Figure 85: LCoH of delivered hydrogen in Switzerland, with and without an active EHB.

The other considered PtX fuels are much easier to transport, partly due to their physical attributes but also because their supply chains are already well established. Transporting these fuels from Australia to Switzerland costs only between 0.12–0.32 CHF/kg, with the carbon-based liquid fuels being the cheapest to transport due to their easy handling (see *Figure 86*). Methane supply chains are more expensive, due to the required liquefaction and regasification steps as well as cooling requirements and boil-off losses along the journey. Regional exporters have even lower transport costs for these fuels, with transport from Spain costing only 0.02 CHF/kg for liquid carbon-based fuels and 0.03 CHF/kg for ammonia. As methane transports can be facilitated through the natural gas pipeline system, no conversions are necessary, leading to low import costs of 0.03 CHF/kg.

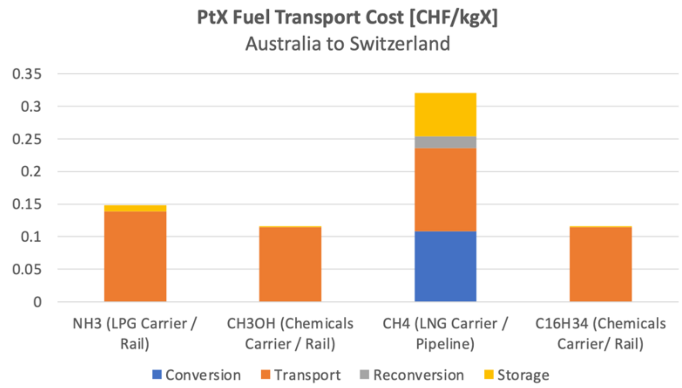

Figure 86: Costs of different PtX fuel import options from Australia to Switzerland in 2023.

Due to the significantly lower transport costs of these PtX fuels, supply chain considerations are less important, making domestic production in Switzerland even less competitive than for hydrogen (see *Figure 87*). However, the production cost advantage of overseas exporters such as Australia, Chile and the United States is partly reduced, due to the lower transport cost of their more regional competitors. As the differences in production costs are projected to reduce over the coming decades while transport costs remain constant the regional exporters catch-up to their overseas counterparts, and become the cheapest alternative for some fuel imports. For methane, Spain becomes the cheapest exporter in the 2030s, due to cheap pipeline supply chains. For ammonia Spain become the cheapest supply option by the 2040s, while the overseas exporters stay in the lead in the case of methanol and *Fischer-Tropsch* fuels, as their transport costs make up less of the overall delivered cost.

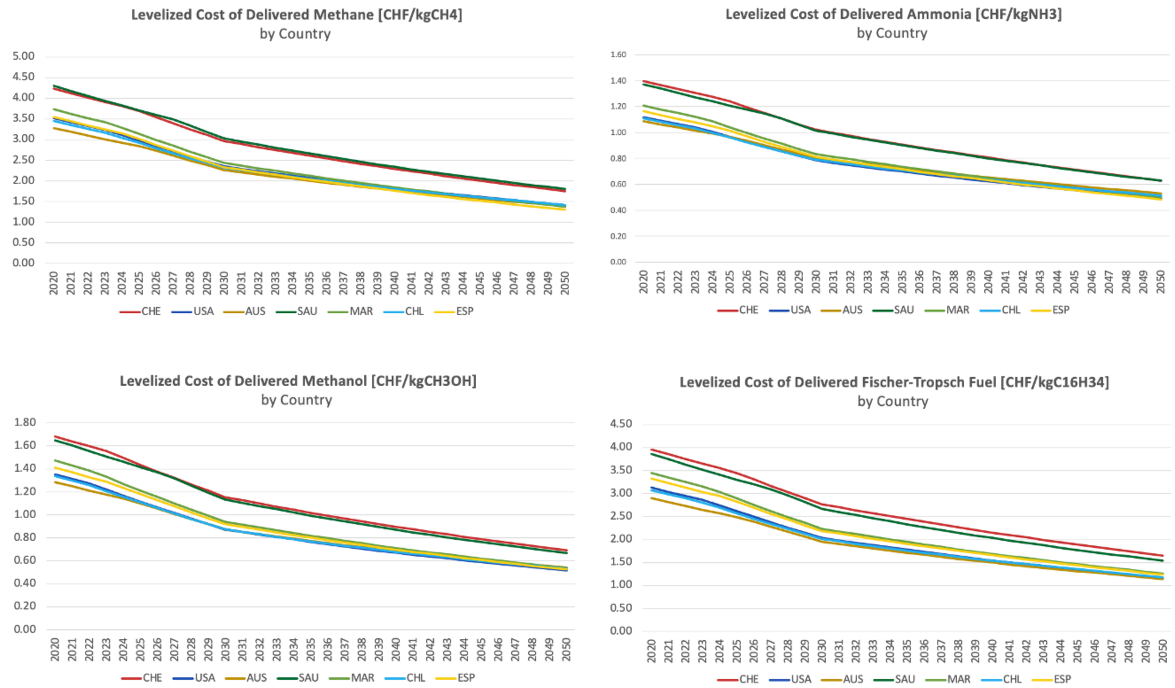

Figure 87: LCoX of delivered PtX fuels in Switzerland.

3.5.5 Energy Efficiency Considerations

As renewable electricity will be in high demand in the future, the available capacity as efficiently as possible will be crucial for the energy transition to be successful. Therefore, the energy efficiency of PtX fuels needs to be an important consideration when evaluating their overall viability. To contribute to this discussion, the following section provides a brief overview of the energy efficiencies associated with the production and conversion steps considered in this study. While the efficiency of hydrogen electrolysis systems has been extensively discussed in *Chapter 3.3.2.4*, the overall process efficiencies of the other PtX fuels will subsequently be elaborated upon.

The determined efficiencies of PtX fuel production considering various levels of heat integration are summarized in *Table 32* and a graphical overview of the respective process efficiencies can be found in *Figure 88*. In cases where no heat integration is considered, the efficiencies for carbon-based fuels are worse than those of nitrogen-based ammonia, due to the higher energy expenditure necessary for the generation of their carbon feedstock. As this low-temperature heat demand can be provided in large part by waste heat from the fuel production processes, the effective efficiencies considering heat integration are significantly improved. Under the assumption that all recoverable waste heat can be utilized in some way, ammonia synthesis reaches an energy efficiency of 75%, while the carbon-based fuels have lower efficiencies between 52–65%.

Table 32: Process energy efficiencies for PtX fuel production.

	No Heat Integration	Heat for Feedstock	Complete Heat Integration
NH_3	53.51%	54.3%	75.1%
CH_4	42.8%	51.0%	58.0%
CH_3OH	43.5%	52.0%	52.0%
$C_{16}H_{34}$	39.83%	48.9%	64.4%

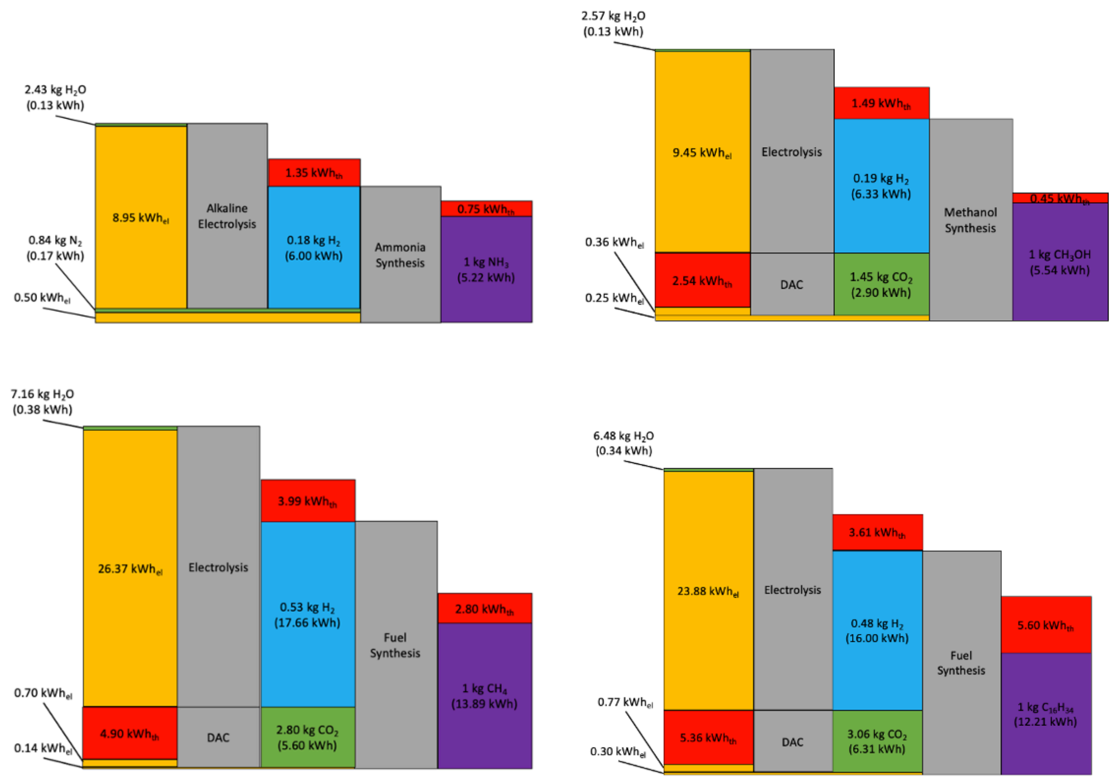

Figure 88: Energy balances of the modelled PtX fuel production process steps (grey), starting from primary energy inputs of electricity (yellow) and heat (red).

When considering the energy efficiency of delivered PtX fuels, the entire supply chain needs to be evaluated. The energy expenditure for transport itself, such as ship propulsion and cooling requirements, are rather low compared to the intrinsic energy content of the transported fuels. An extensive study on the energy efficiencies of PtX fuel production and transport by (Hank *et al.*, 2020) found that the shipping of PtX fuels has an efficiency of somewhere between 97.4% and 99.3%.[13] To facilitate the transport of hydrogen, most of the required energy is actually expended for the energy intensive conversion processes. To transport hydrogen as ammonia, which was determined to be the economically favorable option, the conversion steps along the supply chain consume energy equivalent to 40% of the entire energy content in the transported hydrogen. When accounting for the production process, only 37% of the initial electrical energy reaches its destination in the form of hydrogen (see *Figure 89*). In cases where hydrogen is subsequently reconverted to electricity in a combined cycle gas turbine (CCGT)[14], only a fifth of the initial power input can be recovered, and that is before accounting for any energy demand or incurred losses during transport and storage.

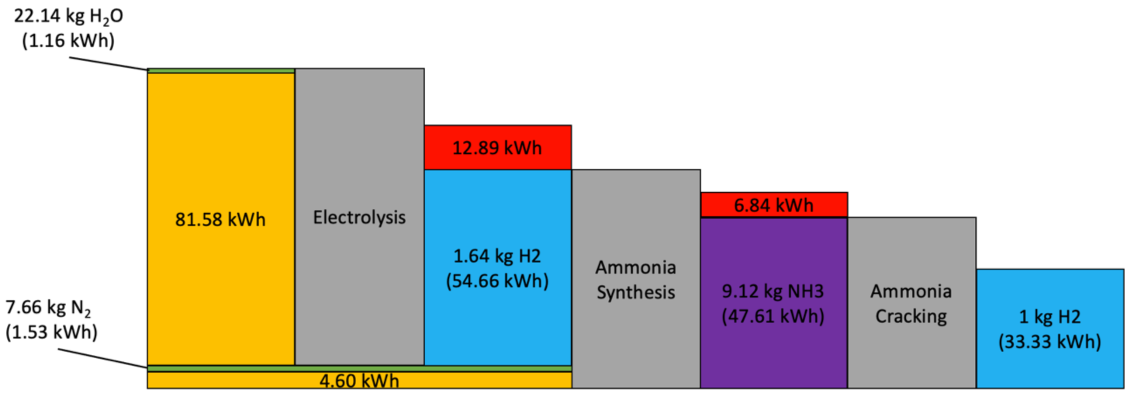

Figure 89: Energy balances of the conversions necessary to transport hydrogen as ammonia.

As discussed in *Chapter 3.3.1.1*, producing significant amounts of PtX fuels will require massive amounts of renewable electricity, which will likely remain a scarce commodity. Due to the energy intensive processes associated with the production and transport of these fuels, as well as the low roundtrip efficiencies when reconverting them back to electricity, their future applications should be carefully considered and compared to other decarbonization options, especially in cases where direct electrification is possible.

[13] Assuming boil-off losses can be used for ship propulsion.
[14] Conversion efficiencies of CCGTs are usually around 60%.

4 Conclusions & Outlook

This thesis aimed at providing a comprehensive overview of the available feedstock and supply options for PtX fuel supply in Switzerland as well as assessing of their economic viability. This task has been achieved through several steps of analysis, which are briefly summarized in the following.

First off, the major PtX fuel exporters were identified through the development of comprehensive assessment framework designed for the evaluation of countries' export potential. Within this framework, the collection of quantitative assessment parameters and a subsequent qualitative assessment served as the basis for the identification of 6 major PtX fuel exporters around the world. Subsequently, a techno-economic assessment model for the production of PtX fuels along various technological pathways has been developed, identifying major cost factors and accounting for relevant country-specific differences. Finally, an analysis of the available supply chain options for the import of PtX fuels to Switzerland has been conducted. Overall, a comprehensive overview of the delivered costs for all available import options for Switzerland was gained and contrasted to domestic production. A comprehensive excel spreadsheet model containing the input parameters, all associated calculations, and the various resulting cost developments has been submitted as part of this thesis.

The obtained results show that the import of PtX fuels can lead to significant cost savings compared to domestic production in Switzerland. The magnitude of these savings depends on the exporter-specific production cost advantages, as well as the available import options. Country-specific differences in PtX fuel production are mainly due to differences in their renewable energy potential and the resulting levelized cost of electricity, as well as differing costs of capital. The lowest levelized cost for production of hydrogen and its derivatives can be achieved in Australia, closely followed by Chile and the United States, all profiting from favorable capacity factors in their electricity generation, coupled with a low to medium costs of capital.

While the supply chain costs for ammonia, methane, methanol and *Fischer-Tropsch* fuels have a limited impact on their delivered cost in Switzerland, they account for a significant fraction of the delivered cost of hydrogen, mainly due to the expensive conversion processes associated with transforming it into a transportable form. Such conversion costs can be circumvented in the case of pipeline transport, provided that a corresponding pipeline infrastructure is available. Therefore, whether Europe will be build a European Hydrogen Backbone in the coming decades to facilitate the intracontinental transport of hydrogen, will have a big impact on the resulting hydrogen supply costs in Switzerland, as well as its choice of suitable exporters. In case such a system is built, imports from more regional exporters, such as Spain and Morocco, will be the most attractive supply option for Switzerland. If not, importing form overseas exporters with lower production costs makes more sense, although such imports will be significantly more expensive. In such a scenario, domestic hydrogen production might become the cheapest supply option by the late 2030s. Nevertheless, it is unlikely that Switzerland will become self-sufficient with regard to its PtX fuel demand, given the fact that the limited domestic renewable energy potential will be needed for the widespread electrification and to substitute the power generation of the aging nuclear fleet.

These conclusions align nicely with comparable techno-economic assessments that have been published on behalf of Germany in recent months. *Table 33* gives an overview of the key assumptions, lowest available PtX fuel supply options, and main conclusions of this study and compares them to the results of these reports, which have been published by (Hank *et al.*, 2023) and (Pfennig *et al.*, 2023). Both the determined PtX fuel supply costs and the main conclusions of these reports are comparable to the results of this study, although they deviate in their approach and methodology.

Table 33: Overview of recently published PtX Fuel import option analyses on behalf of Germany.

Source	Importer	Exporter	Key Assumptions	Delivered Cost	Conclusions
This Study	Switzerland	Spain Chile Morocco Saudi Arabia Australia United States	• Country-specific assumptions with regards to renewable energy potential and CAPEX, electrolyzer capacity factors, and water availability. • Country, technology, and scenario specific WACC between 1.7–16.2%	**2030** 3.6 CHF/kg $\mathbf{H_2}$ 2.3 CHF/kg $\mathbf{CH_4}$ 0.78 CHF/kg $\mathbf{NH_3}$ 0.87 CHF/kg $\mathbf{CH_3OH}$ 1.9 CHF/kg $\mathbf{C_{16}H_{34}}$ **2050** 2.2 CHF/kg $\mathbf{H_2}$ 1.3 CHF/kg $\mathbf{CH_4}$ 0.48 CHF/kg $\mathbf{NH_3}$ 0.52 CHF/kg $\mathbf{CH_3OH}$ 1.1 CHF/kg $\mathbf{C_{16}H_{34}}$	• The cost of capital has a significant impact on resulting PtX fuel production cost. • Lowest PtX fuel production cost can be achieved in Australia, Chile and the United States, thanks to a combination of low electricity prices, favorable capacity factors and lower cost of capital. • A European hydrogen pipeline system would be crucial in facilitating affordable hydrogen imports from regional exporters. • As transport of other PtX fuels is cheap, it often makes sense to import them from the lowest cost producer.
(Hank *et al.*, 2023)	Germany	Spain, Ukraine Morocco, Algeria, Tunisia, Namibia. South Africa Brazil, Colombia, Mexico, India Australia	• Site dependent GIS analyses with regards to wind and solar profiles, topography, and infrastructure conditions. • Country-specific WACC between 5.5–8.0%.	**2030** 4.6 EUR/kg $\mathbf{H_2}$ 0.89 EUR/kg $\mathbf{NH_3}$ 1.1 EUR/kg $\mathbf{CH_3OH}$ 2.0 EUR/kg $\mathbf{C_{16}H_{34}}$	• Brazil and Australia stand out as excellent PtX Fuel exporters, due to their low cost of electricity, high capacity factors, and comparably low capital cost. • The cheapest hydrogen supply comes from regional exporters (i.e. Spain), assuming an operational EHB. Other forms of hydrogen supply are not competitive with domestic production. • Other PtX fuels are cheapest to import from overseas exporters, with the lowest cost of production as transport cost play less of a role.
(Pfennig *et al.*, 2023)	EU27 member states	97 countries with PtX production potential	• Identification of suitable production locations. • Modelling of site specific PtX production configuration at 600 sites, considering hourly weather data. • Considers wind, solar and hybrid systems as well as SOE and PEM electrolyzers. • Technology specific WACC between 8–10%.	**2050** 3.4 EUR/kg $\mathbf{H_2}$ 1.6 EUR/kg $\mathbf{CH_4}$ 0.51 EUR/kg $\mathbf{NH_3}$ 0.64 EUR/kg $\mathbf{CH_3OH}$ 1.4 EUR/kg $\mathbf{C_{16}H_{34}}$	• Long-term global production potential of 3600 Mt hydrogen per year. • The largest suitable areas for PtX production were identified in the United States, Australia, and Argentina. • The lowest production costs were achieved with either wind or hybrid systems. • Countries with the lowest production cost were Chile, Argentina, Venezuela, and Mauritania. • Only liquefied hydrogen transport considered.

As with any emerging technology that has not seen large-scale industrial application, cost estimates regarding the construction and operation of large-scale PtX production plants are associated with significant uncertainty, represented in the wide ranges in cost and operational parameters reported in literature. Projecting the development of such uncertain parameters 30 years into the future requires further assumptions and simplifications. While some industrial players and critical voices deem the bulk of literature as too optimistic (Cuderman and Weber, 2023), cost developments of other renewable energy technologies, such as wind and solar, have shown that even the most optimistic expectations can be radically outperformed once large-scale adoption leads to enormous economies of scale and learning curve improvements.

Taking this into account, one of the key factors that will determine how the cost of producing PtX fuels will develop is how significant their role will be in the energy systems of the future. As mentioned in the introduction, there are currently many proposed applications for hydrogen and its derivatives, ranging from domestic heating over long-duration energy storage to already established applications in the chemical industry (see *Figure 90*). For many of the proposed applications, there is also a suite of other decarbonization options, most prominently electrification and the use of biofuels. Which of the available options establish themselves will have a significant impact on the demand for their underlying technologies.

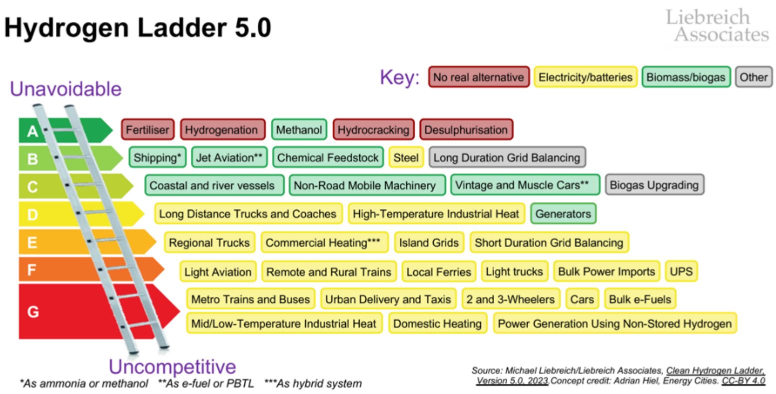

Figure 90: The hydrogen ladder, ranking proposed applications for hydrogen and its derivatives and looking at possible decarbonization alternatives (Liebreich, 2023b).

As for PtX fuel production, their associated supply chain costs will also be strongly dependent on the extent to which these fuels are traded around the world, as this will determine the accessibility and scale of the available transport infrastructure. While some studies predict a massive global hydrogen trading system to emerge in the future (Hydrogen Council, 2022), others are much more skeptical, assuming that hydrogen will only be transported between regions by the use of pipelines, with international PtX fuel shipping playing a very limited role (Liebreich, 2022). One key factor that will determine how the international flow of such fuels will develop, is to which extent industries that have a high demand for hydrogen, will relocate to regions where green hydrogen can be produced cheaply, instead of importing it from there. Such a shift can make sense if the achievable input cost reductions are greater than the cost of shipping their final goods back to demand centers. Industries where this could might become a possibility are commodities such as aluminum, iron & steel, and chemicals (IRENA, 2022a).

Another important aspect that will have a big impact on future PtX fuel supply chains, is the impact of geopolitical factors and industrial policy, both of which have gained in importance over recent years. As the massive implications of renewable energy subsidy programs, such as the IRA, are starting to become evident, and with an increasing trend of “de-risking” and “friend-shoring” crucial supply chains, solely relying on economic indicators is not sufficient to gain a holistic understanding of the changes on the horizon.

The presented work provides a unified framework enabling the consistent economic assessment of supply options for different PtX fuels, produced in different countries around the world along different production pathways powered by different electricity supply types, and imported to Switzerland based on several conceivable supply chain scenarios. In order to provide such an overarching perspective, generalization and simplifications are inevitable, leading to the loss of detail and granularity in specific cases.

To regain some of these details, the existing model could be further expanded as part of future research. To get a clearer picture of the interaction of electricity generation, electricity storage, and electrolyzer operation, simulations based on temporal weather data can give extremely important insights. The framework for PtX fuel production provided in this study might therefore be coupled to a more sophisticated electricity model that is based on such granular data. Furthermore, the included PtX fuel supply chain model can be further expanded by modelling specific supply chain infrastructure assets as well as specific transport vessels, in order to better understand their cost structures. To assess how the gradual build-up of a global PtX fuel supply chain system could develop, several scenarios with increasing amounts of infrastructure assets and transport vessels could be modelled, determining how these assets might interact with each other to facilitate global PtX fuel trade.

Finally, as economics are not the only variable necessary to assess the viability of PtX fuels, the determined cost data needs to be combined with other factors, such as safety considerations, as well as environmental and social impact data. This can be achieved by complementing the techno-economic assessment with a life cycle analysis. Furthermore, to get a comprehensive overview of all the decarbonization options available to Switzerland, other low-carbon fuels need to be assessed, such as biofuels and fossil-based fuels combined with carbon capture technologies. Finally, the available options need to be integrated into an energy system analysis of Switzerland, to determine what the role of low-carbon fuels could be in a decarbonized Swiss energy system. All these points are further steps of the SHELTERED project and will provide the insights necessary for informed policy decisions on behalf of Switzerland.

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6 Annex

This Master thesis has been submitted together with an excel model in electronic form, which contains the entire techno-economic assessment model including all input parameters, calculations, and the determined results. It also contains a Dashboard intended to provide a convenient way of filtering the multitude of results and obtain targeted insights.

In the following, a graphical overview of the conducted calculations to determine the levelized cost of electricity (LCoE), levelized cost of water (LCoW), levelized cost of carbon dioxide (LCOC), levelized cost of nitrogen (LCON), levelized cost of hydrogen (LCoH) and levelized cost of PtX fuels (LCoX) are provided (see *Figures 91-96*). Furthermore, snapshots of the respective excel spreadsheets for each process step are provided (see *Figures 97-107*). For an in-depth understanding of the calculations, data extraction or further development of the model, the reader is recommended to consult the excel file directly.

6.1 Calculation Overviews

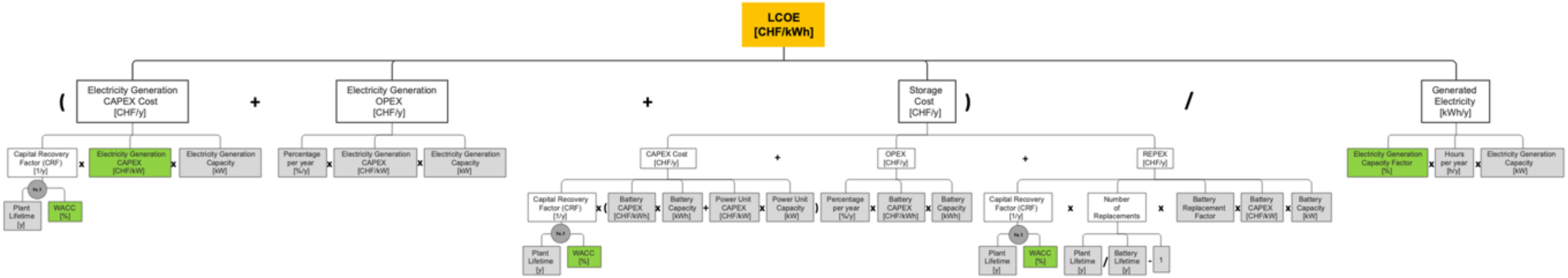


Figure 91:Calculation of the levelized cost of electricity (LCoE). General input parameters are market in light grey, country-specific input parameters in light green.

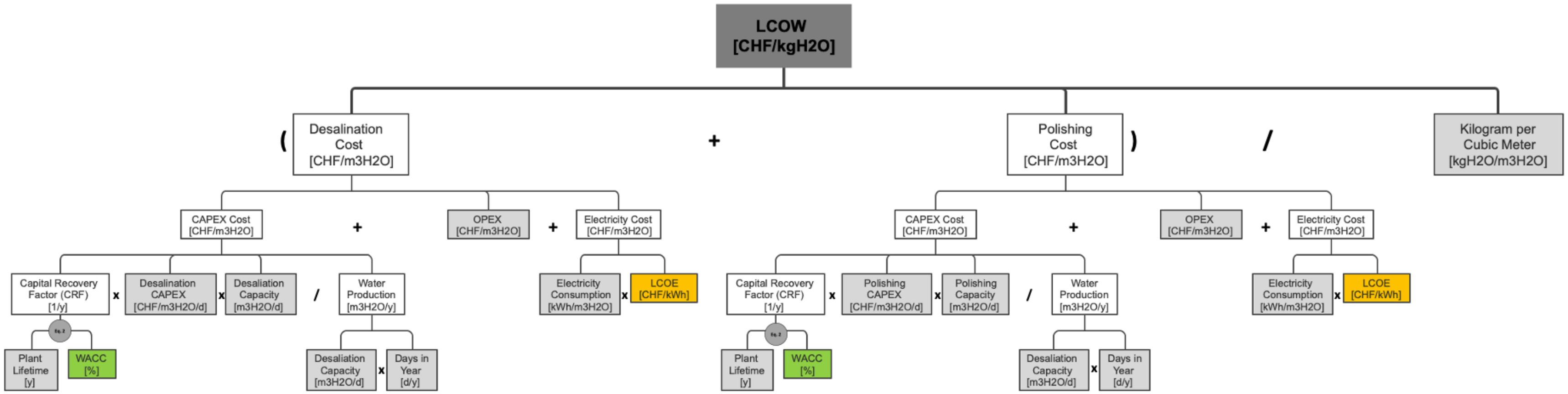


Figure 92: Calculation of the levelized cost of water (LCoW). General input parameters are market in light grey, country-specific input parameters in light green.

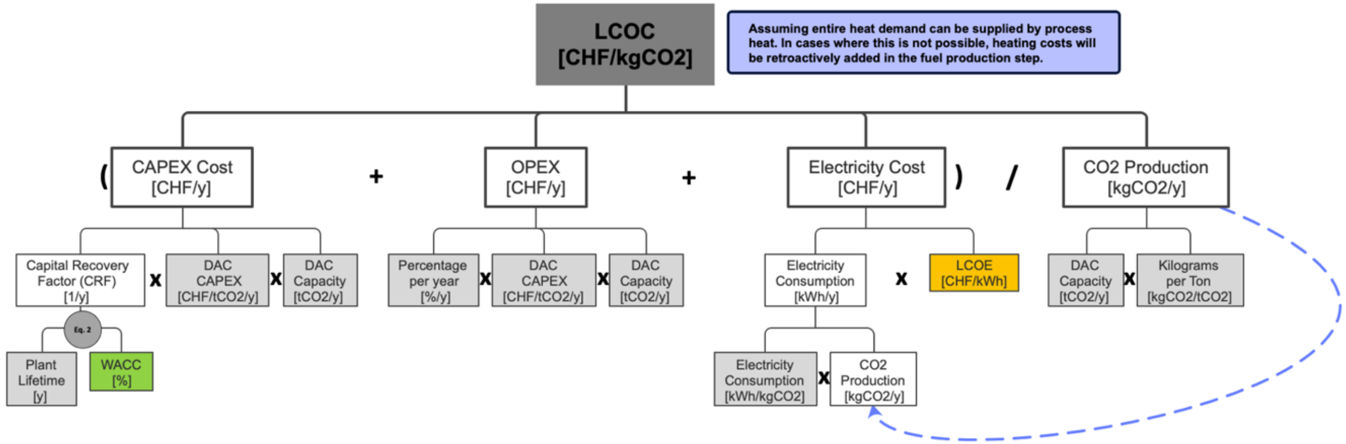


Figure 93: Calculation of the levelized cost of carbon dioxide (LCoC). General input parameters are market in light grey, country-specific input parameters in light green.

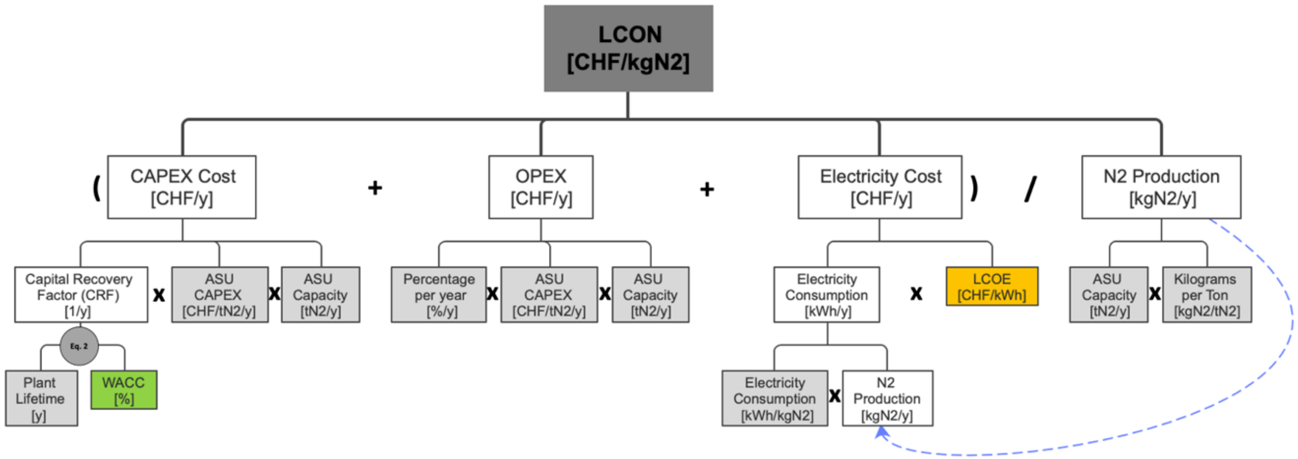


Figure 94: Calculation of the levelized cost of nitrogen (LCoN). General input parameters are market in light grey, country-specific input parameters in light green.

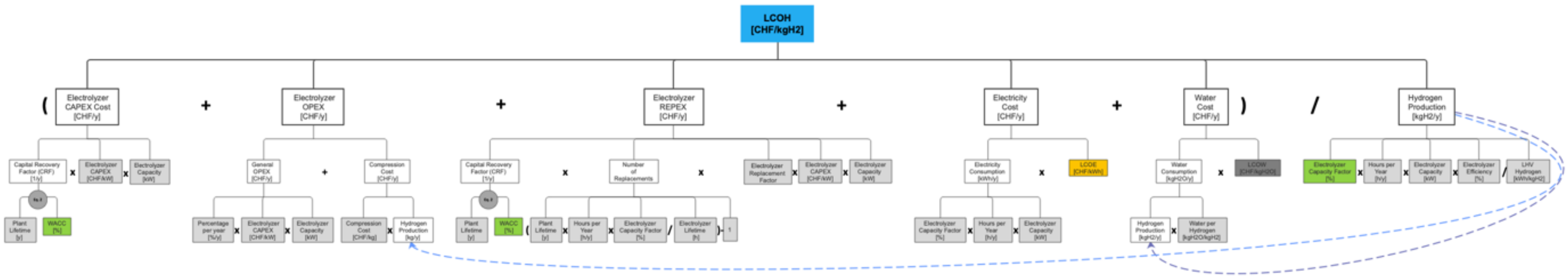


Figure 95: Calculation of the levelized cost of hydrogen (LCoH). General input parameters are market in light grey, country-specific input parameters in light green.

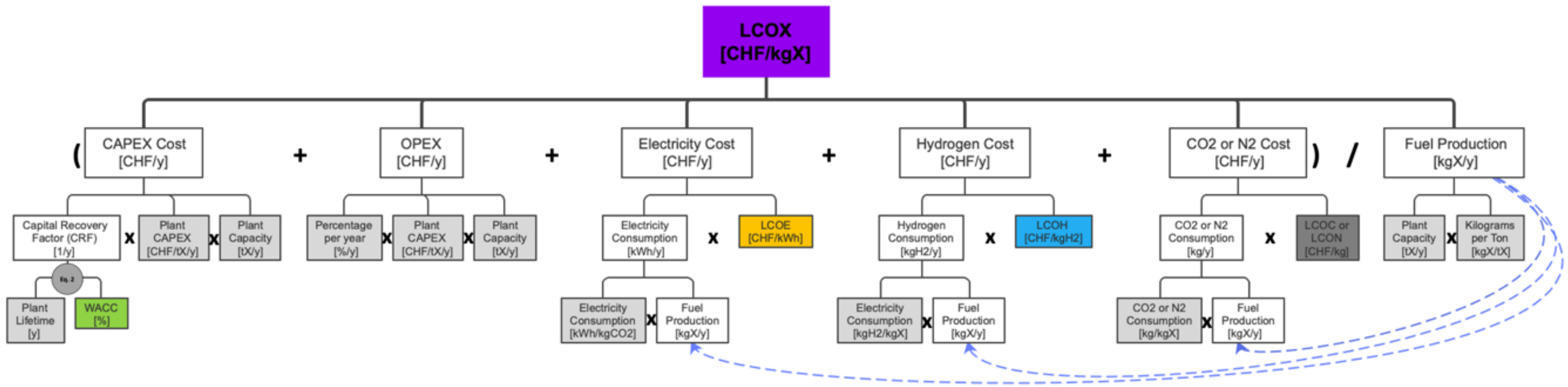
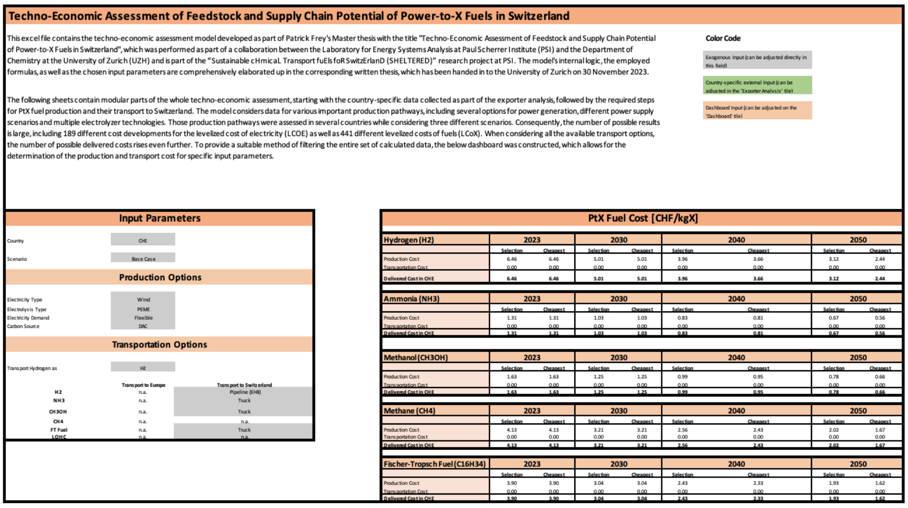


Figure 96: Calculation of the levelized cost of PtX fuels (LCoX). General input parameters are market in light grey, country-specific input parameters in light green.

6.2 Excel Spreadsheets



Techno-Economic Assessment of Feedstock and Supply Chain Potential of Power-to-X Fuels in Switzerland

This excel file contains the techno-economic assessment model developed as part of Patrick Frey's Master thesis with the title "Techno-Economic Assessment of Feedstock and Supply Chain Potential of Power-to-X Fuels in Switzerland", which was performed as part of a collaboration between the Laboratory for Energy Systems Analysis at Paul Scherrer Institute (PSI) and the Department of Chemistry at the University of Zurich (UZH) and is part of the "Sustainable cHmicaL Transport fuEls foR SwitzErlanD (SHELTERED)" research project at PSI. The model's internal logic, the employed formulas, as well as the chosen input parameters are comprehensively elaborated up in the corresponding written thesis, which has been handed in to the University of Zurich on 30 November 2023.

The following sheets contain modular parts of the whole techno-economic assessment, starting with the country-specific data collected as part of the exporter analysis, followed by the required steps for PtX fuel production and their transport to Switzerland. The model considers data for various important production pathways, including several options for power generation, different power supply scenarios and multiple electrolyzer technologies. Those production pathways were assessed in several countries while considering three different scenarios. Consequently, the number of possible results is large, including 189 different cost developments for the levelized cost of electricity (LCOE) as well as 441 different levelized costs of fuels (LCoX). When considering all the available transport options, the number of possible delivered costs rises even further. To provide a suitable method of filtering the entire set of calculated data, the below dashboard was constructed, which allows for the determination of the production and transport cost for specific input parameters.

Color Code

Exogenous Input (can be adjusted directly in this field)

Country-specific external Input (can be adjusted in the 'Exporter Analysis' tile)

Dashboard Input (can be adjusted on the 'Dashboard' tile)

Input Parameters

Country	CHE
Scenario	Base Case

Production Options

Electricity Type	Wind
Electrolysis Type	PEME
Electricity Demand	Flexible
Carbon Source	DAC

Transportation Options

Transport Hydrogen as	H2

	Transport to Europe	Transport to Switzerland
H2	n.a.	Pipeline (EHB)
NH3	n.a.	Truck
CH3OH	n.a.	Truck
CH4	n.a.	n.a.
FT Fuel	n.a.	Truck
LOHC	n.a.	n.a.

PtX Fuel Cost [CHF/kgX]

Hydrogen (H2)	2023		2030		2040		2050	
	Selection	Cheapest	Selection	Cheapest	Selection	Cheapest	Selection	Cheapest
Production Cost	6.46	6.46	5.01	5.01	3.96	3.66	3.12	2.44
Transportation Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Cost in CHE	6.46	6.46	5.01	5.01	3.96	3.66	3.12	2.44

Ammonia (NH3)	2023		2030		2040		2050	
	Selection	Cheapest	Selection	Cheapest	Selection	Cheapest	Selection	Cheapest
Production Cost	1.31	1.31	1.03	1.03	0.83	0.81	0.67	0.56
Transportation Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Cost in CHE	1.31	1.31	1.03	1.03	0.83	0.81	0.67	0.56

Methanol (CH3OH)	2023		2030		2040		2050	
	Selection	Cheapest	Selection	Cheapest	Selection	Cheapest	Selection	Cheapest
Production Cost	1.63	1.63	1.25	1.25	0.99	0.95	0.78	0.66
Transportation Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Cost in CHE	1.63	1.63	1.25	1.25	0.99	0.95	0.78	0.66

Methane (CH4)	2023		2030		2040		2050	
	Selection	Cheapest	Selection	Cheapest	Selection	Cheapest	Selection	Cheapest
Production Cost	4.13	4.13	3.21	3.21	2.56	2.43	2.02	1.67
Transportation Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Cost in CHE	4.13	4.13	3.21	3.21	2.56	2.43	2.02	1.67

Fischer-Tropsch Fuel (C16H34)	2023		2030		2040		2050	
	Selection	Cheapest	Selection	Cheapest	Selection	Cheapest	Selection	Cheapest
Production Cost	3.90	3.90	3.04	3.04	2.43	2.33	1.93	1.62
Transportation Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Delivered Cost in CHE	3.90	3.90	3.04	3.04	2.43	2.33	1.93	1.62

Figure 97: Snapshot of the "Dashboard" spreadsheet from the Excel file.

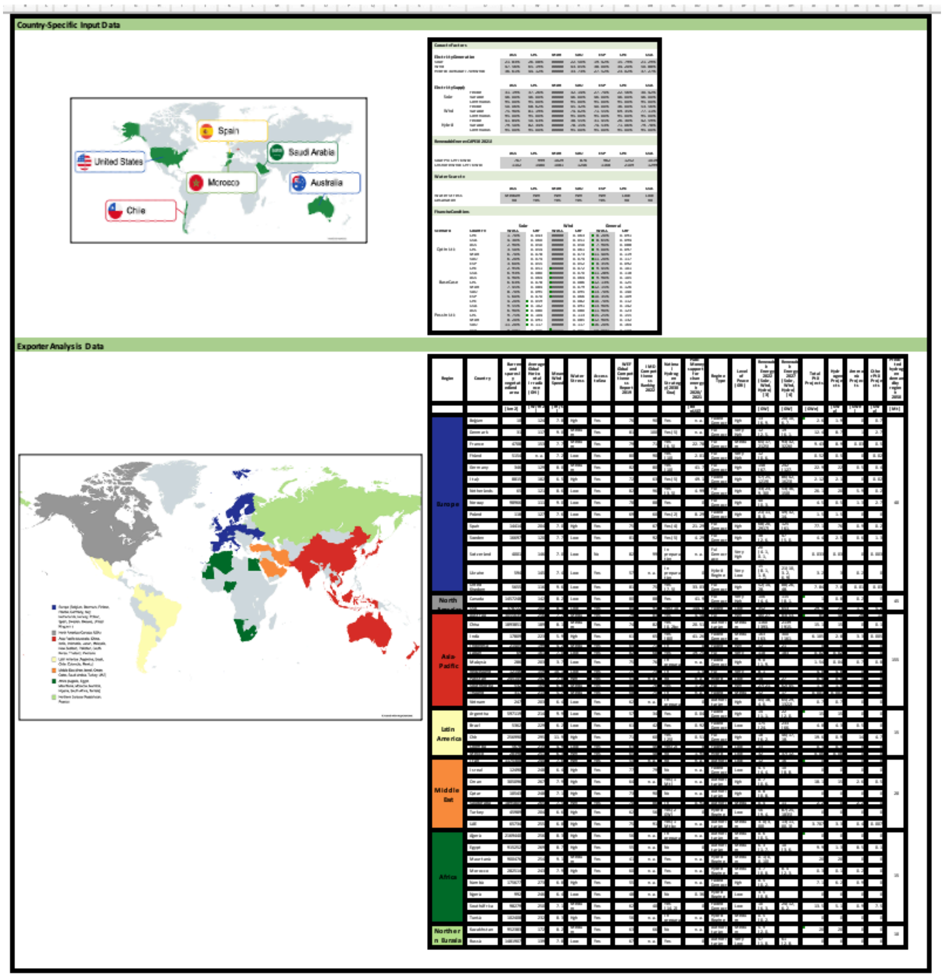


Figure 98: Snapshot of the "Exporter Analysis" spreadsheet from the Excel file.

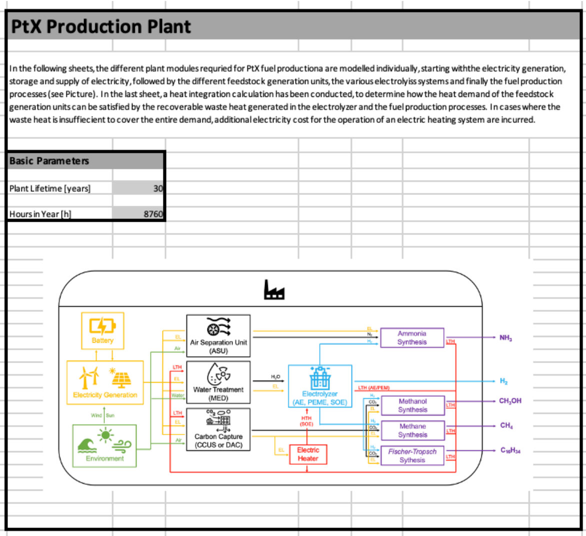


Figure 99: Snapshot of the "PtX Production" spreadsheet from the Excel file.

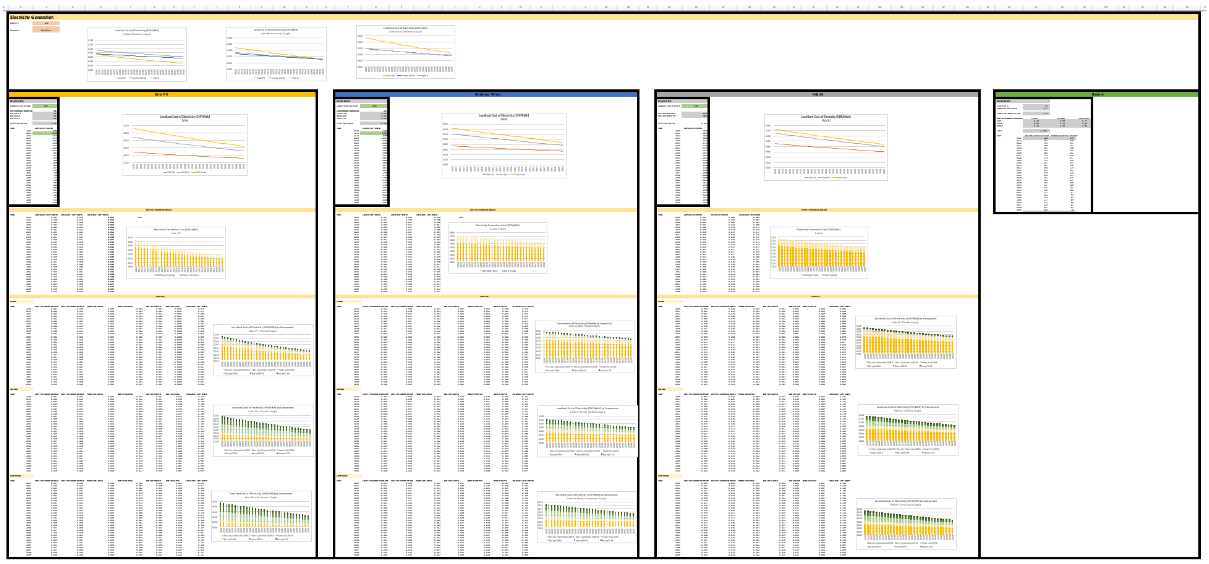


Figure 100: Snapshot of the "Electricity Generation" spreadsheet from the Excel file.

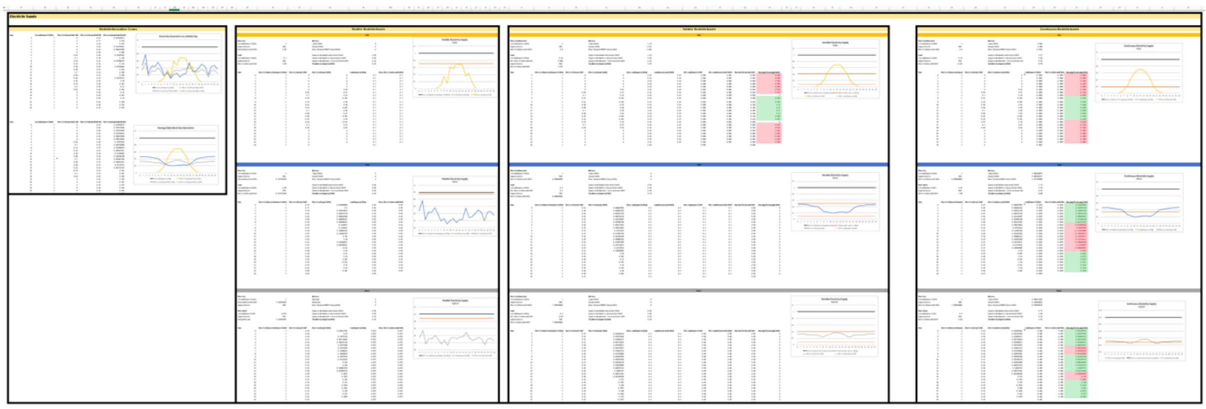


Figure 101: Snapshot of the "Electricity Supply" spreadsheet from the Excel file.

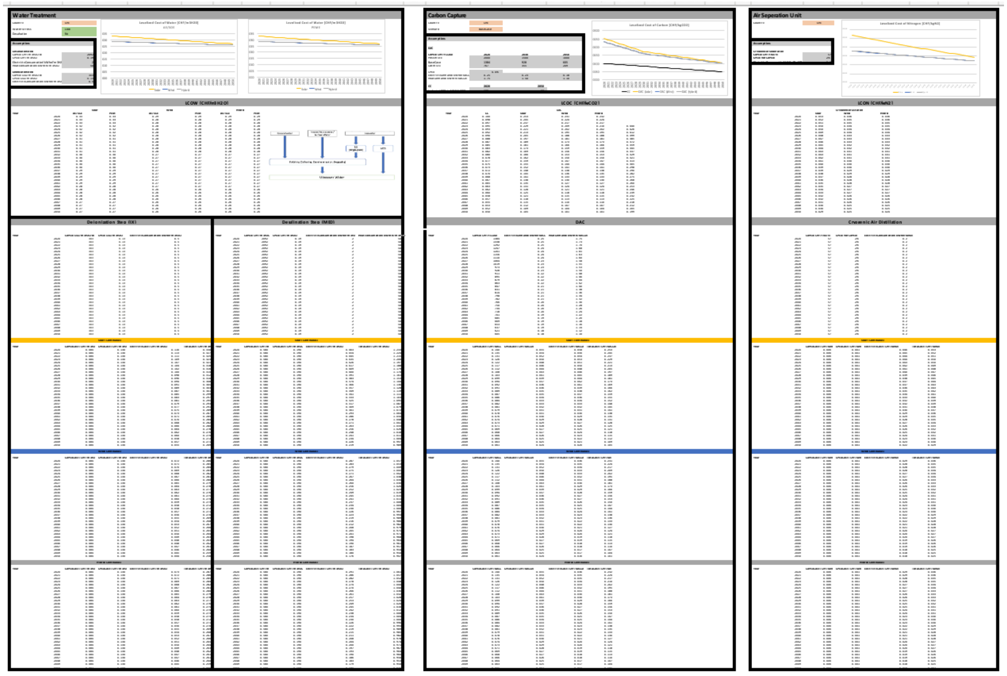


Figure 102: Snapshot of the "Feedstocks" spreadsheet from the Excel file.

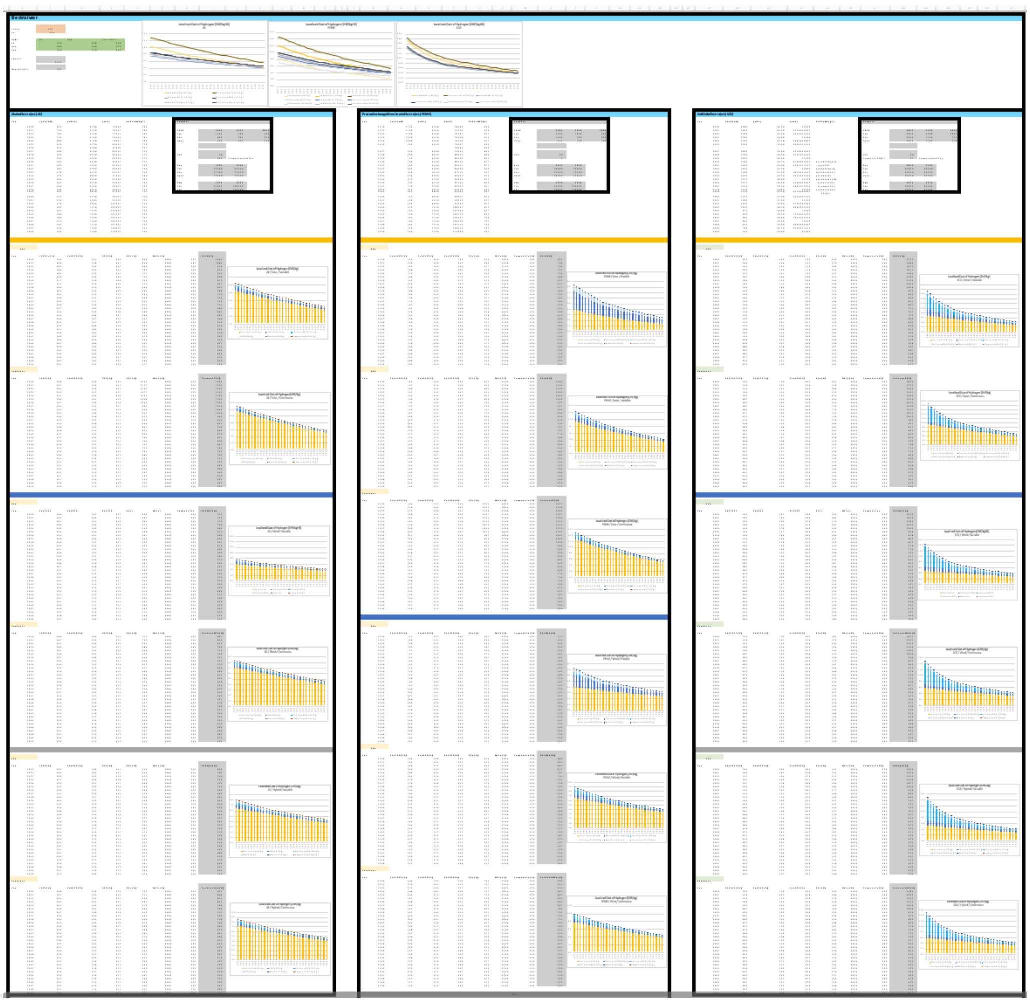


Figure 103: Snapshot of the "H2" spreadsheet from the Excel file.

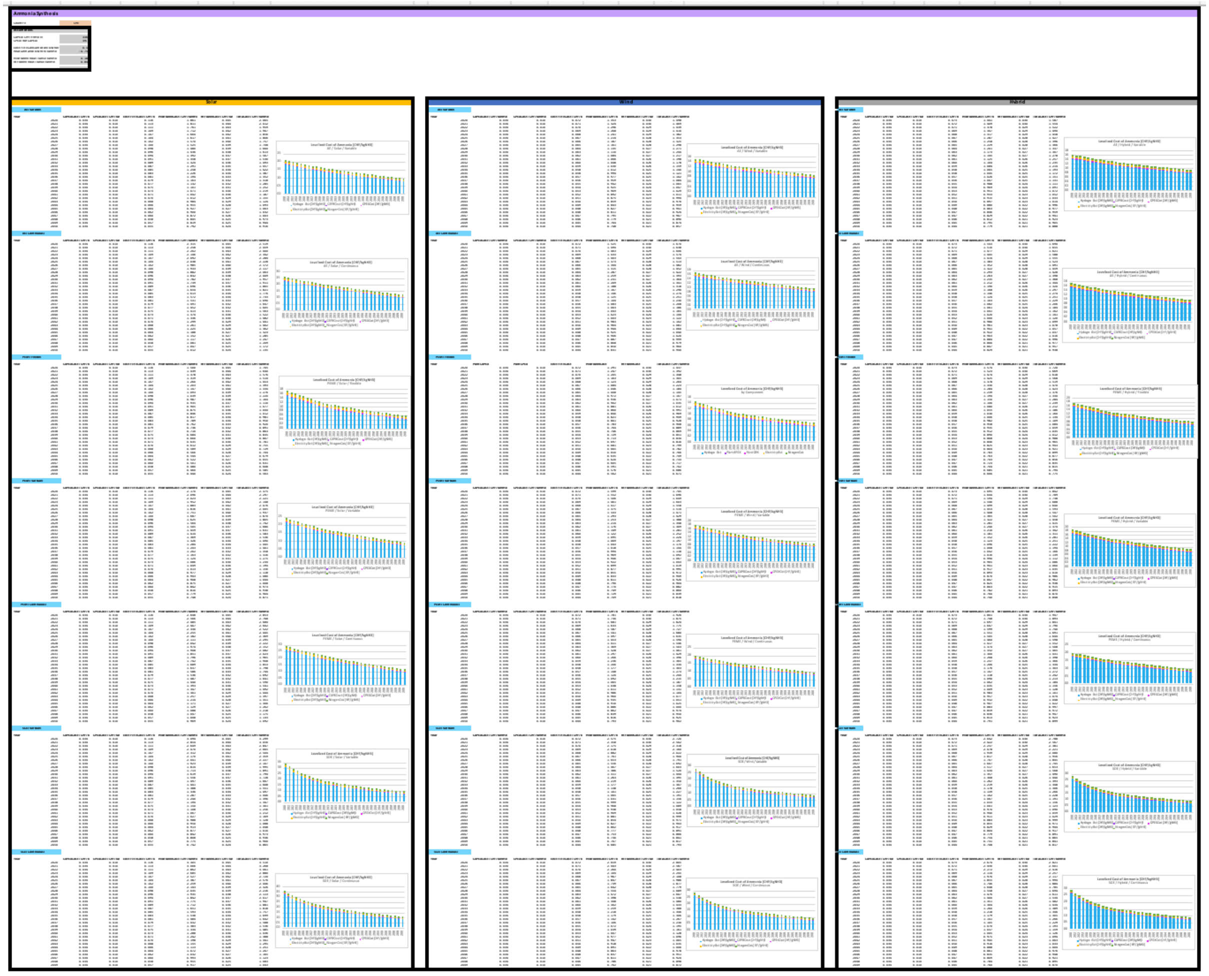


Figure 104: Snapshot of the "NH3" spreadsheet from the Excel file. The spreadsheets for "CH4", "CH3OH", and "C16H34" have the same schematic structure an will therefore not all be explicitly illustrated here.

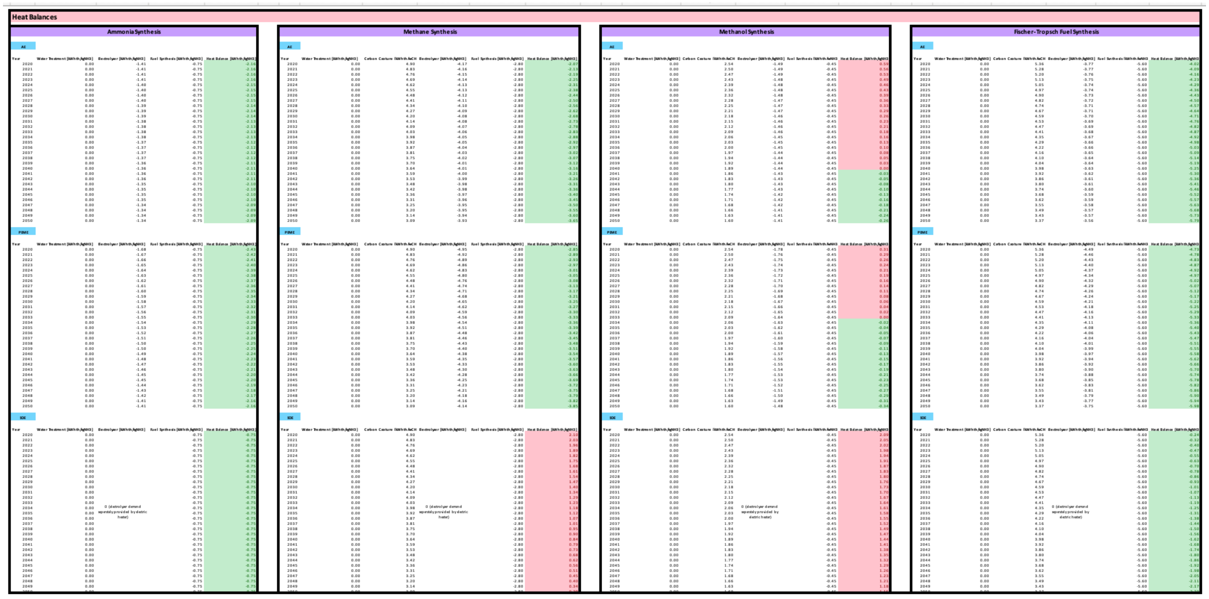


Figure 105: Snapshot of the "Heat integration" spreadsheet from the Excel file.

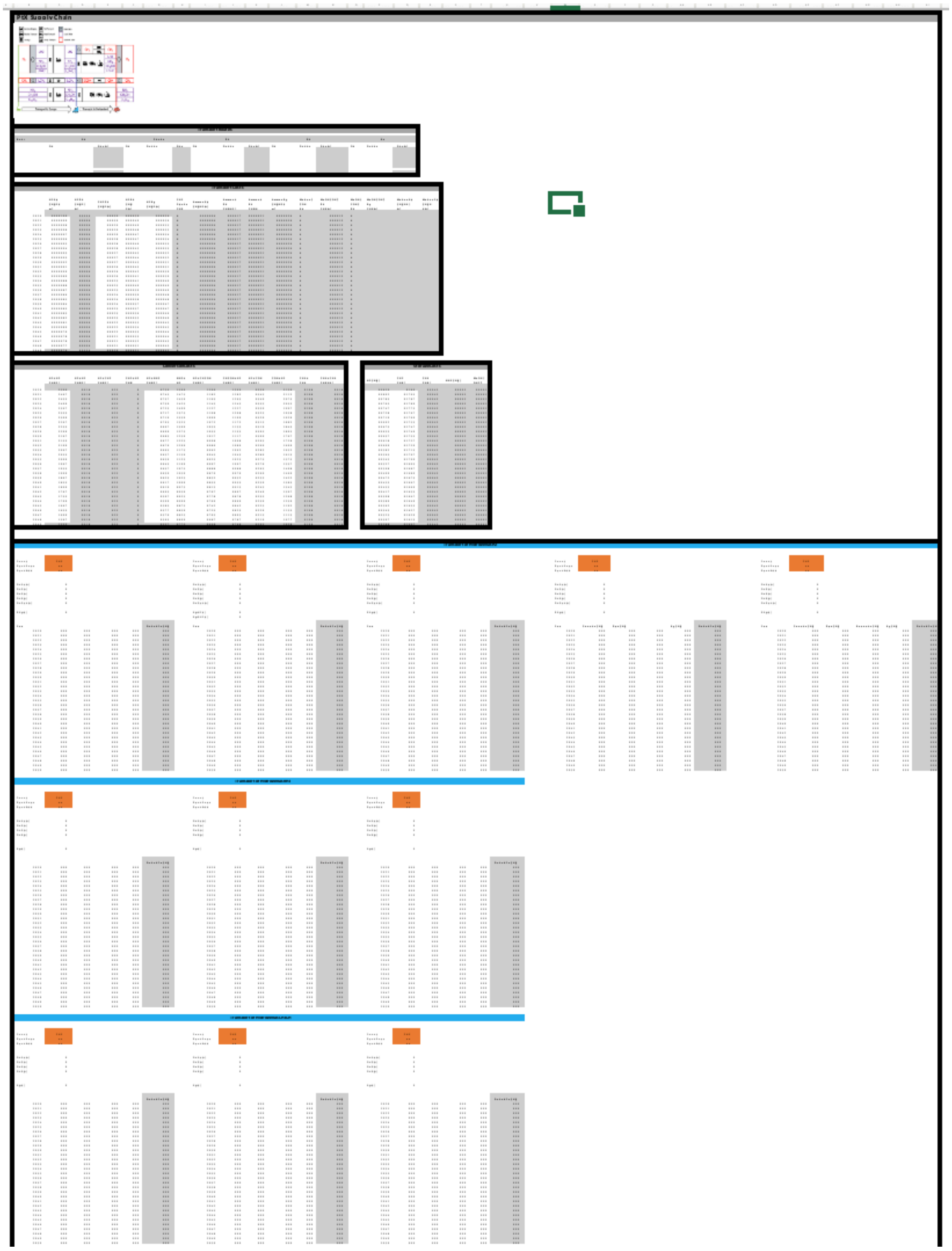


Figure 106: Snapshot of the "Supply Chain" spreadsheet from the Excel file.

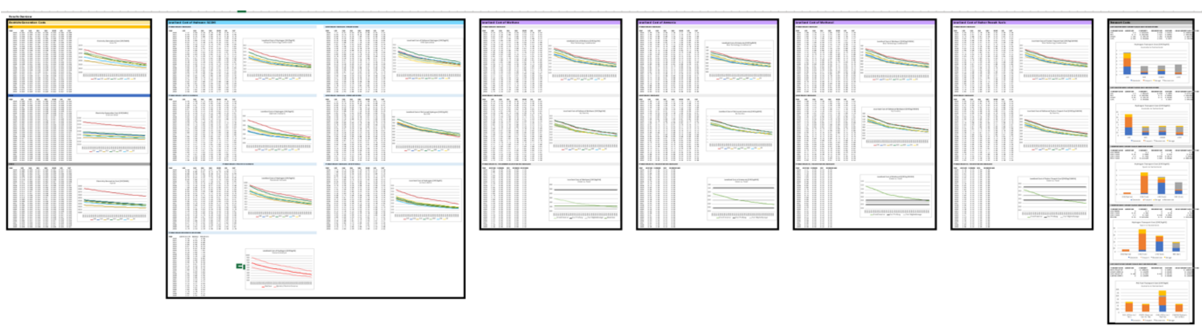


Figure 107: Snapshot of the "Results Overview" spreadsheet from the Excel file.

Selbständigkeitserklärung

Ich erkläre ausdrücklich, dass es sich bei der von mir eingereichten schriftlichen Arbeit mit dem Titel:

Techno-Economic Assessment of Feedstock and Supply Chain Potential of Power-to-X Fuels in Switzerland

um eine von mir selbstständig und ohne unerlaubte Beihilfe sowie in eigenen Worten verfasste Originalarbeit handelt. Zudem habe ich keine anderen Hilfsmittel als die in dieser Arbeit angegebenen benutzt. Ich bestätige überdies, dass die Arbeit in gleicher oder ähnlicher Form noch keiner anderen Prüfungsbehörde vorgelegen wurde und auch noch nicht sowohl als Ganzes oder in Teilen veröffentlicht wurde.

Ich erkläre ausdrücklich, dass ich sämtliche in der oben genannten Arbeit enthaltenen Bezüge auf Quellen und Sekundärliteratur als solche kenntlich gemacht habe. Insbesondere bestätige ich, dass ich ausnahmslos und nach bestem Wissen sowohl bei wörtlich übernommenen Aussagen (Zitaten) als auch bei in eigenen Worten wiedergegebenen Aussagen anderer Autorinnen oder Autoren (indirekte Zitate) die Urheberschaft angegeben habe.

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Ich bestätige mit meiner Unterschrift, dass ich die Selbstständigkeitserklärung gelesen und verstanden habe und deren Inhalt bestätige.

Zürich den 30.11.2023

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(Patrick Frey)