Dissertation

On the role of storage for electricity in the energy transition, with special focus on hydrogen

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Abstract

In Europe, ambitious targets for renewable energy adoption have been set, indicating a significant shift towards wind and solar energy in shaping the European electricity landscape. This transition underscores the increasing importance of integrating storage for electricity, particularly as renewable generation increases and dispatchable thermal generation capacity decreases. The core objective of this dissertation is to conduct an in-depth techno-economic analysis and explore the future economic perspectives of various storage for electricity options. The focus is particularly on the complete decarbonization of the electricity system and the resulting interplay between storage and variable renewable electricity generation, such as wind and photovoltaic sources and the utilization of hydrogen. This dissertation is primarily based on eight scientific publications: four review papers covering storage technologies, technological learning and hydrogen and four papers addressing: i) future scenarios for electricity storage under varying renewable integration, demand patterns and weather conditions; ii) current and future costs of integrated storage technologies in a decarbonized power system; iii) economic and environmental assessments of hydrogen production methods and locations; and iv) the potential use of hydrogen in the transport sector, including wind-powered fuel cell electric buses.

The research methodology employs electricity system modeling to assess the impacts of electrification and decarbonization, with a specific focus on storage for electricity. Techno-economic analyses scrutinize the feasibility and economic implications of integrating different storage technologies, alongside hydrogen production, transportation and utilization. Key findings underscore the critical role of weather patterns in influencing renewable electricity generation and the need for solutions to ensure seasonal balancing. Cost assessments from 2023 to 2050 reveal significant declines in lithium-ion battery costs compared to stable costs for pumped storage hydro, underscoring the importance of strategic deployment strategies. Hydrogen emerges as a component for specific use cases in the energy transition, with analyses revealing varying economic and environmental impacts of different production methods. Challenges in the transport sector, such as investment costs and operational efficiency, currently limit the widespread adoption of hydrogen applications.

In conclusion, strategic planning and investment in storage technologies and hydrogen infrastructure are crucial to enhancing the reliability, cost-efficiency and sustainability of Europe's future renewable energy landscape.

Kurzfassung

In Europa wurden ehrgeizige Ziele für die Einführung erneuerbarer Energien festgelegt, die zu einem Wandel hin zu Wind- und Solarenergie in der europäischen Energiewirtschaft führen. Dieser Übergang unterstreicht die zunehmende Bedeutung der Integration von Stromspeichern, insbesondere da die erneuerbare Erzeugung zunimmt und die verfügbare thermische Erzeugungskapazität abnimmt. Das Hauptziel dieser Dissertation ist es, eine eingehende techno-ökonomische Analyse durchzuführen und die zukünftigen wirtschaftlichen Perspektiven verschiedener Stromspeicheroptionen zu untersuchen. Der Fokus liegt insbesondere auf der vollständigen Dekarbonisierung des Stromsystems und dem daraus resultierenden Zusammenspiel zwischen Speichern und variabler erneuerbarer Stromerzeugung, sowie der Nutzung von Wasserstoff. Diese Dissertation basiert hauptsächlich auf acht wissenschaftlichen Veröffentlichungen: vier Übersichtsarbeiten zu Speichertechnologien, technologischem Lernen und Wasserstoff sowie vier Arbeiten, die sich mit folgenden Themen befassen: i) Szenarien für Stromspeicher mit unterschiedlicher erneuerbarer Erzeugung, Nachfrageprofilen und Wetterbedingungen; ii) aktuelle und zukünftige Kosten integrierter Speichertechnologien in einem dekarbonisierten Stromsystem; iii) wirtschaftliche und ökologische Bewertungen von Wasserstofferzeugungsmethoden und -standorten; und iv) das Potenzial der Nutzung von Wasserstoff im Verkehrssektor.
Methoden beinhalten die Modellierung von Stromsystemen, um die Auswirkungen von Elektrifizierung und Dekarbonisierung zu bewerten, sowie techno-ökonomische Analysen um die Machbarkeit und wirtschaftlichen Implikationen der Integration verschiedener Speichertechnologien sowie der Wasserstoffproduktion und -transport zu untersuchen. Dabei wird gezeigt, dass Wetterbedingungen einen großen Einfluss auf die Notwendigkeit des saisonalen Ausgleichs haben. Kostenbewertungen von 2023 bis 2050 zeigen erhebliche Rückgänge bei den Kosten für Lithium-Ionen-Batterien im Vergleich zu den stabil bleibenden Kosten von Pumpspeicherkraftwerken, was die Bedeutung strategischer Planung verdeutlicht. Wasserstoff erweist sich als Komponente für spezifische Anwendungsfälle, wobei Analysen unterschiedliche wirtschaftliche und ökologische Auswirkungen verschiedener Erzeugungsmethoden aufzeigen. Herausforderungen im Verkehrssektor, wie Investitionskosten und Effizienzen, begrenzen die Einführung von Wasserstoffanwendungen. Abschließend sind strategische Planung und Investitionen in Speichertechnologien und Wasserstoffinfrastruktur entscheidend, um die Zuverlässigkeit, Kosteneffizienz und Nachhaltigkeit der zukünftigen erneuerbaren Energielandschaft Europas zu verbessern.

Contents

Abbreviations

AIT	Austrian Institute of Technology
APG	Austrian Power Grid
BEB	Battery electric bus
CAES	Compressed air energy storage
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CCU	Carbon capture and utilization
CCUS	Carbon capture, utilization and storage
CO_2	Carbon dioxide
CRI	Commercial readiness index
DSM	Demand-side management
E/P ratio	Ratio of power to energy capacity
EAG	Renewable Energy Expansion Act
ENTSO-E	European Network of Transmission System Operators for Electricity
EV	Electric vehicle
FCEB	Fuel cell electric bus
FCV	Fuel cell vehicle
H2	Hydrogen
HP	Heat pump
LCO	Lithium cobalt oxide
LCOE	Levelized cost of electricity
LCOS	Levelized cost of stored energy
LFP	Lithium ferrophosphate
LHV	Lower heating value
LTO	Lithium titanate
NaNiCl	Sodium nickel chloride batteries
NaS	Sodium sulfur batteries
NCA	Lithium nickel cobalt aluminum
NMC	Lithium nickel manganese cobalt

O_2	Oxygen
OM	Operation model
PECD	Pan European Climate Database
PEM	Proton exchange membrane
PSH	Pumped storage hydro
PV	Photovoltaic
SH	Storage hydro
SMR	Steam methane reforming
SOEC	Solid oxide electrolyzer cell
TCU	Total cost of use
TML	Technology maturity level
TRL	Technology readiness level
VRFB	Vanadium redox redox flow
VRLA	Valve-regulated lead-acid
ZBFB	Zinc bromine

1. Introduction

1.1. Motivation

The ongoing global transition from fossil-based to renewable energy sources presents a significant challenge for electricity systems worldwide. In Europe, ambitious targets for renewable energy adoption have been set through initiatives like the "Clean Energy for All Europeans package," indicating a significant shift towards wind and solar energy in shaping the European electricity landscape (European Commission, 2019a). This transition is already underway, as evidenced by Figure 1, depicting the evolution of renewable energy generation from nearly zero in 1990 to 638 TWh in 2022 (Eurostat, 2024).

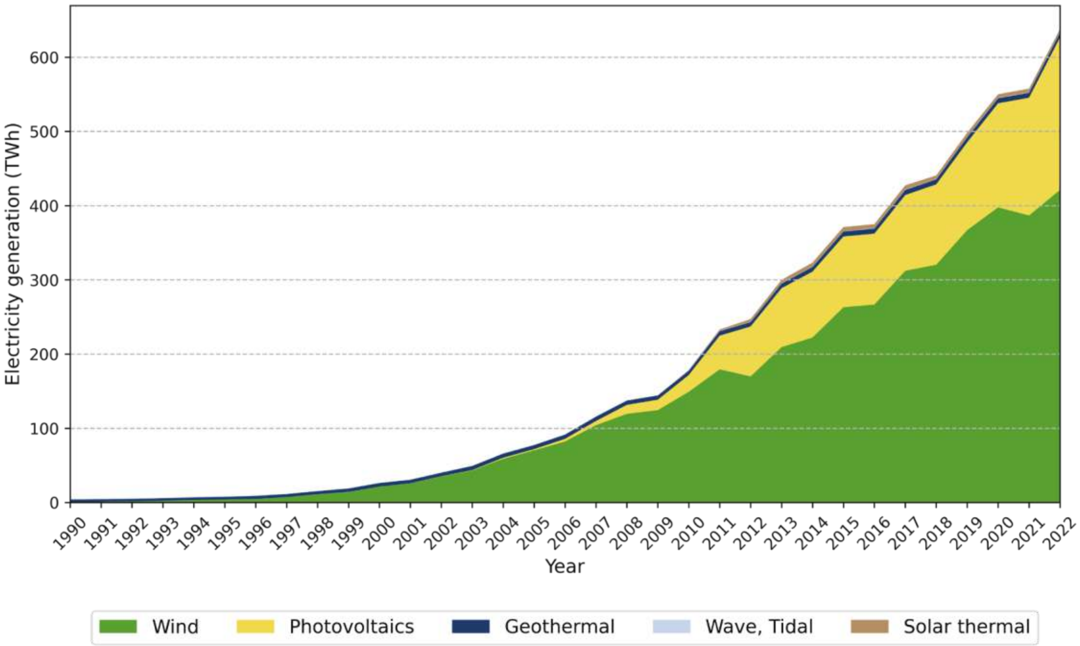

Figure 1: Variable renewable electricity generation in TWh from 1990-2022 in the European Union (Eurostat, 2024, 2014)

The importance of energy storage in facilitating this transition has been underscored by the European Parliament in its resolution on a comprehensive European approach to energy storage, emphasizing the need for increased flexibility and the deployment of more energy storage facilities (EU, 2020). To prepare the electricity system for these developments, the European Commission issued recommendations on energy storage for a decarbonized and secure European energy system in 2023 (European Commission, 2023a), complemented by a staff working document on energy storage (European Commission, 2023b). These recommendations highlight the crucial role of integrating long-term energy storage, particularly as renewable generation increases and fossil-fueled generators are phased out. Energy storage is envisioned to mitigate renewable generation curtailment in systems with high penetration of renewable energy, provide seasonal storage, security of supply, reliability service and also contribute to price stabilization by reducing fluctuations and electricity prices during peak times, providing peak capacity and optimizing energy distribution from periods of energy surplus (low prices) to energy deficits (high prices) (European Commission, 2023a).

In Austria, the enactment of the "Renewable Energy Expansion Act (EAG)" signifies a concrete commitment to achieving 100% renewable electricity by 2030 on a national balance (Österreichisches Parlament, 2021)[1]. This target necessitates the replacement of existing fossil fuel-based electricity generation primarily with wind and solar sources. Additionally, more capacity needs to be added to support the increased electrification of other sectors, particularly transportation. Within this context, the inherent variability of renewable sources poses specific challenges to the existing electricity infrastructure. Figure 2 illustrates this for a scenario of the future electricity system in 2030. In this weekly example, the intraday fluctuations are clearly visible, as well as the differences in generation and consumption between winter and summer.

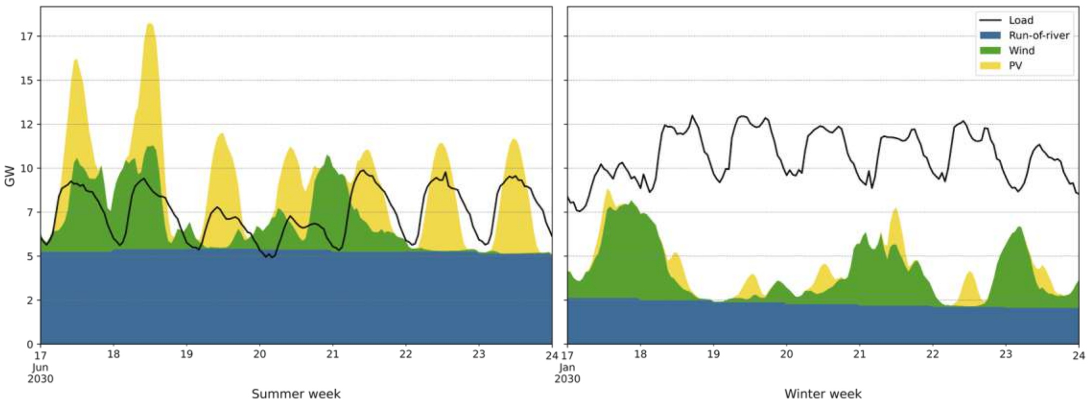

Figure 2: Extract from a summer week (17.6.-24.6.2030) and a winter week (17.1.-24.1.2030) to illustrate renewable generation and load (policy scenario (A), weather year 2016).

This underscores the increasing significance of storage for electricity as part of addressing the challenges associated with variable energy sources. There are fundamentally two main challenges in storing electricity from such sources: managing fluctuations in electricity production and addressing the seasonal variations in production. Additionally, the potential

[1] This goal, calculated on a net basis, entails exporting renewable electricity in equivalent measures to offset electricity generated from fossil fuels throughout the year.

for heat storage and sector coupling is also crucial for tackling these issues. However, this work focuses specifically on storage for electricity due to the extensive scope that would be required to address all aspects in detail.

The future of storage development remains uncertain and will depend on various factors. Currently, pumped storage hydro (PSH) is the dominant technology, but future cost trends, changes in the performance of other technologies, requirements for seasonal storage and geographical limitations of conventional PSH could reshape the landscape. Additionally, each technology has specific technical characteristics with resulting advantages and disadvantages, making it unlikely for a single technology to meet all flexibility requirements. Therefore, a combination of different storage technologies, as well as the utilization of other flexibility options such as demand-side management (DSM), grid expansion, or sector coupling, will be necessary to meet the demands of the transformed energy system.

1.2. Core objective and research questions

The core objective of this dissertation is to conduct an in-depth techno-economic analysis and explore the future economic perspectives of different storage options for electricity. The focus is particularly on the complete decarbonization of the electricity system and the resulting interplay between storage and variable renewable electricity generation, such as wind and photovoltaic (PV) sources. Additionally, the role of hydrogen is being analyzed, including a case study in the transportation sector. To address these objectives, the following research questions have been defined:

Research Question 1: *What form will future storage of electricity scenarios take, considering different variable renewable electricity integration scenarios, demand patterns and underlying weather conditions?*

To answer the first research question, three scenarios (*policy (A)*, *renewables and electrification (B)* and *efficiency (C)*), which include different capacity expansion paths for renewables and storage, electricity demand and weather years and their resulting utilization dynamics within the specified scenarios, are developed, which are based on Sayer et al. (2024a). The aim is to model the Austrian electricity system to demonstrate the impacts of various influencing factors. With a focus on complete decarbonization and extensive integration of hydrogen storage for seasonal purposes, this research seeks to provide insights into the functionality and interdependence among batteries, PSH, storage hydro (SH) and underground hydrogen storage within renewable-based electricity systems. Moreover, it emphasizes significant differences in storage utilization based on weather conditions from an overall system perspective. This also includes, albeit in a somewhat simplified manner, the synergies with other sectors such as the heat and transport sectors to represent the overall energy system. However, the primary focus is on illustrating the interplay of different storage technologies.

An hourly cost-minimizing electricity market and energy storage dispatch model is developed, aiming to minimize the overall variable generation costs associated with dispatchable technologies under externally imposed renewable expansion targets. The model encompasses three scenarios for the capacity expansion of renewables with an ultimate phase-out of fossil generation by incorporating short- (batteries), medium- (PSH) and long-term (hydrogen) energy storage capabilities. It illustrates the optimal dispatch of incorporated storage technologies for meeting the underlying electricity demand each hour.

Research Question 2: *What are the current and projected future total costs of jointly integrated storage technologies in a decarbonized electricity system?*

Based on the insights from the modeling and scenario analysis under the first research question, it is crucial to understand the trajectory of future total costs of energy storage technologies. Hence, the core objective of the contribution under research question two, based on Sayer et al. (2024b), is to conduct a comprehensive assessment of the costs of selected energy storage technologies, both current and future, within the context of the Austrian electricity market and scenario development while considering technical specifics. The aim is to provide insights into potential cost trends and their implications for the energy transition.

The method applied involves a techno-economic assessment of the joint integration of selected storage technologies in a renewable electricity system based on an underlying modeling of the Austrian electricity system using three scenarios that account for the decarbonization goals of the Austrian government. The electricity modeling extends until 2050 to examine the costs of integrating new storage technologies in the future. To evaluate the cost-effectiveness of storage under these scenarios, a comprehensive literature review of current storage costs forms the basis of our economic analysis. Additionally, the analysis utilizes a technological learning approach, which serves to calculate the future investment costs of the analyzed technologies and thus incorporates them as future costs into the evaluation.

Research Question 3: *What are the techno-economic and environmental implications of different hydrogen production methods and locations and which combination is most promising for a sustainable hydrogen economy in Europe?*

Hydrogen, commonly regarded as a carbon-neutral energy carrier, is increasingly important beyond its role in storage for electricity, as covered by research questions one and two, extending to various production processes due to its versatility as an energy vector. However, the transition towards renewable-based hydrogen production faces challenges, prompting debates over the most efficient and sustainable production methods and distribution logistics amidst increasing industrial demand and evolving energy landscapes. Therefore, the core objective of this contribution is twofold: firstly, to provide a comprehensive overview of the state of the art of hydrogen with a focus on production processes (colors) and secondly, to analyze the techno-economic and environmental implications of four defined hydrogen production chains (grey, blue, yellow, green), considering both domestic and imported production scenarios. The general introduction draws upon review papers authored by Ajanovic et al. (2024, 2022), whereas the methodology and findings stem from the research conducted by Sayer et al. (2024c).

Research Question 4: *How can hydrogen be utilized in the transport sector and what are the most viable operation modes for the case study of wind energy powering fuel cell electric buses?*
One of the use cases discussed under research question three is the application of hydrogen in the transport sector, which is being investigated for fuel cell electric buses (FCEB) in this contribution. While this application is not inherently the most advantageous, its widespread discussion and relative maturity make it an interesting subject for examination. However, the question arises

For this reason, a case study concerning the transportation sector, based on Sayer et al. (2022), was conducted to determine the costs incurred when wind power is used for hydrogen production and subsequently for operating FCEB. Initially, the total costs of FCEB compared to diesel buses are analyzed through a total cost of use (TCU) analysis and a resulting sensitivity analysis concerning hydrogen price, carbon dioxide (CO_2) price, travel distance and investment costs. Secondly, the most economical operation mode of the electrolyzer is identified, followed by an assessment of the future cost development of the mentioned technologies until 2050.

This dissertation comprises eight contributions addressing the overall objective. Most parts of this work have already been published in a similar form in the author's papers, either as the main author or as a co-author with substantial contributions to the respective papers (Ajanovic et al., 2024, 2022; Haas et al., 2022a, 2022b; Sayer et al., 2024b, 2024c, 2024a, 2022). Notably, Haas et al. (2022a) provide a comprehensive overview of the economics of storage, while Haas et al. (2022b) explain the concept of determining future cost developments using technological learning. Ajanovic et al. (2022) cover the various colors of hydrogen, emphasizing its production technologies, further expanded by Ajanovic et al. (2024) with a general introduction to different aspects of hydrogen. Building upon these foundations, four papers (Sayer et al., 2024b, 2024c, 2024a, 2022), published in scientific journals, address the defined research questions.

1.3. Structure of the thesis

The remainder of this thesis is structured as follows: Section 2 provides a comprehensive review of the state of the art of storage for electricity. Beginning with an overview of storage technologies for electricity, this section details various types and their operational principles. The economic analysis examines both current costs and future cost projections through technological learning, including studies on current costs of storage technologies, the theory behind technological learning and future cost studies. Other flexibility measures besides storage that enhance system stability and efficiency are also explored. Additionally, the section delves into the modeling of electricity markets and systems, covering electricity market models with high shares of renewables, storage models and models based on time series of variable renewables. Contributions are based on Ajanovic et al. (2024, 2022), Haas et al. (2022a, 2022b) and Sayer et al. (2024b, 2024c, 2024a, 2022). Scenarios on future storage requirements in the Austrian electricity system with high shares of variable renewables are discussed in Section 3. This part of the thesis outlines the methodology, the model setup and scenario definitions. The results include analyses of weather patterns' influence on renewable generation and extreme weather events, the overall renewable electricity system and hydrogen storage and differences in storage utilization and dispatchable generation between 2030 and 2050. Therefore, this section significantly contributes to research question one and analyses in this section are based on Sayer et al. (2024a). Section 4 focuses on the current and future costs of jointly integrated storage technologies in a decarbonized electricity system through technological learning. This includes a methodology section, with a techno-economic analysis of total storage costs and investment cost calculations. The results provide insights into future investment cost analysis, the total cost of storage in a decarbonized system and a yearly comparison of total storage costs. This section, which answers research question two is based on Sayer et al. (2024b). The use of different colors and production locations of hydrogen and their techno-economic and environmental implications is investigated in Section 5. The method description and the results are outlined according to the techno-economic analysis and the environmental assessment. Contributions of this section answer research question three and are based on Sayer et al. (2024c). A case study on the use of hydrogen in the transport sector, specifically focusing on FCEBs, is provided in Section 6. This includes background and current state of hydrogen-powered transportation, the methodology for economic evaluation and results covering cost analysis of FCEB and electrolyzers, analysis of electrolyzer operation modes and future prospects. The case study is based on Sayer et al. (2022). The thesis concludes in Section 7, summarizing the key findings and offering concluding remarks on the feasibility and economic viability of storage technologies for transitioning to a 100% renewable electricity sector in Austria.

2. State of the art of storage technologies for electricity

The integration of large-scale renewable energy sources into electricity grids is a cornerstone of global decarbonization strategies. As these renewable sources, particularly wind and solar, are inherently variable, enhancing the flexibility of electricity systems has become important. One solution to this challenge is the development and deployment of storage of electricity technologies. This section provides a comprehensive examination of the current state of the art of storage of electricity, focusing on technological, economic and modeling perspectives. In Section 2.1, a detailed overview of various storage of electricity technologies is provided. This segment is based on Haas et al. (2022a), offering insights into the different types of storage solutions currently available with a focus on PSH, battery and hydrogen storage. The economic viability of storage technologies is critical for their widespread adoption. Section 2.2 examines this aspect and includes a review of studies on the current costs of storage technologies (Section 2.2.1), followed by a discussion on the theory behind technological learning (Section 2.2.2) and lastly, Section 2.2.3 addresses the future costs of storage technologies through technological learning. Section 2.2 is primarily based on the papers by Sayer et al. (2024b) and Haas et al. (2022b). While storage technologies are a key component of future electricity systems, they are not the sole means of achieving the required flexibility. Section 2.3 explores alternative flexibility measures that can complement storage solutions based on Haas et al. (2022a). These alternatives are crucial in ensuring a resilient and reliable electricity supply in systems with high shares of variable renewables. The final section of this chapter, Section 2.4, shifts focus to the modeling of electricity markets and systems. Based on the work by Sayer et al. (2024a), this section reviews various models that incorporate high shares of renewable energy sources.

2.1. Overview of storage technologies for electricity

The process of energy storage involves taking energy from a supply source and converting it for storage in a device, which is associated with losses (Figure 3). The amount of energy that can be retrieved from the storage device will depend on the type of device and the length of time it has been stored, as well as any additional losses that occur during the process of converting the stored energy back into a usable form. There are two main types of losses in energy storage systems: conversion losses, which occur during the charging and discharging processes and storage losses, which occur during the period of storage. Energy storage devices can be categorized according to the form of energy they store, the length of time they can store it and the specific application they are used for.

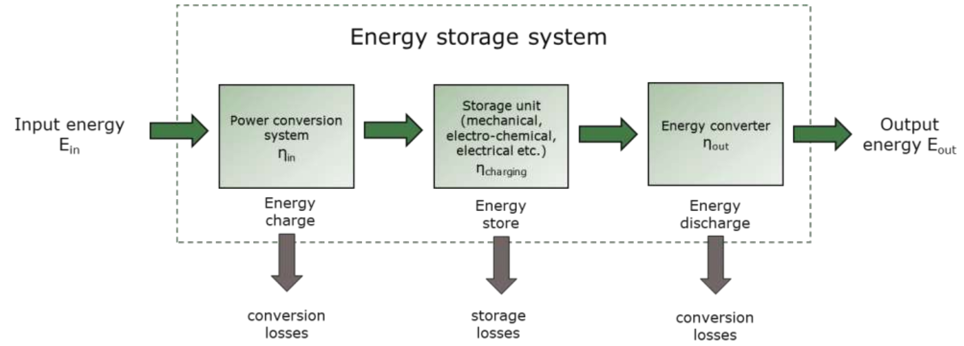

Figure 3: Energy storage system and resulting losses

When considering the form of energy storage, options can be categorized into the following storage classes: mechanical, electrochemical, chemical and electrical, as illustrated in Figure 4. Additionally, thermal constitutes its own storage class; however, it is not considered in this analysis, as it is generally uncommon to efficiently convert low-temperature heat back into electricity. Alongside the main technology of PSH, battery storage is the most mature technology (Behabtu et al., 2020). Approximately 90% of grid-scale batteries belong to the lithium-ion category (IRENA, 2019).

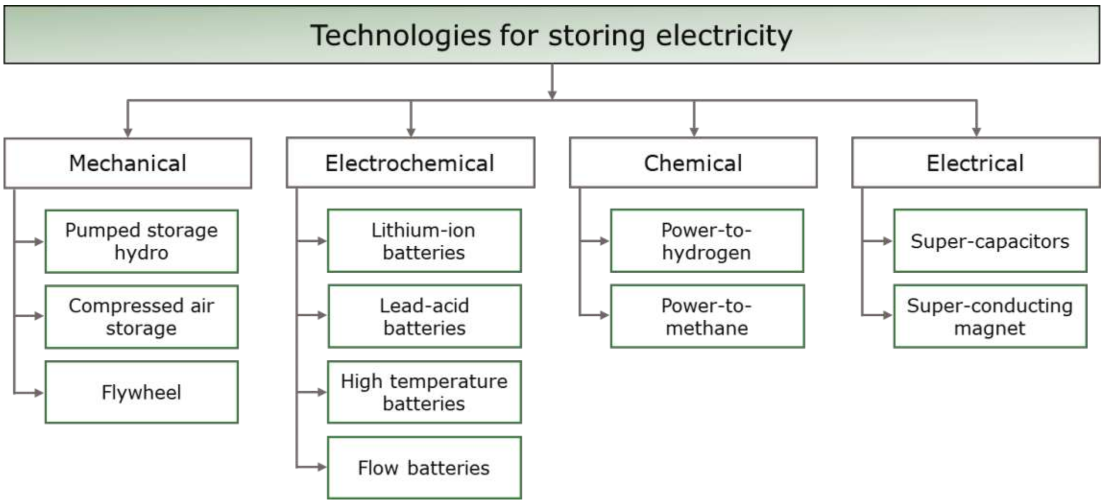

Figure 4: Four storage classes and respective technologies for storing electricity based on the form of energy stored

Another classification of the stated storage technologies is based on the power to energy capacity (E/P) ratios. Energy capacity refers to the maximum amount of energy a storage system can hold at any given time. The selection of this ratio for each technology primarily depends on the energy and power-related costs and round-trip efficiencies (Schill, 2020a). The typical discharge times as a function of installed storage capacity are illustrated in Figure 5.

Broadly, storage is classified into short-term (electrical, flywheels and batteries), mid-term (CAES and PSH) and long-term (hydrogen and methane). An optimal storage portfolio comprises various technologies composed of different power and energy ratios (Belderbos et al., 2017).

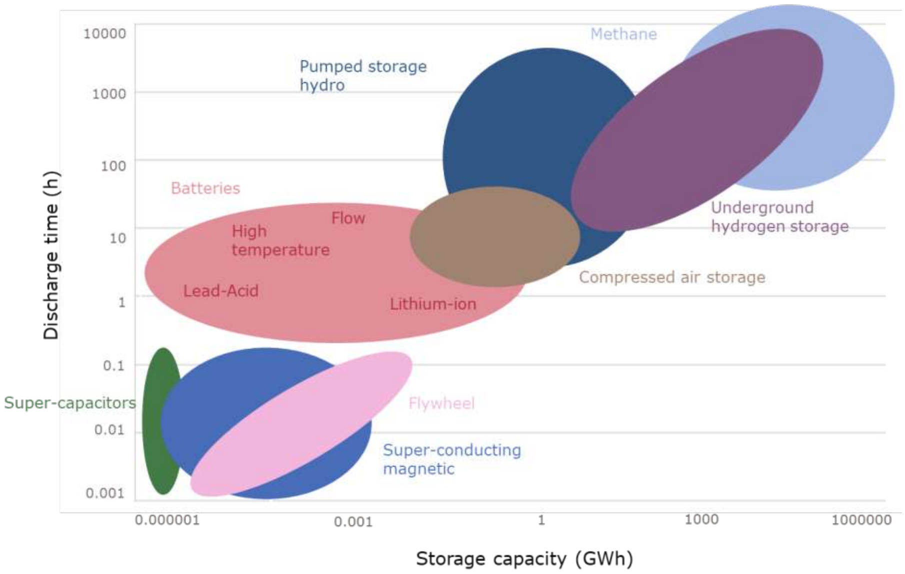

Figure 5: Typical discharge times of various storage of electricity technologies as a function of installed storage capacity (own creation with technical details from Gabrielli et al. (2024) Sterner and Stadler (2019))

Further classification occurs based on the applications for which the respective storage technologies can be utilized. Technologies with higher reaction speeds are well-suited for ensuring supply security, while those with higher energy capacity are primarily used for energy management. Different application fields include ancillary services such as frequency regulation or power reliability for short reaction times. Mid-term storage durations are primarily utilized for energy arbitrage and seasonal storage to balance the different weather-related generation profiles of variable renewable generation over the course of the year (Schmidt and Staffell, 2023). Table 1 provides a comprehensive overview of the specifications of selected mechanical, electrochemical, chemical and electrical storage technologies. Lithium-ion batteries encompass various types, including lithium ferrophosphate (LFP), lithium nickel cobalt aluminum (NCA), lithium titanate (LTO) and lithium nickel manganese cobalt (NMC), while lead-acid batteries comprise valve-regulated lead-acid (VRLA) and flooded lead-acid variants (IRENA, 2020a). However, these are not individually discussed in the table. Regarding classification, sodium sulfur batteries (NaS) and sodium nickel chloride batteries (NaNiCl) fall under the category of high-temperature batteries, while vanadium redox (VRFB) and zinc bromine (ZBFB) belong to the realm of flow batteries.

Table 1: Specifications for different storage technologies (European Commission. Directorate General for Energy. et al., 2023; IRENA, 2017, 2020a)

	Power range	Energy range*	Response time	Roundtrip efficiency (%)	Lifetime (years)	Number of cycles	Energy density (Wh/l)
Mechanical							
Pumped storage hydro (PSH)	10 MW - 3 GW	0.5 - 100 GWh	sec-min	70 - 85	50 - 100	20000 - 100000	0.2 - 2
Adiabatic compressed air storage (A-CAES)	10 - 300 MW	100 MWh - 10 GWh	min	>70	30 +	≤ 1000	2 - 6
Diabatic compressed air storage (D-CAES)	10 - 300 MW	100 MWh - 10 GWh	min	42 - 54	25 - 40	5000 - 20000	2 - 6
Flywheel	1 - 20 MW	5 kWh - 5 MWh	sec	85 - 95	20 +	10^5 - 10^7	20 - 80
Electrochemical							
Lithium-ion batteries	< 500 MW	< 1000 MWh	ms	85 - 89	10 - 20	1500 - 3500	200 - 600
Lead-acid batteries	< 40 MW, typical 1 MW	< 10 MWh	ms	75 - 85	8 - 20	250 - 2000	50 - 100
Sodium sulfur batteries (NaS)	few kW up to 50-100 MW	100 kWh up to 300 MWh	ms	75 - 85	10 - 20	4000 - 7300	150 - 350
Sodium nickel chloride batteries (NaNiCl)	few kW up to 5 MW	few kWh up to 10 MWh	ms	80 - 90	10 - 20	2500 - 4500	180 - 300
Vanadium redox flow batteries (VRFB)	< 200 MW	10 kWh - 800 MWh	ms - sec	68 - 80	10 - 25	>10000	15 - 70
Zinc bromine flow batteries (ZBFB)	5 kW - 10 MW	few kWh to < 100 MWh	ms - sec	94	5 - 15	2000 - 3000	20 - 70
Chemical							
Hydrogen	1 kW -1 GW	some 10 kWh - several TWh	< sec - < min	20 - 40	5 - 30	n.a.	600
Methane	1 MW -1 GW	some 10 kWh - several TWh	sec	18 - 38	30	n.a.	1800
Electrical							
Super-capacitors	up to 300 kW	up to 1 kWh	ms	90 - 95	20 +	10^5 - 10^9	1 - 10
Super-conducting magnetic	up to 40 MW	up to 20 MWh	5 ms	90 - 95	20 - 30	100000	5 - 50

(*Energy range denotes the maximum and minimum amounts of energy that a storage system can store)

To assess the global deployment of various technologies with their respective capacities, Table 2 provides an overview of the DOE Storage Database (DOE, 2024). It lists the power capacity in MW and the energy capacity in MWh for each technology. Figure 6 illustrates the installed power capacity over time. It is evident that PSH has long been the dominant technology. However, newer technologies, particularly battery storage, have been increasingly utilized since around 2015.

Table 2: Cumulative sum of installed energy storage capacity worldwide (excluding decommissioned capacities) (DOE, 2024)

	Power capacity (MW)	Energy capacity (MWh)*
Pumped storage hydro (2020)**	177620	777062
Compressed air energy storage (2020)	1614	40088
Flywheel (2020)	1019	414
Lithium-ion battery (2021)	6976	12542
Lead-acid battery (2020)	96	96
Nickel-based battery (2021)	91	36
Sodium-based battery (2019)	213	1267
Zinc-based battery (2020)	20	309
Flow battery (2020)	333	1248
Hydrogen storage (2017)	20	101
Electro chemical capacitor (2016)	35	22
Unknown technology (2023)	13349	736

(*Energy capacity in this context refers to the maximum overall amount of energy all storage systems can hold at any given time; **Year of the latest update is in the brackets.)

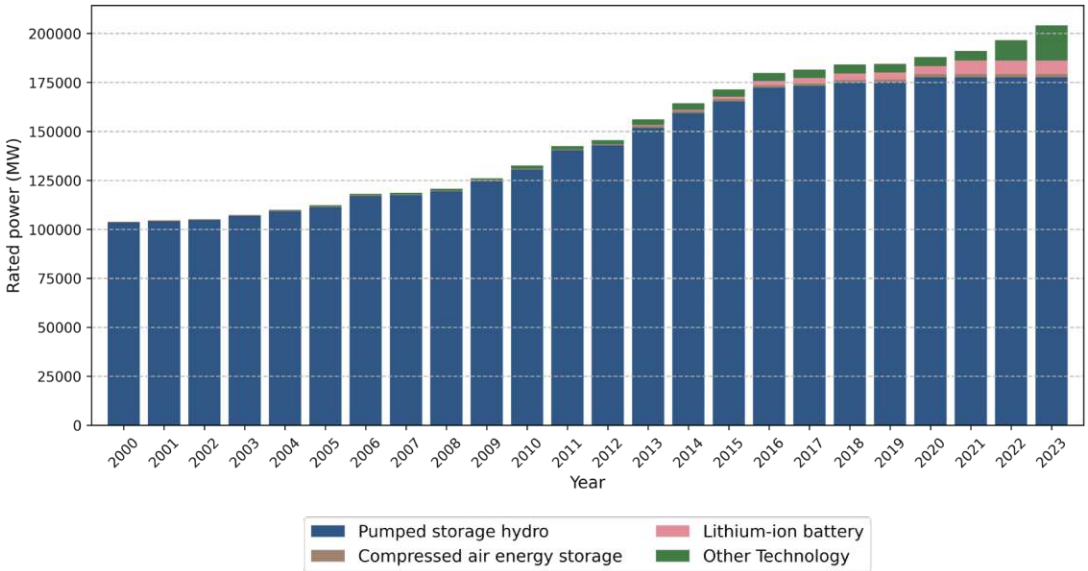

Figure 6: Worldwide installed energy storage capacity per technology and year (based on Table 2) (DOE, 2024)

This work focuses on three major technologies: PSH, battery storage and underground hydrogen storage. While the former two are already widely deployed, the imminent need for long-term storage in decarbonized energy systems suggests an upcoming role for hydrogen storage solutions. The following section provides a brief overview of these three technologies, highlighting their respective properties and typical applications (Section 2.1.1 to 2.1.3). This is followed by an extensive literature review of recent studies concerning the costs and efficiencies of these technologies (Section 2.1.4).

2.1.1. Pumped storage hydro

PSH is one of the most common storage solutions in electricity systems worldwide, providing 96% of installed power capacity and 99% of storage energy volume (Blakers et al., 2021). However, its potential varies across different countries due to geographical constraints (Andrey et al., 2020). For instance, Austria, located in the Alps, has capitalized on its topography to develop a multitude of PSH capacities, some of which include exceptionally large storage reservoirs compared to other European countries. This enables the storage of significant water volumes over extended periods. An example in Austria is the Limberg power plant, which can be used for seasonal storage purposes (Hunt et al., 2020). With even larger reservoirs, the Saurdal power plant in Norway is suitable for pluri-annual storage. For shorter durations, facilities like the Kops II power plant in Austria (for hourly storage) and Goldisthal in Germany (for daily storage) are utilized (Hunt et al., 2020). According to Hunt et al. (2023), PSH is expected to increasingly serve longer, especially seasonal, storage durations as such needs arise, while battery storage technologies take over shorter-term storage due to cost reductions. The power range of PSH typically falls between 10 MW and 3 GW, with an energy range of 0.5-100 GWh (European Commission. Directorate General for Energy. et al., 2023).

PSH utilizes electricity to pump water into an elevated storage reservoir during periods of low demand, storing it for later use. When demand peaks or electricity prices rise, the stored water is released through turbines to generate electricity. PSH systems are characterized by their relatively fast response times (seconds to minutes) and high roundtrip efficiency, typically ranging between 70-85%, depending on turbine and pump types. Moreover, these systems have a lifetime of 50-100 years, enduring 20,000-100,000 cycles, with an energy density of 0.2-2 Wh/l (European Commission. Directorate General for Energy. et al., 2023). An advantage of this technology is the absence of critical raw materials required for this storage type (European Commission. Directorate General for Energy. et al., 2023). Nevertheless, the construction of a power plant requires extensive land use, resulting in significant environmental impacts and social implications. PSH projects often face lengthy approval processes and encounter resistance from local communities. This is particularly evident in regions where the most optimal locations for PSH development have already been utilized. However, PSH offers several advantages, including its status as a proven and widely deployed technology with lower self-discharge rates and relatively high round-trip efficiency, enabling extended storage durations (IRENA, 2017).

Technically, typical PSH power plants can be categorized into open-loop, closed-loop and pump-back storage (Hunt et al., 2020). The former also incorporates natural water inflows into the storage reservoirs, thus determining the electricity generation potential from these natural inflows. This is the typical PSH approach in Austria. In contrast, closed-loop systems necessitate the initial uphill pumping of water before it can be used for subsequent electricity generation, often realized through small, artificially created water bodies. This method minimizes environmental impacts compared to open-loop systems. However, closed-loop systems are typically constrained to shorter storage cycles, with an example project being the PSH Marmora in Canada (Hunt et al., 2020). Planning and approvals tend to be easier for this storage type compared to the aforementioned (Blakers et al., 2021). Pump-back storage systems are installed in existing run-of-river dams to enable the pumping of a portion of the water flowing downstream back uphill. Additionally, emerging technologies such as underground PSH using tunnel-boring machines for storage excavation, underground mine PSH and open-pit mine PSH are under extensive discussion (Koritarov et al., 2022). These innovations offer promising solutions, particularly in regions lacking natural topographical differentials, facilitating the creation of new storage capacities with minimal environmental impact. In countries with a large number of coal mines, such as the Czech Republic, this could offer a practical solution to the challenge of finding suitable locations for new PSH projects, as there are many flooded residual pits remaining after coal mining, (Prikryl and Kabrna, 2016). The first PSH of such kind was planned for the Prosper-Haniel mine in Germany by the University of Duisburg-Essen and the Ruhr University Bochum. However, there have been no new developments thus far due to perceived high costs (Brücker and Preuße, 2020).

2.1.2. Battery storage

Another widely utilized technology is battery energy storage, which operates by altering its load through electrochemical reactions. Batteries serve as pivotal components in providing short-term flexibility to the energy system (Andrey et al., 2020). Among these, lithium-ion technology stands out as the most used, having undergone extensive development and achieving widespread adoption (European Commission. Directorate General for Energy. et al., 2023). The concept originated in the 1970s through the work of Exxon chemist Stanley Whittingham, with the first batteries being deployed in consumer electronics in 1991 (Energy Storage Association, 2024). Lithium-ion batteries employ lithium ions to store energy by generating an electrical potential difference between the negative and positive poles of the battery (dragonfly Energy, 2022). They find application across a diverse spectrum of energy storage needs, ranging from small-scale residential systems with rooftop PV arrays to large-scale containerized batteries providing grid ancillary services in the multi-megawatt range. Within this spectrum, various types of batteries exist, differing in their active materials and chemical reactions, as well as suitability for different applications (dragonfly Energy, 2022). The most common type is lithium cobalt oxide (LCO) batteries, primarily used in portable consumer products. However, due to concerns over the use of cobalt, limited lifespan and safety issues related to thermal instability, they are gradually losing market share. LFP, on the other hand, is well-suited requiring high energy capacity. Its key advantages include durability, long lifespan and safety due to the materials used. However, it has a relatively lower specific energy compared to other lithium battery types and performance may suffer at low temperatures. NCA batteries, commonly used in EVs (including Tesla), offer high specific energy and long lifespan but are comparatively more expensive. Another material, LTO, replaces graphite in the anode, resulting in a highly safe battery with a long lifespan and fast charging. They find applications in various fields, especially in EVs and energy storage systems for wind and solar power. Challenges include low energy density and high costs. NMC batteries, mainly employed in transportation (e-bikes, EVs), offer high energy density, longer lifespan and lower costs, albeit with slightly lower voltage (dragonfly Energy, 2022). In summary, these technologies typically operate at power ranges below 500 MW and energy below 1000 MWh, with a millisecond response time and high roundtrip efficiency of 85-89%. Their lifespan ranges from 10 to 20 years, with a cycle count of 1500-3500 and an energy density of 200-600 Wh/l. However, a significant challenge lies in the heavy reliance on lithium resources (European Commission. Directorate General for Energy. et al., 2023). Additional resources needed in current battery production, which are on the list of critical raw materials, include natural graphite as the primary material used as anode material, cobalt and bauxite for aluminum production (Vranken, 2023). It is important to note the emerging trend of reducing cobalt usage in batteries, a shift exemplified by companies like Tesla (Holman, 2022). Additionally, there is ongoing research on avoiding cobalt. For example, a battery cathode based on organic materials was recently developed (MIT, 2024).

The second technology examined closely in this work is lead-acid batteries. Lead batteries have been successfully utilized in energy storage, with their capabilities and limitations extensively studied (Energy Storage Association, 2024). Moreover, lead batteries can be easily recycled and there are working collection and recycling programs for this technology (Energy Storage Association, 2024). Typically operating within a power range under 40 MW and an energy capacity under 10 MWh, lead batteries have milliseconds as response times roundtrip efficiencies ranging between 75-85%. They offer a lifespan of 8-20 years, with cycle counts ranging from 250-2000 and an energy density of 50-100 Wh/l (European Commission. Directorate General for Energy. et al., 2023). Primary technological challenges include water loss during cycling and gas generation during charging (European Commission. Directorate General for Energy. et al., 2023).

2.1.3. Hydrogen storage

Hydrogen storage is expected to play an increasingly significant role in the energy system's decarbonization, particularly due to its potential for seasonal storage. This technology is anticipated to become crucial for the final stages of decarbonization, as highlighted by Victoria et al. (2019) for emissions reductions exceeding 80% of 1990 levels in the electricity sector. Electrolyzers are employed for hydrogen production as a storage of electricity option. Currently, there are three major electrolysis technologies, alkaline water electrolysis, proton exchange membrane (PEM) electrolysis and solid oxide electrolyzer cell (SOEC), which will be explained in more detail in Appendix F.

The produced hydrogen can be stored and transported in various forms (gaseous, liquid, ammonia, or liquid-organic hydrogen carrier) before being converted back into gaseous hydrogen. The main hydrogen storage possibilities include (i) physical storage in compressed gas or liquid forms and (ii) chemical storage opportunities such as chemical bonds using materials like metal hydrides and chemical hydrides (Olabi et al., 2020). In most instances, hydrogen is stored as compressed gas or liquid, while chemical storage with metal or chemical hydrides is still in the research and development phase (Zhang et al., 2016).

When assessing large-scale, longer-term storage options, recent research suggests that subsurface storage will emerge as the dominant technology (Lysyy et al., 2021). Currently, four types of underground storage are utilized for natural gas: salt caverns, depleted gas fields, aquifers and lined hard rock caverns, which can also be used for hydrogen (IEA, 2022a). Notably, industrial-scale storage of gaseous hydrogen in salt caverns is already operational (Andersson and Grönkvist, 2019), with active projects located in Teesside, UK, as well as Clemens, Moss Bluff and Spindletop in the United States (Miocic et al., 2023). Among depleted gas reservoirs, salt caverns and saline aquifers, depleted gas reservoirs are deemed the least mature but are identified by Chen et al. (2022) as the most cost-effective technology in the long term. This storage methodology has been in use since 2010, with implementations in the Yakshunovskoe field in Russia (Miocic et al., 2023). Hydrogen exhibits a distinct advantage, particularly in storage applications, as it enables the storage of significant energy quantities (TWh) over prolonged durations with minimal losses.

For re-electrification, hydrogen gas turbines or hydrogen fuel cells can be employed. Utilizing the direct combustion of hydrogen in a combined cycle gas turbine (CCGT) allows for leveraging the maturity of the gas turbine industry (MIT, 2022). Moreover, retrofitting existing gas turbines to run on hydrogen is also feasible and currently under development (MIT, 2022). One notable challenge with this approach is the generation of NOx emissions during hydrogen combustion. While NOx emissions also occur during natural gas combustion, the higher temperatures associated with hydrogen combustion can lead to NOx levels twice as high (Ditaranto et al., 2020). These pollutants can contribute to acid rain and ground-level ozone. However, when hydrogen is converted to electricity in fuel cells, NOx emissions are eliminated (Lewis, 2021). Fuel cells are primarily utilized in smaller-scale applications with storage in salt caverns. They offer greater flexibility compared to CCGT power plants and have a slightly lower efficiency of 50% compared to 58% for a CCGT facility (MIT, 2022).

The lifespan of hydrogen storage systems is estimated to range from 5 to 30 years. Challenges arise from the high conversion losses inherent in the process. Each step in the energy supply chain involving conversion processes contributes to a reduction in the overall system efficiency, compounded by the low volumetric energy density of hydrogen (Ajanovic et al., 2024).

In the model employed in this work, hydrogen storage refers to the power-to-gas process involving electrolysis, followed by storage using underground facilities and subsequent re-electrification of hydrogen through CCGT for power generation.

2.1.4. Investment costs and efficiencies of storage technologies

This section presents a literature review of the investment costs and efficiencies associated with the analyzed storage technologies. Table 3 provides, where available, the investment costs for both the power (€/kW) and energy (€/kWh) components of the storage system. In cases where both components are not specified, it can be assumed that they have been combined into a single value, typically by setting a fixed discharge duration. In such cases, a direct comparison may not be feasible, as storage sizes can vary for the same rated power. In some instances, cost assumptions are provided as a range, in which case, minimum and maximum values are provided. These ranges account for cost differences across systems: larger storage systems tend to have lower specific costs, whereas smaller systems incur higher specific costs.

All costs identified in the literature have been converted to €2023. If a specific year was not provided for the cost assumptions, the year of publication was considered. Inflation rates were adjusted according to the country and year (Inflationtool, 2024). The exchange rates refer to the final day of each respective year and were sourced from the OeNB (2023).

Table 3: Literature review on investment costs of energy storage systems (Sources are displayed in alphabetical order)

	Power component (€/kW)		Energy component (€/kWh)*		Source and remarks
	Min	Max	Min	Max	
Pumped storage hydro	1190	5950			(AIT, 2018)
	577	4135	5	96	(Das et al., 2020) (100 MW – 5000 MW)
	400	2200	40	470	(European Commission. Directorate General for Energy. et al., 2023) (10 MW - 3 GW)
	456	1710	46	171	(EASE, 2021) (10 MW – 3 GW)
	1473	2209			(Haas et al., 2022a) (200 MW - 350 MW)
	362	905	1.8	45	(Hunt et al., 2023) (30 MW – 10 GW; seasonal storage)
		1100		27	(Lovegrove et al., 2018) (200 MW, 1200 MWh)
		1309		12	(Schill and Zerrahn, 2018)
		995		45	(Schmidt and Staffel, 2023; Schmidt and Staffell, 2023)
	1549	1844	63	75	(Viswanathan et al., 2022) (100 MW – 1 GW, 10 hours)
Lithium-ion batteries	238	833			(AIT, 2018)
	577	3846	577	3654	(Das et al., 2020) (up to 100 MW)
	600	3500	350	1200	(European Commission. Directorate General for Energy. et al., 2023) (< 500 MW)
	171	1140	798	1482	(EASE, 2021) (1 kW – 50 MW)
	1227	2945			(Haas et al., 2022a) (2.5 kW – 0.5 MW)
	226		136	181	(Hunt et al., 2023) (0.001 MW – 1000 MW)
		286		505	(Lovegrove et al., 2018) (1 MW, 1 MWh)
		42		223	(Schill and Zerrahn, 2018)
		226		271	(Schmidt and Staffel, 2023; Schmidt and Staffell, 2023)
				678	(Tsiropoulos et al., 2018)
	104	154	363	436	(Viswanathan et al., 2022) (1 MW – 10 MW, 2 hours – 10 hours)
Lead acid batteries	119	298			(AIT, 2018)
	288	577	192	385	(Das et al., 2020) (up to 40 MW)
	250	2000	300	1000	(European Commission. Directorate General for Energy. et al., 2023) (< 40 MW)
	114	570	114	228	(EASE, 2021) (some MW)
		271		290	(Schmidt and Staffel, 2023; Schmidt and Staffell, 2023)
	164	223	412	488	(Viswanathan et al., 2022) (1 MW – 10 MW, 2 hours – 10 hours)
Hydrogen storage	2280	5700	1	11	(EASE, 2021) (1kW - 1 GW)

	2000	5000	5	13	(European Commission. Directorate General for Energy. et al., 2023) (1 kW – 1 GW electrolyzer and fuel cell)
		1283		0.48	(Lovegrove et al., 2018) (geologic storage, PEM electrolyzer, CCGT)
		2985		1	(MIT, 2022) (geologic storage, PEM electrolyzer, CCGT)
		5069		1	(MIT, 2022) (geologic storage, PEM electrolyzer, fuel cell)
		1190		0.24	(Schill and Zerrahn, 2018) (Power-to-gas only)
		4525		27	(Schmidt and Staffel, 2023; Schmidt and Staffell, 2023)
		2861		6	(Viswanathan et al., 2022) (100 MW – 1 GW, 10 hours – 24 hours)
PEM electrolyzer		2633			(Böhm et al., 2020) (5 MW)
	1666	2499			(Buttler and Spliethoff, 2018)
	1638	2574			(Haas et al., 2022a) (0.5 MW – 10 MW)
	1538	1810			(IEA, 2023a)
		2691			(IndWEDe, 2018)
	688	1376			(IRENA, 2020b) (minimum 10 MW)
		80			(Lovegrove et al., 2018) (20 MW)
		1703			(MIT, 2022)
	3193	2737			(Sayer et al., 2022) (500 kW – 5 MW)
	1452	1755			(Tractebel, 2017) (1 MW – 20 MW)
		590			(Welder et al., 2019)
		1301			(Viswanathan et al., 2022)
Energy storage hydrogen				38	(Chen et al., 2023) (depleted gas reservoir, including cushion gas, compressor andwell)
				7	(European Commission et al., 2020)
				0.48	(Lovegrove et al., 2018) (20000 MWh)
				8	(MIT, 2022) (aboveground, pressurized tank)
				1	(MIT, 2022) (geologic)
			14	17	(Olabi et al., 2021) (very small system)
				6	(Viswanathan et al., 2022)
Gas turbine hydrogen		1269			(MIT, 2022) (including NOx control)
		595			(Welder et al., 2019)
CCGT hydrogen		1203			(Lovegrove et al., 2018) (20 MW)
		1282			(MIT, 2022) (including NOx control)
		897			(Welder et al., 2019)
PEM fuel cell		3366			(MIT, 2022)
		1305			(Viswanathan et al., 2022)
		1089			(Welder et al., 2019)
Solid oxide fuel cells		1770			(Welder et al., 2019)

(*Energy component refers to the investment costs associated with the energy storage capacity of a system, expressed in €/kWh (e.g., underground reservoir for hydrogen storage))

Besides the difference in cost assumptions depending on storage system sizes, investment costs may vary between countries; for example, labor-intensive technologies are highly influenced by labor costs in countries of production and installation. Furthermore, costs also differ depending on the location of construction, as observed in PSH (Sterner and Stadler, 2019). Another determinant of PSH investment costs is that expanding existing power plants typically incurs lower investment costs compared to new developments, necessitating significant alterations to the water regime through the construction of additional reservoirs and conveyance systems (Steffen, 2012). Variations in storage types within a given technology, such as tank storage versus underground hydrogen storage, further contribute to cost disparities. Furthermore, different system boundaries are often drawn for cost analysis, such as in the case of battery storage, where sometimes only the battery packs are considered without factoring in the balance of system costs or installation costs. This disparity leads to varying cost estimates. The large differences, depending on the factors mentioned and the source selected, are also clearly visible in Figure 7 and Figure 8.

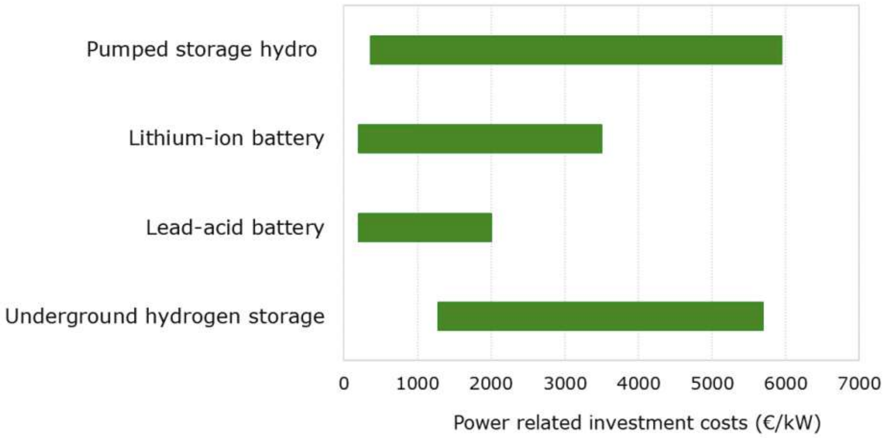

Figure 7: *Graphical summary of power related investment costs of literature review (minimum and maximum values)*

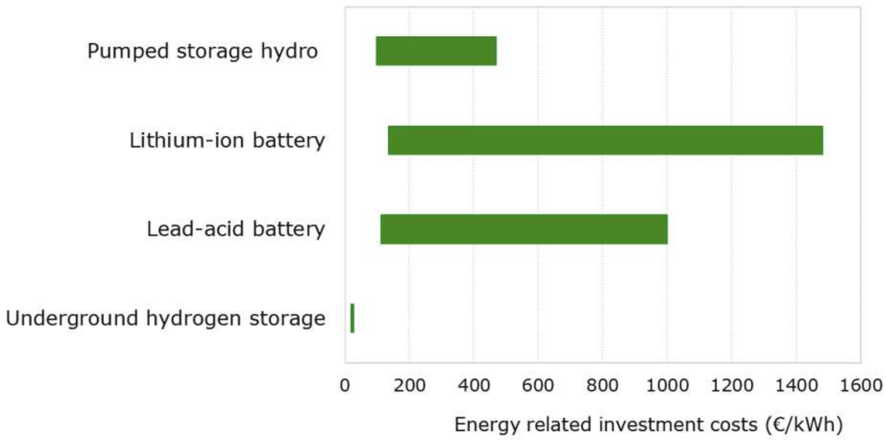

Figure 8: *Graphical summary of energy related investment costs of literature review (minimum and maximum values)*

When comparing the power and energy components, it can be noted that technologies characterized by high costs for the power component and low costs for the energy component (e.g., hydrogen) generally prove more economically viable for long-term storage applications. Conversely, technologies featuring low costs for the power component and high costs for the energy component are better suited for short-duration storage (Augustine and Blair, 2021). This consideration was factored into the selection of technologies and resulting storage durations in the present model.

Another important factor concerning economic viability is the efficiencies of respective technologies, as these directly impact electricity costs and the overall cost per unit of stored energy. A literature review of the efficiencies of each technology is presented in Table 4. Figure 9 illustrates that the cycle efficiencies of PSH range between 65 and 90%, those of lithium-ion batteries between 78 and 96%, lead-acid between 65 and 90% and hydrogen storage between 25 and 45%. Despite the high conversion losses associated with hydrogen, it is being discussed as a promising technology for long-term storage in both industry and academia. This is primarily because there are currently few alternatives for long-term storage of electricity in the electricity sector (Egeland-Eriksen et al., 2021).

*Table 4: Literature review on roundtrip efficiencies of energy storage systems**

	Roundtrip efficiencies (%)		Source and remarks
	Min	Max	
Pumped storage hydro	65	87	(Das et al., 2020)
	70	85	(European Commission. Directorate General for Energy. et al., 2023)
		80	(IRENA, 2020a)
	65	90	(Koohi-Fayegh and Rosen, 2020)
		80	(Lovegrove et al., 2018)
	65	80	(Olabi et al., 2021)
		80	(Schill and Zerrahn, 2018)
		80	(Schmidt and Staffel, 2023; Schmidt and Staffell, 2023)
		80	(Viswanathan et al., 2022)
Lithium-ion batteries	85	90	(Das et al., 2020)
	85	89	(European Commission. Directorate General for Energy. et al., 2023)
	86	96	(IRENA, 2020a) (LFP, NCA, LTO and NMC batteries)
	85	98	(Koohi-Fayegh and Rosen, 2020)
		90	(Lovegrove et al., 2018)
	78	88	(Olabi et al., 2021)
		92	(Schill and Zerrahn, 2018)
		86	(Schmidt and Staffel, 2023; Schmidt and Staffell, 2023)
		83	(Viswanathan et al., 2022)
Lead acid batteries	70	90	(Das et al., 2020)

	75	85	(European Commission. Directorate General for Energy. et al., 2023)
		81	(IRENA, 2020a) (VRLA)
	65	90	(Koohi-Fayegh and Rosen, 2020)
	75	80	(Olabi et al., 2021)
	71	79	(Viswanathan et al., 2022)
Hydrogen underground storage (roundtrip efficiency)	20	40	(European Commission. Directorate General for Energy. et al., 2023)
		37	(IEA, 2019a) [2]
	25	45	(Komarov et al., 2021)
	30	40	(Olabi et al., 2021)
		35	(Schmidt and Staffel, 2023; Schmidt and Staffell, 2023)
		31	(Viswanathan et al., 2022), DOE [3]
PEM electrolyzer	60	70	(Haas et al., 2022a)
	63	70	(IEA, 2019a, 2023a) (LHV)
		67	(Komarov et al., 2021)
		65	(Lovegrove et al., 2018) Electrolyzer 20 MW
		46	(Schill and Zerrahn, 2018) (Power-to-gas only)
	67	82	(Schmidt et al., 2017a) (HHV)
		70	(Welder et al., 2019)
Geologic hydrogen storage		90	(Lovegrove et al., 2018) 20000 MWh
		93	(MIT, 2022) [4]
Gas turbine hydrogen,		30	(MIT, 2022) including NOx control
		40	(Welder et al., 2019)
CCGT hydrogen,		57	(Lovegrove et al., 2018) 20 MW
		45	(MIT, 2022) including NOx control
		60	(Welder et al., 2019)
PEM fuel cell		45	(MIT, 2022)
		51	(Viswanathan et al., 2022) (HHV)
		51	(Welder et al., 2019)
Solid oxide fuel cells		70	(Welder et al., 2019)

(*As hydrogen storage systems are a special case with individual components, their efficiencies are stated separately.)

[2] Compressed hydrogen

[3] AC-AC inclusive of inverter and transformer efficiency losses

[4] This is basically compressor efficiency, excluding electrolysis, etc.

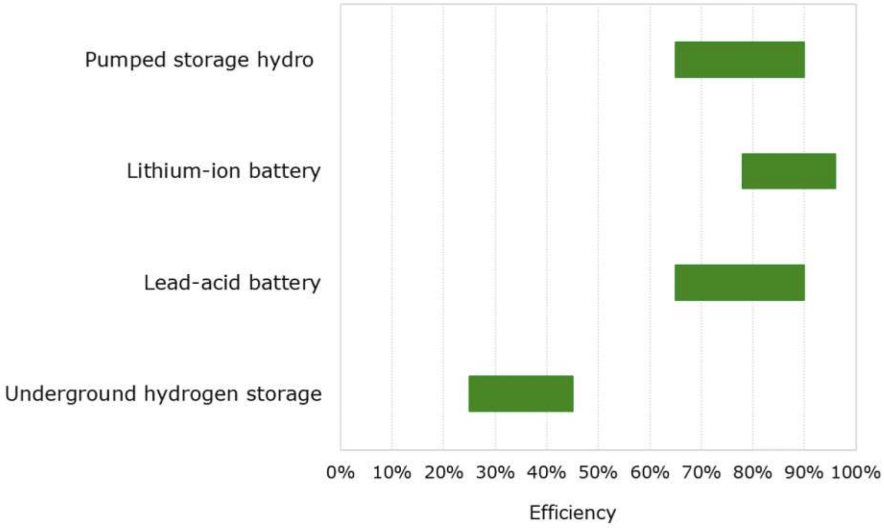

Figure 9: Roundtrip efficiencies of selected storage systems (minimum and maximum values)

2.2. Literature on economics of storage technologies

Within the framework of economic analysis in the energy sector, understanding the costs of storage technologies is important. Section 2.2.1 explores current costs, synthesizing existing literature to show their findings. Meanwhile, Section 2.2.2 discusses the fundamentals behind the technological learning theory, while Section 2.2.3 shows the literature on future cost analysis through technological learning of storage technologies.

2.2.1. Studies on current costs of storage technologies

Considerable research has been dedicated to exploring various storage technologies and their respective technical characteristics, such as Amirante et al. (2017) and Rahman et al. (2020). However, the costs associated with these technologies remain a significant barrier to widespread integration. Consequently, a literature strain focuses on conducting economic analyses of selected storage technologies. These analyses can be categorized into cost analysis, profit analysis and system-value analysis, each serving distinct objectives (Parzen et al., 2022). In this work, we concentrate on cost analysis, aligning with the research objectives. Specifically, we explore techno-economic analyses of different storage technologies and analyze future trends in storage cost development.

Primarily, such analyses rely on an approach that calculates the discounted costs per stored energy to assess the technology (the electricity from the storage must be sold at least at the cost per stored energy to make the storage investment economically viable) and to compare different technologies. In the literature, various terms are used for this purpose (levelized cost of electricity (LCOE), levelized cost of stored energy (LCOS) and life cycle cost), which methodologically differ only in minor details. LCOE is primarily used to calculate the levelized cost of electricity for renewable energy systems like PV and wind, determining how much it costs to generate one kWh of electricity by accounting for both investment and operational costs. To assess storage technologies, the LCOS metric is used, which incorporates the costs associated with energy storage over its entire lifetime and divides these costs by the total amount of electricity delivered. The result represents the cost per unit of discharged energy that was previously stored. Similar to LCOE, LCOS includes both investment and operational costs. The scope of costs considered over the entire lifecycle often depends on the authors. For instance, costs related to recycling, decommissioning, or disposal at the end of the technology's life might often be excluded due to data availability. However, these costs should be included in a life cycle cost analysis, especially for technologies with significant end-of-life expenses, to enhance the comparability of different technologies. As noted, the boundaries are individually defined and some authors do include total lifecycle costs in their LCOS calculations.

An interesting paper that chose life cycle costs to compare PSH, compressed air energy storage (CAES), flywheel, electrochemical batteries, flow batteries, superconducting magnetic energy storage, supercapacitors and power-to-gas technologies is Zakeri and Syri (2015). The results show that the two examined mechanical energy storage systems are the most cost-effective options, particularly at the utility-scale (at the point of their investigation, 2015 published). However, for CAES, there is some uncertainty due to additional fuel and, thus, emission costs, which could not be accounted for over the entire lifetime of the facility.

A further analysis using the LCOS method by Jülch (2016) arrives at similar conclusions regarding PSH, identifying it as the most economical solution for both short-term and long-term storage needs. At the time of the analysis (published in 2016), battery storage systems still incur high investment costs, although substantial cost reductions are anticipated. Through sensitivity analysis, it is demonstrated that the amount of energy discharged (storage utilization) and the electricity costs for charging have the greatest impact on the overall costs. Regarding PSH, Obi et al. (2017) report varying costs per stored energy, depending on the reservoir size of the facility. Similarly, concerning battery storage, they conclude that these systems exhibit relatively higher costs for long-term storage and are thus particularly suited for short-term storage (frequency regulation). Vanadium redox flow (VRFB) batteries, according to Nikolaidis et al. (2019), are particularly suitable for demand-shifting and reactive support, albeit still associated with high uncertainties. Mostafa et al. (2020) also incorporate various power and energy ratings into their analysis and confirm that PSH offers the lowest costs for long-term storage. For medium-term storage, sodium-sulfur batteries are the most cost-effective, while for short-term storage, supercapacitors are preferred (Mostafa et al., 2020). In a more recent paper by Mulder and Klein (2024), storage costs are compared between a fixed electricity purchase price and a market-based variant simulated using an algorithm for strategic electricity procurement. PSH and thermal storage emerge as the most cost-effective options for durations of up to several days. Another significant finding is that, in the model, demand flexibility can reduce system-related electricity costs from 150 \$/MWh to 100 \$/MWh. Accounting for regional aspects in the analysis, Topalović et al. (2022) find that, compared to battery storage, PSH offers the most economical solution in the Western Balkans. Across the studies reviewed, PSH consistently exhibits the lowest costs, which is unsurprising given its widespread adoption with considerable experience and technological maturity. However, forecasting the future competitiveness of alternative technologies remains less straightforward in the existing literature. Results vary considerably based on application contexts and regional factors, underscoring the importance of an application-specific analysis. This is exemplified in this work through electricity system modeling of Austria based on various decarbonization scenarios. Consequently, by considering the specific use case and existing policies, the total costs of new storage capacities can be calculated.

The expansion of analysis to include hybrid storage systems is explored by Moschos et al. (2023), who combine lithium-ion batteries, superconducting magnetic energy storage and flywheel energy storage. Their findings reveal that the combination of lithium-ion batteries and superconducting magnetic energy storage yields the lowest storage costs at around 37 €/MWh. Härtel et al. (2016) address concerns regarding curtailment through a scenario analysis focused on Germany's congested transmission grids. They introduce storage technologies to mitigate curtailment and observe that the necessity for storage is proportional to grid expansion; the less expanded the grid, the more essential storage becomes. Regarding current cost analyses, it is demonstrated that storing only the amounts of energy curtailed in the study year and in 2025 does not cover costs. Additional storage units that solely respond to surplus energy are not economically viable within the examined timeframe. However, it should be noted that this situation changes in the future. An increase in generation from renewable sources, particularly from PV during midday hours, can lead to negative electricity prices, increasing the potential arbitrage profits of the storage operators. This trend results in a pattern that resembles the shape of a duck, commonly referred to as the "duck curve" (Haas et al., 2023). This phenomenon is already evident in California, where the duration of negative electricity prices is rapidly increasing, presenting opportunities for energy storage solutions. The widespread implementation of energy storage systems, such as batteries, enables some of the solar energy produced during the day to be stored for use after sunset. Storing solar generation during the midday hours helps to level out the duck curve and utilizing the stored solar energy in the evening reduces the steepness of the duck's neck (EIA, 2023a). The duck curve is not exclusive to California. This trend is becoming more prevalent globally in countries, where the proportion of solar generation is growing relative to conventional sources. Within the European Union, there has been a twelvefold increase in the occurrence of negative prices in 2023. For instance, in absolute terms, the number of hours with negative prices in Austria has risen to 111. This is attributed to several factors, including the rapid expansion of renewable production especially PV, as well as a decrease in demand despite declining spot prices, affected by delayed economic impacts and the withdrawal of support measures (ACER, 2024).

Other studies focus their analyses on emerging technologies, such as Berrada (2022) examining large-scale gravity energy storage and comparing it with conventional storage methods. Their findings suggest that gravity energy storage, with a cost of 202 $/MWh (based on calculations involving 1 GW power and 125 MWh energy for the system), presents a cost-effective alternative to conventional storage technologies. Similarly, Smallbone et al. (2017) conduct a comparative analysis for pumped heat energy storage, indicating that the examined system, coupled with CAES, achieves cost competitiveness, potentially rivaling PSH. This comparative study underscores the profound influence of storage utilization rates on the overall economics of storage solutions. Another viable alternative for storage and flexible power generation is biogas plants. These facilities can store the produced biogas in gas stacks and generate electricity on demand in a cogeneration unit when power is scarce. Research on the German electricity system, such as the study by Lauer and Thrän (2017), has introduced the average integration costs of surplus generation (AICSG) as a metric to evaluate the economic efficiency of flexibility options. Their findings suggest that expanding the capacities of flexible biogas plants could reduce the necessary curtailment of variable renewable generation by up to 35% compared to a scenario where these plants are phased out. An economic assessment for the period from 2016 to 2035, conducted by Lauer et al. (2020), indicates that for biogas plants to be economically sustainable, expenses must be lowered or supplemented with benefits from other industries. The viability can be improved by the early decommissioning of lignite and coal-fired power stations. Additionally, the work of Güsewell et al. (2021) emphasizes that biogas plants, when operated in response to power demand, can effectively meet the demands of future energy systems dominated by variable renewable energy sources. Profitability is increased through both immediate and prolonged seasonal adjustments, which also mitigate low heat utilization issues. However, a broad range of income sources and prolonged support initiatives are crucial for maintaining financial viability under the current market landscape in Germany.

Another strain of literature compares the costs of two storage technologies, as seen in Shahid et al. (2022) and Escamilla et al. (2023), particularly focusing on hydrogen and battery storage when operating as isolated systems. Both studies calculate that a combination of these technologies leads to the lowest costs. In Shahid et al. (2022), these costs average 420 €/MWh across 21 French reference islands, while Escamilla et al. (2023) report costs ranging from 860 to 1500 €/MWh, highlighting a 20% cost reduction achieved through hybridization in three European cities. A particular emphasis on underground hydrogen storage and resulting costs is found in Chen et al. (2022). Key storage types include depleted gas reservoirs, salt caverns and saline aquifers. Storage investment costs comprise four crucial components: cushion gas cost, geologic site preparation cost, compressor capital cost and well capital cost, with depleted gas reservoirs exhibiting the lowest overall costs. Recognizing the limitations of traditional cost-centric evaluations, Parzen et al. (2022) introduce the "market potential method" as a complementary valuation approach. This method aims to identify storage options that are most valuable from an energy system perspective, which may not necessarily correlate with the lowest-cost storage type. In summary, hybrid storage systems exhibit lower costs and purely cost-based analyses without considering the entire system may prove insufficient. Therefore, this analysis provides input data for calculations using an electricity system model that integrates different storage technologies and optimizes them from a system perspective, ensuring that the integrated storage types are utilized optimally. What must also be emphasized is that in this work, storage for electricity is treated from a system perspective. This means that in both the electricity market modeling and the storage cost calculations, revenue streams for storage operators, such as those from energy price arbitrage or ancillary grid services, are not considered. A general comparison of results regarding storage costs among studies is challenging due to varying assumptions, different analysis time frames (e.g., battery storage costs have changed significantly in recent years) and differing system designs, including system sizes. Additionally, it is often unclear whether both power and energy-related costs are included in the analysis for all technologies, which could also distort comparisons.

2.2.2. Theory behind technological learning

Based on current cost analyses, much will also depend on the future cost development when considering which storage technologies will prevail in the future energy system. Both market growth and innovation in storage technologies have the potential to drive down costs (Kittner et al., 2017). Long-term forecasts of the future costs of technologies are difficult to make due to some uncertainties and should therefore be interpreted with appropriate caution. Nevertheless, longer-term statements cannot be made without taking into account possible future cost reductions and efficiency increases in the calculation. One approach to estimating future costs is through the experience curve or learning curves approach, which are often used interchangeably. In the following subsection, the theory behind technological learning is being explored, encompassing its types, historical evolution, common features and criticisms. Section 2.2.2.1 covers various learning types like learning-by-doing and learning-by-searching and distinguishes between learning curves and experience curves. The subsequent discussion in Section 2.2.2.2 provides a historical overview of significant milestones from the inception of learning curves in manufacturing to their application in energy policy. Further in Section2.2.2.3, key features influencing learning rates, such as modularity and regulatory stability, are identified. Finally, Section 2.2.2.4 addresses major criticisms, including data reliability and forecasting uncertainties, offering a comprehensive understanding of technological learning's impact on cost reduction and policy development.

2.2.2.1. Learning types and basic principle of technological learning

The main learning effects identified in the literature are "learning-by-doing" and "learning-by-searching" (Pieper, 2003). Two additional types, namely the Technology Readiness Level effect (first part of the learning-by-searching effect until the product is on the market) and the background effect, were explained by Thomassen et al. (2020). As the latter, they considered changes in the surrounding circumstances of different input factors, like the electricity mix or materials. All mentioned learning effects can be found at various steps of the market diffusion process, with different significances.

Learning curves and experience curves are frequently used interchangeably. In contrast to the learning curve, the experience curve should not be based on individual input costs, such as labor costs, but on the total costs of a production process and thus include all cost elements that could affect each other (Henderson, 1968). Hence the learning curve is limited to one input factor and is a subcategory of experience curves (Wei et al., 2017). According to Thomassen et al. (2020) the line between the two blurs, especially with an assembly of different components as the end product. We will therefore use both interchangeably in this work.

Two approaches are used when applying the learning curve concept to the energy sector. In some studies, cumulative electricity production by the respective technology is considered an influencing variable on costs. It corresponds to the original concept in which cumulative goods production was used. The specific costs are thus expressed as the cost per kilowatt-hour of electricity produced, e.g., €/kWh. The common approach is to use the cumulative installed capacity as a variable to influence costs. In that approach, the costs refer to the pure manufacturing costs of the energy conversion plant. This means costs that are directly associated with producing and installing the energy conversion technology, excluding other factors such as operational or maintenance costs. These costs are expressed in euros per installed capacity, for example, euros per kW for wind turbines, or euros per square meter for PV modules (Pieper, 2003).

The origin of learning occurs through research and development or investment in new technologies across a multitude of companies that are part of a value chain. The resulting learning effects occur through improved know-how, improved design and economies of scale. These learning phenomena are practically described with the help of learning curves based on a calculated learning rate. Typically, production costs decrease with increasing output (in the form of an exponential curve). The resulting exponentially decreasing function is usually represented with a logarithmic scale, resulting in a straight line, restricted by a certain floor price, which is being used in some learning rate models to keep the technology from becoming unrealistically cheap, see Figure 10 (Kohler et al., 2006). In a more recent work, the floor price has been introduced for the calculation of cost development for EVs, as some components (e.g., car frame) are already mature technologies with many years of experience (Edelenbosch et al., 2018). The basic principle of technological learning is explained in Figure 10. On the horizontal axis, the cumulative quantity installed is indicated using a logarithmic scale and on the vertical axis, the costs per unit are shown. When analyzing learning curves, it is critical that the doubling of the cumulative quantity is assessed numerically rather than through time. The time required to double the installed capacity does not influence the learning rate. As a result, applying learning curves in future years implies estimating how the cumulative quantity will develop.

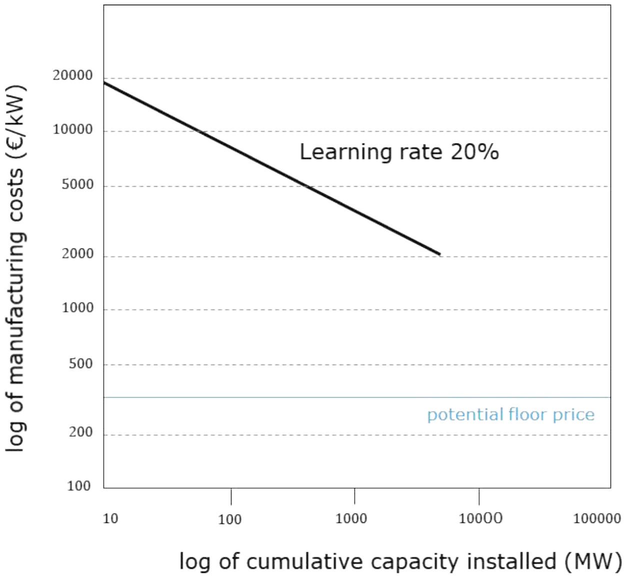

Figure 10: The basic principle of technological learning curves

As with most concepts, several strengths and weaknesses of the concept of technological learning were identified in the literature, which will be further analyzed in this work. Among the strengths, Pieper (2003) identified the good empirical confirmation of the causal relationship between costs and cumulative production or cumulative installed capacity and the ability to predict cost developments of specific technologies based on past learning curves. One shortcoming when using this concept is that dividing the cost reductions into different areas (e.g., economies of scale, material costs, automation, etc.) often proves difficult (also pointed out by McDonald and Schrattenholzer (2001). It is specifically problematic when two- or multi-factor approaches are used. Additionally, he highlights a need for further research on the long-term extrapolation of learning curves, when the learning rate is changing or the life cycle of a technology, what might happen frequently within energy system technologies. (Pieper, 2003).

The following aspect of the cost assumptions of calculated learning curves is essential. Because market prices are more accessible than production costs, market prices are often used for the calculation. Those prices could induce uncertainty in technological learning as they might obscure the cost structure of the related company, especially in the case when the company has a particular price-setting agenda. Nevertheless, prices are frequently utilized in learning calculations when cost data is not available (Wei et al., 2017).

Learning rates are often used to develop government policies and subsidy schemes. It allows the identification of the driving force for past technology cost reduction and helps to forecast future developments. Overall, the concept is used to incorporate technological change of renewable energy technologies in energy and climate change analyses, to evaluate the energy technology policies of governments to estimate future costs on a company level and to create global energy technology development scenarios (Junginger et al., 2005; Nemet, 2006).

2.2.2.2. Historical developments

The concept of learning curves was first published by Wright (1936) as a tool for determining costs for mass-produced products in an airplane manufacturing plant. The idea is that if a particular technology is used more and more due to ever-increasing technological maturity, an increasingly improved product will result, usually characterized by higher operational reliability, lower costs and improved efficiencies. Other studies on cost decrease in the manufacturing sector were published by Alchian (1963) for aircraft and Rapping (1965) for shipbuilding. More recently, Nolan (2012) showed in the Boeing case study that the approach of learning curves is still used in the aviation industry. Dutton and Thomas (1984), later expanded the first learning curve approach by clustering and analyzing specific sectors. A good overview of the initial learning curve process in production economics is given by Grosse et al. (2015) through a detailed meta-analysis.

Yet, regarding learning, one has to be careful. The original definition of Arrow (1962) was very narrow and encompassed better performance using the same capital stock. In short, the workers improved the efficiency of using the equipment. This may be too narrow, but it is probably useful to distinguish between design changes that arose because technical change/progress allowed new options to be pursued and design changes that resulted from experience with existing designs. Later this definition was generalized by Conley (1970) to include all production cost reductions, not only the learning of workers.

Another approach was published by Moore (1965), using time instead of the cumulative installed capacity. He showed with the example of integrated circuits that technology advances exponentially throughout time. However, Nagy et al. (2013), find that Moore's concept might only provide good results for brief periods of time. Compared to the learning concept initiated by Wright, it shows less accurate predictions over longer timeframes, which has also been highlighted by McDonald and Schrattenholzer (2001), saying that not exactly the time has a substantial effect but the experience gained over that period. They mention the example of leaving a technology on the shelf and not using it, leading to "forgetting by not doing" and rising costs.

While the first research on learning curves was production-oriented and focused on the manufacturing process and learning by doing on one plant or product, in 1968, the Boston consulting group introduced with Henderson (1968) a more inclusive approach, which also focused on business and management and the aggregation of entire industries. They introduced the term "experience curve" and highlighted its importance in predicting potential competing companies' production cost decreases. Additionally, there is a strict separation of experience curves and learning curves (only including labor and production inputs) in the publications of Henderson, which we use, as indicated earlier, interchangeably in this work.

Among the first ones to criticize the learning concept of manufacturing processes were Hall and Howell (1985) with their analysis "The Experience Curve from the Economist's Perspective." They highlighted that the advantages of learning-by-doing for one single site are quickly saturated. Furthermore, they found that the association of cumulative production and the average cost is misleading and concluded that experience curves are rather distorted and have limited practical utility for strategic planning. After this work, more authors criticized the learning approach. Those will be further analyzed in Section 2.2.2.4.

On a more general level, it has to be pointed out that prior to the work of Romer (1986) technological change was exogenous to the models (e.g., Solow (1956)), which earlier were classified as “external learning” or even disregarded in the models (Azar and Dowlatabadi, 1999). Beginning with Romer (1986) also energy supply models introduced the learning curve concept, thus endogenizing technological change, which has then evolved into a robust and frequently used model for forecasting technological learning (Nemet, 2006). Some important references, in this context are: Neij (1999), Grübler et al. (1999), Wene (2000), McDonald and Schrattenholzer (2001) and Kobos et al. (2006).

Wene (2000), can be seen as a major work dealing with technological learning. Besides analyzing the experience curves, it also discusses certain uncertainties of the concept that decision-makers should consider when evaluating the respective policy. Experience curves are essential for predicting technological progress and evaluating energy policy decisions. For instance, it may be used to assess government measures supporting innovative technologies (Duke and Kammen, 1999). Especially for energy, studying wind power and wind turbines, the European Commission implemented the project “EXTOOL” to further develop and evaluate the concept (Neij et al., 2003). They concluded that experience curves could be used to evaluate the cost-cutting effects of policy measures, however, not to assess the cost-effectiveness of the respective measures. Van der Zwaan and Rabl (2004) applied the policy research on PV, calculating that with certain policy measures, PV will hold a significant share of energy production worldwide in 2020. With the work of Wiesenthal et al. (2012), the European Commission published additional research on the concept in view of policy support.

Most studies that evaluate policy acknowledge certain uncertainties when using the learning curve concept. An approach to how those might be taken care of has been applied by Neij (2008). By combining the economically oriented “top-down” experience curve concepts with the engineering-oriented “bottom-up” approach and a “judgmental expert assessment,” she shows that in most situations, the outcomes of all three methodologies match. By including additional concepts in her analysis, specific technologies with uncertainties have been revealed through the additional methods and were pointed out (Neij, 2008). Yeh and Rubin (2012) suggest that for the development and validation of more robust models of technological change, ways to significantly improve the characterization and reporting of learning model uncertainties and their impacts on the results of energy-economic models have to be identified to help reduce the potential for drawing inappropriate or erroneous policy conclusions.

The main historical developments discussed in this section are documented in Figure 11.

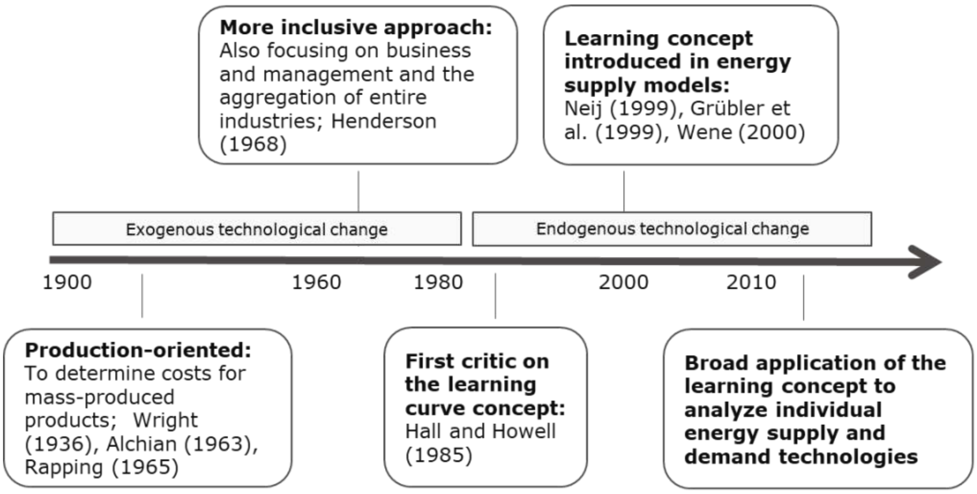

Figure 11: A timeline of major milestones in the development of technological learning

2.2.2.3. Common features and requirements for technological learning

One main conclusion regarding technological learning is that the learning rates among energy technologies differ remarkably as highlighted in in Figure 12. From this, a key insight is that learning rates practically cannot be generalized. Therefore, this section will outline which features lead to high learning rates and which ones rather hinder the development.

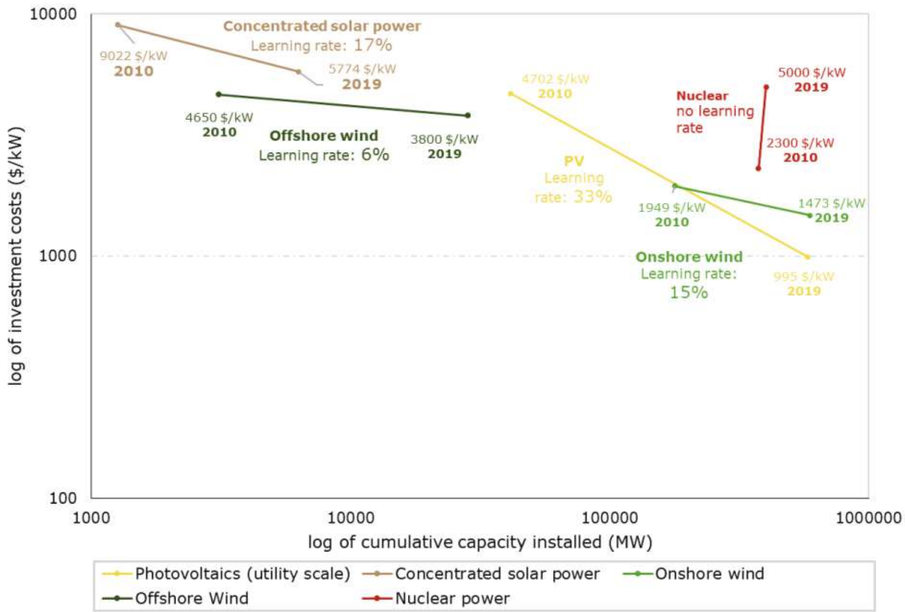

Figure 12: Comparison of the main energy supply technologies (Own elaboration based on data from (IAEA, 2022; IEA, 2020a; IRENA, 2022a)), Remark: We use total installed costs for analysis (e.g., including balance of system costs for PV) for better comparison among the technologies.

Analyzing all technologies, we find that modularity (size of the plant), granularity and homogeneity of the technology, as well as continuous development, are essential for high learning rates. Modularity and granularity have been discussed by Wilson et al. (2020), with granular technologies providing more room for repetition and reproducing specific processes for faster cost reductions. Moreover, it is easier to improve the performance of modular technologies and test them in actual demonstration facilities with smaller capacities. Another aspect of smaller, modular technologies is that they can easily be assembled in a factory and then shipped to the site where they are used, whereas non-modular, larger capacities mostly have to be assembled and constructed to a certain extent on the construction site of the power plant (e.g., nuclear reactors). One good technology example that shows homogeneity, modularity and granularity is PVs. In the case of PV, the panels showed tremendous cost reductions and were traded globally and shifted production to countries where they could be produced with the lowest costs. Generally, the learning rate is higher when technologies are globally traded since international learning rates tend to be higher than national ones due to stronger competition. Modular technologies tend to have a higher international share as they are mostly traded worldwide without being country-specific. Those higher global learning rates have also been found by Schaeffer et al. (2004) as they conclude that PV had an average global learning rate of 23%, whereas the national module prices in, for example, Germany, have been stable or elevated (Schaeffer et al., 2004). Regarding the overall PV system costs, this has also been visible in comparing PV modules to the balance of system costs. Modules being highly granular result in much higher learning rates than the balance of system costs which include various required parts and have substantial price differences among countries. Junginger et al. (2008) also find that especially large-scale technologies lack an EU-wide action to boost investment and prevent uncertainties for investors. They also highlight that the interchange of information often works well nationally but not internationally (Junginger et al., 2008).

Another aspect that has been prevalent and has been pointed out by Samadi (2018) is the size respective the modularity. The larger the capacities of the individual power plants (e.g., nuclear reactors, offshore wind), the lower the learning effects were. A reason for that is that small-scale technologies can be easier standardized, whereas, in large-scale applications, the construction must be done at the respective construction place (Samadi, 2018). In addition, larger plants such as nuclear power plants consist of more different components compared to a PV module. In addition, there are different reactor types, which makes standardization difficult, similar to the discussion on concentrated solar thermal power. There are also four different technologies, each of which differs in the storage tank size, which leads to fewer learning opportunities. This issue has already been discussed very early on by Neij (1997), who clustered the technologies into modules (e.g., PV panels), large and small plants (whole power plants) and continuous processes (e.g., mass production of chemicals). Neij identified learning rates from 30-5% (average of 20%) for modules, up to 18% (average of 10%) for power plants and 36-10% (average of 22%) for processes (Neij, 1997).

Another similarity between CSP and nuclear power is the number of power plants. Although a relatively large amount of nuclear power capacity is installed, it consists of only 448 power plants due to the size of a power plant (IAEA, 2022). Furthermore, there has been no remarkable capacity expansion of nuclear power in recent years (+27 GW in the last nine years (IAEA, 2022)). This also leads to lower learning opportunities. CSP, in comparison, has a small number of power plants and capacities but has increased fivefold in the last nine years.

When reviewing the learning rates of PV compared to nuclear reactors, we found that having stable conditions in terms of environmental regulations for implementing the technologies is essential. PV has become a high-demand technology with minor environmental implications attached, whereas nuclear power manufacturers often had to adapt to tighter safety standards due to nuclear disasters, which was partly a reason for the cost increase. On a more general note, we can also apply that to fossil power plants as generally, the focus of energy technology evolved into supplying electricity generated through environmentally friendly and cheap means from originally only cheap ones.

2.2.2.4. Major points of criticism regarding technological learning

Based on the preceding analyses, in this section, the criticisms of technological learning by various authors are documented.

The first major concern is that often price data instead of costs are used, simply, because most of the time, the cost data is not available. As a result, new uncertainties are introduced and have to be considered. The concept, in general, builds upon showing the true production cost of a technology, as the market price of a technology might also depend on the price-setting of the manufacturers (in each step of the product life cycle), the demand, the competition, availability of the technology and subsidies, see Figure 13 (Junginger et al., 2008). Nemet (2006) proves this argumentation through an empirical study of different periods of the price development of PVs. He finds that the industry structure, meaning the level of competitiveness, influences the learning rate (Nemet, 2006). Nevertheless, he recommends using cost data, where available, which might be hard to obtain due to the fear and hesitation of companies to disclose real costs. For the analysis of technologies that are in strong competition with each other, it might give more insight to use prices for the calculations as this is the basis for the customer’s decision to purchase the technology (Nemet, 2006).

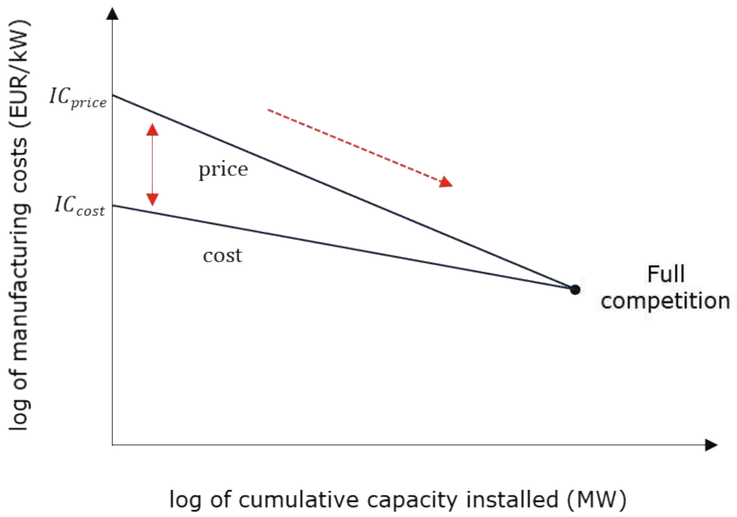

Figure 13: Development of price versus cost data

The above argument leads to the result that at some point in the lifetime of a technology, no substantial further learning effect takes place and market aspects take over because full competition is reached. For example, for a major conventional car, the costs increase because improvements in the quality of services (e.g., air conditioning, additional electronic devices…) cause additional costs, which have virtually offset most of the cost savings that have occurred in the "naked" car due to learning.

Another reason may be, as already mentioned, that the technology has changed (and realistically every technology changes over time, efficiency is increased and service features are extended). This also applies e.g., to PV modules and wind turbines, which are not the same as a few years ago due to further developments and innovations of components to increase the functions and costs.

Some adjustments are also required by regulation, e.g., wind turbines also have to provide an operating reserve within the ENTSO-E grid-connection codes or PV inverters with storage functions. In addition, non-technology-specific costs, such as labor or land, increase total costs or limit further learning. Especially the latter tends to increase as soon as the most favorable locations are built. Moreover, labor or land costs also inflict variability or biases as they are influenced by labor and property markets (McDonald and Schrattenholzer, 2001).

One great uncertainty problem in the concept of technological learning is that small parameter changes might substantially affect the slope of the learning curve. For example, Junginger et al. (2008) point out that variations concerning initial capacity deployed, initial costs, methodology of data collection, inflation and different system boundaries of energy technologies might have great effects on cost development. This has also been confirmed by

Neij (1999) and Van der Zwaan and Seebregts (2004). Further, uncertainties in the progress ratios hence the learning rates, are often discussed in the literature, as the forecasts of the development of energy technologies are very sensitive. It is suggested to implement the progress ratio error to account for errors (Junginger et al., 2008). Van Sark and Alsema (2010) analyze, including an error in the progress ratio's value in the best possible way and also provide instructions for use. Lafond et al. (2018) provide a model to take precautions for forecast uncertainties. Another important aspect is to consider an appropriate software for calculating and displaying learning rates, as Van Sark and Alsema (2010) found different results depending on the software used (Excel, Origin).

Nordhaus (2014) argues that using technological learning in modeling raises three potential problems. First, he shows that there is a fundamental statistical identification problem in trying to separate learning from exogenous technological change and that the estimated learning coefficient will generally be biased upwards. Second, two empirical tests illustrate the potential bias in practice and show that learning parameters are not robust to alternative specifications. Finally, he shows that an overestimate of the learning coefficient will provide incorrect estimates of the total marginal cost of output and will therefore bias optimization models to tilt toward technologies that are incorrectly specified as having high learning coefficients.

Since an important aspect of technological learning is assessing policies and guiding policymaking to further decide on renewable promotion instruments, some uncertainties in this respect have to be highlighted. Wene (2000) points out that they must be accounted for when deciding on subsidy programs and suggests including the most current cost data. Either R&D or subsidies can be chosen for dissemination.

Promotion programs might influence the price of technologies. For example, the German wind power plant prices were relatively stable over the period 1995-2001. According to Junginger et al. (2008), this resulted from the feed-in tariff and the resulting high request for turbines which lead to market prices higher than the costs. They assure that, in general, market simulation has no negative effect on learning rates, although it might have an impact on the pricing. They recommend addressing the market development (demand and supply) in every analysis over the period studied to account for discontinuities. According to Haas et al. (2008) investment subsidies, feed-in tariffs, tax incentives, portfolio standards, quota-based tradable green certificates and tendering systems are major renewable promotion instruments. There is no clear consent regarding which scheme will help achieve climate targets with minimal costs. Through an analysis of different countries, they found that the fixed feed-in tariff in Germany, Denmark and Spain showed promising results, while the competitive tendering in the UK and France did not (Haas et al., 2008). As a further outlook, power purchase agreements may play a more important role than subsidies.

2.2.3. Studies on future costs of storage technologies – technological learning

In recent years, there have been major literature reviews on various energy technologies. Rubin et al. (2015) analyze electricity supply technologies in view of learning rates, including coal-based, natural gas-fired, nuclear, hydro, wind, PV, biomass and geothermal power plants. They discover a significant range of predicted learning rates among the investigated studies. Another review of energy supply technologies has been conducted by Samadi (2018). He analyzes 67 empirical studies between 1997-2017 and finds that renewable energy technologies show a substantial negative link between cost and installed capacity. Furthermore, he acknowledges the limitations and uncertainties of the technological learning concept, like commodity price variations or stricter environmental and safety regulations, that may have also influenced the technology costs. Despite that, the analysis suggests that learning does occur when an energy generation technology is more widely deployed (Samadi, 2018). Thomassen et al. (2020) build upon this work and define recommendations for incorporating learning curves based on the analyzed literature. Their main suggestion is to include environmental factors besides the learning concept because as the experience of renewables grows, so will the negative effects on the environment. Another major work on experience curves is Junginger (2020), giving a comprehensive overview, including case studies on major renewable technologies. The learning effect has been empirically observed in the past and applied to various technologies. A broad range of literature investigates the learning rates of the most common renewable technologies, such as PV (e.g., (Goldschmidt et al., 2021; La Tour et al., 2013; Liu et al., 2021; Mauleón, 2016; Nemet, 2006)) and wind technologies (e.g., (Häner, 2021; Junginger et al., 2005; Lindman and Söderholm, 2012; Odam and Vries, 2020; Tang, 2018; Yu et al., 2017)). In Yao et al. (2021), the future levelized costs of electricity from wind, solar, geothermal, hydropower and bioenergy are analyzed with the learning curve concept, concluding that wind and solar show a substantial cost decrease due to competition and upgraded technologies. In contrast, the others require more site-specific adaptations for each project, making them more expensive. Also, nuclear energy has been widely analyzed (e.g., (Berthélemy and Escobar Rangel, 2015; Escobar Rangel and Leveque, 2015; Grubler, 2010; Haas et al., 2019; Lang, 2017; Lovering et al., 2016)). Additional research is conducted on bioenergy systems Junginger et al. (2006), the development of fossil fuel systems with carbon capture Li et al. (2012), the transition scenario to renewables Handayani et al. (2019) and low-carbon power plants Rubin (2019). Fukui et al. (2017) discuss the substantial cost reductions in the US shale gas industry based on a 13% learning rate and highlight that these learning effects cannot be fully compared to renewables as the impacts on the environment, including water consumption, might already be the lower constrained for future price development.

One of the primary works exploring the future cost trajectory of storage technologies based on experience curves is by Schmidt et al. (2017b), wherein the future investment costs of 11 storage of electricity technologies are examined based on a capacity expansion of up to 1 TWh per technology. At this expansion rate, approximate average investment costs of 340 $/kWh (+/- 60) for stationary storage systems are projected, regardless of the technology. Through a bottom-up analysis, it is assessed that such capacity expansions with investments ranging from US$175–510 billion could be feasible and could be achieved around 2027-2040. In Schmidt et al. (2019), these cost analyses are expanded from investment costs to future lifetime costs. It is calculated that from 2030 onwards, lithium-ion batteries are the most cost-effective, as long as they are utilized for short-term storage. The conclusion drawn from the analysis is that even with the cost reduction of lithium-ion batteries, alternative technologies may not be able to match their performance advantages, potentially rendering investments in alternatives futile. Kittner et al. (2020) focus their analysis on storage technologies using technological learning for grid-scale energy storage. It is noted that due to the lack of public access to data and experiences regarding storage costs, there is some uncertainty, making it difficult to incorporate the rapid advancements in the development of different storage technologies into the analyses. It is also confirmed that from an economic standpoint, costs are the most critical indicators, underscoring the importance of publicly available cost data. Furthermore, one of the conclusions is that more data and studies across a variety of technologies and regions are needed to improve model accuracy and validation (Kittner et al., 2020). These analyses are comprehensively summarized and expanded upon in the book "Monetizing Energy Storage" (Schmidt and Staffell, 2023). Within the integrated assessment model MESSAGE, McPherson et al. (2018) apply future cost development of storage. They conclude that the overall costs of the energy transition in the scenario with a pessimistic storage cost development are greater than if costs of storage and hydrogen technologies are further reduced through, for example, R&D investments.

Several studies specifically address the future cost development of one technology such as (Beuse et al., 2020; Matteson and Williams, 2015a, 2015b; Nykvist and Nilsson, 2015) for batteries and the following for power-to-gas technologies for storage. Baumann et al. (2013) consider power-to-gas as one of the most promising technologies for long-term storage. Challenges include high capital costs and uncertainty about future cost and performance improvements. Therefore, in the paper by Schmidt et al. (2017a), an expert survey is conducted. It reveals that increased R&D funding could reduce capital costs by 0-24% and solely ramping up production could lead to cost reductions between 17-30%. Böhm et al. (2020) present another learning cost analysis, indicating that investment costs for large power-to-gas plants could decrease by up to 75% in the long term. Short- and medium-term advantages of proton exchange membrane (PEM) and solid oxide over alkaline electrolyzers have been found. In a more recent paper, Zeyen et al. (2023) demonstrate that integrating the concept of technological learning into a sector-coupled model for Europe could reduce the overall system costs of electrolysis by 13% compared to scenarios without dynamic learning. They further illustrate that a faster expansion of electrolysis than in the RePowerEU plan could be cost-optimal. Ajanovic and Haas (2019) offer a less optimistic view of future development compared to other studies, concluding that despite high technological learning potential, power-to-gas may struggle to compete in electricity markets.

2.2.4. Advances in research and analysis

Building upon the reviewed literature, this work advances the current state of research in the following dimensions. Firstly, it provides an up-to-date and comprehensive analysis of current storage costs. Given the dynamic shifts in the energy landscape, including rising electricity prices, lower overall investment costs, especially for batteries and more stringent decarbonization goals, a reassessment based on recent cost data is important. Secondly, the main contribution lies in conducting a detailed cost analysis for the joint integration of PSH, battery storage and underground hydrogen storage into the Austrian electricity system, aligning with the specific decarbonization objectives set forth by the EU, particularly Austria's 100% renewable electricity target. Parameters needed in the economic modeling, such as storage utilization (full-load hours) and electricity prices, were derived based on different decarbonization scenarios through a developed electricity system model, specifically for Austria. Within this model, specific applications of short- to long-term storage across various technologies were considered. Furthermore, when considering hydrogen storage, unlike many existing studies that predominantly focus on power-to-gas technology (electrolyzers), this research comprehensively considers the entire hydrogen storage process, including costs of underground storage as well as re-electrification. Lastly, this work delves into the detailed calculation of future storage costs using the concept of technological learning, reflecting the expected cost changes of energy storage technologies. This analysis not only forecasts potential future cost trajectories but also highlights economically significant factors such as storage utilization rates. Overall, these application-specific economic valuation models add to the current literature to reduce uncertainties surrounding energy storage deployment.

2.3. Other flexibility measures besides storage

Storage for electricity will not be the only solution to bring demand and generation closer together in the electricity system of the future. A variety of other flexibility measures exist, which are discussed most thoroughly by Lund et al. (2015). The paper discusses energy storage, DSM, grid ancillary services, supply-side flexibility, advanced technologies, infrastructure and electricity markets. The main conclusion of the analysis is that there is a large number of options for flexibility from which many are already built in the current system. Electricity demand has been changing; thus, such measures were necessary already early on. Additional flexibility demand can easily be treated with added storage units in the long run.

Other important options besides the energy storage option can be summarized in the following:

- Extensions of the transmission network lead to evening out load profiles as well as generation profiles;
- Smart grids: This technical option offers opportunities to switch between different voltage levels and allow additional load balancing;
- Supply-side flexibility;
- Technical demand-side measures implemented by electric utilities such as load management, e.g., of air-conditioning systems and cycling;
- Demand response because of time-of-use prices especially addressing large customers.

Extension of the transmission grid extension is the most important option, as it provides a remarkably significant contribution to the integration of larger amounts of electricity from variable renewable electricity as shown by Burgholzer and Auer (2016). Additionally, they analyze different scenarios up to 2050 in Austria and find that the deployment of new transmission systems such as flexible AC and dynamic line rating can contribute to reducing the shedding of electricity from variable renewables considerably.

One measure under supply-side flexibility that is being widely discussed, especially in Germany, is the curtailment of variable renewable electricity when there is a mismatch between production and demand. Schill (2014) models different storage capacities that are required for variable renewable electricity integration. He finds that already a small percentage of curtailment has a substantial effect on the required additional storage capacity, given that alternative flexibility options are available in the respective electricity system.

Regarding possible DSM options, Zweifel et al. (2017) point out that today mostly constant end-user electricity prices (regardless of the magnitude of the wholesale price) for smaller customers are offered by power retailers in combination with a delay of smart meter rollout, making it very hard to apply adequate demand response options especially. Further, they recommend flexible tariffs in view of the growing energy from variable renewable electricity being integrated into the system. Müller and Möst (2018) outline demand-side possibilities to balance short-term volatility in the residual load curve. According to Haas and Auer (2019), the key to balancing fluctuations in the residual load is to incorporate an efficient portfolio of measures for increasing flexibility solutions that are already available.

Bloess et al. (2018) explicitly research the topic of interlinking the electricity sector with the heat demand on a residential basis and conclude that HPs and passive thermal storage are particularly favorable options. Also, on an industrial level, this linkage is favorable as it is possible to electrify 78% of the industrial energy demand (Madeddu et al., 2020). Another important flexibility aspect is the power-to-gas option for surplus energy (no re-electrification), as highlighted by Schill (2020b). Through the coupling of the electricity sector to others, we can try other types of storage, including electricity in transport (smart charging) and heating (direct resistive, HPs). Vehicle-to-grid technology can additionally play an active role in resolving bottlenecks in the transmission grids and saving on redispatch costs, as shown by Staudt et al. (2018). Additionally, EV owners can receive compensation for the flexibility provided to the electricity system.

The latest research on optimal investments in flexibility options, based on the REFLEX project, is from Möst et al. (2021). With the electricity market model ELTRAMOD, different scenarios differing in the respective variable renewable electricity amounts, are analyzed regarding sector coupling and flexibility options. They conclude that cross-sectoral influences are essential for identifying the right investment and dispatch solutions. As a result, applying ,for example, DSM reduces the possible storage profit hence supporting that flexibility options are generally in competition with each other.

However, not all mentioned options are in perfect competition with each other due to differences in long-or short-term flexibilities provided. Some storage technologies provide more long-term flexibility, for example, DSM or geographical balancing, which depends on the balancing area. The electricity sector coupling can use excess electricity but in general, no re-electrification takes place (Schill, 2020b).

2.4. Modeling of electricity markets

The integration of increasingly larger amounts of variable renewable generation into existing power systems, driven by ambitious decarbonization goals, is making system flexibility more crucial. To meet these emerging requirements, recent literature has extensively explored electricity market models with high shares of renewables, which will be examined in Section 2.4.1. Section 2.4.2 discusses models specifically developed to simulate storage solutions. Finally, Section 2.4.3 looks at models based on time series data of variable renewables, all sections together providing a foundation for the further modeling efforts presented in this dissertation.

2.4.1. Electricity market models with high shares of renewables

In recent years, numerous electricity system models have been developed, such as those by Lund et al. (2021) and Möst et al. (2021) focusing on the European Union, to better understand the associated challenges of integrating variable renewable generators. However, no single modeling tool comprehensively addresses all aspects of renewable energy integration (Connolly et al., 2010) as various objectives lead to different model designs and choices concerning data and other inputs (Lund et al., 2017). Comprehensive reviews of electricity system models with large shares of renewables can be found in Subramanian et al. (2018), Ringkjøb et al. (2018) and Connolly et al. (2010). Furthermore, studies have explicitly calculated the necessary levels of flexibility. The magnitude of necessary flexibilities depends on the quantity of variable generation, the mix and the geographic system size (Huber et al., 2014). Flexibility options include DSM, supply-side flexibility, electricity markets, transmission grid expansion and storage, which are also the focus of this thesis (Lund et al., 2015). Notable storage studies include those by Ajanovic et al. (2020), Hiesl et al. (2020) and Haas et al. (2022a). Curtailment also plays a crucial role in supply-side flexibility (Villamor et al., 2020). Suna et al. (2022) have previously analyzed the short- to long-term flexibility requirements for the Austrian electricity system up to 2030, incorporating DSM, e-mobility, power-to-heat technologies and storage. In the model presented in this work, supply-side flexibility is also included allowed with curtailment, if necessary, along with a flexible response from dispatchable power plants and a certain proportion of DSM is integrated into demand profiles. However, the focus lies on the integration of storage of electricity into a renewable energy system and its interlinked functionality with a long-term outlook up to 2050.

The feasibility of implementing electricity systems with up to 100% renewable generation is still debated in the literature (Brown et al., 2018), but it has been confirmed in several studies that this transition is economically competitive and technically feasible (Child et al., 2019). An optimal composition of 55% wind and 45% PV across Europe was identified by Heide et al. (2010) as a seasonal optimal mix in a 100% renewable electricity system scenario where only wind and PV were applied in the electricity sector. Another analysis conducted by Zerrahn et al. (2018) concludes that the energy transition is unlikely to fail due to insufficient storage capacities, addressing Sinn's (2017) suggestion that further expansion of wind and solar energy in Germany will reach a limit due to the lack of storage of electricity. Sinn's analysis considers only extreme solutions, i.e., either no storage of electricity or no curtailment of renewable energies, but a combination of storage and curtailment is economically more plausible (Schill et al., 2018). Austria set itself the goal of achieving an electricity system with 100% renewable energy by 2030 (on a national balance), with the aim of being climate-neutral by 2040. Although certain scenarios and model calculations until 2030 are already available, such as those by Haas et al. (2017), the current conditions are changing rapidly (e.g., stricter emission reduction targets) for the European electricity system, necessitating calculations with updated scenarios and models. This also affects electricity import and export capacities to and from neighboring countries, which could decrease in the future, especially in the necessary winter months, as coal-fired capacities are scaled back. These impacts are considered in two of the scenarios developed in this work, with a tighter limitation on import/export exchanges (modeled as artificial storage in this case).

The question of the required storage capacities in a fully renewable electricity system has also been intensely debated (Blanco and Faaij, 2018; Böcker et al., 2015; Pleßmann et al., 2014; Rasmussen et al., 2012; Safaei and Keith, 2015). Examining the required storage of electricity capacities at the European level, Cebulla et al. (2017) calculate a required capacity of 206 GW and 30 TWh with 89% renewable generation (of the annual gross electricity generation). Steffen and Weber (2013) applied peak-load pricing theory to determine the optimal storage capacity, finding that significant storage expansion becomes essential only at around 80%. Additionally, Victoria et al. (2019) conclude that substantial storage capacities are only deemed necessary when achieving a CO_2 emission reduction of more than 80% from the 1990 level. Nevertheless, without fossil power plants capable of compensating for the seasonal fluctuations of renewables, seasonal storage becomes necessary, as Safaei and Keith (2015) found in their paper focusing on the United States electricity system. There is a broad consensus in the literature that storage of electricity requirements will remain moderate until quite high shares of renewables are integrated into the electricity sector (Schill, 2020b). This approach is also employed in the developed model, aiming to achieve an optimal balance between renewable energy generation and storage, ensuring the balance of supply and demand in each hour, even during weather years with unfavorable conditions. Nonetheless, maximizing the utilization of storage technologies is paramount to ensuring their cost-effective operation.

In addition to the aforementioned expansion of renewable generation, there are also ongoing demand-side changes (Sharifi et al., 2017). In order to achieve climate neutrality as energy-efficiently as possible, the electrification of end applications such as heat pumps (HPs) and electric vehicles (EVs) is often the most efficient, but also applications that are not electrified per se, such as hydrogen applications, are electricity-based (Plötz, 2022). Naturally, this transition impacts the electricity system by increasing consumption (previously served mainly by fossil fuels) and changing consumer load profiles. The impacts of integrating HPs and EVs are examined in the case of Switzerland by Rüdisüli et al. (2019), revealing that without additional storage capacities, significant electricity imports will be necessary in winter and at night despite surplus PV electricity in summer. However, a study at the EU level by Möst et al. (2021) concluded that DSM diminishes potential storage profits, indicating competition among flexibility options. Building on a base case scenario, Sousa et al. (2023) compare it with a scenario that includes EVs, storage technologies and hydrogen systems in the Portuguese electricity sector. They propose a cost-minimization mixed-integer programming problem for the future energy system, illustrating the corresponding cost-minimal dispatch of dispatchable generation and storage. These aspects are examined in the present work for Austria, which envisions a transition of the Austrian electricity system to 100% renewable energy. For each developed scenario, different demand profiles are modeled to capture potential developments and to integrate different market trends of HPs and EVs. The specificities in the demand of both are also integrated using charging profiles for EVs and temperature profiles for HPs.

However, the author acknowledges that a comprehensive representation of all sectors is advantageous in energy system modeling and to view the energy system holistically and implement a smart energy system (Lund et al., 2016). This is particularly important for the utilization of surplus energy, which can often be deployed more cost-effectively in other sectors (Schill, 2020b). Due to the complexity arising from this, no bidirectional interactions between different sectors were modeled during the initial development step. The heating and transport sectors, however, have been included by integrating HP and EV profiles in the overall load with different scenarios. Regarding hydrogen, the present model only restricts hydrogen storage by power capacities (electrolysis and re-electrification). The energy capacity, i.e., the underground reservoir, can store as much hydrogen as necessary or even higher quantities than ultimately required for re-electrification to achieve cost-effective scenarios. This surplus can then be utilized in sectors other than the electricity system, such as in the industry. The lack of restrictions on hydrogen storage is justified by the availability of large capacities in depleted gas fields or existing fossil gas storage facilities for underground hydrogen storage, as noted by Talukdar et al. (2024). Therefore, surplus amounts can be incorporated as hydrogen for other sectors in the model.

2.4.2. Storage models

One strand of the literature is dedicated to electricity sector modeling with a focus on storage of electricity, encompassing different geographical coverage, time horizons and methodological approaches (López Prol and Schill, 2021). According to López Prol and Schill (2021), these models can be further classified into price-taking arbitrage models utilizing historical electricity market prices, models based on time series of variable renewables and state-of-the-art electricity sector models, often incorporating capacity expansion. In the comprehensive review by Sioshansi et al. (2022), existing modeling types are categorized into price-taking, very short-run, production cost, strategic behavior, capacity expansion and portfolio planning and resource adequacy. An essential overview of storage of electricity models is provided by Zerrahn and Schill (2017). Lai et al. (2021) focus on the analysis of long-term electricity system models, while Bistline et al. (2021) survey models at the regional and national levels with technological, temporal and spatial details, offering an overview of how research on representing renewable energies and energy storage has evolved over the last ten years. In Guo et al. (2022), advancements in optimization methods for the dispatch and control of energy storage are highlighted to gain a holistic understanding of various methods. These are categorized into multistage optimization, online optimization and multi-timescale optimization.

Some storage studies reviewed here adopt a technology-specific approach. For instance, Babrowski et al. (2016) focus on optimizing battery storage in the German electricity system until 2040. Thema et al. (2016) undertake calculations for the necessary power-to-gas capacities, suggesting that expansion must commence by 2035 to achieve an installed capacity of 89-134 GW in Germany by 2050. According to their analysis, this could lead to annual cost savings of 2-6 billion euros (by 2040) and up to 18 billion euros (by 2050) compared to a scenario without power-to-gas. These estimations are based on the assumption that in the absence of power-to-gas, expenses for remunerated curtailment would escalate and supply shortfalls would necessitate the use of costly gas power (due to a CO_2 price of €100/t CO_2). Another paper with a power-to-gas focus was conducted by Lyseng et al. (2018), where wind and PV are modeled for an 80% variable renewable electricity scenario. The findings demonstrate a 23% reduction in the required wind and PV capacities and up to an 87% decrease in curtailment when power-to-gas capacities are integrated. In addition to the aforementioned papers with a technological focus, other optimization models concentrate on individual countries such as Finland (Elberry et al., 2021), Spain (Brey, 2021), as well as the United States by Arbabzadeh et al. (2019) and Dowling et al. (2020).

2.4.3. Models based on time series of variable renewables

What is often scarcely or not included in the aforementioned state-of-the-art electricity sector models, except in Dowling et al. (2020), is the influence of climatic conditions on storage requirements and seasonal balancing due to the high temporal resolution and long computational times of optimization when multiple years are included (Novo et al., 2022). Studies addressing the varying temporal patterns of variable renewable generation are termed models based on time series of variable renewables (López Prol and Schill, 2021). Numerous studies concentrate on wind energy analysis, exemplified by that of Grams et al. (2017), who elucidate the extended fluctuations in European wind energy production with different weather profiles. Periods of low wind power events in particular are analyzed by Ohlendorf and Schill (2020), revealing that such events occur less frequently in winter than in summer. In all years analyzed, there is a period of five consecutive days with an average capacity factor of less than 10% of the wind capacities. Extended to eight days, such events occur every ten years (Ohlendorf and Schill, 2020). The authors, therefore, recommend integrating multiple weather years into modeling. In the present model, a weather year with the mentioned eight days below 10% capacity, alongside two others with an average of five days, was integrated to adhere to these recommendations. In their analysis focusing on Switzerland, Kruyt et al. (2017) find that such low wind events decrease with an increase in the topographic height of the installation sites, suggesting an opportunity for expanding wind energy in higher altitudes. A spatial expansion of the area investigated (grid integration) also reduces the occurrence of low wind power events, as demonstrated by Handschy et al. (2017), who find that the annual number of hours with low wind events decreases exponentially with the number of aggregated sites. A joint analysis of wind and PV is presented by Collins et al. (2018), concluding that in decarbonized energy systems, the influence of long-term weather patterns is greater, estimating a five-fold increase in operational variability by 2030.

All the studies mentioned, however, focus on analyzing various weather conditions of different technologies but are not electricity sector models. However, this becomes increasingly crucial as the share of renewable electricity generation rises, particularly during periods of energy deficit (Ruhnau and Qvist, 2022). The modeling approach within this dissertation aims to integrate both aspects. We utilize an optimization model incorporating the influence of different weather years, as previously conducted for Germany by Ruhnau and Qvist (2022). In this context, three weather years are included in the optimization to depict diverse conditions. Although fewer in comparison to the aforementioned paper, this research does show scenarios with different electricity generation and demand trajectories. Moreover, this work provides a more detailed analysis of storage interaction. Additionally, we include the impact of three weather years, encompassing variations in PV, wind and water production, while also considering temperature disparities for HPs and air conditioning electricity demands. These three weather years are limited in scope as we rely on data from the Austrian transmission system operator Austrian Power Grid (APG) for wind and PV analysis, available from 2015 onwards and data from ENTSOE for hydraulic analysis (natural water inflows into reservoirs and run- and river plants), available up to 2017. Nonetheless, the optimization is predicated on a weather year characterized by a confirmed period of dark doldrums. Dark doldrums are characterized by low renewable generation due to low water levels in reservoirs, minimal wind, cloudy weather with low temperatures and consequently, high demand. We include the year 2017 in this model, which witnessed the most well-known dark doldrums in Austria and Germany (Suna et al., 2022).

To summarize, the main aim of this work is to achieve a deeper understanding of the dynamics of batteries, PSH, SH and underground hydrogen storage in the context of electricity systems largely or fully based on renewable sources, contingent upon the different trajectories of renewable electricity system development. Additionally, essential differences regarding storage utilization depending on weather conditions are highlighted. We see this as a vital contribution as the investigated studies focusing on the joint integration of different storage technologies to achieve a 100% renewable electricity system often lack consideration of climate variabilities. This modeling approach also emphasizes long-term development, wherein the electricity system is fully transitioned to renewable technologies and is more electrified on the demand side. The latest policy developments from Austria, such as the 100% renewable energy target and the objective of climate neutrality, are also incorporated into the analysis. While Austria serves as the primary case study, the model's adaptability allows for calibration to other countries with a high share of renewable electricity generation.

3. Scenarios on future storage requirements in the Austrian electricity system with high shares of variable renewables[5]

As part of the transition to a sustainable energy future, there is much debate about what shape the electricity system will or should take. Integral to the discussion is the question of the required storage capacity, which has led to considerable discussion in the energy community, particularly regarding the transfer of surplus electricity generated in the summer months for use in the winter period. This work contributes to this discussion by presenting three scenarios (*policy (A)*, *renewables and electrification (B)* and *efficiency (C)*), which include different expansion paths for renewable energies, electricity demand and storage capacities, weather years and their resulting utilization dynamics within the specified scenarios. The aim is to model the Austrian electricity system to demonstrate the impacts of various influencing factors. With a focus on complete decarbonization and extensive integration of hydrogen storage for seasonal purposes, this research seeks to provide insights into the functionality and interdependence among batteries, PSH, SH and underground hydrogen within renewable-based electricity systems. Moreover, it emphasizes significant differences in storage utilization based on weather conditions from an overall system perspective.

The following primary research question and its corresponding sub-questions are addressed:

- *What form will future storage of electricity scenarios take, considering different variable renewable electricity integration scenarios, demand patterns and underlying weather conditions?*
    - *How does the variability of weather patterns impact renewable energy generation and the resulting utilization of storage and dispatchable generation in Austria, specifically focusing on low wind power events and dark doldrums?*
    - *What are the differences in the full-load hours of storage technologies between 2030 and 2050 in Austria's fully renewable electricity system?*
    - *What constitutes the cost-optimized dispatch of flexible generation and storage for each defined economic scenario and weather year?*

Section 3.1 outlines the methodology, namely the hourly cost-minimizing electricity market and energy storage dispatch model, employed in this work. The results of this work are presented in Section 3.2. The overall section is based on the work by Sayer et al. (2024a).

[5] This chapter is based on Sayer et al. (2024a).

3.1. Methodology

The analytical framework employed is a cost-minimizing electricity market and energy storage dispatch model, extending the work of Ramsebner and Haas (2021). This model, designed to optimize the hourly dispatch of generation and storage units, aims to minimize short-term variable costs, effectively portraying a stylized merit-order structure, implying perfect competition. To explore future scenarios up to the year 2050, we define three distinct scenarios (*policy (A)*, *renewables and electrification (B)* and *efficiency (C)*), necessitating the formulation of a range of simplifying assumptions. Among these is the modeling of Austria as one node ("copper plate"), whereby regional and network-specific constraints have been disregarded. The spatiotemporal resolution is on an hourly basis for a representative year for one node, allowing the model to account for short-term dynamics and seasonal features within the system. Dispatchable generation is aggregated across all power plants of a particular technology within the market, while renewable generation is partially modeled based on different historical weather years but incorporates adaptations in generation profiles for component improvements such as wind turbines. HPs are modeled based on temperature data, electric mobility is based on driving patterns and the remaining load components are modeled based on historical load profiles, taking into account the scenario assumptions regarding the development of electricity consumption.

The modeling framework encompasses a set of exogenous model parameters. These are, on the generation side, availability/capacity factors for renewable generators on an hourly basis and hydraulic data for natural inflows of PSH, SH and run-of-river hydroelectricity generation, spanning three weather years and simulating the behavior of hydropower plants under diverse weather conditions. Time series on an hourly resolution are used for the renewable generation and the load. Hourly historical power factors for wind and PV were calculated from renewable generation profiles based on actual measurements provided by the APG (2023), adjusted for the efficiency increases (e.g., increase of hub height and rotor diameter) according to industry estimates (EVN, 2023). Comprehensive datasets are available, beginning with the year 2015. Hourly data concerning run-of-river hydroelectricity generation and natural inflows of SH and PSH are derived from the Pan European Climate Database (PECD), a dataset employed by the European Network of Transmission System Operators for Electricity (ENTSO-E) in their Ten-Year Network Development Plan for 2022 (ENTSO-E, 2022). For this analysis, we use the 2015-2017 dataset to incorporate different meteorological conditions to account for changes in renewable electricity production among weather patterns. These three weather years are limited in scope because, for the analysis of wind and PV, we rely on data from the APG to integrate efficiency improvements of wind and PV, which are available from 2015 onward and for hydraulic analysis, we use data from PECD (natural water inflows into reservoirs and run- and river plants), which are available until 2017. However, this excerpt includes typical weather years, including an extreme year, as well as a year with particularly high renewable generation of each specific technology.

Demand-side inputs encompass load time series on an hourly basis, including individual profiles for EVs and HPs, along with temperature data influencing HP profiles. The load time series used in this work constitutes a compilation derived from three data sources. HP profiles were obtained by utilizing the load profile generator developed by the Austrian Institute of Technology (AIT) (AIT, 2023a). This tool facilitates the selection of specific scenario outlines aligned with the designated scenarios outlined in the subsequent section, enabling the generation of electricity load profiles for the HPs based on inputted temperature data profiles. The temperature profiles are taken from the Open Power System Data Platform (Pfenninger and Staffell, 2020). Similarly, EV profiles are generated by employing the AIT load profile generator, accounting for the scenarios, driving and charging behaviors and market developments in EVs, incorporating a degree of load management (AIT, 2023b). The residual electricity load was sourced from historical load profiles provided by the APG, available from 2015 onwards and adjusted according to scenario outline demand trajectories. These three distinct time series were merged and integrated into the model as electricity consumption across all network levels, including losses within the grid, stabilization and control of grid operations, electricity utilized by power plants for internal operations, but excluding own consumption of companies covered by own plants when not included into the public grid and households demand covered by PV and batteries. This is also in line with the Environment Agency Austria and Suna et al. (2022).

Parameter inputs are variable production costs (including fuel and CO_2 costs), capacities and technical details of storage technologies and scenario data. The optimization process involves the simulation of renewable generation based on weather years, resulting in the residual load and the subsequent minimization of variable costs under imposed restrictions, using the programming language Python and solved with the Gurobi Optimizer. The model's outputs include the residual load for each scenario, hourly dispatch of power plants and storage and curtailment. The underlying logic is that any surplus in the electricity system requires curtailment. However, such curtailment is not invariably due to grid constraints but rather to insufficient demand or storage capacities within the system at a given hour (unused renewable surplus). In the following, only the term curtailment is used. The method is summarized in Figure 14.

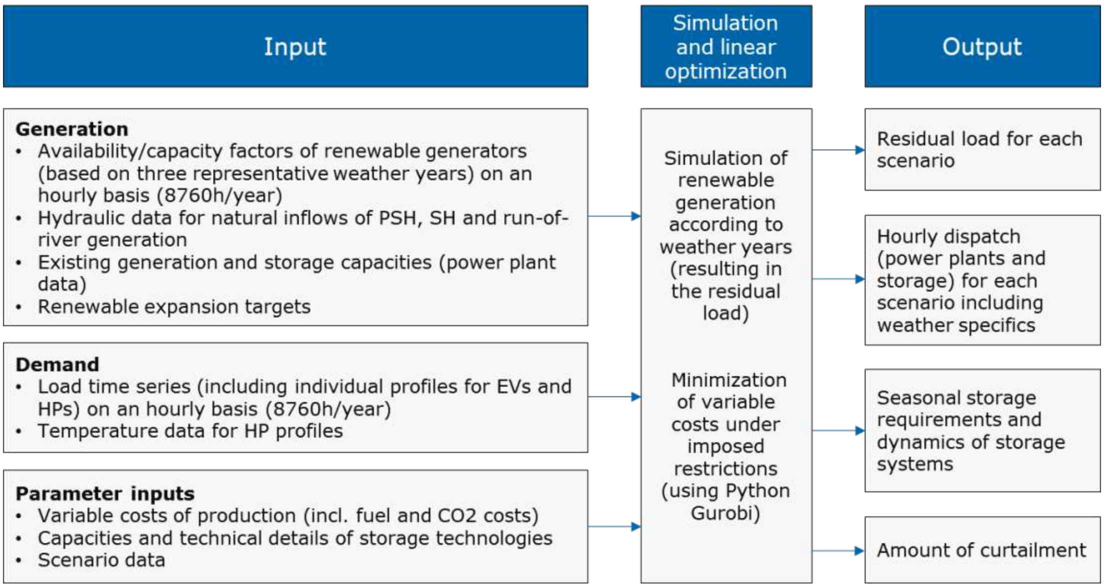

Figure 14: Overall structure of the model

We calibrate the model parameters based on the characteristics of the Austrian electricity system due to the availability of detailed input data. Specifically, this model is tailored to represent the Austrian electricity landscape, characterized by an already high share of renewable generation and with the aim of achieving 100% renewables in the electricity sector (national balance) by 2030. Notably, the insights derived hold relevance not only for Austria but also for other countries undergoing the same transition towards renewable sources.

3.1.1. Model setup

The objective function of the model is designed to achieve cost minimization for dispatchable electricity generation and storage in each defined scenario:

$$\min \left(\sum_{t\in T} \sum_{i\in I} c_i \; P_{i,t} \; + \sum_{t\in T} \sum_{sto\in STO} c_{sto} \; P_{sto,t} \right) \qquad (€/a) \qquad (1)$$

The model operates on an hourly basis, aiming to minimize the overall variable generation costs of existing capacities according to scenario design within the entire single-price market zone and is formulated as the sum of two terms: the first term represents the variable costs associated with dispatchable power plants (i) (fossil, waste, biomass and biomethane) over the number of time periods (T), considering variable costs (c, *in €/MWh*) and the dispatchable power plant capacity (P_i, $in\ MW$). The second term accounts for the variable costs of storage technologies (PSH, SH, battery and hydrogen storage) (sto) over the same time horizon. The variable costs of storage (c_{sto}, in €$/MWh$) only include operation and maintenance costs since the aim is to optimize based on a system view and overall welfare. Therefore, profit maximization of individual storage operators is not taken into account in this analysis.

Variable costs are computed from fuel costs (c_{fuel}, $in\ €/MWh$), CO_2 costs (c_{CO2}, $in\ €/MWh$), operation and maintenance costs ($c_{O\&M}$, $in\ €/MWh$):

$$c = c_{fuel} + c_{CO2} + c_{O\&M} \qquad (€/MWh) \qquad (2)$$

The costs utilized, along with the literature references, are provided in Appendix C. Regarding curtailment, we have made an assumption that the variable cost slightly exceeds that of the most expensive storage option. This approach ensures that not every surplus hour needs to be curtailed and allows for the construction of additional hydrogen capacity. Biomass, which includes the combustion of solid biomass and biogas, is assumed to be operated flexibly in the future. Notably, renewables are excluded from the objective function as they are presumed to generate power with zero variable costs, serving as must-feed capacities in the model. The merit-order curve is utilized to order power plants based on ascending variable costs, optimizing system-wide costs.

Subject to the condition that demand must be met every hour, the model's constraints ensure a continuous balance between demand and supply:

subject to

$$P_{RE,t} + \sum_{i \in I} P_{i,t} + \sum_{sto \in STO} (P_{sto,out,t} - P_{sto,in,t}) + P_{imp,t} - P_{exp,t} - P_{curt,t} - P_{load,t} = 0$$
$$\forall t \in T,\ i \in I, sto \in STO \qquad (MW) \qquad (3)$$

This includes the requirement that in every hour, the power of renewable electricity (P_{RE}, $in\ MW$) plus the power output of all storage technologies discharging ($P_{sto,out}$, $in\ MW$), the power of all dispatchable power plants and import (P_{imp}, $in\ MW$) minus the power of storage technologies charging ($P_{sto,in}$, $in\ MW$), the exports (P_{exp}, $in\ MW$), the curtailment (P_{curt}, $in\ MW$) and the overall load of the system (P_{load}, $in\ MW$) must equal zero. The power of renewable electricity comprises run-of-river hydroelectricity, wind and PV sources. Hydroelectric power plants are categorized into run-of-river hydroelectricity, SH and PSH capacities, with run-of-river hydroelectricity included in must-feed renewable capacities and SH and PSH modeled as dispatchable storage constrained by natural inflows and reservoir levels. The storage capacities are subject to certain constraints that define the storage state of energy/charge (E_{sto}, $in\ MWh$) (filling level of the energy capacity of the respective storage capacity), the efficiency of the charging and the discharging (η) and natural water inflows (E_{inflow}, $in\ MWh$) of each timestep, considering the energy stored in the previous period and the charging and discharging power of in this period.

$$\sum_{sto \in STO} \left(E_{sto,t} - E_{sto,t-1} - \mathrm{P}_{\mathrm{sto,in,t}}\, \eta_{\mathrm{sto,in}} 1 + \frac{\mathrm{P}_{\mathrm{sto,out,t}}}{\eta_{\mathrm{sto,out}}} 1 - E_{inflow,t} \right) = 0$$
$$\forall t \in T, sto \in STO \qquad \text{(MWh)} \qquad (4)$$

As storage technologies, SH, PSH, battery systems and hydrogen storage, with respective efficiencies and energy and power capacities, were considered. For SH units, there is no pumping possibility, hence the parameter storage charging power ($P_{sto,in}, in\ MW$) does not apply here. Similarly, the variable natural water inflow does not apply to battery systems and hydrogen storage. The hydrogen storage system's parameter definition includes details on its components, such as maximum storage charging and hydrogen injection capacity. Withdrawal capacity is determined based on data from gas storage facilities and the system's maximum output is calculated based on the efficiency of the re-electrification process. The upper limit of the energy storage capacity is determined by the maximum energy capacity, while the lower limit is set by the depth-of-discharge rate. Constraints ensure non-negativity for power plant generation, storage charging and discharging, load and stored energy. The energy stored in battery systems at the beginning of the year has to be equal to the energy storage at the end of the year.

Meanwhile, hydrogen storage facilities already contain a certain amount of hydrogen — enough to cover the winter period—and must ensure that the energy stored at the beginning of the year is at least equal to the energy stored at the end of the year. This allows flexibility for producing hydrogen for other sectors as needed. The climate data utilized restrict SH and PSH start and end filling levels. Cross-border electricity exchanges are managed through a virtual storage capacity constrained by total import/export capacities and maximum power limits. To prevent potential grid overload during periods of highly fluctuating renewable generation, the model automatically curtails a portion of the generation based on a specified grid restriction factor. Total curtailment is restricted to the power of renewable generation in each hour. Residual load is calculated by subtracting the total power generated by renewable energy sources (including run-river hydro, wind and PV) from the electricity demand of the public grid for each timestep. Further explanations of the formal description of the model can be found in Appendix B.

3.1.2. Scenario definition

Three scenarios are defined to cover a wide range of trajectories for electricity demand and generation capacities driven by policy objectives, electrification efforts and efficiency measures. A detailed description of the scenario definition can be found in Appendix D.

Scenario A: In the *policy* scenario, based on existing policy objectives, electricity demand is projected to rise due to the shift to EVs and heat HPs. By 2030, approximately 650000 HPs and 1 million EVs are expected in Austria, contributing to increased electricity consumption. The scenario also anticipates ongoing decarbonization efforts in various industries, leading to consistent growth in total electricity consumption.

Scenario B: There is an ambitious expansion of renewable and hydrogen capacities alongside a high degree of electrification in the *renewables and electrification* scenario. This leads to higher increases in electricity demand for space heating, cooling and electromobility. The scenario envisions a substantial rise in EV adoption and a shift towards HPs, resulting in heightened electricity demand.

Scenario C: In the *efficiency* scenario, gradual decreases in conventional electricity consumption are expected through increased efficiency measures. This results in lower electricity demand than the other scenarios, driven by energy-efficient practices and conservation initiatives. The scenario also incorporates lower market penetration of EVs and HPs, reducing electricity demand for these purposes.

Table 5 presents the installed capacities of RE, dispatchable generation and storage across all scenarios, while Figure 15 visually represents these figures. The expansion targets for 2030 are largely determined by the EAG and thus deviate only in scenario *renewables and electrification (B)*, which emphasizes a more ambitious wind expansion. Fossil capacities still play a certain role here, as a 100% renewable electricity target has been set, but this only counts over the year and fossil fuel generation can therefore be offset by exports of renewable electricity. Looking ahead to 2050, it is evident that an even more extensive expansion of renewables occurs in this scenario. Based on the assumptions made, the hourly demand of each scenario can be met across all scenarios and weather years. For instance, if run-of-river hydroelectricity capacities are reduced due to renaturalization efforts, other renewable generators, such as wind and PV, must undergo increased capacity expansion to meet the demand. Assumptions regarding hydrogen production capacities (electrolyzers) are in alignment with the Austrian national hydrogen strategy (BMK, 2022a). Across all scenarios, it is assumed that there will be no fossil fuel generation in the energy system by 2050. Storage technologies employed include battery storage (short-term), PHS and SH (medium-term) and hydrogen storage (seasonal). Further details, including assumed efficiencies and storage capacities (energy) for these technologies, are presented in Table 6.

Table 5: Generation and storage capacities for 2023, 2030 and 2050 in MW (AURES, 2022; ENTSO-E, 2022; Haas et al., 2017; Österreichisches Parlament, 2021; Platzenbecker et al., 2019; Porada et al., 2023; SECURES, 2023)

Scenario		*Policy (A)*		*Renewables and electrification (B)*		*Efficiency (C)*	
	2023	2030	2050	2030	2050	2030	2050
Run-of-river hydroelectricity	5820	6100	7000	6100	7000	6100	7000
Wind	3950	7000	12000	9000	20000	7000	10000
PV	5880	12000	22000	12000	40000	12000	20000
Biomass	500	650	1000	650	1000	650	1000
Waste	80	100	500	100	500	100	500
CCGT Fossil	4230	3000	0	3000	0	3000	0
CCGT Biomethane	0	500	1000	500	500	500	1000
PSH (turbining/pumping)	3490	5000/ 4300	6043/ 5206	5000/ 4300	6043/ 5206	5000/ 4300	6043/ 5206
SH	2520	2489	2489	2489	2489	2489	2489
Storage charge/discharge grid-scale batteryand	0	534	3000	534	3000	534	3000
Storage in/out hydrogen	0	1000/ 440	5000/ 2200	2000/ 880	7000/ 3080	1000/ 440	5000/ 2200
Import/export	8855/ 9100	2500	2500	6000	6000	2500	2500

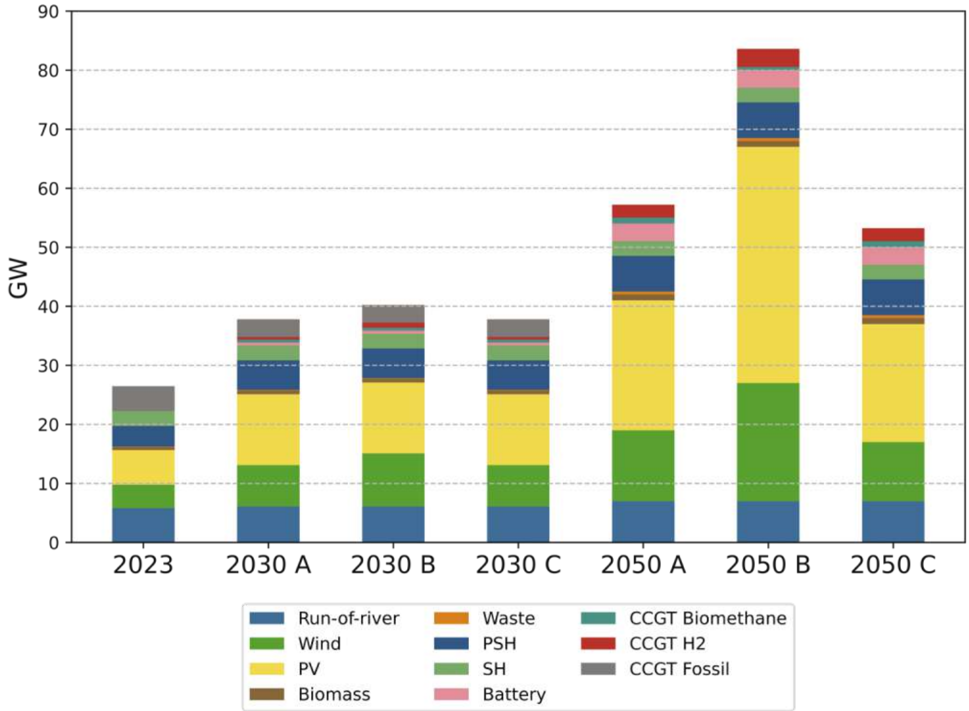

Figure 15: Installed generation and storage capacities in Austria per scenario (Remarks: A=Policy scenario, B=Renewables and electrification scenario, C=Efficiency scenario; PSH describes the turbine capacity and CCGT H_2 describes the capacity for re-electrification from the hydrogen storage units; 2023 data is from (APG, 2024) as of 09.01.2024, due to its reporting dates).

Table 6: Efficiencies and storage capacities (energy) (ENTSO-E, 2022; European Commission. Directorate General for Energy. et al., 2023; Lovegrove et al., 2018; Webb, 2018; Welder et al., 2019)

Parameter	Unit	2030	2050
Maximum energy capacity PSH	GWh	1732	1732
Roundtrip efficiency PSH		0.79	0.79
Maximum energy capacity SH	GWh	757	757
Efficiency SH		0.9	0.9
Maximum energy capacity grid-scale battery storage	GWh	1.07	6
Roundtrip efficiency battery		0.9	0.9
Maximum energy capacity hydrogen	GWh	not restricted	not restricted
Roundtrip efficiency hydrogen		0.37	0.45

Table 7 provides the input data on the total electricity demand in the considered scenarios. Notably, it only encompasses the load required from the electricity grid, excluding consumption from companies utilizing their plants not integrated into the public grid and household demand covered by PV and batteries. Additionally, the total electricity demand incorporates demand from HPs and EVs, alongside grid losses. However, it is important to note that the electricity consumption of the storage systems is a modeling result and must therefore be regarded as an additional component to the total load indicated.

Table 7: Electricity load/demand input data in TWh (AIT, 2023a, 2023b; AURES, 2022; Haas et al., 2017; Kranzl et al., 2018; Krutzler et al., 2016; SECURES, 2023; Suna et al., 2022)

Scenario	*Policy (A)*		*Renewables and electrification (B)*		*Efficiency (C)*	
	2030	2050	2030	2050	2030	2050
Total load/demand (excluding storage consumption)	73	79	70	83	95	80
Of which: HP	3.5	8	2.7	9	16	6.2
Of which: EV	1.8	3	1.4	6	10.3	5

We solve the model for three described scenarios, each pertaining to the years 2030 and 2050, under three different weather conditions, as outlined above.

3.2. Results

This section presents the main results of the three scenarios, namely the *policy* scenario *(A)*, *renewables and electrification* scenario *(B)* and *efficiency* scenario *(C)* within the case study of Austria. The primary focus is on the year 2050, marking the complete phase-out of fossil fuel generation and increased availability of renewable energy within the system, with a comparison between 2030 and 2050. Due to the comprehensive scenario analysis involving 18 cases (economic scenarios A, B, C; weather years 2015, 2026, 2017; target years 2030 and 2050), detailed results cannot be fully presented in this section but are available in the Appendix of this work (Appendix E). The description is divided into three parts. First, Section 3.2.1 analyzes the impact of weather patterns on renewable generation and extreme weather events (such as low wind power and dark doldrums), using the *policy* scenario *(A)* as an example. Section 3.2.2 presents the influence of weather patterns on the overall system, underground hydrogen storage size and possible surplus hydrogen production, while Section 3.2.3 focuses on differences in storage utilization and dispatchable generation between 2030 and 2050, as well as among economic scenarios.

3.2.1. Influence of weather patterns on renewable generation and analysis of extreme weather events

In order to meet the established targets for achieving climate neutrality in Austria, a significant increase in wind and PV generation is necessary, see Figure 16. The emphasis on PV is particularly noteworthy, with a substantial surge already underway. In 2022, PV contributed 3.8 TWh of electricity; however, in the outlined scenario, this must escalate to approximately 13-17 TWh (roughly a factor of 4) by 2030 and 25-27 TWh by 2050. A comparable trajectory is observed for wind power generation, starting from a higher baseline of 7.25 TWh in 2022 and rising to approximately 19-21 TWh (approximately a factor of 3) by 2030 and 30-37 TWh by 2050. The annual generation volumes fluctuate based on the weather year, necessitating a specified range of weather years for scenario development. The respective generation for wind and PV, in contrast to historical production, is illustrated in Figure 16, clearly showing variations in production. Across the year, these are most pronounced for wind generation. In the depicted *policy* scenario *(A)*, there is a difference of nearly 6 TWh between the lowest production (weather year 2016) and the highest production (weather year 2017) when calculating total annual generation. For PV, the differences are smaller, at approximately 1.6 TWh.

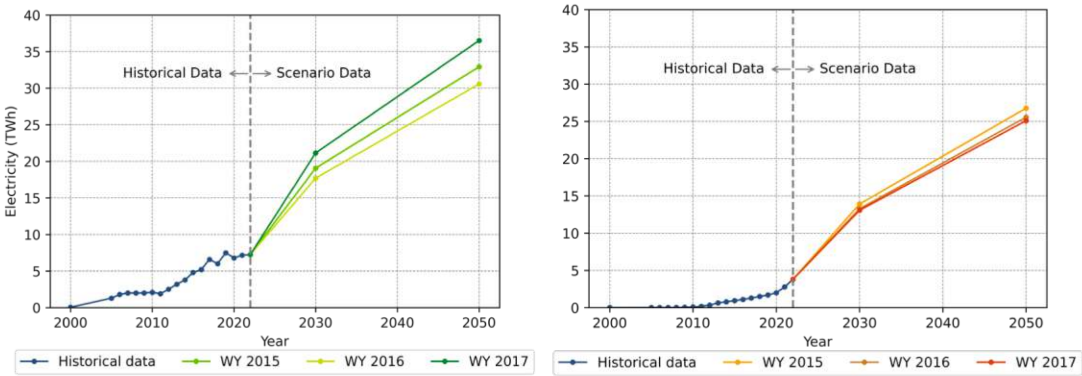

Figure 16: Annual wind (left) and PV (right) generation from 2000 (historical data, (BMK, 2023a; Veigl, 2022)) up to 2050 (simulation results, policy scenario (A))

The weather year 2017 is notable for several reasons: It records the highest total wind generation, the lowest PV generation and the lowest natural water inflows in PSH and SH reservoirs. While the yearly totals provide valuable insights, a more detailed breakdown is crucial for the reliable operation of a power system. Examining monthly generation reveals that although there is an overall high wind generation in weather year 2017, it drops markedly in February. This disparity is evident when comparing Figure 17 (weather year 2016) and Figure 18 (weather year 2017), highlighting significant monthly generation variations.

Coupled with the low water flow in run-of-river hydroelectricity plants and minimal natural inflows, this can pose challenges or require increased flexibility, as analyzed further below. The substantial increase in PV electricity generation during summer months is also apparent, which in Austria coincides with peak levels of reservoir storage in summer due to snowmelt. Consequently, these PSH and SH reservoirs have reduced capacity to absorb PV electricity, necessitating alternative flexibility options. The high water levels of run-of-river hydroelectricity plants, as well as the increased inflows from May through the summer, represent a particular characteristic of the Alpine region. In warmer, drier countries without snowfall, these higher water levels occur in the opposite manner, leading to dry spells in the summer. Presently, Austria faces challenges where, due to increased PV generation around midday, particularly in the first week of May 2024, run-of-river hydroelectricity plants were curtailed as surplus electricity could not be absorbed, highlighting capacity constraints (Fraunhofer ISE, 2024a).

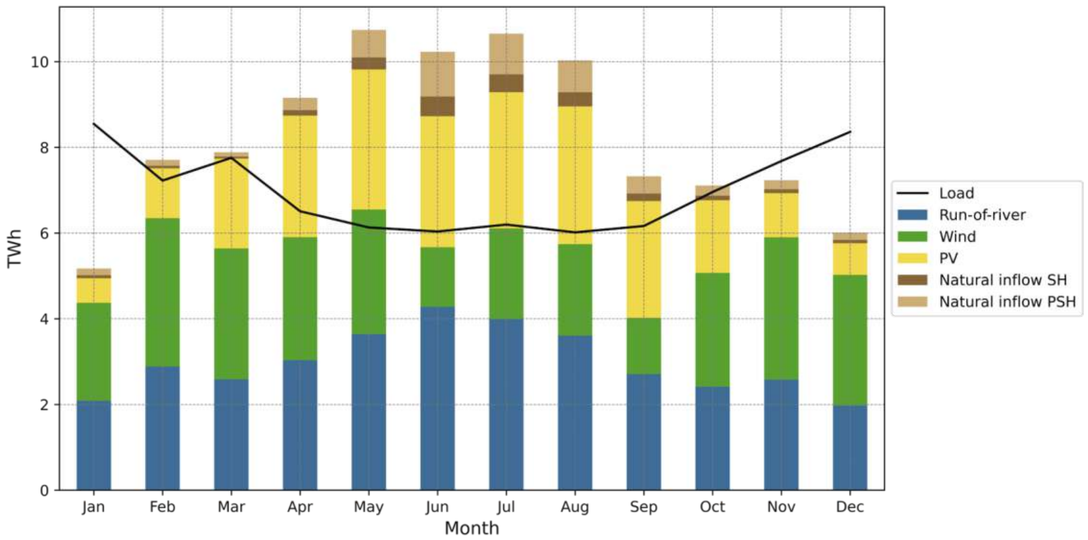

Figure 17: Monthly variable renewable generation and natural water inflows in 2050 with the underlying weather year 2016

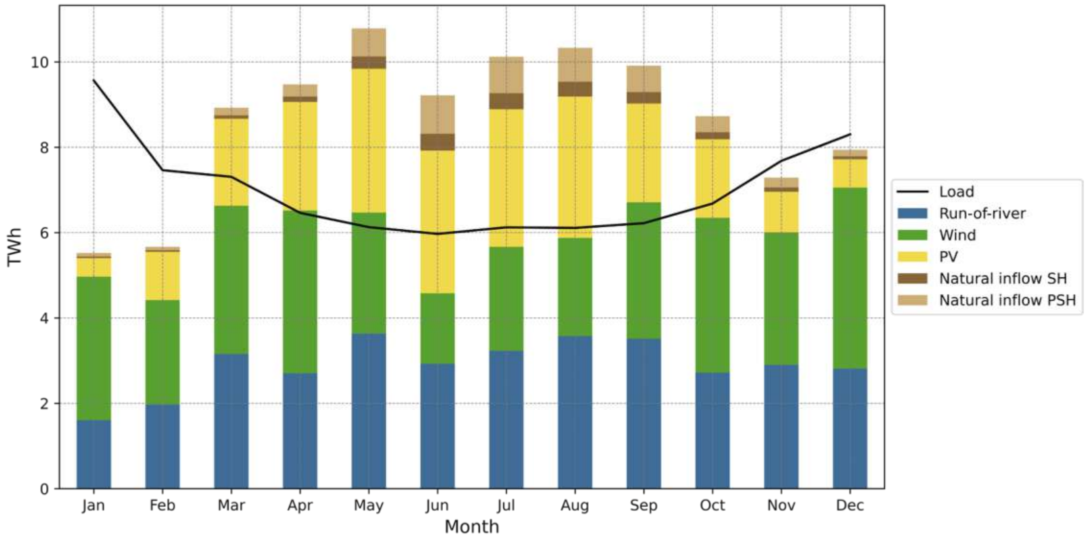

Figure 18: Monthly variable renewable generation and natural water inflows in 2050 with the underlying weather year 2017

Analysis of the wind patterns of the three selected weather years confirms that in weather year 2017, there was a prolonged period with low wind power lasting over eight days, with an average capacity factor of less than 10% of the wind capacities, as depicted in Figure 19. This occurrence, as noted by Ohlendorf and Schill (2020), happens approximately once every ten years. In contrast, the other two weather years each exhibited shorter periods of low wind power events lasting fewer than five consecutive days.

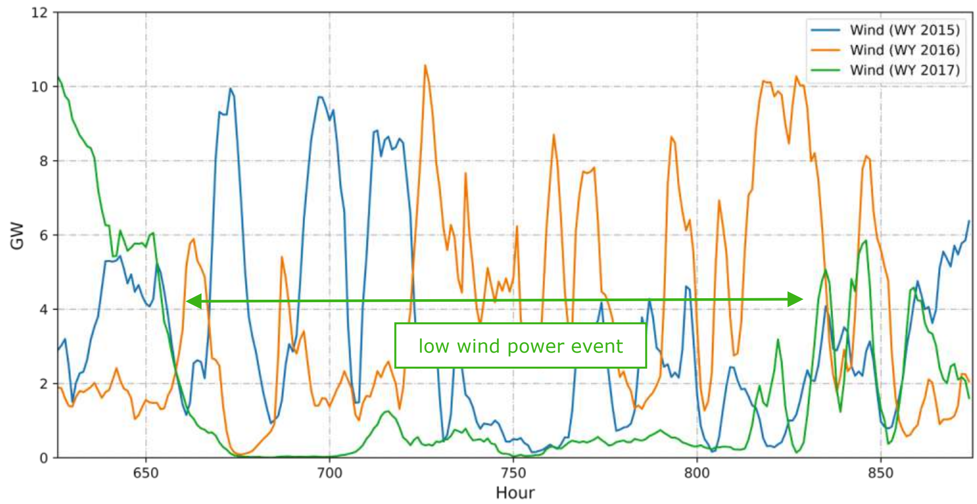

Figure 19: Low wind power event over eight days with an average capacity factor of less than 10% in weather year 2017 in comparison to weather years 2015 and 2016 in the same period

In a further analysis, we examine the residual load (see Figure 20) and identify a high positive residual load for the low wind power event defined earlier in the weather year 2017. This finding aligns with Suna et al. (2022). Alongside the noted low wind generation, temperatures are also low, resulting in high heating demand and thus electricity demand for HPs, as well as reduced PV generation due to fog and low inflows in hydro reservoirs, resulting in so-called dark doldrums. Regarding hydraulic conditions, simulations from the PECD (ENTSO-E, 2022) were utilized, revealing that during this period in weather year 2017, the lowest storage levels and water flows were recorded. This was also confirmed by E-Control, stating that at the beginning of the year 2017, the available storage capacity was particularly low compared to long-term averages (E-Control, 2021). All these factors are reflected in the residual load, as temperature data are also factored into HP electricity demand, depending on the weather year. It should also be noted that this analysis of the residual load only covers Austria. European climatic interactions are not considered here. However, the dark doldrum in 2017 was also observed in Germany, suggesting a certain correlation of conditions (Next Kraftwerke, 2018).

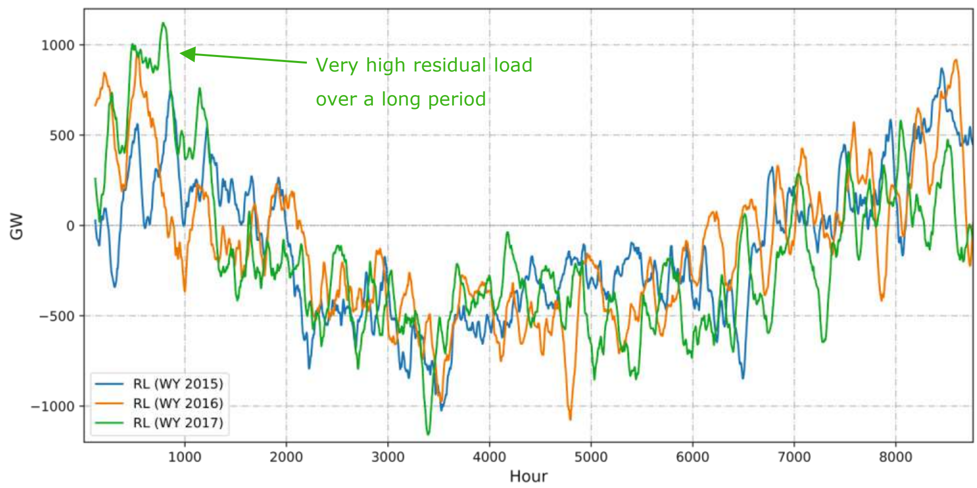

Figure 20: Annual residual load for the policy scenario (A) 2050 and three regarded weather years (smoothed with a 5-day moving average)

In summary, the weather year 2017 can be classified as an extreme year due to the significantly lower water inflows and wind generation in January and February compared to the other two weather years. Additionally, relatively low temperatures in weather year 2017 contribute to an overall increasing demand for electricity to operate HPs compared to the other two scenarios. This divergence was also observed in the optimization results. When applying weather year 2017 for optimization, increased use of storage and dispatchable generators is necessary during winter months. Thus, one extreme year and two normal years were included in the optimization.

3.2.2. Influence of weather patterns on the overall fully renewable electricity system, possible surplus hydrogen production and underground hydrogen storage size

To analyze the interplay between renewable generation and respective storage technologies in a fully decarbonized electricity system, Figure 21 illustrates the monthly total generation for 2050 per weather year, exemplified by the *policy* scenario *(A)*. In this graph, energy amounts utilized for electricity generation by the storage technology (PSH, SH, battery and hydrogen) are depicted positively, while energy amounts to charge the storage (consumption) are plotted as negative values. Both energy amounts used for discharging and charging, are labeled identically for simplification. The dark doldrums identified in previous analyses in January of weather year 2017 are clearly visible in this representation. Here, compared to other weather years, the necessary load coverage is highest, accompanied by the lowest input of run-of-river hydroelectricity, wind and PV. To cover the load, all available storage capacities, renewable dispatchable generators and available import quantities are utilized to the fullest extent, as determined through sensitivity analysis by adjusting parameters. Reducing capacities led to periods of undercoverage. Regarding the optimization explanation, PSH and SH are limited based on initial water levels at the start of the year, as simulated by the PECD model, which aligns with real-world conditions as demonstrated in the preceding section. Biomass and biomethane are constrained by their installed capacities, while batteries are also restricted to energy capacities. Import and export capacities are modeled as virtual storage, with their full energy capacity available at the beginning of the year. Hydrogen storage is modeled as a special case, assuming unlimited availability with no restrictions on initial hydrogen quantities (energy component of the storage), provided that at least the initial storage quantity is maintained by the end of the year, with the potential for additional accumulation. Limitations on hydrogen usage to cover the dark doldrums stem from the re-electrification plant's power component. Hydrogen production for storage via electrolysis occurs exclusively during summer months (power-to-gas), with significant variations in the extension of hydrogen production periods into autumn across different weather years. In weather year 2015, surplus renewable generation is considerably lower, with hydrogen production primarily occurring from April to October, whereas in the other weather years, hydrogen production can also extend into March and November. The seasonality of hydrogen utilization in the electricity system is thus evident. The same occurs with dispatchable renewable generation, which is prominently utilized during winter months.

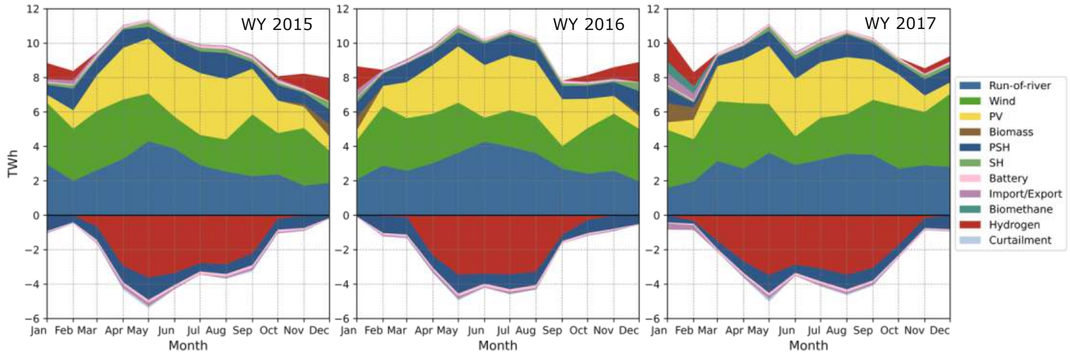

Figure 21: Total electricity generation (positive) and consumption (negative) per month of the year 2050 per weather year in TWh (policy scenario (A))

To provide a more detailed analysis with respect to the different economic scenarios (*policy (A)*, *renewables and electrification (B)* and *efficiency (C)*), Figure 22 illustrates the total electricity generation per technology for the year 2050 across all developed scenarios. It is evident that in all scenarios, biomethane is exclusively used in weather year 2017 due to the necessary load coverage in winter. Biomass and waste are also increasingly utilized in weather year 2017 among all scenarios, but at least in two scenarios, they are needed across all weather years. In scenario *renewables and electrification (B)*, these capacities are no longer needed in weather years 2015 and 2016 due to the generally higher renewable generation and higher utilization compared to other scenarios. Alongside increased generation, the higher utilization of PSH and increased import and export possibilities in this scenario also play a role. This means that a higher level of balancing can be covered by alternative flexibilities. Total generation must also be higher in this scenario due to the higher electricity demand modeled. It is also evident in scenario *efficiency (C)* that lower flexibilities are required when the electricity demand is lower.

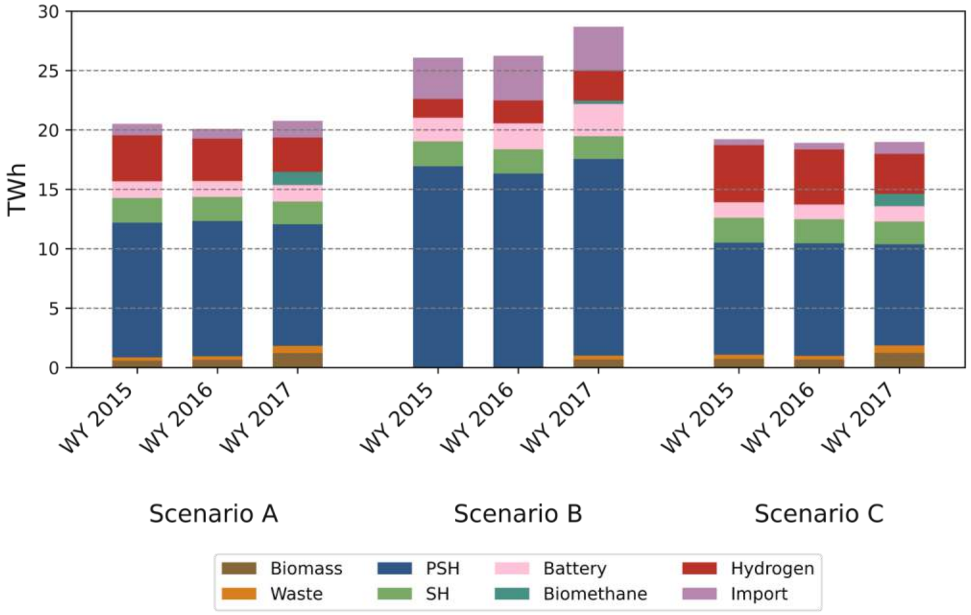

Figure 22: Total yearly electricity generation in 2050 for each scenario and weather year in TWh

The utilization of storage is also dependent on weather conditions. The respective state of charge of underground hydrogen storage, PSH and battery storage in each hour over the year, depending on the weather year in 2050, is depicted in Figure 23. In the case of hydrogen storage, it is apparent that the storage maintains a relatively constant accumulation of hydrogen over the summer months. This is attributed to the characteristic of a high seasonal surplus in the middle of the year in all weather years. However, the amount of hydrogen needed for reconversion in winter depends on the underlying weather year. In weather year 2017, a considerable amount is required at the beginning of the year, but significantly higher quantities remain in storage by year-end. These additional amounts of hydrogen remaining in the storage signify increased renewable capacities in 2050. In 2030, almost all generated capacities were required for reconversion.

In the other two weather years, the storage level is more balanced. Approximately equal amounts of hydrogen are needed in the winter months at the beginning and end of the year. PSH also exhibits strong seasonality due to natural inflows, resulting in consistent intra-year patterns in storage levels. The storage is discharged to the maximum depth during hours 2000 to 3000 in all weather years, then recharged with natural inflows occurring due to snowmelt. Typically, the storage reaches its peak level in early September and is subsequently utilized to varying extents for winter demand coverage. In weather year 2015, the highest initial water levels are available, leading to a slower discharge and faster recharge. Additionally, a relatively deep discharge of the storage occurs around hour 6000. From weather year 2016 to 2017, the summer storage levels are replenished more slowly but remain at higher levels.

Besides the seasonal pattern, the shorter to medium-term fluctuations of PSH are also evident. This is compared to hydrogen storage, which is exclusively used for seasonal coverage and exhibits no shorter-term fluctuations. Battery storage, on the other hand, is used solely for short-term balancing of intraday fluctuations, such as balancing PV surplus during midday. This is attributed to the E/P ratio in the model assumptions. Since batteries can be most cost-effectively utilized for rapid, short-term storage, an E/P ratio of 2 was employed in this case. If battery storage were not available to the extent modeled, the other two storage technologies would also need to cover short-term balancing, altering their state-of-charge profiles.

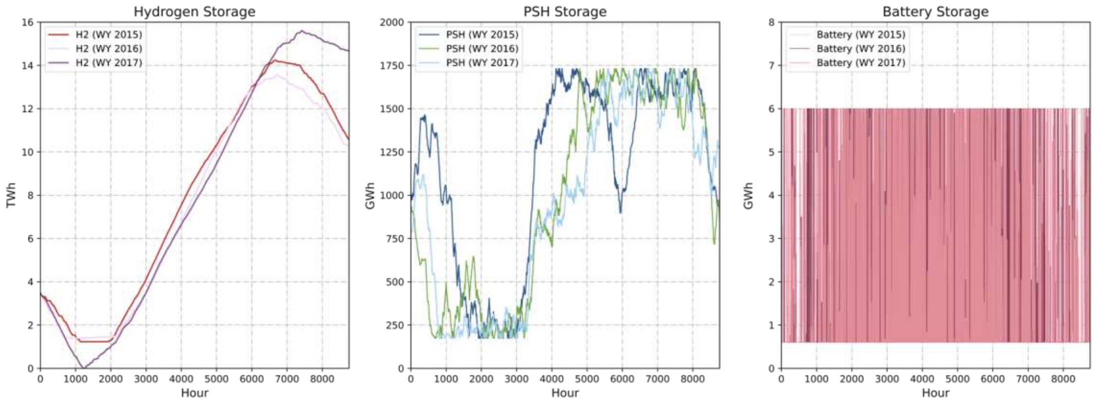

Figure 23: State of charge of underground hydrogen storage (left), PSH (middle) and battery (left) storage in 2050 (policy scenario (A))

As discussed earlier, the model also allows for hydrogen production aside from reconversion if this is cost-optimal. The amount of hydrogen remaining after deducting the demand in the electricity sector largely depends on climatic conditions (weather year 2017 has the highest production potential due to the surplus in the second half of the year) and the scenario design, see Figure 24. In scenario *renewables and electrification (B)*, there is the greatest potential for hydrogen production, as it involves the most significant expansion of renewable generation overall. Therefore, despite the overall higher demand, a larger summer surplus is available. In total, 26.10-30.11 TWh_{H2} are produced in this scenario. Of this, 23.14-26.23 TWh_{H2} remains as surplus for use in other sectors or as backup capacity for other weather years, as the demand for reconversion as seasonal compensation is lower in this scenario. In scenario *policy (A)*, hydrogen production amounts to 12.21-15.6 TWh_{H2}, with a surplus of 6.71-11.17 TWh_{H2}. In scenario *efficiency (C)*, production amounts to 10.24-12.68 TWh_{H2}, with a surplus of 3.12-7.51 TWh_{H2}. These quantities are heavily dependent on the planned expansion of wind and PV. The higher these expansions, the greater the quantities of hydrogen production that can also be utilized in other sectors.

With the specific model design (the initial quantity of hydrogen available was not restricted), it was demonstrated that even if surplus quantities remain in storage for the next weather year, this does not alter the model results, as reconversion capacities are the limiting factor in our cases. The necessary storage size (energy component) of the hydrogen storage is determined by not restricting the storage volume. This amounts to the maximum filling level minus the minimum filling level. However, as hydrogen storage behaves strictly seasonally, storing relatively constant amounts to then release them consistently results in the required storage size being identical to the total hydrogen production, as illustrated in Figure 24. These sizes are thus in the range of approximately 10-30 TWh_{H2}. For underground hydrogen storage, current installations in Austria are limited to a pilot plant. However, as an alternative, the current natural gas storage capacities in Austria amount to approximately 94 TWh_{NG}, equivalent to approximately 25 TWh_{H2} (AGSI, 2024). Therefore, the demand in scenarios *policy (A)* and *efficiency (C)* could be entirely met by existing storage facilities converted to hydrogen. Additional storage would need to be built for scenario *renewables and electrification (B)* if the total hydrogen quantities were to be stored. However, these are only theoretical considerations because, in the case of alternative utilization of hydrogen, deliveries would already be made intrayearly, thus relieving storage facilities. The total demand for reconversion, which must be stored seasonally, would amount to only up to 7.4 TWh_{H} and could thus be adequately covered by the currently existing storage capacities.

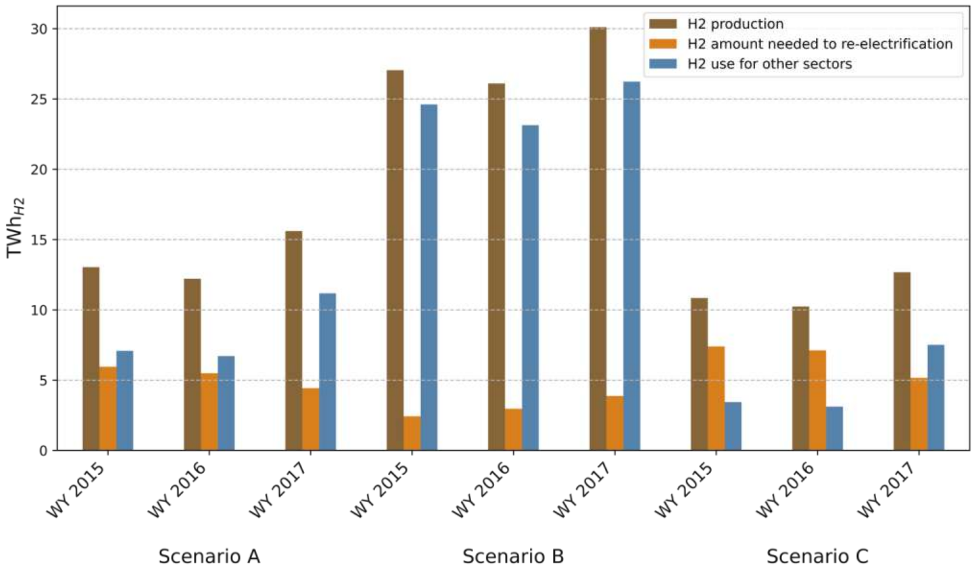

Figure 24: Production, re-electrification and surplus amounts of hydrogen for each scenario and weather year in the year 2050

3.2.3. Differences in storage utilization and dispatchable generation between 2030 and 2050

In this section, the characteristics of storage (utilization of charging and discharging, total charged amount) will be analyzed in more detail based on the *policy* scenario *(A)*, comparing the target years 2030 to 2050. The utilization of storage changes with the target year (2030, 2050) and depends on the weather year. Utilization refers here and in Figure 25 to the full-load hours of discharging for storage technologies and for other technologies, it refers to the full-load hours of electricity generation. To simplify the description, full-load hours are referred to as such for all technologies. The clear trend that full-load hours decrease in 2050 for almost all technologies is due to the availability of larger amounts of renewable energy, but because of the limited correlation between fluctuating wind and solar power generation and hourly demand, increasing capacities of these technologies do not lead to a linear decrease in residual load. In 2050, fluctuating renewable energies replace a large part of fossil fuel generation (given the phase-out of flexible fossil fuel power plants as model input) but hardly reduce the flexibility requirement (maximum power) of the systems, necessitating other flexibilities with higher capacities to balance the load. Therefore, significant backup capacity must be maintained for a few hours per year in this case. Truly pure backup capacities are in biomethane in 2050; full-load hours are zero in all weather years, with only slightly over 1100 hours in weather year 2017.

Also interesting is the general utilization depending on the weather year, as shown in Figure 25. Biomass in 2030 in weather year 2015 and 2016 ranges between 3500 and 4000 full-load hours, while only 700 full-load hours are required in weather year2017. This changes in 2050; in weather year 2015 and 2016, only 550-650 full-load hours are needed, but in weather year 2017, the utilization increases to 1200 full-load hours. Due to the absence of flexible fossil fuel generation, other flexibilities become more important in extreme years. Conversely, PSH exhibits a counter-trend, with higher turbine utilization in weather year 2015 and 2016, but with only a slight reduction in deployment from 1760 to 1690 full-load hours in weather year 2017. Additionally, it should be noted that the total available water volumes from natural inflow and the initial storage level depend on the underlying hydraulic model for PSH, which also has an influence on the possible utilization of storage. Conversely, batteries show a slightly declining trend in utilization (approximately 100 fewer full-load hours) in all scenarios. Similarly, in hydrogen re-electrification (discharging), there is a significant decline in full-load hours of up to 1380 hours.

With increasing decarbonization in the system, storage and other power plants focus on covering the positive residual load, which decreases as the share of renewable generation in the system increases, but the installed capacities must remain available. Extreme years are particularly relevant here because some of the implemented capacities generate few full-load hours during such events (in the model, weather year 2017) but none at all in other years. However, without these capacities, shortages would occur in certain periods, as tested in the model. Therefore, the reduction of flexible capacities in the system due to lower utilization is not feasible as long as the condition that demand must be met every hour remains included.

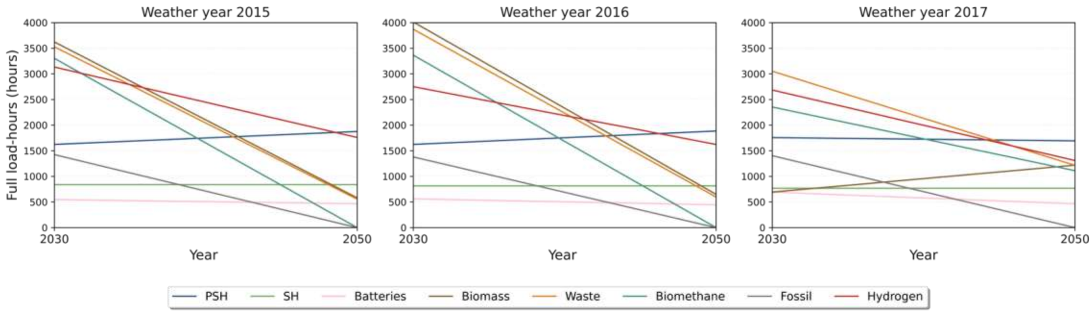

Figure 25: Utilization of technologies (full-load hours, discharging hours) in comparison from 2030 to 2050 and weather year (policy scenario (A))

Examining the charging hours of storage technologies in Figure 26 reveals a clear trend, similar to that observed in the discharging hours for battery storage. This is expected based on the model assumptions for batteries since only as much can be stored as was previously stored. The trend for PSH also aligns in the opposite direction (except for weather year 2017, where the utilization of pumping power increases slightly from 1330 to 1440 full-load hours) with overall lower utilization of pumping power compared to turbine power of the storage, as the reservoirs can also be filled by natural inflow. However, the seasonal component is evident with PSH. Since more electricity from renewables will be available in 2050, especially in summer, PSH will increasingly store it to utilize in periods of scarcity. This is particularly pronounced with hydrogen, as storage volumes are not limited in the model. Increasing amounts are stored, except for weather year 2015, some of which are surpluses that can be used in other sectors or remain in storage for subsequent years. Hence, the overall range of total charging (power to gas) utilization (3200-4460 full-load hours) in both 2030 and 2050 is significantly higher than discharging (re-electrification) utilization (1300-3130 full-load hours).

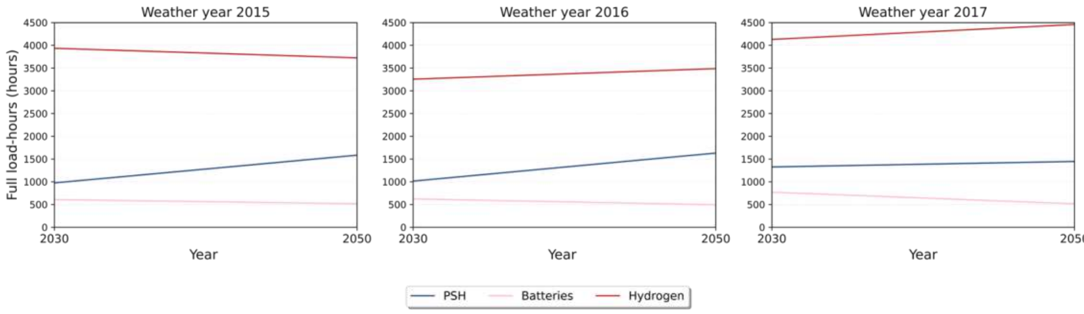

Figure 26: Charging hours or storage technologies in comparison from 2030 to 2050 and weather year (policy scenario (A))

The following illustrates how the respective storage technologies function and how they will change from 2030 to 2050, using the policy scenarios and weather year 2017 as examples. Figures 27–29 show the charge and discharge profiles as well as the resulting storage levels for each technology.

Long-term storage, in this work, hydrogen storage, is primarily used to shift large amounts of energy between seasons (in the Austrian electricity system, from summer to winter). Figure 27 demonstrates this behavior, confirming the system design where hydrogen storage is intended for long-term storage. Hydrogen discharge is only required in the winter months, while the storage is charged exclusively during the summer months. Therefore, the long-term storage cycle occurs only once a year, as seen clearly in the state of charge curve. In 2030, electrolysis capacities operate at nearly full capacity to store hydrogen from mid-April to mid-September. Before and after, storage reacts and operates flexibly based on over and undercoverage of the residual load. In 2030, the re-electrification capacities are also more utilized compared to 2050, primarily from the end of February to the end of October.

In 2050, the initial utilization is approximately the same (due to extreme conditions in weather year 2017), but there is lower utilization of re-electrification (due to other flexibility options), starting only in November, leading to higher storage levels compared to 2030. Additionally, throughout the summer, electrolysis capacities are more flexible as higher capacities are available, allowing for higher amounts of electricity to be converted into hydrogen. Specifically, the comparison of electricity inputs for charging (power-to-gas) is 4.13 TWh in 2030 and 22.29 TWh in 2050 (utilization 4130 to 4460 full-load hours). In 2030, 1.18 TWh and in 2050, 2.88 TWh of electricity are provided to the system through discharging (re-electrification) of hydrogen storage in 2050 (utilization 2690 to 1310 full-load hours).

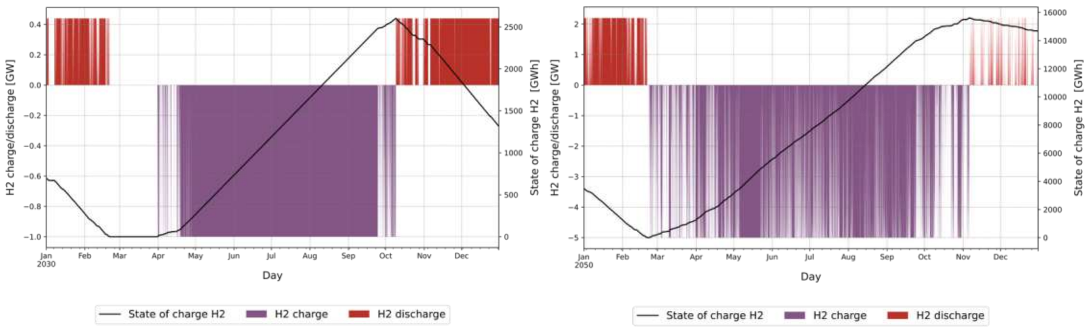

Figure 27: Hydrogen charge and discharge profiles and the resulting state of charge of storage in 2030 (left) and 2050 (right) (policy scenario (A), weather year 2017)

PSH also exhibits a certain seasonal component, as shown in Figure 23, depicting the annual state of charge profile; however, it primarily addresses short and medium-term requirements, as seen in Figure 28. Here, the profile over 28 days is displayed to visualize these shorter charge and discharge cycles. Throughout the year, it is observed that, contrary to the other two weather years, in weather year 2017, the times of utilization for PSH discharging slightly decrease and within the specific observation period, the storage level in 2050 is higher (a possible reason being the slightly lower utilization of the discharging capacities/turbines, from 1760 to 1690 full-load hours). Overall, due to higher available power capacities in 2050, a greater amount is discharged (turbining), namely 10.23 TWh compared to 8.78 TWh in 2030. The electricity inputs for charging (pumping) amounted to 5.70 TWh in 2030 and 7.53 TWh in 2050, with a utilization of 1330 (2030) and 1450 (2050) full-load hours.

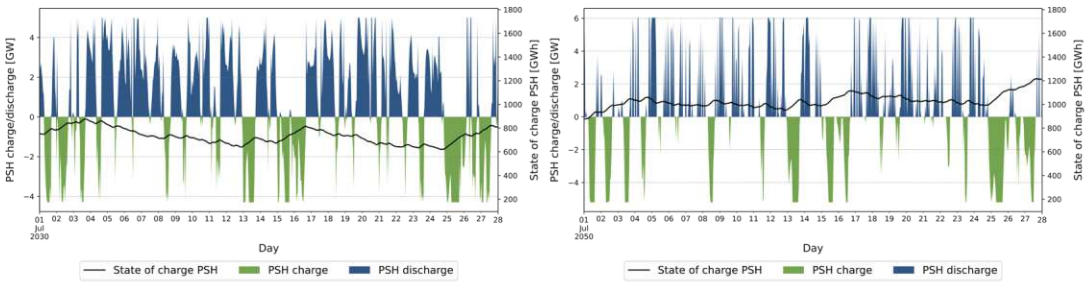

Figure 28: PSH charge and discharge profiles and the resulting state of charge of storage over 28 days in 2030 (left) and 2050 (right) (policy scenario (A), weather year 2017)

Battery storage, on the other hand, is utilized for short-term daily balancing due to its high power ratio and efficiency but limited energy capacity, as defined per model design. Figure 29 illustrates, for a two-day interval, that batteries are frequently used to provide small amounts of stored energy and are cycled one to two times per day, often reaching their full installed energy capacity. The overall utilization of battery storage decreases slightly from 2030 to 2050 (690 to 460 full-load hours discharging and 771 to 516 full-load hours charging), but the total energy quantities increase due to higher installed power and energy capacity. Specifically, charging amounts to 0.41 TWh in 2030 and 1.55 TWh in 2050. In 2030, 0.37 TWh and in 2050, 1.39 TWh of electricity are provided through the discharging of battery storage.

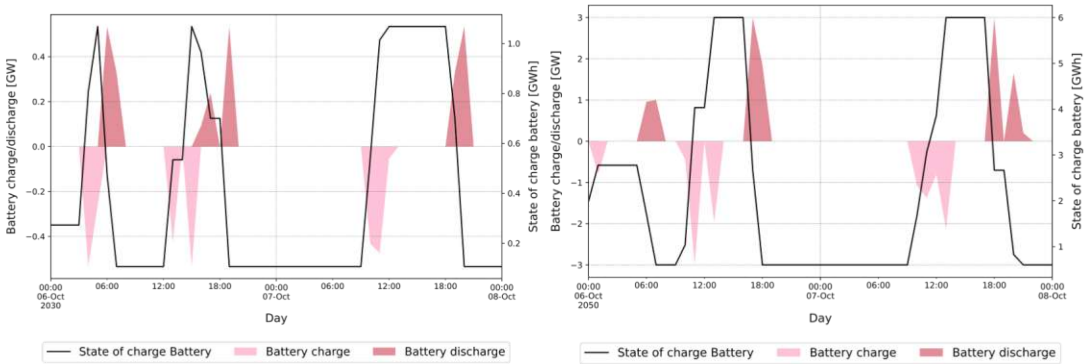

Figure 29: Battery charge and discharge profiles and the resulting state of charge of storage over two days in 2030 (left) and 2050 (right) (policy scenario (A), weather year 2017)

The annual dispatch in the *policy* scenario *(A)* (Figure 30 smoothed with a 5-day moving average) illustrates once again the seasonality of renewable generation (blue, green and yellow) with the highest generation levels in the summer months, thus also indicating the greatest power-to-gas (red) production potential. The difference between 2030 and 2050 is very clear, showing a massive increase in capacities in the model. However, in both years, the generation levels of variable renewable generation are not sufficient to cover the total demand. In 2030, fossil fuel power plants (grey) are mainly used for this purpose, while in 2050, everything is covered by storage and flexible renewable generation. This requires a seasonal shift in generation from summer, when renewable resources (mostly PV and run-of-river hydroelectricity) are abundant, to winter, when combined resources are relatively scarce. PSH competes to some extent with hydrogen storage, as they also cover a certain proportion of the seasonal demand, as seen in the shared charging periods of PSH (blue) and hydrogen (red) in the summer months. Batteries (pink) are routinely charged and discharged in small quantities throughout the year. Curtailment (light blue) mainly occurs in the summer months during peak loads.

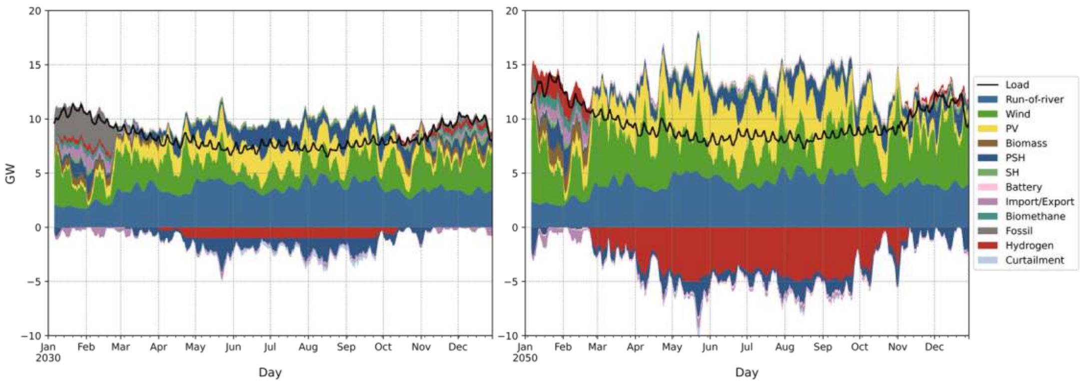

Figure 30: Electricity generation and consumption throughout the years 2030 (left) and 2050 (right) (smoothed with a 5-day moving average, policy scenario (A), weather year 2017)

3.2.4. Limitations

The model is subject to certain limitations and constraints due to the extensive scenario analysis, which includes economic scenarios, target years weather conditions (18 cases). One notable restriction is the adoption of a "copper plate" approach, where Austria is modeled as a single node, neglecting regional and network-specific constraints. Welder et al. (2019) recommend situating electrolyzers in proximity to surplus electricity sites to obviate the need for additional grid expansion. In order to account for network restrictions, the model implements curtailment if an exceptionally high share of renewables is fed into the grid in a specific hour. We acknowledge, however, that adapting the network infrastructure is imperative to fully harness the potential of these storage technologies.

Additionally, the model abstracts from a detailed representation of flexibility restrictions in thermal generators. Power plants and storage technologies are aggregated as a unified capacity within the model, portraying the Austrian electricity sector in a simplified manner as cumulative national capacity per technology. Particular emphasis should be placed on the simplification regarding PSH, as an available storage capacity was modeled without separately modeling individual power plants, including their upper and lower reservoirs, which is indeed a restriction in reality. This is because pumping can only occur if sufficient water is available in the lower reservoir. Additionally, PSH plants vary significantly in terms of their power and energy components. Including PSH as individual plants without the chosen level of aggregation was not feasible due to the number of scenario runs and data availability and is also in line with (Schill, 2014; Sousa et al., 2023). No exact load flows and no exact exchange with other countries were modeled; here, too, the possible total exchange capacities are combined as a virtual import and export storage facility in order to allow a certain amount of balancing in the model. Moreover, it is important to acknowledge that, alongside storage, DSM is an important flexibility component. While DSM has been integrated into the load profiles to a certain extent, it does not constitute a separate optimization variable in the model. This represents a limitation in the current version of the model and should be considered in future iterations.

Furthermore, the assumption of a perfectly efficient market and perfect competition implies that generators with the lowest variable costs are always ranked first within the merit order structure, with one market and trading horizon in an energy-only market. Balancing markets were not considered. The model assumes perfect foresight, which means that there are no forecast errors for electricity generation within any one year, thus eliminating uncertainties. To avoid this to a certain extent, three weather years were considered, aiming to achieve representativeness in capturing climatic variability, but in the knowledge that all uncertainties in RE generation could not be captured this way. Another limitation is that despite different weather patterns, climate change was not included in this work. While the assumptions made facilitate the modeling process, it is crucial to acknowledge that they may also lead to an overestimation of the flexibility potential within the overall electricity system, despite advancements in renewables forecasting and discussions about shorter trading horizons.

4. Current and future costs of storage for electricity in a decarbonized electricity system[6]

Austria's aim to achieve 100% renewable electricity in its energy system by 2030 underscores the increasing importance of energy storage (Österreichisches Parlament, 2021). However, the future of storage development remains uncertain and will depend on various factors. Currently, PSH is the dominant technology, but future cost trends, changes in the performance of other technologies, requirements for seasonal storage and geographical limitations of conventional PSH could reshape the landscape. Additionally, each technology has specific technical characteristics with resulting advantages and disadvantages, making it unlikely for a single technology to meet all flexibility requirements. Therefore, a combination of different storage technologies, as well as the utilization of other flexibility options such as demand-side management, grid expansion, or sector coupling, will be necessary to meet the demands of the transformed energy system.

In this context, understanding the trajectory of future investment costs of energy storage technologies is crucial. Hence, the core objective of this section is to conduct a comprehensive assessment of the costs of selected energy storage technologies, both current and future, based on the Austrian electricity market and scenario development while considering technical specifics. The aim is to provide insights into potential cost trends and their implications for the energy transition. This leads to the following research question: *"What are the current and projected future total costs of jointly integrated storage technologies in a decarbonized electricity system?"*

Subsequently, in Section 4.1, the techno-economic assessment of the joint integration of selected storage technologies in a renewable electricity system is explained. In Section 4.2, the results of the techno-economic assessment based on Sayer et al. (2024b) are demonstrated.

[6] This chapter is based on on Sayer et al. (2024b).

4.1. Methodology

The method applied is a techno-economic analysis to evaluate the joint integration of key storage technologies within a decarbonized energy system. It entails the development of an economic model to assess the current and future total lifetime costs (overall cost of electricity coming from energy storage systems, including the energy purchase price) of new utility-scale storage systems across different transformation scenarios of the Austrian electricity system. The current investment costs of the storage systems and other costs are determined through an extensive literature review, while a technological learning approach is being employed to calculate future investment costs. Additionally, parameters such as storage utilization in the future energy system and electricity costs are derived from a self-developed representative model for the Austrian electricity system, reflecting scenarios for 2030 and 2050, as explained in Section 3.1. This allows the respective total costs of storage (per kWh electricity output) to be calculated depending on the renewable expansion scenarios developed in the upstream model.

4.1.1. Techno-economic analysis of total costs of storage

For the cost analysis, the initial step involves determining the total investment costs of each storage technology ($IC_{sto}, in\ €/kW$). This encompasses incorporating all components of investment costs, including energy storage system and installation costs, based on the methodology outlined by Viswanathan et al. (2022), as depicted in Figure 31. These components comprise the specific investment costs of power equipment, controls, communication and grid integration ($IC_p\ , in\ €/kW$), the specific unit energy cost for the energy component of the energy storage system, incorporating supporting cost components ($IC_e\ , in\ €/kWh$), other specific costs ($IC_o\ , in\ €/kWh$), covering system integration, engineering, procurement and construction, project development and the discharge time ($t, in\ hours$). Using this calculation, the power-specific costs are converted into capacity-specific costs depending on the discharge time.

$$IC_{sto} = IC_p + (IC_e + IC_o)t \qquad (€/kW) \qquad (5)$$

		Pumped storage hydro	Li-ion	Lead-acid	Redox Flow	Hydrogen
Storage system	Storage block	Reservoir construction and infrastructure	Li-ion modules in racks	Lead-acid modules in racks	Stacks and electrolyte tanks	Electrolyzer, underground storage, CCGT hydrogen turbine
	Balance of system		Container, cabling, switchgear and air conditioning		Pumps and piping	Blowers, humidifiers, mass flow controllers, and compressors
Energy storage system	Power equipment	Electromechanical powertrain – pumps/turbines, motors/generators and powerhouse construction and infrastructure	Power conversion system and DC-DCconverter			Rectifier & Inverter
	Controls and communication		Controls/Energy management system			
	System integration		System integration			Included in above costs
Installment costs	Engineering procurement and construction	Included in above ESS costs Contingency fees	Engineering procurement and construction	Engineering procurement and construction	Engineering procurement and construction	EPCEngineering procurement and construction
	Project development		Project development			
	Grid integration		Grid integration			

Figure 31: Investment cost components (adapted from (Viswanathan et al., 2022))

In addition to the investment costs, the annual fixed ($C_{O\&M_f}, in \frac{€}{kW}/yr$) and variable ($C_{O\&M_v}, in\ €/kWh$) operating, maintenance and repair costs, which include labor, parts and refurbishment-related costs, are also important for calculating the total lifetime costs of the storage system. Furthermore, end-of-life costs ($IC_{end}, in\ €/kW$), which are discounted to present value terms using a discount rate ($r, in\ \%$) over the service life ($n, in\ years$), are considered.

$$IC_{end_{dis}} = \frac{IC_{end}}{(1+r)^n} \qquad (€/kW) \qquad (6)$$

To annualize the investment costs the capital recovery factor (α) is calculated. This factor is determined using the service life and the discount rate applied.

$$\alpha = \frac{(1+r)^n \cdot r}{(1+r)^n - 1} \qquad (7)$$

With all calculated parameters, including the respective full-load hours ($FLH, in\ hours$), the electricity costs (average energy purchase price at market rate) ($C_{ele}, in\ €/kWh$) and the round-trip efficiency of the storage system ($\eta_{sto}, in\ \%$), the total lifetime storage costs ($C_{sto}, in\ €/kWh$) per kWh from different storage systems can now be calculated.

$$C_{sto} = \frac{(IC_{sto} + IC_{end_{dis}}) \cdot \alpha + C_{O\&M_f}}{FLH\ \eta_{sto}} + \frac{C_{ele} + C_{O\&M_v}}{\eta_{sto}} \qquad (€/kWh) \qquad (8)$$

The future full-load hours and electricity costs are extrapolated from the model outcomes of previous scenario calculations (refer to Section 3.1). Hence, the resulting full-load hours (FLH) as model outcomes are presented in Table 8 and were calculated by dividing the energy discharged ($E_{out}, in\ MWh$) by each technology for each year through the installed capacity ($P_{sto\_max}, in\ MW$) of the respective technology:

$$\text{FLH} = E_{out} \,/\, P_{sto\_max} \qquad \text{(h/yr)} \qquad (9)$$

Table 8: Full-load hours modeling results according to scenarios

Scenario	*Policy (A)*		*Renewables and electrification (B)*		*Efficiency (C)*	
Year	2030	2050	2030	2050	2030	2050
Pumped storage hydro	1606	1777	1165	2599	1687	1461
Lithium-ion batteries	577	417	401	646	576	379
Electrolyzer	3201	3210	2447	5120	3458	2685
Re-electrification	2704	1788	2067	690	2922	2265

The respective average electricity prices for 2030/2050 were derived for the *policy* scenario *(A)* at 64/44 €/MWh, for the *renewables and electrification* scenario (B) at 62/39 €/MWh and for the *efficiency* scenario *(C)* at 60/46 €/MWh. These values serve as the input parameters for the economic model in this work. The total costs of storage for the year 2023 are calculated using the average day-ahead spot market price for 2023 (102 €/MWh) (Fraunhofer ISE, 2024b), along with the data on full-load hours from Haas et al. (2022a).

Based on the assumptions in the literature, the efficiency and service life of respective storage systems are determined. The real discount rate is held constant (García-Gusano et al., 2016; Steinbach and Staniaszek, 2015) and is assumed to be 5% following Blakers et al. (2021). All storage technologies are assessed using the same methodology without asserting specific risk profiles. The input data for the economic analysis are detailed in the following tables, along with their respective sources. Parameters are collected from both scientific literature and industry reports. Potential taxes or subsidies are not taken into account. Table 9 provides a summary of the various assumptions concerning technical parameters utilized in this work. The E/P ratio is chosen based on model parameters and assumptions.

Table 9: Summary of the technical parameters used in this research (2030/2050)

Parameter	Power capacity (MW)	Energy capacity (MWh)	Round-trip efficiency (%)	Service life (years)	Source
Pumped storage hydro - small	100	1000	79	60	(Viswanathan et al., 2022; Webb, 2018)
Pumped storage hydro - large	1000	10000	79	60	
Lithium-ion battery - small	1	2	90	16	(Lovegrove et al., 2018; Viswanathan et al., 2022)
Lithium-ion battery - large	10	20	90	16	
Lead-acid battery - small	1	2	85	10	(European Commission. Directorate General for Energy. et al., 2023; Viswanathan et al., 2022)
Lead-acid battery - large	10	20	85	10	
Underground hydrogen storage - small	20	20000	37/46	25	(European Commission. Directorate General for Energy. et al., 2023; Lovegrove et al., 2018; Welder et al., 2019)
Underground hydrogen storage - large	500	500000	37/46	25	

The underlying principle of the respective storage systems was that batteries serve as short-term, PSH as medium-term and hydrogen as long-term storage. Consequently, different E/P ratios were used and therefore, do not allow a direct cost comparison of the storage systems, but must be placed in relation to the respective area of operation. To show that the areas of operation of the technologies were chosen to be advantageous for the cost development in each case, the total investment costs for a uniform E/P ratio of 2 to 24 are shown in Figure 32 for comparison. Particularly important is the increase in total investment costs for both battery storage types with increased energy capacity, attributed to the higher influence of energy over power components. Hydrogen storage emerges as a long-term solution, with only minor changes in total investment costs relative to energy capacity expansion due to its minor energy component costs. The optimal use for long-term storage can be clearly seen here.

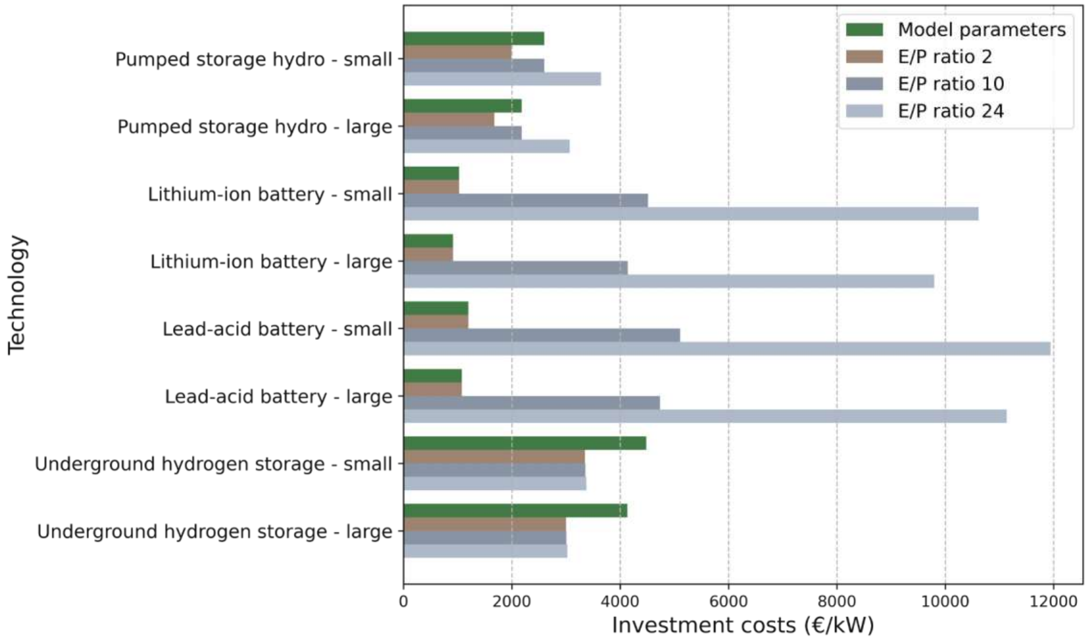

Figure 32: *Total investment costs according to selected E/P ratio of the respective storage system (real value €2023)*

The costs of the investigated storage systems were selected from the literature as outlined in Table 3 and are summarized in Table 10. All costs were converted to €2023 (OeNB, 2023) and adjusted for inflation (Inflationtool, 2024). It must be noted that obtaining reliable data for investment costs from literature is challenging. Often, the specifics regarding the plant size to which the cost data relate, the components included (e.g., solely battery pack or entire system) and the origin year of these data are not clearly specified. Additionally, investment costs differ by region due to varying technical standards and conditions (IEA, 2023a). In this analysis, efforts were made to utilize cost data from Europe and North America, as they best reflect Austrian requirements.

Table 10: Summary of the economic parameters used in this research (real value €2023)

Parameter	Specific investment costs power (€/kW)	Specific investment costs energy (€/kWh)	Fixed O&M costs (€/kW /yr)	Variable O&M costs (€/MWh)	End of life cost (€/kW)	Source
Pumped storage hydro - small	1844	75	28	0.95	20	(European Commission. Directorate General for Energy. et al., 2023; Schill and Zerrahn, 2018; Schmidt and Staffel, 2023; Viswanathan et al., 2022)
Pumped storage hydro - large	1549	63	15	0.95	20	
Lithium-ion battery - small	154	436	3.13	1.09	20	
Lithium-ion battery - large	104	404	2.56	1.09	20	
Lead-acid battery - small	223	488	3.91	1.00	20	
Lead-acid battery - large	164	457	2.87	1.00	20	
Underground hydrogen storage - small	3347	1	28.78	2.02	20	(European Commission. Directorate General for Energy. et al., 2023; IEA, 2023a; Lovegrove et al., 2018; MIT, 2022; Viswanathan et al., 2022; Welder et al., 2019)
Underground hydrogen storage - large	2996	1	24.71	2.02	20	

4.1.2. Investment cost calculations by means of technological learning

The main methodology employed in the literature for calculating technological learning is the one-factor approach. This approach calculates future cost reductions as a function of cumulative production expressed by cumulative installed capacity and a constant learning rate over certain market phases throughout distinct market phases, a methodology also used in this work. Mathematically, technological learning can be calculated using the cost function:

$$IC(x_t) = IC(x_{t_0}) \cdot \left(\frac{x_t}{x_{t_0}}\right)^{-b} \qquad (€/kW) \qquad (10)$$

In this model, investment costs of one unit at time t ($IC(x_t), in\ €/kW$)) decline as cumulative output at time t ($x_t, in\ kW$) rises. It is essential to have data on the investment cost of one unit at the time t_0 ($IC(x_{t_0}), in\ €/kW$) and the total output at the time t_0 ($x_{t_0}, in\ kW$). The cumulative output can be viewed as the installed capacity of a technology at time t, which can be represented by a diffusion curve. For instance, in the case of storage systems, we consider the overall global installed capacity. The exponent $-b$ in this formula characterizes the "learning effect" and is utilized in determining the learning rate (LR). The learning rate signifies a consistent percentage reduction in investment costs, with each doubling of cumulative installed capacity.

$$LR = 1 - 2^{-b} \tag{11}$$

For more detailed calculations, we can split the investment costs of the technology into conventional ($IC_{Con}(x_t), in\ €/kW$) and new components ($IC_{New}(x_t), in\ €/kW$) using the formula:

$$IC(x_t) = IC_{Con}(x_t) + IC_{New}(x_t) \qquad (€/kW) \tag{12}$$

The conventional "mature" components are typically associated with lower learning rates due to their larger "knowledge stock," thus not showing any observable learning effects. The new components reflect the innovative new technology components. This can further be broken down into national and international effects, where $IC_{New}(x_{Nat_t})$ (in €/kW) denotes the specific national share and $IC_{New}(x_{Int_t})$ (in €/kW) the international share:

$$IC_{New}(x_t) = IC_{New}(x_{Nat_t}) + IC_{New}(x_{Int_t}) \qquad (€/kW) \tag{13}$$

The learning rates utilized in this work, along with their respective sources, are presented in Table 11. Table 12 displays the future cumulative storage capacities considered in the model calculations. The data encompass a global geographic scope. For underground hydrogen storage the component-based approach, wich is being used for newer technologies is employed. The technology is divided into various components or subareas and the learning effects are then calculated based on the experiences of the component or another component related to it. Ultimately, the learning curve is the result of the sum of all analyzed components (Rubin et al., 2015). In this case each component—electrolyzers, re-electrification and underground storage reservoir— is examined due to significant discrepancies in the literature regarding the assumptions made about hydrogen storage. Some studies solely address the power-to-gas process (costs of electrolyzers), while others consider small above-ground storages within the framework of fuelling stations, etc., without re-electrification and still, others calculate re-electrification with fuel cells. Therefore, the components are calculated separately. For the other storage technologies, an average learning rate is assumed that includes all new parts of the technology. Regarding the scope of the learning rate, it is assumed that no or even negative further learning rates are factored in for PSH, given that it is already a fully mature technology, where additional learning effects are challenging to attain.

Moreover, prices for PSH systems are anticipated to persistently increase, primarily due to the scarcity of sites with feasible costs and a lack of widespread acceptance. Conversely, it is anticipated that the prices of hydrogen storage and battery technologies will decrease due to learning effects, mass production, standardization and spillovers. This projection is supported by the International Energy Agency (IEA, 2020a), which anticipates high learning rates not only for batteries but also for other small, simple, modular and adaptable designs such as electrolyzers and fuel cells. However, recent increases in materials and labor costs, particularly in Europe due to high inflation, have led to rising costs of electrolyzers (IEA, 2023a).

Table 11: *Learning rates in % used in this research for new components of each storage technology*

Parameter	High	Source	Low	Source
Pumped storage hydro	0	(Viswanathan et al., 2022)	-2	(Kittner et al., 2020)
Li- ion batteries	18	(RMI, 2019)	16	(Kittner et al., 2020)
Lead-acid batteries	10	(Kittner et al., 2020)	4	(Kittner et al., 2020)
PEM Electrolyzers	15	(Böhm et al., 2019; IRENA, 2020b)	12	(Detz and Weeda, 2022)
Hydrogen re-electrification	12	own assumption	10	(Viswanathan et al., 2022)
Underground storage reservoir	15	(Talukdar et al., 2024)	15	(Talukdar et al., 2024)

Table 12: *Future cumulative storage capacities**

Parameter	Unit	2023	2030	2040	2050	Source
Pumped storage hydro	GW	179	211	213	213	(EIA, 2023b; IEA, 2023b)
Battery storage	GW	58	126	388	945	
Lithium-ion batteries	GW	49	107	328	800	(DOE, 2024; IEA, 2023b)
Lead-acid batteries	GW	1.0	2.5	7.7	18.8	
Electrolyzers - PEM	GW	0.9	56	558	982	(IEA, 2024, 2023a; Statista, 2024)
Hydrogen electricity generation (by CCGT)	GW	0.03	4	52	100	(IEA, 2023a), own assumption
Underground storage (depleted gas reservoir)	TWh	0.24	5	18	30	(IEA, 2023a)

(*The underground hydrogen storage is being investigated by each component separately, namely electrolyzers, re-electrification and underground storage reservoir.)

4.2. Results

4.2.1. Future investment cost analysis

The future investment cost development of storage technologies is being calculated using the technological learning approach. This is carried out for scenarios with both low learning rates (Figure 33) and high learning rates (Figure 34). In both figures, investment costs are plotted against the cumulative installed capacity of the analyzed storage technologies, with the latter depicted on a logarithmic scale. This methodology provides an objective, evidence-based overview of potential future cost trends.

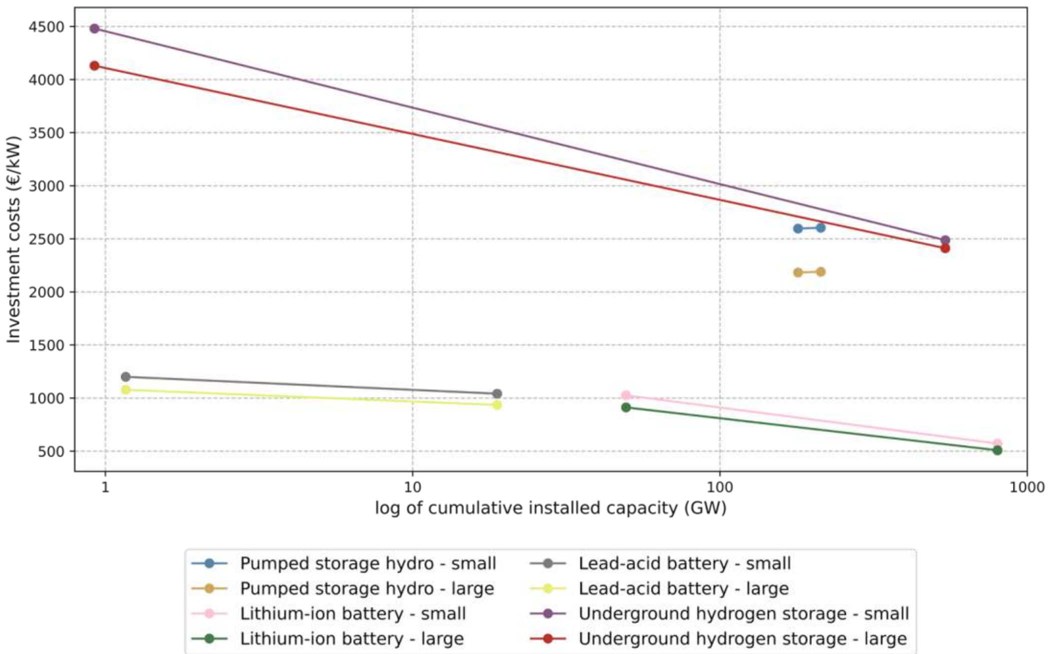

Figure 33: Investment cost reductions depending on the cumulative installed capacity of analyzed storage technologies with low learning rates (corresponding learning rates and cumulative installed capacities as documented in Table 11 and Table 12)

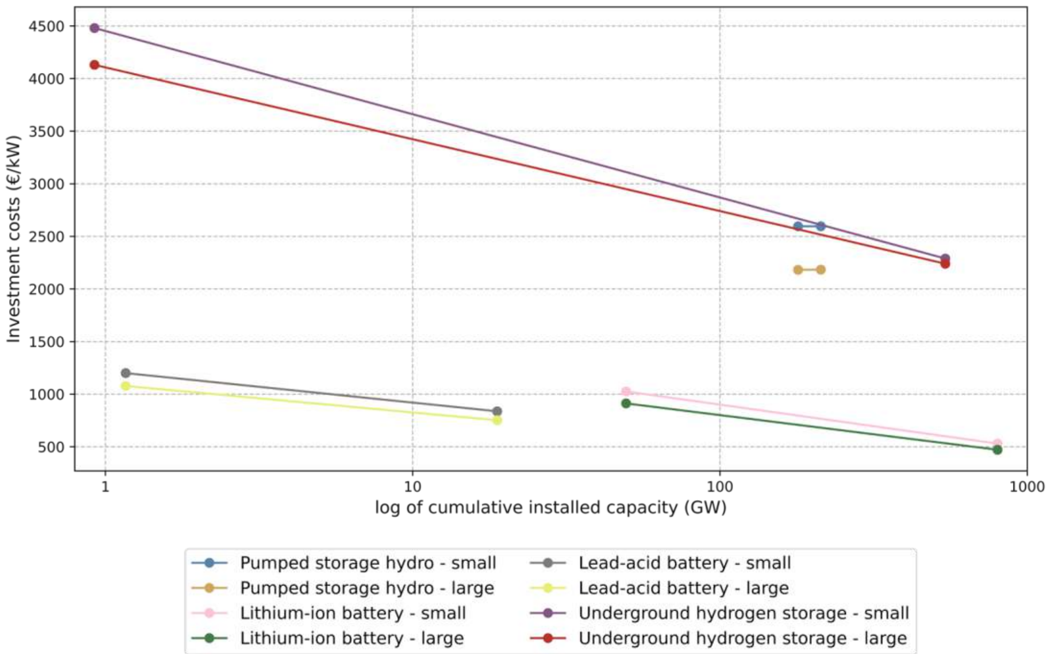

Figure 34: *Investment cost reductions depending on the cumulative installed capacity of analyzed storage technologies with high learning rates (corresponding learning rates and cumulative installed capacities as documented in Table 11 and Table 12)*

Cost reductions are observed across all technologies except for PSH. This is attributed to the absence of further or negative learning effects (0% low and -2% high) assumed for PSH, as it is considered a mature technology. Moreover, it is assumed that prices may rise due to the spatial constraints of conventional PSH, as many suitable locations have already been developed, leading to challenging social acceptance. Additionally, PSH is already the most deployed technology (179 GW worldwide in 2023) and doubling the installed capacities would be difficult to achieve. It is estimated that PSH capacities will reach approximately 213 GW by 2050. Hence, the results of PSH development are plausible. Regarding battery capacities, lead-acid batteries show lower cost reductions compared to lithium-ion batteries. This is mainly due to the expected lower expansion of installed capacities. Currently, approximately 1 GW of lead-acid batteries are available in 2023, which is expected to increase to about 19 GW by 2050. The learning rates of lead-acid technology are also reported to be lower in the literature (4% low and 10% high), resulting in lower learning effects compared to lithium-ion batteries. It is expected that lithium-ion will be the dominant battery technology in the future energy system, with corresponding capacity expansions expected (from 49 GW in 2023 to 800 GW in 2050), leading to an approximate halving of the investment costs of lithium-ion batteries with the respective learning rates. These rates are 16% in the low scenario and 18% in the high scenario.

The most substantial cost reductions occur in hydrogen storage, comprising of electrolyzers, underground storage and hydrogen turbines for re-electrification. Approximately 1 GW of PEM electrolyzers were already in use in 2023, but only 0.03 GW of CCGT turbines were for electricity conversion. However, existing natural gas turbine know-how can already be applied to the turbines, reducing the "new technology" part of it but resulting in lower overall costs. Consequently, the largest cost reductions are expected in electrolyzers, partly due to their relatively homogeneous nature and also because of the planned expansion (982 GW of PEM electrolyzers by 2050), which is significant. While these will not be exclusively used for hydrogen storage with electricity conversion, resulting cost effects will also reduce overall hydrogen storage costs. Calculations are performed using the three components and learning rates, namely electrolyzers (12% low and 15% high), underground storage (15% for both) and hydrogen turbines (10% low and 12% high). The learning rates per scenario and the assumed installed capacities, including sources, are summarized in Table 11 and Table 12.

When examining the cost development of storage technologies in Figure 35 and Figure 36 over the period from 2023 to 2050, the mentioned effects become even more apparent. The costs of PSH remain nearly unchanged or have increased. Due to significant cost reductions in underground hydrogen storage, cost parity between PSH and hydrogen storage is expected to be achieved from 2038 in the low scenario and from 2032 in the high scenario. By 2050, underground hydrogen storage costs in both scenarios are projected to be lower than those of small PSH and higher than those of large PSH. A substantial cost reduction of underground hydrogen storage is anticipated until 2030, attributed to increasing capacity expansions, followed by a slight flattening of this cost reduction curve. Overall, underground hydrogen storage costs are expected to decrease by 44% (small system) and 42% (large system) in the low scenario and by 49% (small system) and 46% (large system) in the high scenario between 2023 and 2050. Regarding battery storage, it is evident that lithium-ion batteries experience greater cost reductions, thus maintaining investment costs below those of lead-acid batteries over time. The cost gap between the two widens in the low scenario. Specifically, lead-acid battery costs are projected to decrease by 13% in the low and 30% in the high scenario and lithium-ion batteries by 44% in the low and 48% in the high scenario between 2023 and 2050. Lithium-ion batteries have demonstrated a remarkable price reduction in recent years, often linked in literature to that of crystalline silicon solar cells. The cost of battery cells has seen a remarkable 97% decrease since 1991 (Ritchie and Roser, 2024). Consequently, it can be inferred that battery technologies (or at least the battery cells) are well suited for cost reductions through technological learning. It should be noted again that this is based on a defined E/P ratio through previous modeling. Altering these E/P ratios will change the investment costs or the relations between individual technologies, as demonstrated in Figure 32. For example, at an E/P ratio of 10, battery technologies are among the most expensive, while at a ratio of 2, they are among the cheapest when investment costs are regarded.

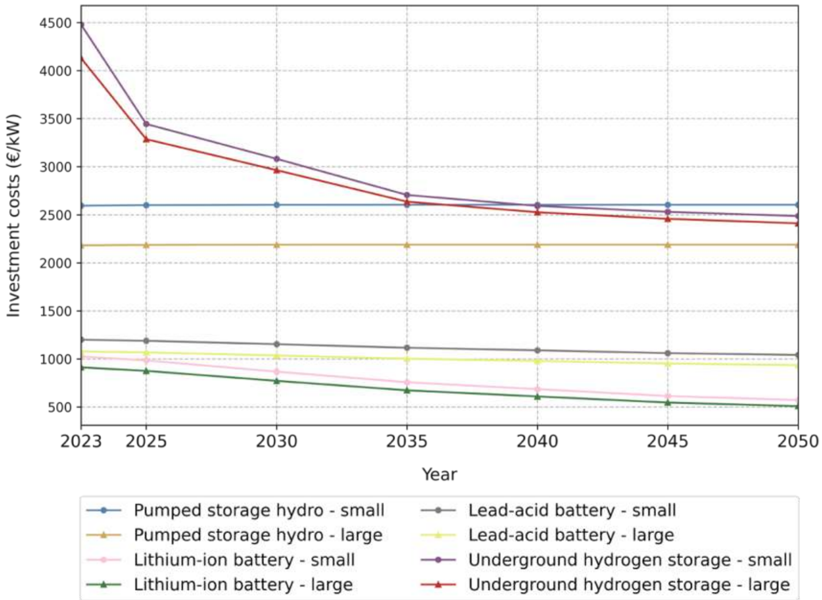

Figure 35: Investment cost reductions per year of selected technologies with low learning rates (corresponding learning rates and cumulative installed capacities as documented in Table 11 and Table 12)

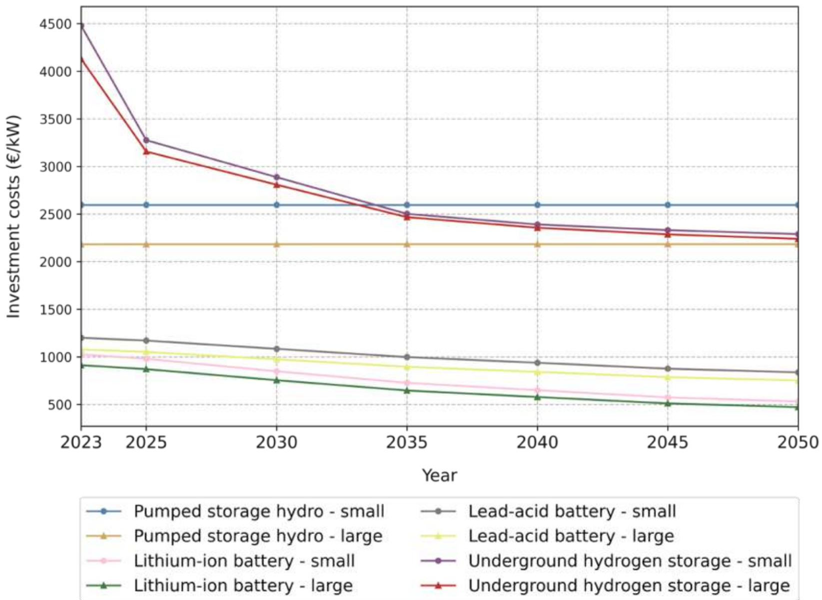

Figure 36: Investment cost reductions per year of selected technologies with high learning rates (corresponding learning rates and cumulative installed capacities as documented in Table 11 and Table 12)

The calculated values of future investment costs are then further utilized in the subsequent analysis. However, it must be noted that extrapolating into the future is subject not only to the uncertainty of the derived rates but also to uncertainties associated with unforeseeable future changes. These may include technological breakthroughs, knowledge spillovers and shifts in raw material prices, all of which can fundamentally alter the rate of cost reduction (Schmidt and Staffell, 2023). Consequently, they cannot be used for short-term precise price forecasts. Nonetheless, this method provides a solid foundation for estimating future costs for long-term scenarios depending on the assumptions.

4.2.2. Total cost of storage in a decarbonized electricity system

In a further step, the total costs of storage are now calculated. Starting from the year 2023, as shown in Figure 37, calculations for the years 2030 and 2050 are conducted for the *policy (A)*, *renewables and electrification (B)* and *efficiency (C)* scenario. In 2023, there is a wide range of total costs among different technologies, ranging from 0.22 €/kWh (PSH large) to 0.8 €/kWh (underground hydrogen storage small). However, the influence of system size is also evident. Larger systems lead to lower total costs of storage for all storage technologies due to lower investment costs. The largest cost differences between small and large systems are observed in battery storage systems. Figure 37 provides a breakdown of capital, O&M and energy costs. In absolute terms, underground hydrogen storage shows the highest costs in all three areas in 2023. This is attributed to high investment costs and low roundtrip efficiency, resulting in higher electricity costs for storage In contrast, PSH exhibits the lowest costs, owing to its relatively high efficiency, low investment costs and long service life of equipment. Proportionally, energy costs represent the largest cost component for PSH in 2023 (52-58% of total costs). For all other examined technologies, it is the investment costs, accounting for 50-60% for lithium-ion batteries, 65-64% for lead-acid and 57-59% for underground hydrogen storage. For PSH, it is only 37-39%. Notably, electricity prices in 2023 remained relatively high, whereas earlier calculations before 2021 featured significantly lower electricity costs.

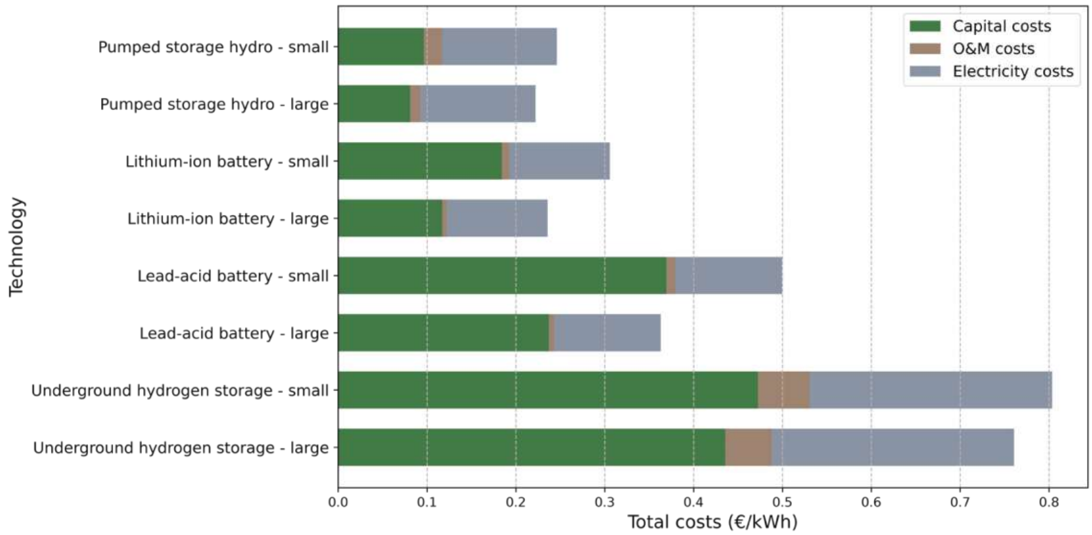

Figure 37: Total storage costs in €/kWh for each analyzed technology divided into capital, O&M and energy costs in 2023 (corresponding technical and economic parameters as documented in Table 9 and Table 10)

Using the calculated future investment costs, the respective scenario assumptions and resulting full-load hours (Table 8) as well as electricity prices per scenario, the future total costs of storage for the year 2030 are computed in Figure 38 and for the year 2050 in Figure 39. These analyses are based on the investment cost development from the high learning rates scenario. In addition to the reduction in investment costs, an efficiency improvement in underground hydrogen storage has also been considered. Due to the reduction in investment costs and the lower electricity prices compared to the year 2023, a decrease in storage costs can already be observed. PSH large remains the most cost-effective technology in all scenarios, with costs ranging from 0.18-0.22 €/kWh in 2030 and 0.11-0.17 €/kWh in 2050. However, large lithium-ion batteries are also becoming increasingly economical, with a cost range of 0.2-0.25 €/kWh in 2030 and 0.12-0.17 €/kWh in 2050 due to investment cost reductions and high efficiencies of the technology. Underground hydrogen storage has been replaced by lead-acid batteries small, as the most expensive technology. In 2030, initially, only in the renewables and electrification scenario with 0.5 €/kWh, but in 2050, across all scenarios with a range of 0.25-0.41 €/kWh. Underground hydrogen storage small costs are between 0.38-0.46 €/kWh in 2030 and 0.24-0.27 €/kWh in 2050. Meanwhile, underground hydrogen storage has slightly lower costs, ranging from 0.37-0.45 €/kWh in 2030 to 0.23-0.27 €/kWh in 2050. For this cost reduction, the lower electricity price plays a role, but since the roundtrip efficiency in 2050 is still only 46%, not comparable to other storage technologies, the strong utilization of electrolyzers and storage in a fully decarbonized energy system largely contributes. Here, hydrogen storage becomes essential for shifting electricity from summer to winter.

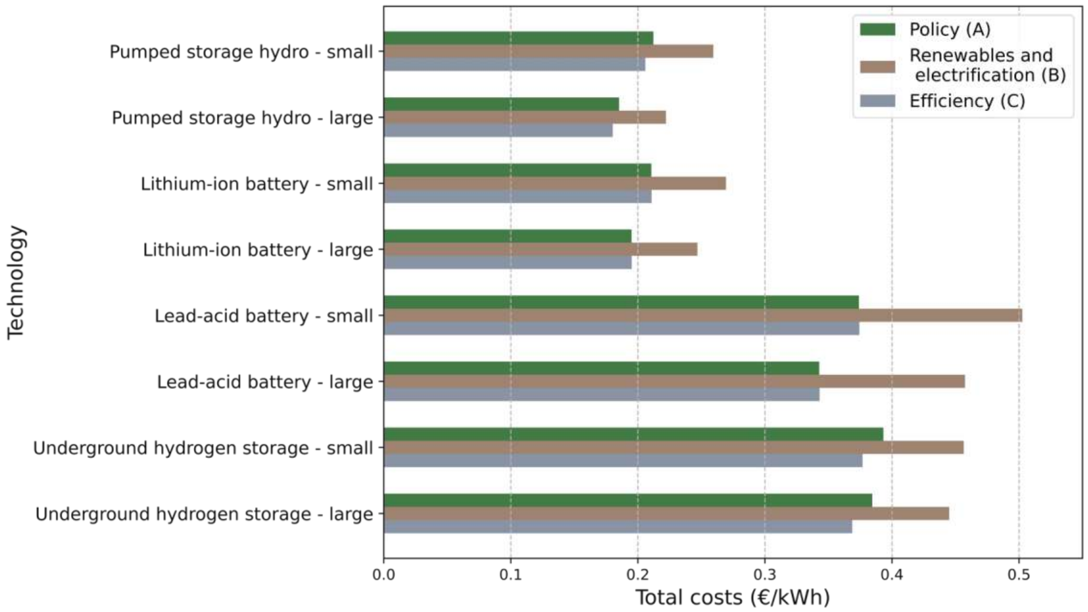

Figure 38: *Comparison of total costs of storage per storage technology and scenario in the year 2030*

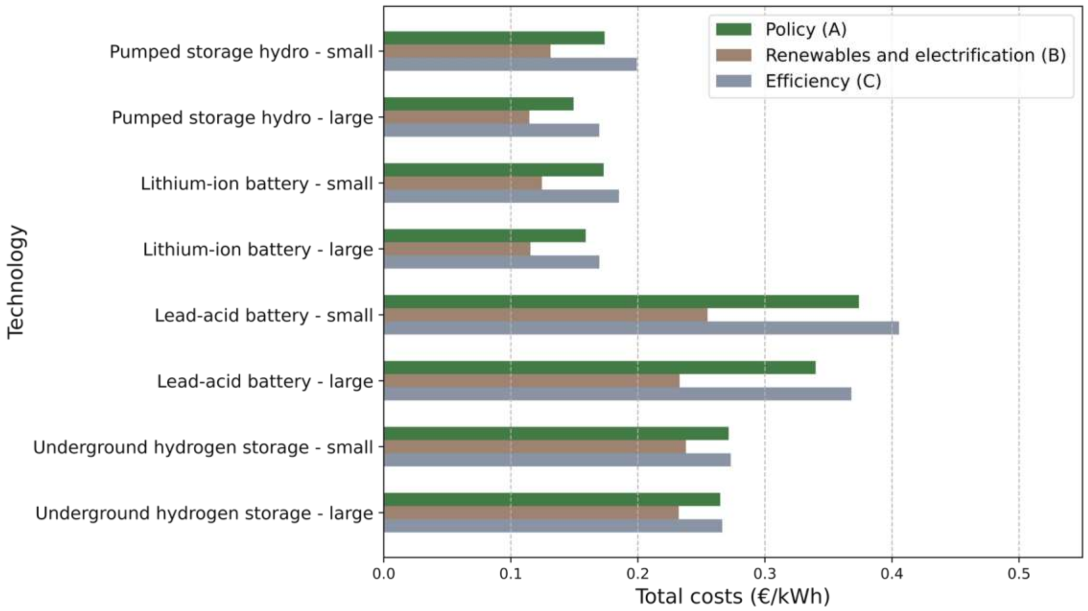

Figure 39: *Comparison of total costs of storage per storage technology and scenario in the year 2050*

Analyzing not only technologies but also a scenario comparison is of interest. Overall, in 2030, the highest total costs of storage occur in the *renewables and electrification* scenario *(B)* for all technologies. The reason for this is the higher deployment of underground storage technologies, leading to lower utilization of all storage technologies. However, this scenario assumes a higher overall electricity demand in the energy system and a higher expansion of renewable energy generation. With this background, a higher capacity of long-term storage is necessary to meet the electricity demand at all hours, resulting in higher storage costs. Conversely, the situation shifts in 2050, where the total storage costs in the *renewables and electrification* scenario *(B)* are the lowest. Driven by a further increase in electricity demand (95 TWh) compared to alternative scenarios (80-83 TWh), coupled with the absence of fossil fuel generation, the planned storage capacities are utilized to a bigger extent. In the efficiency scenario, with lower consumption and lower variable renewable generation, the highest storage costs arise due to lower storage utilization. Therefore, optimal planning of storage capacities depending on their necessity in the energy system is important to maximize the utilization of existing storage and reduce overall costs. The detailed results of all scenarios and years are provided in Table 13.

Table 13: Total costs of storage for each analyzed technology per scenario and year in €/kWh

Scenario	*Policy (A)*		*Renewables and electrification (B)*		*Efficiency (C)*	
	2030	2050	2030	2050	2030	2050
Pumped storage hydro - small	0.21	0.17	0.26	0.13	0.21	0.20
Pumped storage hydro - large	0.19	0.15	0.22	0.11	0.18	0.17
Lithium-ion batteries - small	0.21	0.17	0.27	0.12	0.21	0.19
Lithium-ion batteries - large	0.20	0.16	0.25	0.12	0.20	0.17
Lead-acid batteries - small	0.37	0.37	0.50	0.25	0.37	0.41
Lead-acid batteries - large	0.34	0.34	0.46	0.23	0.34	0.37
Underground hydrogen storage - small	0.39	0.27	0.46	0.24	0.38	0.27
Underground hydrogen storage - large	0.38	0.26	0.45	0.23	0.37	0.27

4.2.3. Yearly comparison of total costs of storage

A direct comparison between years is also of interest. When examining the *policy* scenario *(A)*, it is evident that the costs decrease (except for small lead-acid batteries, where they remain the same) for all technologies, as depicted in Figure 40. The reduction in investment costs and declining electricity prices contribute to the reduced total costs per kWh for new storage technologies. It is important to note here that these costs were assumed for an exogenously determined expansion of storage capacity in the underlying storage model and the utilization of the storage (full-load hours) was determined based on these assumptions. However, if there were to be a higher expansion of storage capacities than assumed in the scenario development (see Table 5), this would reduce the full-load hours of the assumed capacities and lead to what is known as 'self-cannibalism'. That is to say, each new storage unit added would have fewer full-load hours than the previous one, thereby decreasing the price spread and, consequently, its own economic efficiency (Ehlers, 2011).

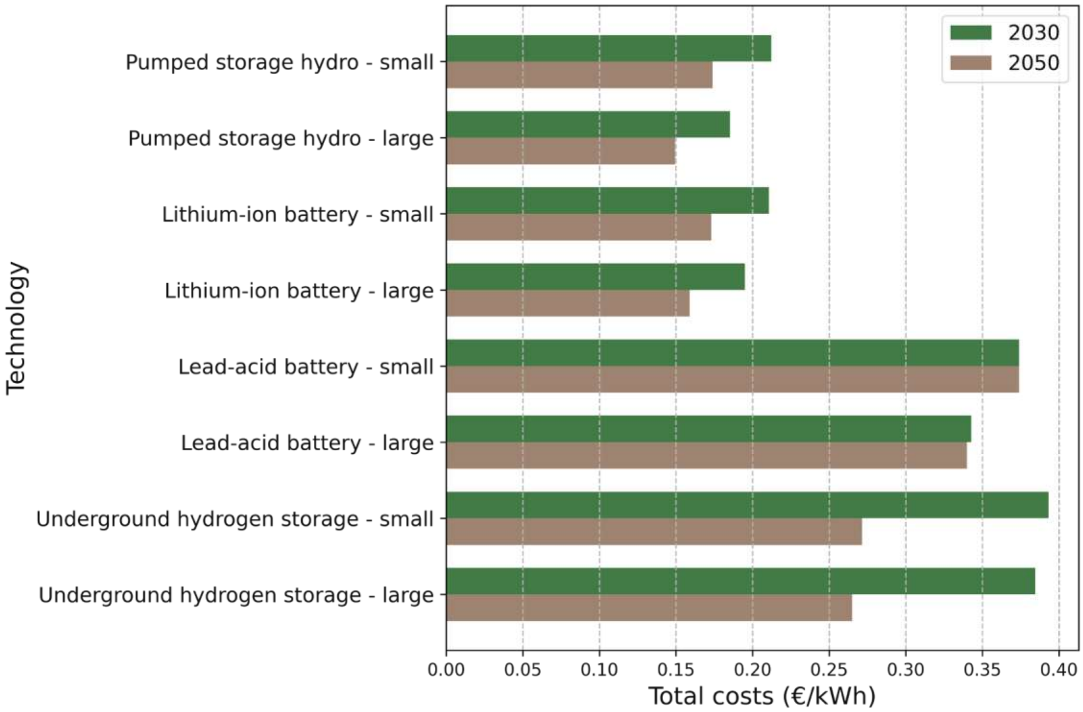

Figure 40: Comparison of total costs of storage between 2030 and 2050 for the policy scenario (A)

This relationship between the full-load hours of storage and total costs is illustrated in Figure 41. When examining the overall storage costs of underground hydrogen storage, they are approximately five times higher at 500 full-load hours per year compared to 2500 full-load hours per year. Although not as strong, this influence is also noticeable with other technologies. This is crucial because full-load hours directly influence investment costs, which constitute the majority of total storage costs. The lower the annual utilization of the storage, the higher the total storage costs. Full-load hours in the range of 1500 appear to be necessary for the profitable operation of storage systems.

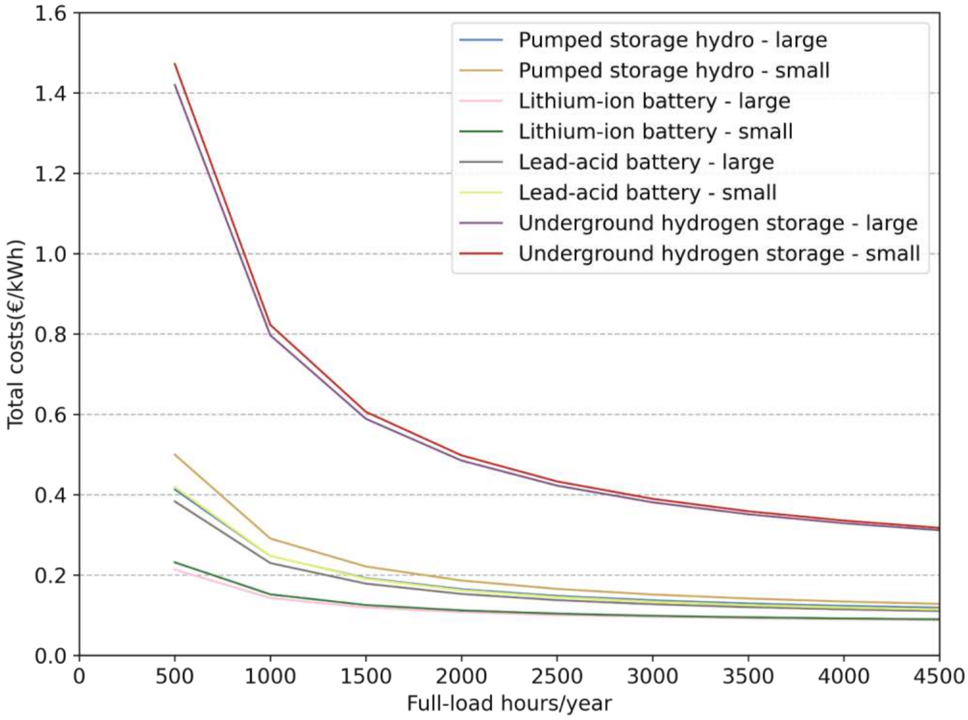

Figure 41: *Total costs of storage related to the number of annual full-load hours for the policy scenario (A) 2030*

Figure 42 and Figure 43 present the trajectory of total costs of storage in the *policy* scenario *(A)* throughout the year up to 2050 for both learning rate scenarios (low and high). The reductions in costs over the year, as previously demonstrated for investment costs, are once again evident here. The most cost-effective technologies are PHS and lithium-ion batteries. However, it must be noted that the latter are explicitly employed for short-term storage in the model.

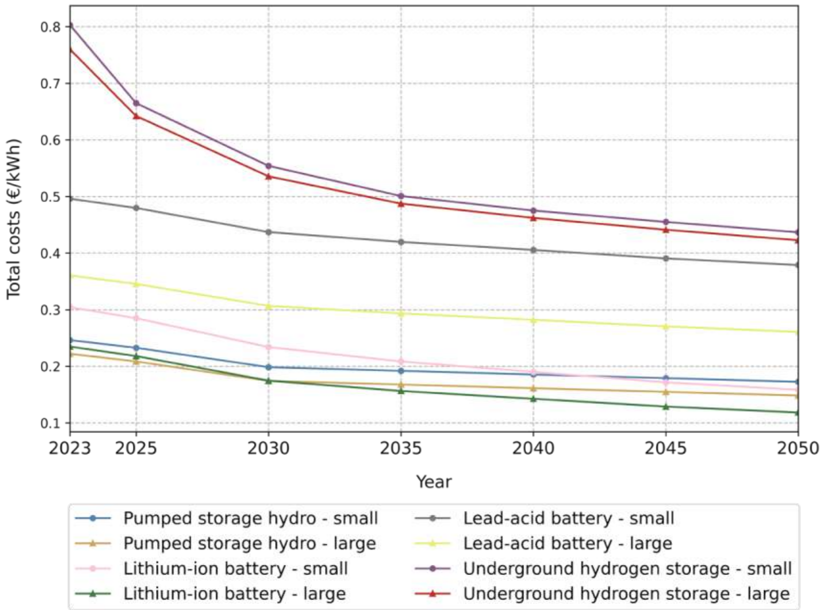

Figure 42: Prospects for the total cost of storage of electricity with selected storage technologies until the year 2050 with low learning rates

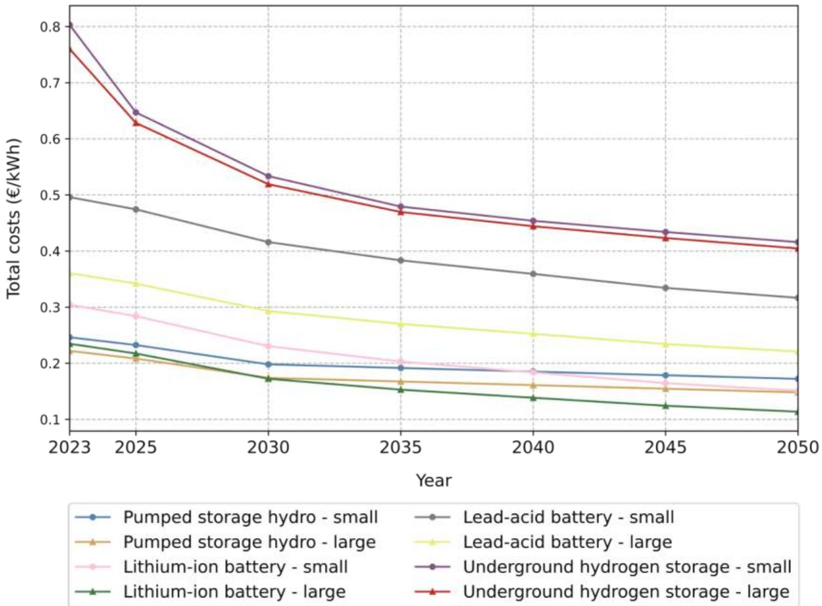

Figure 43: Prospects for the total cost of storage of electricity with selected storage technologies until the year 2050 with high learning rates

5. Options for hydrogen and its techno-economic and environmental implications in the process of energy transition[7]

Hydrogen has already been discussed as a storage option within the electricity sector. In this section, its role will be expanded to other production processes as hydrogen is like electricity, a secondary energy carrier, but it is also an energy vector, which can be used to convert, store and release energy. Hydrogen is largely considered a carbon-neutral energy carrier of the future, often neglecting the rather high energy losses for hydrogen provision—encompassing production, storage, transport and distribution.

As, on earth, hydrogen can be mostly found in molecular forms, it has to be produced from various sources. Currently, hydrogen is mostly used in various industrial applications, such as refining, steel-, ammonia- and methanol production. These industries primarily source hydrogen from hydrocarbons in fossil gas or coal. Over the past few years, the demand for hydrogen has continuously increased. Presently, we are navigating through a phase termed mid-transition (Grubert and Hastings-Simon, 2022), where there is an endeavor to shift towards hydrogen production from renewable energy sources to mitigate emissions. Therefore, the discussion on production technologies is becoming even more imminent, with different players in the energy sector pushing for different solutions. On the one hand, hydrogen produced with steam methane reforming (SMR) or coal gasification adding carbon capture, utilization and storage (CCUS) is from certain players praised as an essential bridging technology in the transition to a sustainable hydrogen economy (Oni et al., 2022). On the other hand, others argue that only hydrogen from electrolysis with electricity from RES shows clear environmental benefits compared to using fossil fuel directly or indirectly for hydrogen production (Howarth and Jacobson, 2021; Longden et al., 2022). And on top of that, there is the discussion if green hydrogen should be imported from countries with favorable renewable electricity generation conditions, resulting in higher full-load hours of the electrolyzers but having higher transport costs and hydrogen losses on the way, or if the hydrogen should be locally produced in the country of use (Merten et al., 2020).

Therefore, the core objective of this work is to investigate the techno-economic and the environmental impacts of four defined hydrogen production chains (grey, blue, yellow,

[7] This chapter is based on Sayer et al. (2024c).

green). In the case of a production location outside of the designated hydrogen hub, the two main hydrogen transport possibilities (pipeline and ship) from North Africa to Europe are analyzed. The specific investment costs of the hydrogen plant, the full-load hours per year, the electricity or fossil fuel price and the costs of the respective hydrogen transport method play an important role and they are included in our calculations. The major contribution of this work is to show which production methods at which locations, including the required transport, are currently most promising from an economic and ecological point of view. This means that hydrogen transport is only available to a limited extent and is associated with higher costs compared to studies that focus on the future. In detail, we intend to answer the following research question: "*What are the techno-economic and environmental implications of different hydrogen production methods and locations and which combination is most promising for a sustainable hydrogen economy in Europe?*"

To answer this question, selected hydrogen production chains and possible transport technologies and routes are analyzed. In the analysis of hydrogen transport, the focus lies on longer-distance transportation since the distribution part is the same for all hydrogen production options. Therefore, two transport options, transport via pipeline and transport by ship, are analyzed in more detail. In the latter's case, two further process steps are necessary, namely liquefaction and reconversion, which will be discussed in more detail.

This section is based on the work of Sayer et al. (2024c) and is outlined as follows: Section 5.1 covers the state of the art of production and transportation costs and environmental analysis of hydrogen production and transportation. Following this, Section 5.2 describes the methods applied, detailing the techno-economic analysis and environmental assessment. The results are then presented in Section 5.3. In Appendix F of this thesis, a detailed account of the background of hydrogen can be found, including its history, current status, production in the European Union and the global market, production technologies (the different colors of hydrogen) and the potential uses of hydrogen in various sectors.

5.1. State of the art on production and transportation costs and environmental analysis of hydrogen

The recent surge in interest in hydrogen, as evidenced by the comprehensive works of the International Energy Agency (IEA, 2019a, 2023a) and the International Renewable Energy Agency (IRENA, 2022b, 2020b), underscores the need for a more focused examination of production and transportation costs. Existing studies primarily focus on either a single technology, only production or transportation issues, or provide an economic or environmental analysis. Studies that examine all aspects within one work and also include different production sites (within the analyzed country and imports) could not be found. The following overview thus first addresses studies from recent literature that combine the cost aspect of hydrogen production and emissions, followed by an analysis of separate parts mentioned above. From each part, where relevant to this work, conclusions were drawn to also compare to the main findings in the result section of this work (Section 5.3). For that, it has to be noted that, in general, studies vary significantly regarding the hydrogen production technologies and locations they analyze and the supply chain components they cover (e.g., to include or not include storage or distribution).

Newborough and Cooley (2020) conducted one of the key studies on the primary production techniques and all related issues, including the costs and emissions. They conclude that green hydrogen generation will become more affordable than alternatives, such as blue hydrogen as a result of less expensive renewable power and electrolyzers. They also highlight green hydrogen as the most environmentally friendly option. A possible cost reduction of hydrogen production via electrolysis to 2 €/kg H_2 in the year 2040 is being calculated by Terlouw et al. (2022), making it competitive with SMR, even under historically low gas prices. Considering recent price increases, electrolysis could become economically viable sooner. Regarding emissions, it is found that purely renewable production causes the least emissions. However, a hybrid approach combining electrolyzer operation with wind energy and grid electricity from a renewable mix is deemed most advantageous for cost-effective and environmentally friendly production (Terlouw et al., 2022).

Oni et al. (2022) focus specifically on the economic and environmental analysis of blue hydrogen production methods such as SMR, autothermal reforming and fossil gas decomposition, indicating that autothermal reforming results in lower emissions. However, since only blue hydrogen production technologies are compared, no conclusions can be drawn regarding the comparison of different production methods. Carbon capture and storage (CCS) specifically for hydrogen production from coal in China is being studied by Li et al. (2022) and show very high CO_2 savings compared to other studies. The cost due to CCS increases the process cost by about 44-60%. In summary, renewable hydrogen production shows the lowest emissions when compared comprehensively with common production technologies, with a positive outlook for future cost reductions in electrolyzers. However, emission estimates and conclusions vary widely depending on calculation methods and assumptions. For example, Li et al. (2022) estimate emissions ranging from 4.92 to 10.90 kg CO_2/kg H_2 for coal-based hydrogen production after CCS installation, suggesting that those emissions are close to those from solar electricity-based hydrogen production. In contrast, Longden et al. (2022) calculate emissions ranging from approximately 8 (bituminous coal) to 5 (lignite) kg CO_2/kg H_2, leading to different conclusions, namely that hydrogen generated using fossil fuels is incompatible with the switch to a sustainable energy system. Even when a portion of the emissions are caught for blue hydrogen, significant fugitive methane emissions occur, which most analyses do not account for. They claim that electrolysis will become considerably cheaper in the future.

Bartels et al. (2010) undertook a purely economic examination of several production technologies and concluded that grey hydrogen was the most cost-effective way at the time of the investigation. However, they note that other approaches may become less expensive in the future. Yukesh Kannah et al. (2021), who present a techno-economic review of several production technologies, continue to recommend SMR as the most cost-effective way of production. The production, though with SMR but with additional CO_2 capture, is investigated by Pruvost et al. (2022). They conclude that an 80% capture rate can be achieved cost-effectively before combustion. For the missing 20%, the cost increases from 35 €/ton to 150 €/ton and therefore, a capture of the last 20% after incineration is recommended. They also investigate the use of green electricity to run the reformer and conversion to solid carbon (turquoise hydrogen).

Nikolaidis and Poullikkas (2017) examined 14 production processes and discovered that thermo-chemical pyrolysis and gasification have the best possibilities of being competitive in the future. However, since decarbonization of the energy sector is an important goal, green hydrogen production via electrolysis will be essential. For this reason, Shiva Kumar and Lim (2022) present a comprehensive overview of the techno-economic prospects of different electrolysis technologies. Nami et al. (2022) compare hydrogen production with alkaline electrolyzers with production from fossil gas and find that with today's investment costs, a gas price of 30 €/MWh and an electricity price of 30 €/MWh, a CO_2 tax of 90 €/tCO_2 would make hydrogen from alkaline electrolyzers more cost-effective. A general long-term cost reduction of 24% for alkaline electrolyzers and 56.5% for PEM electrolyzers has been calculated by Yang et al. (2023). The main conclusion drawn from the studies regarding the costs of different production processes is that, currently, SMR remains the cheapest option. However, significant cost reductions in electrolysis are anticipated. The success of achieving these reductions will largely depend on the market ramp-up of electrolysis. The pace at which electrolysis is integrated into the market will be pivotal in attaining these objectives.

However, the literature also highlights that the comparison of electrolysis costs with conventional hydrogen production technologies should not be limited solely to costs. Other potential revenue streams, such as oxygen as a byproduct of electrolysis, should also be considered to reduce overall costs. In many instances, when oxygen is integrated into models, it is marketed as a medical gas, as illustrated in Moradpoor et al. (2023), deriving a price of 20 €/ton. Maggio et al. (2022) examine on-site hydrogen production for hospital use and identify numerous benefits stemming from this dual production setup. They suggest that the hospital could achieve independence from external oxygen suppliers and additionally utilize hydrogen as a backup energy source for emergencies. Their analysis suggests that this arrangement could prove cost-effective if the market price of oxygen exceeds 3–4 €/kg. A parallel conclusion is drawn by Squadrito et al. (2021), indicating that an oxygen market price of 3 €/kg is necessary to attain economic viability within a 20-year investment horizon. In addition to the aforementioned conventional production technologies, natural hydrogen is also gaining prominence in scientific discourse. In Lapi et al. (2022), a cost comparison is made between natural hydrogen discovered in Mali and hydrogen produced through SMR and electrolysis from various countries. The analysis clearly demonstrates that natural hydrogen, with costs at 1 USD/kg H_2, emerges as the most cost-effective option. It is noted that this hydrogen discovery benefits from favorable geological conditions in Mali, which may differ in other locations.

Another strain of literature comprises studies investigating the potential of hydrogen imports into Europe. Sens et al. (2022) focus very specifically on the cost of green hydrogen using local production in Europe versus production in North Africa and delivery to a demand center in Germany. They predict a decrease in hydrogen production costs in the well-suited areas from 3 €/kgH_2 to 2 €/kgH_2 in 2050, with very high technical potential in North Africa. Even if transport costs are included, they arrive at hydrogen costs of 3 €/kgH_2 with delivery by pipeline from North Africa, while production in Germany would cost 4.5 €/kgH_2. Timmerberg and Kaltschmitt (2019) deal specifically with the procurement of hydrogen from North Africa but with subsequent blending into existing fossil gas pipelines. That large quantities of hydrogen can be imported into the EU at lower costs than self-production has been demonstrated by Nuñez-Jimenez and De Blasio (2022) in three scenarios spanning up to the year 2050. The authors, however, highlight the importance of avoiding the repetition of existing patterns of energy dependencies in hydrogen and thus advocate for diversification through long-distance imports. Srettiwat et al. (2023) also examine a longer import route, specifically imports from Namibia, in addition to Morocco. They find that, under the given assumptions, imports from Namibia are more cost-effective than local production in Belgium. Contrasting findings are presented in Galimova et al. (2023), which compare production costs in Germany and Finland with the production and transportation costs for hydrogen from Morocco and Chile. The analysis calculates that imported hydrogen will be 39-70% more expensive in Germany and 43-54% more expensive in Finland compared to locally produced hydrogen. Eckl et al. (2022) come to a somewhat more balanced conclusion in their paper, which examines the economic feasibility of supplying solar hydrogen from Portugal to a pipeline in Germany or producing it locally. The analysis reveals significant cost disparities between production in Portugal, with 2.09 €/kg H_2 and Germany at 3.24 €/kg H_2, although the discrepancy diminishes when considering the entire value chain to the delivery point in Germany. This implies that varying assumptions and calculation methods yield markedly different results, which do not present a clear-cut argument either for or against hydrogen imports. This could partly stem from the fact that there is currently no substantial hydrogen trade in operation, as most of the produced quantities are immediately consumed within industrial areas. Even in cases where hydrogen trading occurs, it typically involves a single supplier distributing to various nearby industries (IRENA, 2022b). Nonetheless, the IEA forecasts a significant increase in hydrogen export projects by 2030, with a focus on hydrogen production via electrolysis, constituting 88% of export volumes. The produced hydrogen is intended for direct exports or facilitated by ammonia as a carrier for long-distance shipping (IEA, 2022a).

The IEA's assumptions regarding the anticipated hydrogen trade are also visible in the scientific discourse, particularly within the context of comparing hydrogen and electricity as energy vectors under certain assumptions. D'Amore-Domenech et al. (2021) conclude that water transport in the onshore-to-onshore scenario by hydrogen pipelines is cheaper than electricity under the assumptions of a 2 GW power transmission and a distance of about 1000 km in deep waters. For the offshore to onshore scenario with the 600 MW capacity, there is a lower cost for transport in the power cable. Another comparison of energy volume transport in the form of hydrogen using pipelines or electricity in submarine cables is by Miao et al. (2021). They find that the installation cost of pipelines per km is higher than that of electricity cables but has a higher transmission capacity. The energy losses of power cables are higher, while pipelines generally have higher operating costs due to gas compression. In the cases studied, transportation via pipelines over longer distances was more cost-effective.

Cerniauskas et al. (2020) investigate already available fossil gas infrastructure and the conversion of the German grid to hydrogen transport. The result of the paper is that 80% could be converted and the hydrogen costs would then be reduced by more than 60% in contrast to the construction of new pipelines. Building on lower-cost pipeline transportation, Patel et al. (2022) are exploring a 'Hydrogen Interconnector System' (HIS) for transporting electricity over long distances. The idea is to convert the hydrogen back into electricity at the demand center in gas turbines or fuel cell plants. They compare the proposed system with high voltage direct current systems and find them competitive in 2050. Besides pipeline transport, Rong et al. (2024) extend the analysis to the transportation of compressed gas hydrogen, liquid hydrogen and liquid organic hydrogen carriers in combination with the necessary storage. D'Amore-Domenech et al. (2023) and Graf (2021) investigate additional options like ship transport besides the already discussed transport possibilities. Johnston et al. (2022) especially focus on the shipping route from Australia to Rotterdam and investigate the transport of liquid hydrogen, ammonia, liquified natural gas, methanol and liquid organic hydrogen carriers. The emphasis on liquid organic hydrogen carriers is taken in Reuß et al. (2017), with a focus on smaller quantities of hydrogen and seasonal storage in caverns, while Cui and Aziz (2023) concentrate on transporting hydrogen using methanol and ammonia. The costs of the entire value chain from production to hydrogen transport from electrolysis are analyzed by Martin et al. (2022), with a dynamic cost model based on Norway. In addition to hydrogen, ammonia and efuels are modeled for fuel consumption for long-distance truck transport, short-distance maritime transport and short-distance air transport. They conclude that the best options are hydrogen for long-haul truck transport, ammonia for short-haul maritime transport and hydrocarbon efuels for short-haul air transport. This study has been extended in Martin et al. (2023), where 150 technical-economic parameters were identified that could potentially increase costs. Cost reductions ranging from 41% to 68% for renewable fuels by 2050 were calculated. The review by Faye et al. (2022) also focuses on the entire value chain. The literature review is complemented by a discussion of the state of the art of respective technologies. Meanwhile, Alabbadi et al. (2024) specifically emphasize hydrogen production through nuclear energy, along with its transport and storage. The mentioned options, such as liquid organic hydrogen, methanol and ammonia for simplified transportation, albeit with greater conversion losses, present an alternative to pure hydrogen transport that warrants further exploration in future works, however, it is not being covered in this work.

Numerous researchers, including Ozbilen et al. (2013), Parra et al. (2017), Valente et al. (2017),Sanchez et al. (2020) and Mio et al. (2024), conduct an environmental assessment of greenhouse gas emissions for different hydrogen production methods. Some lay a specific focus on certain technologies, for example, Lotrič et al. (2021) and Zhao et al. (2020) on electrolyzers, Aydin and Dincer (2022), especially on clean hydrogen production methods (including also nuclear electricity), Diab et al. (2022) on turquoise hydrogen and Bauer et al. (2021) and Howarth et al. (2021) on grey and blue hydrogen. According to Howarth et al. (2021), utilizing blue hydrogen releases 18-25% fewer GHG emissions than grey hydrogen but still emits 20% more than using natural gas or coal for heating purposes. The emission accounting is even expanded by Al-Qahtani et al. (2021) to evaluate other environmental issues that arise during production. Moreover, Rinawati et al. (2022) expand the field of study by researching hydrogen-based power generation life cycle assessments.

When counting the emissions during the hydrogen emission process, it becomes evident that green hydrogen through electrolysis is the most environmentally friendly option as per findings of Acar und Dincer (2019) and Ozturk and Dincer (2021), who find that the lowest emissions occur when the electrolyzer is powered by solar. An analysis similar to this one, conducted by Cho et al. (2023), offers location-specific calculations, concentrating on production technologies with potential for commercialization. Wind electrolysis shows the lowest global warming impact among the technologies studied, while biogas reforming demonstrates the highest impact. According to the calculations by Maciel et al. (2023), optimal ecological efficiency is attainable when hydrogen is produced from hydropower, followed by wind and PV sources. Dincer (2012) has previously conducted a thorough analysis of the environmental effects of producing green hydrogen. In summary, while the literature presents varying results regarding the choice of renewable electricity generation with the lowest emissions, all studies concur that only renewable generation truly yields low CO_2 emissions.

Other authors primarily focus on life cycle assessments of hydrogen transportation and distribution, like Lucas et al. (2013), Wulf et al. (2018) and Frank et al. (2021). Tayarani and Ramji (2022) primarily focus on two transportation modes, namely pipelines and trucks and find that all investigated pipeline routes contain lower emissions than similar routes by trucks.

Other authors primarily focus on life cycle assessments of hydrogen transportation and distribution. Tayarani and Ramji (2022) concentrate specifically on two transportation modes, pipelines and trucks and conclude that all investigated pipeline routes contain lower emissions than similar routes by trucks. This consensus on pipelines having lower environmental impacts than truck transportation is evident among the analyzed studies, except for very short transport distances (100 km), as found by Wulf et al. (2018). Transport via shipping was not considered in the mentioned studies. Additionally, Frank et al. (2021) highlight the necessity of preparing hydrogen for transportation by increasing its energy density via compression, liquefaction, or chemical conversion. Liquefaction poses the greatest challenge due to its high energy intensity and dependence on the electricity mix of each country. It is important for future studies to consider these variations depending on where liquefaction occurs.

As evident from the preceding section, many studies of life cycle assessments exist that examine the environmental impacts of hydrogen production at a specific location or assess various transport options separately. However, comprehensive evaluations encompassing the entire hydrogen chain, including production and transport, are scarce in the literature. Three studies were found that focus on such holistic assessments. The most comprehensive study in this regard is conducted by Kolb et al. (2022), which investigates local production in Germany and imports from Chile, Canada and Morocco. The study concludes that, under certain conditions, the emissions of the entire import chain can be lower than those of local production. In the specific case of the base case scenario, emissions from hydrogen sourced from wind in Canada or hydrogen from PV have lower associated emissions. However, it is noted that shipping distance plays a significant role in emissions and the use of grid electricity for hydrogen liquefaction substantially increases CO_2 emissions. Hren et al. (2023) calculate the emissions, energy footprints and acidification eutrophication, human toxicity potential and eco-cost for eleven hydrogen production sources, including the related supply chains and conclude that glycerol and alcohol waste steam reforming and water electrolysis with renewable electricity has the lowest greenhouse gas emissions. The focus of Vilbergsson et al. (2023) lies in comparing Iceland-produced hydrogen with the resulting transport requirement to Austria or Belgium to locally produced hydrogen in the named countries. They conclude that the electricity mix is the most influential part of the emissions, whereas transport emissions do not play a significant role. Therefore, hydrogen production in Iceland emits fewer GHG emissions. The authors calculate higher than average emissions of the respective electricity mix since they assume that when additional hydrogen capacities are built, additional peak capacities (mostly gas-fired power plants) are used and not the share of renewable generation of the respective country. Lee et al. (2022) also conclude that the power mix of the production site plays a critical role.

The existing literature on hydrogen production and transportation presents a comprehensive overview of various technologies and methodologies. A critical observation reveals that only a few studies explicitly compare all facets of production and transportation chains holistically, integrating both techno-economic and environmental analyses. Notably, prior research often overlooks upstream fugitive methane emissions from fossil gas, a crucial factor highlighted by (Parra et al., 2017; Reiter and Lindorfer, 2015; Wulf and Kaltschmitt, 2012). Further, the distinction of different regional production sites for renewable power generation, including possible increased transportation costs due to longer distances, are often not regarded, hence not showing the broader picture of renewable generation costs. Comparisons between local production and imported hydrogen entail different costs and emissions and must, therefore, be examined separately. To our knowledge, such comprehensive analyses comparing production in Austria versus North Africa (Morocco and Tunisia) have not been published previously despite numerous politically motivated discussions on this topic. Given the high uncertainty of many input parameters, particularly in cost estimations, previous studies rarely conduct sensitivity analyses, which are vital for providing comprehensive insights. This work not only presents the main case study but also includes sensitivity analyses with two outlier case studies (low and high costs or emissions), as point estimates could be misleading. All of the aforementioned points are addressed holistically in this work to facilitate a comparison of costs and emissions among the selected chains under the assumed conditions.

5.2. Methodology

The method used in this work is divided into a techno-economic analysis and a carbon emission assessment of defined hydrogen supply chains. For this purpose, four types of production are distinguished depending on the form of energy supplied and whether, in the case of fossil gas, part of the greenhouse gas (GHG) emissions is captured. The processes of SMR (grey), SMR and CCUS (blue), electrolysis with electricity input from the power grid (yellow) and electrolysis with electricity from PV and wind (green) are used and applied according to the color scheme further explained in Appendix F for better visual representation (Figure 44).

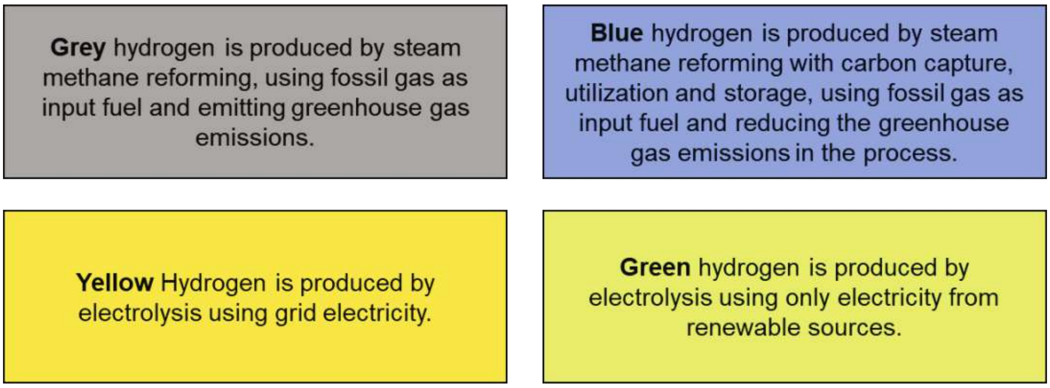

Figure 44: Colors of hydrogen analyzed in this work. (Remark: We distinguish the two researched renewable electricity inputs by applying light green for PV and dark green for wind.)

The production location of the grey, blue and yellow hydrogen is assumed to be in a hydrogen hub, in this analysis in Austria. For green hydrogen, production can be at the hydrogen hub in Austria (local production) and in a country with favorable climatic conditions for renewable electricity production. In the case of PV, Morocco and the case of wind, Tunisia is used since approximate capacity factors of 21 % and 43 % can be achieved, which was derived from Pfenninger and Staffel (2023). Further information can be found in the mentioned references (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016).

Since the different production types and locations are to be compared with each other, the system is simplified. Steps such as storage of hydrogen in the country of consumption, local distribution and hydrogen consumption are not included, as these factors are the same for all supply chains. However, storage that occurs during production, for example, for intermediate storage during electrolysis up to transport, is considered. A graphical representation is shown in Figure 45.

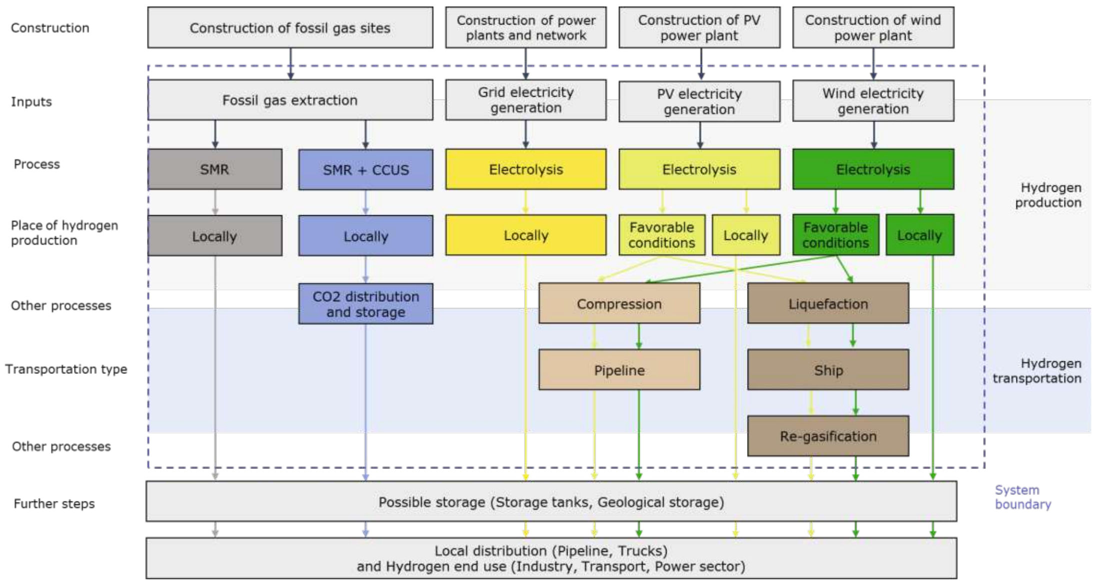

Figure 45: Outline of the investigated hydrogen supply chains and definition of system boundaries

We exclude the emissions that occur during the manufacturing and construction of power plants, fossil gas extraction sites, or hydrogen production facilities for the environmental assessment in line with the European Commission accounting method ("EUR-Lex - Ares(2022)3836721 - EN - EUR-Lex," 2018). In the analysis of transport costs and emissions, only the transport of pure hydrogen (gaseous or liquid) via pipelines or ships is considered. Other hydrogen carriers, such as liquid organic hydrogen carriers or ammonia, are not included, as researched by Niermann et al. (2021) and Hurskainen and Ihonen (2020). Blue hydrogen production also considers all associated costs and emissions of hydrogen capture, transport and storage or use. Here it is assumed that CO_2 cannot be stored permanently in the country of the hydrogen hub due to the legal situation and non-existing CO_2 storage facilities, as it is the case in Austria (Federal Ministry for Sustainability and Tourism, 2019a).

5.2.1. Techno-economic analysis

For the cost comparison of each of the hydrogen production chains, the total hydrogen costs $C_{H2_{Total}}$ are calculated. Those include the costs of each section of the supply chain, namely hydrogen production C_{H2_P}, hydrogen transportation C_{H2_T} and other processes $C_{H2_{OP}}$ as per system boundaries displayed in Figure 45.

$$C_{H2_{Total}} = C_{H2_P} + C_{H2_T} + C_{H2_{OP}} \qquad (€/kg_{H2}) \qquad (14)$$

The production costs (C_{H2_P}) are calculated using the investment costs of the hydrogen production facility ($IC_{Ely/SMR}$ $, in\ €/kW$), other project costs (e.g., compressor, installation, analysis and infrastructure) ($IC_{Other_{Ely/SMR}}, in\ €/kW$), the capital recovery factor (α), the annual operating, maintenance and repair costs ($C_{O\&M_{Ely/SMR}}, in \frac{€}{kW}/yr$), the full-load hours ($FLH_{H2}$) and the fuel or electricity costs ($C_{fuel/ele}, in\ €/kWh$) and the efficiency of the production system (η):

$$C_{H2_P} = \frac{(IC_{Ely/SMR} + IC_{Other_{Ely/SMR}}) \cdot \alpha + C_{O\&M_{Ely/SMR}}}{FLH_{H2}} + \frac{C_{fuel/ele}}{\eta} \qquad (€/kg_{H2}) \qquad (15)$$

and the calculation of α with discount rate (r) and service life (n)

$$\alpha = \frac{(1+r)^n \cdot r}{(1+r)^n - 1} \qquad (16)$$

Production costs of hydrogen in €/kWh $_{H2}$, as calculated in equation (15), are converted into €/kg$_{H2}$ using the energy content of hydrogen (33.33 kWh/kg). This conversion aligns with the typical unit for hydrogen and enhances the clarity of the graphical representation in the results. The cost of fossil gas C_{fuel} is used for grey and blue hydrogen and C_{ele} refers to either the cost of electricity from the power grid (yellow hydrogen), based on average historical cost data or to the cost for electricity from PV and wind ($C_{PV/Wind}$) power plants. The latter is calculated based on the local topological conditions, with different full-load hours ($FLH_{PV/Wind}$) for the locations of Austria (local production), Morocco and Tunisia and the costs are calculated as follows:

$$C_{PV/Wind} = \frac{(IC_{PV/Wind} + IC_{Other_{PV/Wind}}) \cdot \alpha + C_{O\&M_{PV/Wind}}}{FLH_{PV/Wind}} \qquad (€/kWh) \qquad (17)$$

The efficiency of the hydrogen production system (η) is based on efficiency assumptions in the literature on SMR, CCUS and PEM Electrolysis. One limitation of this approach is that the real efficiency of an electrolyzer might fall short of the theoretical maximum efficiency when operating at lower loads. This is referred to as Faraday efficiency, representing the ratio of real efficiency to theoretical efficiency. As the load factor decreases, this efficiency also reduces (Ramsebner et al., 2024). Given the model's scope and the choice of a PEM electrolyzer, which exhibits smaller reductions in efficiency at lower loads, an average efficiency value was utilized for the calculations. In the calculations, a uniform interest rate was used for simplification without considering individual risk profiles, which represents another limitation of the model, as the risk premium is likely to vary depending on the technology as well as the location of the plant. Renewable energy projects with widely adopted technologies like wind and PV often have lower operational risks and more predictable cash flows compared to the incumbent technology of hydrogen production via electrolysis. Developed/mature markets like Austria have lower risks compared to emerging markets like North Africa due to political conditions, currency risks and general market risks. For simplification, however, it was assumed that the same conditions apply across all technologies and locations.

The transport costs C_{H2_T} of each pipeline and ship were taken from IRENA (2022b) and extrapolated to the respective distances.

Other processes costs $C_{H2_{OP}}$ include CO_2 transportation and storage costs in the case of blue hydrogen, compression as a required process chain before pipeline transportation and liquefaction and re-gasification in the case of transportation via ship.

It is important to note that we only calculate production and transportation costs, given the system boundaries and parameter inputs. This analysis does not provide any guidance on how the actual market prices for hydrogen might evolve due to energy market conditions (e.g., oligopolistic market power) which are highly uncertain.

The input data for the economic analysis are given in the following tables, including the sources used. Parameters are collected from scientific literature and industry reports. No potential subsidies on renewable electricity generation or any taxes were included in the analysis for comparability reasons. Table 14 gives the data used for the main case study. It is very difficult to obtain reliable data for investment costs in the literature. Usually, it is not clearly stated to which plant size the cost data refer, which elements are included (only stack or overall system) and from which year these data originate. For this reason, a sensitivity analysis of certain parameters with two outliers case studies (low and high costs) is also carried out in a further step. The data used can be found in Table 15. In general, we tried to harmonize the parameters for all four production technologies. We also include the balance of plant costs in line with IRENA (2020b), hence calculating production investment costs. Other essential parameters besides the investment costs are the full-load hours of the hydrogen production plants and the fuel or electricity costs. As the latter are affected by a range of variations, a sensitivity analysis is also performed in that case (Table 15). In the case of green hydrogen production, as assumed here from PV and wind, the full-load hours are also very different depending on the location. They were taken from the assumptions regarding the PV or wind electricity production location. The significant difference in full-load hours between yellow and green hydrogen production has a substantial impact on the overall economics. Yellow hydrogen production benefits from nearly continuous operation, while green hydrogen production operates with lower and more variable full-load hours due to reliance on renewable energy sources, leading to differences in capital utilization and unit costs. The data for the cost calculation of the electricity from PV and wind and the regions considered (Local, Tunisia and Morocco) are given in Table 16.

Table 14: Calculation data for main case study (Ajanovic et al., 2022; eurostat, 2023a, 2023b; IEA, 2019a, 2021; Pfenninger, 2023; Sayer et al., 2022)

Parameters	SMR		Electrolysis	
	Grey	Blue	Yellow	Green
Production investment costs (€/kW)	1100	1878	2400	2400
Operation and maintenance costs including CO_2 storage and transport costs (€/kW)	52	103	44	44
Interest rate	0.05	0.05	0.05	0.05
Depreciation period	25	25	20	20
Full-load hours	8322	8322	8322	1314-3767
Fuel or electricity costs (€/kWh)	0.05	0.05	0.09	0.04-0.07
Efficiency (LHV)	0.76	0.69	0.66	0.66

Table 15: Calculation data for high and low-cost case studies (Ajanovic et al., 2022; EU, 2018; eurostat, 2023a; IEA, 2019a; IRENA, 2020b; Komarov et al., 2021; Younas et al., 2022)

Parameters	Sensitivity case	SMR	Electrolysis
Overall investment costs (€/kW)	High costs	1321	3200
	Low costs	991	1616
Operation and maintenance costs (€/kW)	High costs	62	44
	Low costs	47	44
Fuel or electricity costs (€/kWh)	High costs	0.07	0.11
	Low costs	0.03	0.08
Efficiency (LHV)	High costs	0.74	0.5
	Low costs	0.85	0.8

Table 16: Calculation data for electricity costs from PV and wind (IRENA, 2022a; Pfenninger, 2023)

Parameters	PV		Wind	
	Local	Morocco	Local	Tunisia
Investment costs (€/kW)		876		1299
Operation and maintenance costs (€/kW)		35		52
Interest rate		0.05		0.05
Depreciation period		25		25
Capacity factor	0.15	0.21	0.3	0.43

Table 17 shows the parameters of the transport costs by means of pipelines and ships. These depend, in each case, on the distance to be transported. The transport volume was assumed to be rather low (small-medium according to (IRENA, 2022b)) since the transport infrastructure is not yet developed. In this situation of small hydrogen flows, road transport might still be a cheaper option (Ajanovic, 2008), which has not been considered in this analysis.

With higher volumes, however, the costs would also decrease accordingly. To illustrate how the total costs would change with the mentioned cost reductions, Table 18 displays the input parameters for the sensitivity analysis covering the transport costs. Cost reductions of 15% and 30% were taken in each case. The transport costs also include the costs for compression (pipelines) and liquefaction and re-gasification in the case of transport by ship.

Table 17: Calculation data for transport and other process costs (IEA, 2019a; IRENA, 2022b)

Parameters	Ship		Pipeline	
	Tunisia	Morocco	Tunisia	Morocco
Transport costs, including compression (€/kg)	0.84	1.09	1.25	1.5
Transport distance pipeline (km)	400	400	1900	2400
Transport distance ship (km)	800	1800	0	0
Liquefaction (€/kg)	0.88	0.88	0	0
Re-gasification (€/kg)	0.009	0.009	0	0

Table 18: Calculation data for sensitivity analysis on transport and other process cost (IEA, 2019a; IRENA, 2022b)

Parameters		Ship		Pipeline	
	Sensitivity case	Tunisia	Morocco	Tunisia	Morocco
Transport costs,	15%	0.72	0.93	1.07	1.27
including compression	30%	0.59	0.76	0.88	1.05
(€/kg)					
Liquefaction (€/kg)	15%	0.75	0.75	0	0
	30%	0.62	0.62	0	0
Re-gasification (€/kg)	15%	0.007	0.007	0	0
	30%	0.006	0.006	0	0

5.2.2. Environmental assessment

All greenhouse gas emissions along the process chain are evaluated in the environmental assessment according to the system boundaries described in Figure 45. This means that only exogenous GHG emissions are included. GHG emissions that occur during the production of facilities or infrastructure are not considered following the calculation method of the European Commission, which reads “Electricity qualifying as fully renewable according to the methodology set out in Directive 2018/2001, shall be attributed zero greenhouse gas emissions” (“EUR-Lex - Ares(2022)3836721 - EN - EUR-Lex,” 2018). Thus, the calculated GHG emissions are lower than the full life cycle emissions (cradle-to-grave).

The total emissions $CO_{2\,eq\,Total}$ of the respective process chain, within the system boundaries, consist of the emissions that occur in the hydrogen production process $CO_{2\,eq\,P}$, the upstream emissions $CO_{2\,eq\,UPS}$ (electricity generation or upstream fugitive methane emissions) and, in the case of green hydrogen production outside the hydrogen hub, the transport emissions $CO_{2\,eq\,T}$.

$$CO_{2\,eq\,Total} = CO_{2\,eq\,P} + CO_{2\,eq\,UPS} + CO_{2\,eq\,T} \qquad (\text{kg } CO_{2\,eq}/\text{kg } H_2) \tag{18}$$

Upstream fugitive methane emissions are also taken into account, according to the calculations of Howarth und Jacobson (2021). We base the values on the time horizon of GWP100, as commonly used, for better comparison with the reported figures on the emission intensity of the electricity grid. It must, however, be noted that methane emissions are thus included in the calculations at a lower level. Since methane has a disproportionally large effect on near-term temperature because of its shorter lifespan, the emission metric GWP100 has an approximate uncertainty of 50% for methane as mentioned in the newest IPCC report (Shukla et al., 2022). As the scientific literature increasingly shows the importance of accounting for methane emissions along the entire value chain, especially in Europe and Australia (Yu et al., 2021) the sensitivity analysis examines three leakage rate case studies, including the IPCC default rate of 1.7% (Longden et al., 2022).

We exclude climate consequences on hydrogen leakages in this work as researched by Hormaza Mejia et al. (2020) and Ocko and Hamburg (2022). Recent findings by Cooper et al. (2022) suggest that while methane emissions of fossil gas and hydrogen within the supply chain have similar emission rates, the effect on global warming is less significant. Nevertheless, the issues of hydrogen leakages should be addressed in further studies. Also, the water usage and the acidification potential of sulfur dioxide released on soil and water are highly relevant and the latter was discussed thoroughly by Amin et al. (2022), however not included in this work.

As electricity input for yellow hydrogen production, we consider the Austrian electricity mix of 2021 according to the European Environment Agency (2023). In the sensitivity analysis, we apply the electricity mix of Europe in the high emissions case study and a lower emission intensive year (2019) of Austria in the low case study. For green hydrogen, no emissions apply in the case of local production due to the accounting method used in this analysis. A CO_2 capture rate of 85% has been assumed for blue hydrogen production (Howarth and Jacobson, 2021).

In pipeline transport, the key elements of compression as preparation and transport emissions (e.g., recompression along the way) were investigated. The technical data is taken from the following sources (Danish Energy Agency, 2021; Frank et al., 2021; Graf, 2021; Wulf et al., 2018). To operate the compressor, the electricity mix of the respective country (IRENA, 2023a, 2023b) and for electricity inputs required along the pipeline, the electricity mix of the EU was used. In the case of transport by ship, liquefaction (here also with the electricity mix of the respective country), shipping and reconversion (EU electricity mix) were included (Graf, 2021; IEA, 2019b; IRENA, 2022b). The vessel was assumed to be operating on heavy fuel oil. Hydrogen losses along the transport routes were not considered for either transport option since pure green hydrogen was produced with no emissions based on the calculation method, as only the required energy input increases.

For both transport options, it is difficult to obtain reliable figures since, in the case of pipelines, these exist but are only used for small distances and ship transport of liquid hydrogen is only just emerging. The first ship started its journey in 2022 from Australia to Japan (Australian Government, 2022). One kg of hydrogen is used as the functional unit for the GHG impact of CO_2 equivalents (kg $CO_{2\ eq}$/kg H_2). All energy input data, such as hydrogen production efficiency, are used identically to the economic analysis.

5.3. Results

5.3.1. Techno-economic analysis

Production cost calculations have shown that grey hydrogen production has the lowest total cost when externalities such as GHG are not incorporated by means of carbon tax or certificates, see Figure 46. Investment costs only play a minor role, as costs of fossil gas account for the majority of those costs. On the contrary, regarding the higher costs for all production chains in which electrolyzer technology is used, the investment costs play a slightly higher role in the case of yellow hydrogen and a substantially higher one for all cases of green hydrogen production. It is important to note here that grey hydrogen has been and is still the dominating production method. The SMR plants are in the GW range, having already experienced high economies of scale, while electrolyzer capacities are still substantially smaller. When blue hydrogen is being regarded, it is in-between, the part of the SMR technology is mature, but the process of CCUS is still under development, with a particular uncertainty regarding the storage aspects of carbon.

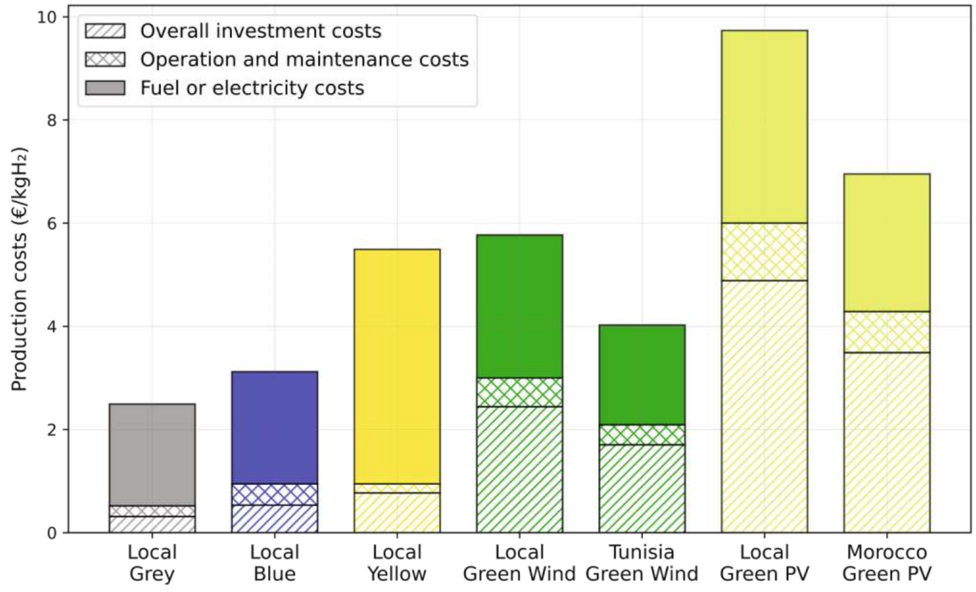

Figure 46: Comparative analysis of hydrogen production costs of different technologies (colors) and regions for the main case study (local is in this case production at the assumed hydrogen hub in Austria)

The investment costs play a smaller role with yellow hydrogen since the utilization of the electrolyzer is very high, as the grid electricity is available evenly throughout the year. It is important to emphasize that in a decarbonized energy system, yellow hydrogen would also be fully renewable when storage of electricity technologies are being used. In the mid-transition phase, especially when no subsidies are utilized and required storage capacities are not in place, efforts are made to maintain a constant utilization of electrolyzers, particularly when replacing existing SMR facilities, for example, in fertilizer production. In that continuous operation case, fossil sources would be used during specific hours. The same regarding investment costs also applies to grey and blue hydrogen production. Green hydrogen, in contrast, relies on the production capacities of PV and wind and thus achieves a much lower number of full-load hours. Therefore, green hydrogen production depends on the climatic conditions of the region of operation of the renewable power plan. In more favorable regions, higher operation hours of renewable electricity hence electrolyzer operation can be achieved and lower costs (Yukesh Kannah et al., 2021). Figure 47 shows the hydrogen production costs of wind and PV, respectively, in the considered hydrogen hub (Austria), as well as in Tunisia and Morocco. Due to the higher utilization of the electrolyzer, the generation costs in Tunisia and Morocco are significantly lower.

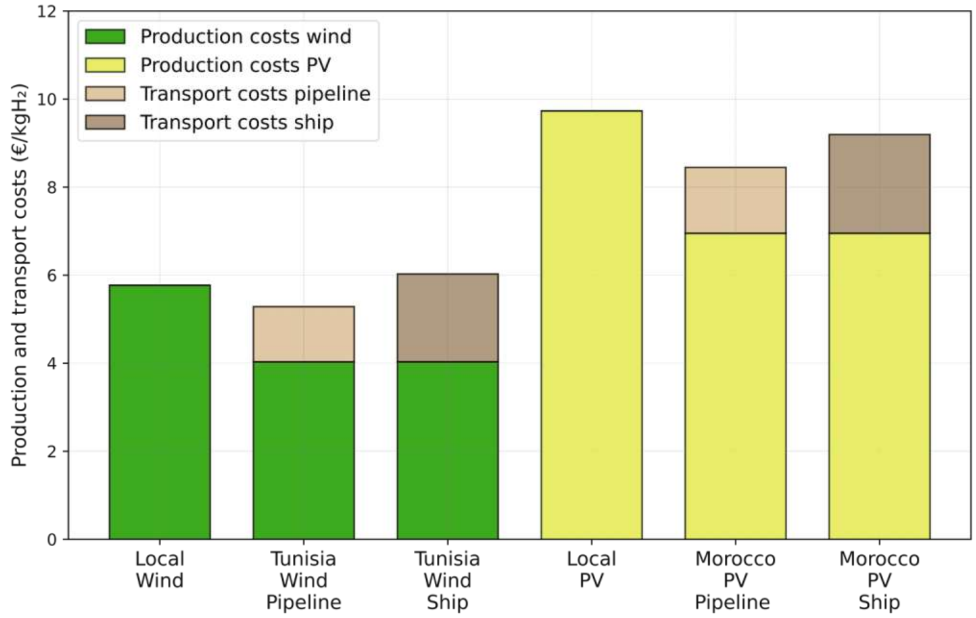

Figure 47: Comparative analysis of hydrogen transportation cost and renewable hydrogen production (Local, Tunisia and Morocco)

On a more specific note, it can be clearly seen that green hydrogen from wind is the cheaper option when compared to PV-powered, even when considering the most suitable production sites for both. This lies in the fact that on average PV powered electrolyzers have the lowest normalized efficiency, according to Ozturk and Dincer (2021). However, due to different operating patterns, a combination of PV and wind can result in higher utilization and lower costs. This hybrid approach should be considered in further research, as by Sens et al. (2022).

However, a pure comparison of production costs at different locations is not permissible since the location where the hydrogen is being used is also relevant. In the case under consideration, the hydrogen is consumed in Austria, so additional transport costs are incurred in the case of production from Tunisia and Morocco. For this purpose, the two possibilities of pipeline and ship transport are considered. This analysis indicates that pipeline transport is generally cheaper and therefore preferable in the case that it is possible. The total costs of hydrogen production in the case of pipeline transport are lower in both cases (PV and wind) in Morocco and Tunisia, respectively. When comparing the transport costs by ship, only the PV production costs in Morocco are slightly cheaper than the locally produced green hydrogen from PV. As transport costs depend on the distance, the calculated costs are very location-specific. No assumptions can be drawn for hydrogen import from locations further away. Table 19 depicts the exact results of the calculations of each defined process chain for the main case study.

Table 19: Results of the economic assessment - main case study

Production chain	Production costs (€/kg)	Transport costs (€/kg)	Production and transport costs (€/kg)
Grey Local*	2.49	0	2.49
Blue Local	3.12	0	3.12
Yellow Local	5.49	0	5.49
Green Wind Local	5.77	0	5.77
Green Wind Tunisia- Pipeline	4.02	1.25	5.27
Green Wind Tunisia- Ship	4.02	2.00	6.02
Green PV Local	9.73	0	9.73
Green PV Morocco - Pipeline	6.95	1.50	8.45
Green PV Morocco - Ship	6.95	2.25	9.20

(*Local is in this case production at the assumed hydrogen hub in Austria)

However, since the cost savings from hydrogen imported from North Africa are relatively low due to the transport costs, but additional hydrogen losses or additional energy consumption and, in the case of the use of fossil fuels, also GHG emissions occur, the question arises whether locally produced hydrogen is not the preferred option in the status quo, with low volumes and only cost being accounted. However substantial cost reductions in hydrogen transportation are to be expected, which can make importing hydrogen the viable option in the future, see Nuñez-Jimenez & De Blasio (2022). In Morocco only, 19% (2021 values, (IRENA, 2023a)) and in Tunisia, 3% (2021 values, (IRENA, 2023b)) of the generated electricity comes from renewable sources, meaning that additional renewable generation is urgently needed for own consumption. Nearly all of the additional electricity production in Morocco, namely 60%, is produced by coal power plants, making it one of the countries with the highest carbon intensity of electricity worldwide ("Carbon intensity of electricity," 2022). Moreover, according to new studies, enough potential for additional renewable electricity generation capacities exists within the EU. Kakoulaki et al. (2021) analyze the technical potential of renewable energy in Europe, considering environmental constraints, land use restrictions and various techno-economic parameters. They conclude that the available renewable electricity potential far exceeds the electricity demand and the demand for hydrogen generation by electrolysis in all countries studied.

Except for the case of purely green hydrogen, where the costs are accounted for by newly built PV or wind power plants, the energy input costs are a dominant factor. Those costs fluctuate at the moment and provide a high uncertainty factor. That is why two further case studies (low and high cost) are being considered as sensitivity analyses. In those case studies, the investment, operation and maintenance, fossil gas and electricity costs and efficiencies of the hydrogen production facilities are included with their upper and lower limits, with the results displayed in Figure 48.

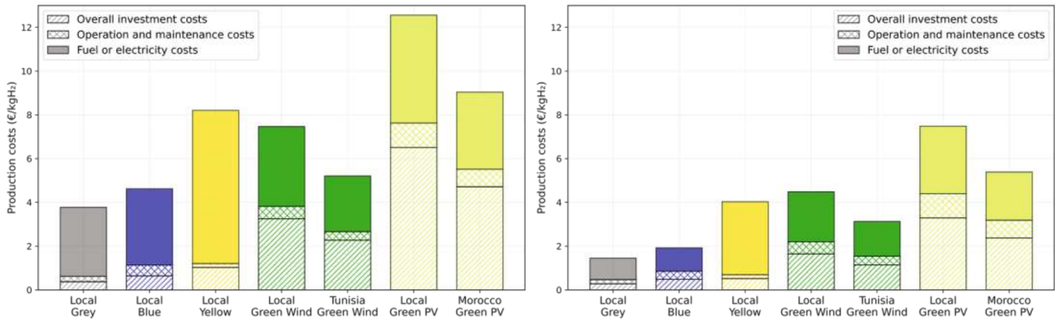

Figure 48: Sensitivity analysis of hydrogen production costs of different technologies (colors) and regions for a high (left) and low-cost (right) case study

The sensitivity analysis shows significant cost variations for all technologies, but the hydrogen production costs using electrolysis are still the highest. However, this will change in the future because a combination of cost reductions of green electricity production and electrolysis and further efficiency improvements can lead to an 80% cost reduction, according to IRENA (IRENA, 2020b). From 2030, green hydrogen production is expected to be cheaper than blue hydrogen production (BNEF, 2021).

A sensitivity analysis was also carried out concerning the transport costs, revealing that in all case studies, costs are below those of local production when there is only a 15% reduction in total transport costs, as depicted in Figure 49. Given that this analysis considered very low to moderate hydrogen transport volumes, such cost reduction becomes achievable with higher transport volumes in the future.

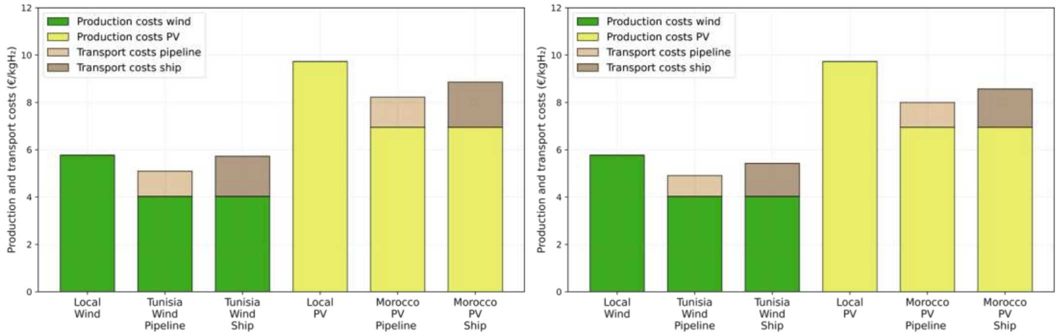

Figure 49: Sensitivity analysis with a 15% (left) and a 30% reduction of hydrogen transportation costs

5.3.2. Environmental assessment

It is evident from the emission calculation that grey hydrogen by SMR has the highest emissions in the main case study, see Figure 50. Blue hydrogen, likewise, with over 9 kg $CO_{2\ eq}$/kg H_2, is in no way an alternative to green hydrogen (with no emissions according to the defined system boundaries and emission calculations according to the methodology set out in Directive 2018/2001 ("EUR-Lex - Ares(2022)3836721 - EN - EUR-Lex," 2018)). This is due to the fact that the capture rates are not 100%, the use of additional processes for carbon capture and then further transport of the carbon and storage requires a large amount of energy and last but not least due to the still used fossil raw material of fossil gas. It is becoming increasingly clear in the literature that there are much higher emissions associated with the use of fossil gas than initially thought, mainly due to the high methane emissions upstream (Kemfert et al., 2022). Methane is emitted during fossil gas extraction and along the entire transport process. Partly through regular leakage, malfunctions and equipment failure (National Academies of Sciences, 2018). In the calculations, we include a relatively small amount of methane emission simply because we use the time horizon of 100 years for calculating the global warming potential (GWP). In this metric, according to the newest IPCC report (AR6), methane has a 29.8 times higher GWP than CO_2, whereas when using 20 years as a metric, it has 82.5 times higher GWP due to its shorter lifetime (IPCC, 2021).

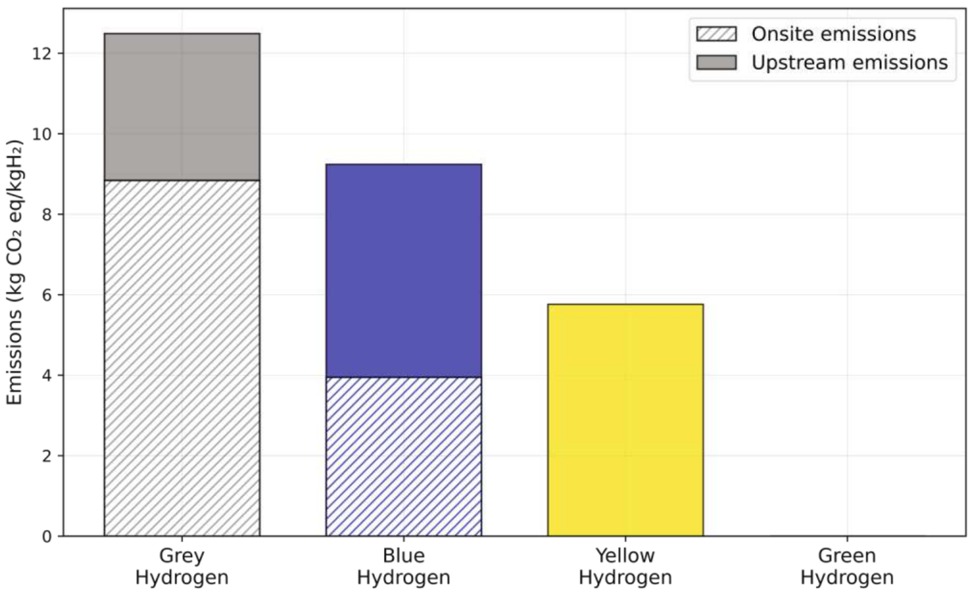

Figure 50: Comparative analysis of hydrogen production emissions (GWP100) of analyzed technologies (colors) for the main case study (green hydrogen has no emissions according to the defined system boundaries and emission calculations according to the methodology set out in Directive 2018/2001 ("EUR-Lex - Ares(2022)3836721 - EN - EUR-Lex," 2018))

In addition to the 9 kg $CO_{2\ eq}$/kg H_2 emitted during the hydrogen production process, the IEA noted in the 2021 hydrogen report (IEA, 2021) that methane emissions occurring upstream at the production and storage of fossil gas result in additional emissions of 1.9–5.2 kg $CO_{2\ eq}$/kg H_2 (2.7 kg $CO_{2\ eq}$/kg H_2 on average globally). Those figures appear to be in line with the calculations in this work. Nevertheless, the actual rates appear to be much higher than previously predicted, as research, including measurements in the US and Canada, suggests (Alvarez et al., 2018; Hmiel et al., 2020; MacKay et al., 2021; Schwietzke et al., 2016). Bauer et al. (2021) applied leakage rates ranging from 0.2% to 8%, demonstrating overall emission from 11 – 30 kg $CO_{2\ eq}$/kg H_2. Unfortunately, there is no reliable statistic for the fugitive emissions from fossil gas, as they depend on the technical equipment and processes (Kemfert et al., 2022). However, studies suggest that they are 50 – 60% higher than in previous studies (Alvarez et al., 2018). For this reason, we conducted a sensitivity analysis by varying the leakage rates (from 3.5% to 4.3% and 1.7%) and the efficiencies of the generation processes in line with the sensitivity analysis of the economic assessment, which can be seen in Figure 51.

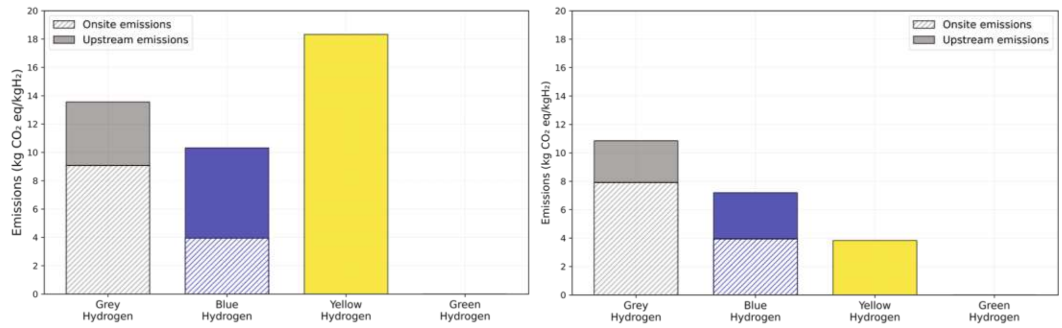

Figure 51: Sensitivity analysis of hydrogen production emissions of different technologies (hydrogen colors) for high (left) and low-emission (right) case studies

Also, in the two outlier case studies (low and high emissions) of the sensitivity analysis, it can be seen that the emissions of blue hydrogen do not drop drastically because the local capture of CO_2 does not affect the upstream emissions and more energy has to be utilized, which increases them further. Currently, blue hydrogen is considered by a few people as a bridging technology before a complete transition to green hydrogen (Woody and Carlson, 2020) and carbon capture and sequestration were promoted heavily a few years back. However, this term is only used to keep fossil industries in business so that they can continue to develop and operate the gas infrastructure (Kemfert et al., 2022) and the promotion of carbon capture and sequestration has also is also far from the expected goals. The new worldwide database of CCUS projects of the IEA (2023c) illustrates this.

What is significant, however, is the increase in emissions of yellow hydrogen when it is produced using the EU electricity mix. Emissions are more than tripled and more CO_2 is produced than with grey hydrogen. The EU electricity mix currently contains only a relatively small share of renewable energies and therefore causes higher emissions than Austria's electricity mix, which is more renewable due to its historically grown hydropower. This shows the importance of a switch to renewable energy sources, especially in the electricity sector, where great low-cost alternatives to fossil generation already exist. Then hydrogen could also be produced cost-effectively within the EU with relatively low emissions.

Once emissions from hydrogen transport are also taken into account, green hydrogen production in Tunisia and Morocco also involves a share of emissions. As can be seen in Figure 52, pipeline transport has better environmental balance. In both countries studied, the hydrogen transport path via pipelines has lower emissions. The transport distance also plays a role, since the longer the hydrogen has to be transported, the higher the emissions. This distinction is relatively smaller in the case of transport by ship since the largest share of emissions occurs during liquefaction of the hydrogen. Table 20 indicates the GWP of all hydrogen pathways investigated in this analysis.

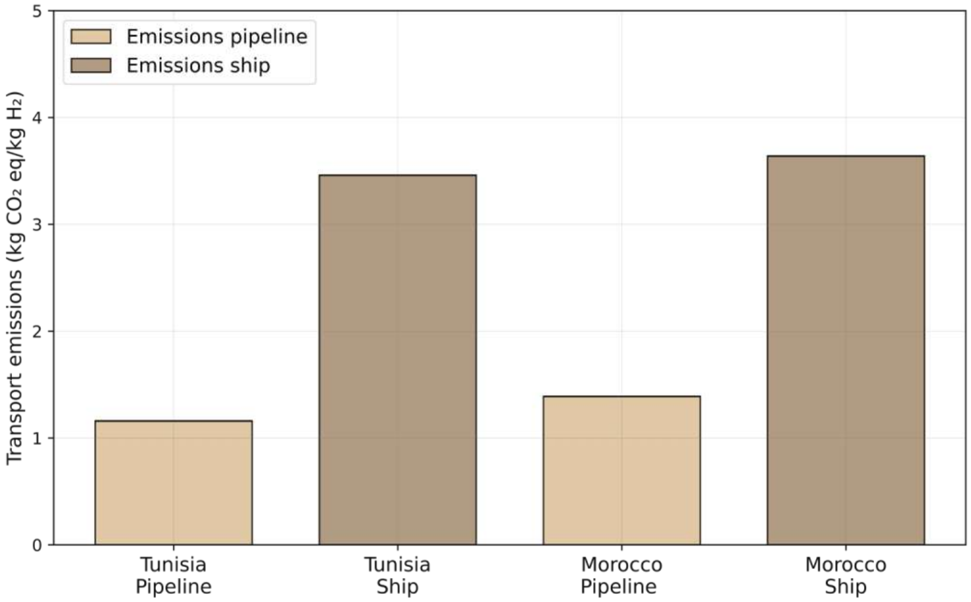

Figure 52: Comparative analysis of hydrogen transportation emissions by pipeline or ship from Tunisia and Morocco

Table 20: Results of environmental assessment – main case study without CO_2 costs, excluding locally produced green hydrogen due to zero emissions

Production chain	Onsite emissions (kg $CO_{2\,eq}$/kg H_2)	Upstream emissions (kg $CO_{2\,eq}$/kg H_2)	Transport emissions (kg $CO_{2\,eq}$/kg H_2)	Overall emissions (kg $CO_{2\,eq}$/kg H_2)
Grey Local	8.84	3.65	0	12.49
Blue Local	3.94	5.29	0	9.24
Yellow Local	0	5.76	0	5.76
Green PV Morocco Pipeline	0	0	1.16	1.16
Green PV Morocco Ship	0	0	3.46	3.46
Green Wind Tunisia Pipeline	0	0	1.39	1.39
Green Wind Tunisia Ship	0	0	3.64	3.64

To demonstrate the impact of emissions on the total costs per kg of hydrogen, a carbon price is now implemented. This ranges from 0 to 1000 € per tonne of CO_2, as shown in Figure 53. It is evident that a significant price increase occurs, especially for grey hydrogen. Blue hydrogen becomes competitive with grey hydrogen even before an emission price of 200 € per tonne of CO_2. Looking ahead, future cost reductions for green imported hydrogen quantities will be important and can be reached by higher import volumes and technological learning of the electrolyzers, as previously discussed.

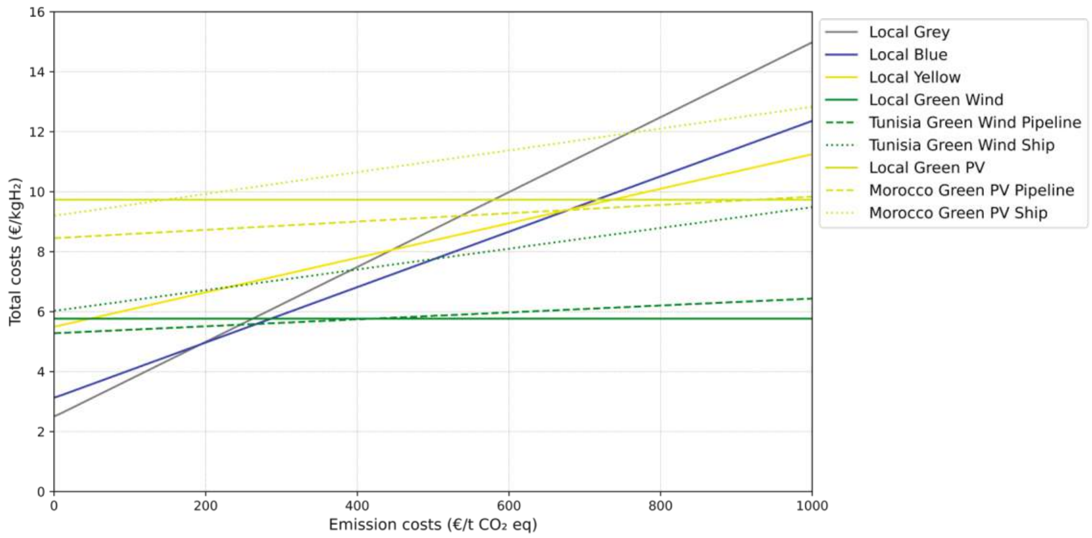

Figure 53: Total hydrogen costs (production and transportation) including CO_2 costs from 0 to 1000 €/t $CO_{2\,eq}$ (main case study)

6. Use of hydrogen in the transport sector – a case study for fuel cell electric buses[8]

The following section, based on a published paper by Sayer et al. (2022), explores the use of hydrogen in the transport sector through a detailed case study. This is not necessarily because it is the most favorable application, but because it is currently among the most widely discussed and mature applications (Additional information on different applications and use cases of hydrogen can be found in Appendix F). The case study examines the economics of an FCEB fleet fueled by green hydrogen produced using electricity from a large wind park in Austria. A major derived goal is to identify the most economical operation mode for the electric utility owning wind power plants using the actual hourly operation data of the respective wind park, minimizing the total costs of the overall fuel supply (hydrogen production) and use (bus and operation costs) system. First, the overall costs of an FCEB compared to a diesel bus are investigated by means of a TCU analysis and a resulting sensitivity analysis regarding hydrogen price, CO_2 price, driving distance and investment cost. Second, the most economical operation mode of the electrolyzer is identified, followed by the future cost development of the mentioned technologies up to 2050.

To set the stage for this analysis, Section 6.1 covers the background and state of the art in FCEB and electrolyzers. Section 6.2 details the methods used in the work, while Finally, Section 6.3 presents the results, including a cost analysis of FCEB and electrolyzers, an examination of different electrolyzer operation modes and future prospects.

6.1. Background and state of the art on fuel cell electric buses

The European Green Deal lays the foundation for Europe to become the first climate-neutral continent by 2050 and sets the stage for Europe's transition to a sustainable economy with economic growth decoupled from resource use. In addition, it explicitly identifies clean hydrogen and fuel cells as priority areas (European Commission, 2019b). In 2019, the amendment to the "Directive on the promotion of clean and energy-efficient road transport vehicles" was adopted for public procurement and became national law in 2021 (EU, 2019). This implies that 22.5% of newly purchased buses until the end of 2025 have to be zero-emission vehicles and from 2026 onwards, this share increases to 32.5% (BMK, 2021). FCEB

[8] This chapter is based on Sayer et al. (2022).

could be a promising technology, especially for long driving distances, where battery electric or trolleybuses are not an option. Unlike the combustion of diesel in an internal combustion engine, no CO_2 is released when hydrogen is used in FCVs. Nitrogen oxides are only produced when fuels are burned at extremely high temperatures, which is not the case for PEM fuel cells. Particulate emissions, which are typically produced during the combustion of diesel, are also eliminated here. Particulate emissions from tire and brake wear, while not avoidable, are significantly lower than for diesel buses because recuperation reduces the need to use the brakes. In addition, the use of FCEB reduces local noise pollution. Increased noise pollution only occurs at refueling stations in connection with the coolers (for compressors) and compressors used.

Fuel cell buses have different advantages, but their full environmental benefits only come into effect when green hydrogen from renewable electricity is used. In view of that, within this work, a potential combination of benefits of hydrogen production from potential surplus electricity from wind energy in a bus fleet is being investigated for a province in Austria, which is characterized by two essential aspects. On the one hand, Burgenland is the province in Austria with the largest specific wind power potential. It covers 100% of its electricity demand from renewable energy sources and even exports electricity to other regions. In the meantime, many wind power plants have already dropped out of subsidies, which is why alternatives are being sought for these wind power volumes, as at times of analysis, the electricity prices were rather stable. On the other hand, Burgenland has the least beneficial public transport infrastructure within Austria in terms of environmental aspects. These two aspects motivate to investigate a possible business model where hydrogen is produced from electricity generated by wind power plants and used in public fuel cell buses. However, the economic viability of such a model has not yet been conclusively demonstrated.

The core objective of this work is to investigate the economics of an FCEB fleet fueled by green hydrogen produced with electricity from a large wind park in Austria. A major derived goal is to identify the most economical operation mode for the electric utility owning wind power plants using the actual hourly operation data of the respective wind park, minimizing the total costs of the overall fuel supply (hydrogen production) and use (bus and operation costs) system leading to the following research question: "*How can hydrogen be utilized in the transport sector and what are the most viable operation modes for the case study of wind energy powering fuel cell electric buses?*"

To the authors' knowledge, the analysis conducted in this section is the first one of the overall supply chain of FCEB powered by wind energy, including a definition of possible business models of the electric utility owning wind power plants. We analyze the electrolyzer setup considering the electricity market system and calculate the costs of different models such as stand-alone or grid integrated systems.

The first research on combining the benefits of an FCEB with hydrogen generation from wind electricity was conducted by Geer et al. (2005) on the island of Martha's Vineyard in Massachusetts in the United States. A relatively small system was analyzed with the operation of one or three buses at a time. Prior to that work, small demonstration projects combining an electrolyzer with wind energy have already been in operation in Sweden, Italy, Canada, Norway and the United States, all in the range of a 2-50 kW of electrolyzer capacity (Geer et al., 2005). Different end-use applications of hydrogen from wind power, among others, the use in methane-hydrogen buses, were subject to economic analysis within the HyFrance 3 project (Menanteau et al., 2011). The paper has shown that constant hydrogen production without intermediate storage is the cheapest production method. Within a country analysis, Gunawan et al. (2021) model the techno-economic aspects of hydrogen fuel supply chains, including FCEB. For hydrogen production, they assume the electrolyzers to be operating at each currently exiting wind farm supplemented by storage and PV panels. With those arrangements in place, they find that the hydrogen costs lie between 5-10 €/kg H_2, making the fuel costs equal to those of diesel buses. An early review without a specific focus on FCEB but on hydrogen-fueled FCVs has been conducted by Veziroglu and Macario (2011), concluding that in any way, a change to FCVs will reduce overall emissions compared to the actual transport sector with the further benefit of no local emissions in now highly polluted cites. Oldenbroek et al. (2017) improve the idea of emission reductions in cities by applying a smart city concept where FCVs, together with hydrogen as an energy carrier produced through solar and wind, can provide all required energy (electricity, heat and transport). Applying different future scenarios, using European statistics, they conclude that this approach is feasible for smart city areas (Oldenbroek et al., 2017). An overall life cycle assessment of hydrogen production has been conducted by Burkhardt et al. (2016), who conclude that fuel consumption bears the biggest potential for emission reduction (86–89% fewer emissions compared to ICEs). Further, they highlight the problem of fewer emissions for the construction of the electrolyzer with more full-load hours but an additional electricity is source needed when only using renewables or excess capacities (Burkhardt et al., 2016). That substantial emission reduction can only be achieved when green hydrogen is being used for the operation of FCVs is also confirmed by Miotti et al. (2017). Granovskii et al. (2006) analyze different hydrogen production methods for use in FCVs and confirm that wind energy combined with electrolysis has the most advantages to lower greenhouse gas emissions. In a later paper, Valente et al. (2020) also conclude that renewable electricity, in their research scenario from wind, is important for overall emission reduction. Life cycle assessments for FCVs with a focus on specific regions have been conducted by Ahmadi and Kjeang (2015) for Canadian provinces and by Watabe and Leaver (2021) for Japan. Among the newest developments, a vertical wind turbine in a fuel cell passenger car for hydrogen production is being proposed by Oruc and Dincer (2022).

Other works focus either on different aspects of FCEB or on the specifics of hydrogen production with electricity from wind power. Sarrias-Mena et al. (2015) analyzed the technical configuration of different PEM electrolyzer models combined with wind electricity and found that all models were suitable for operation. Including not only the electrolyzer in the system but an optimized hydrogen energy storage system Mirzaei et al. (2019) show that combining it with a price-based demand response proves to substantially lower the necessary curtailment of wind power plants and the daily running costs. Further important technical aspects, especially regarding the optimal operation of a wind farm combined with a hydrogen energy storage system, were presented in Abdelghany et al. (2021) through a model predictive controller. Various feasibility studies on the combination of wind and electrolyzer have been conducted, e.g., by Aiche-Hamane et al. (2009) for the region of Ghardaia in Algeria, Nagasawa et al. (2019) for Texas in the US, Berg et al. (2021) for Denmark and Almutairi et al. (2021) for the Yazd province in Iran. A life cycle analysis of Ghandeharium and Kumar (2016), which includes the emissions of all production steps from the wind farm to the electrolyzer, comes to the conclusion that the greenhouse gas emissions of wind-based hydrogen systems are 94 % lower than those of hydrogen production by steam reforming (grey hydrogen) (Ghandehariun and Kumar, 2016). When further carbon capture, utilization and storage are being applied to the SMR process (blue hydrogen), the overall emissions can be reduced. Nevertheless, the operation of the capture technologies also requires further energy inputs and the fugitive methane emissions that occur upstream of the gas extraction sites play a fundamental role in grey and blue hydrogen (Ajanovic et al., 2022). For wind-hydrogen plants, the manufacturing and installation of the plants have significant environmental impacts. However, hydrogen produced from wind energy can significantly reduce the greenhouse gas footprint of the energy industry (Ghandehariun and Kumar, 2016). Earlier, an integrated wind-fuel cell system for remote communities has been analyzed by Khan et al. (2005), with the conclusion that despite emissions that occur at the production of the wind turbine and fuel cell, the overall greenhouse gas emissions are well below the comparison of a diesel system. In Vandenborre and Sierens (1996) a diesel bus was modified to use hydrogen as fuel and was tested successfully in 1996. This historical development has been well documented by Hua et al. (2014), who give a comprehensive analysis of the overall aspects of FCEB. Already in 2007, broad acceptability of FCEB was detected in four major cities: Berlin, London, Luxembourg and Perth, even when associated with higher expenses for the public (O'Garra et al., 2007).

These findings have been supported by Bigerna and Polinori (2015) for Perugia. Also, focusing on Italy Santarelli et al. (2003) provide a comprehensive economic, environmental and social analysis. They conclude that proper policies have to be in place to include the benefits such as lower emissions of FCEB in monetary terms and subsequently would lead to more equal costs of FCEB and diesel buses. This is supported by Ajanovic et al. (2021), stressing a policy framework including all environmental impacts for each bus mode. Additionally, they highlight the importance of renewable hydrogen usage, which is solely the case when renewable electricity is being used for hydrogen production. In that case, 93% of CO_2 emissions could be saved in comparison to a diesel bus. Correa et al. (2017) also point to the use of renewable hydrogen to reduce environmental impacts. Overall the literature confirms the environmental benefits and emission reductions of FCEB, e.g. Lajunen and Lipman (2016), Lozanovski et al. (2018) and Lee et al. (2019). In two further case studies, one for Oujda city in Morocco (Jelti et al., 2021) and one for the city of Rosario in Argentina (Iannuzzi et al., 2021), the same conclusions were derived. Further case studies on the applications of FCEB in different cities, regions or, countries were conducted by Langford and Cherry (2012) in Knoxville in the US, Chang et al. (2019) for public buses in Taiwan, Coleman et al. (2020) for the Rhine-Main area in Germany and Zhang et al. (2020) for Zhangjiakou in China. Stempien and Chan (2017) compare the main available bus technologies (conventional and alternative) and conclude that for FCEB as well as battery electric buses (BEB), a reduction in the total cost of ownership is expected with the advantages of the FCEB of higher travel range and shorter charging time compared to BEB. As an outlook to 2030, still, a 15.4% higher TCO for the FCEB compared to diesel buses are expected including a scaling effect of electrolyzers and they could even become cheaper in 2030 (Kim et al., 2021).

6.2. Methodology

The methods used in this work are threefold.

First, we analyzed different cost aspects of the FCEB, as the market penetration has not yet been achieved. In addition to the lack of hydrogen infrastructure, the initial investment costs, which are not yet competitive, represent barriers. In order to better understand how these market barriers can be removed in the long term, the cost structure of the buses was analyzed in detail by comparing the TCU of FCEB and diesel buses. The TCU include not only the investment costs but also consider the cost structure of the buses over their entire lifetime. For a better understanding of the calculation results, a sensitivity analysis regarding the major input parameters such as the hydrogen price, the CO_2 price, the distance driven per year and the investment costs of the FCEB was conducted. The ultimate goal is to identify measures to minimize the total cost of hydrogen production and to lower the TCU of the fuel cell bus, as illustrated in Figure 54.

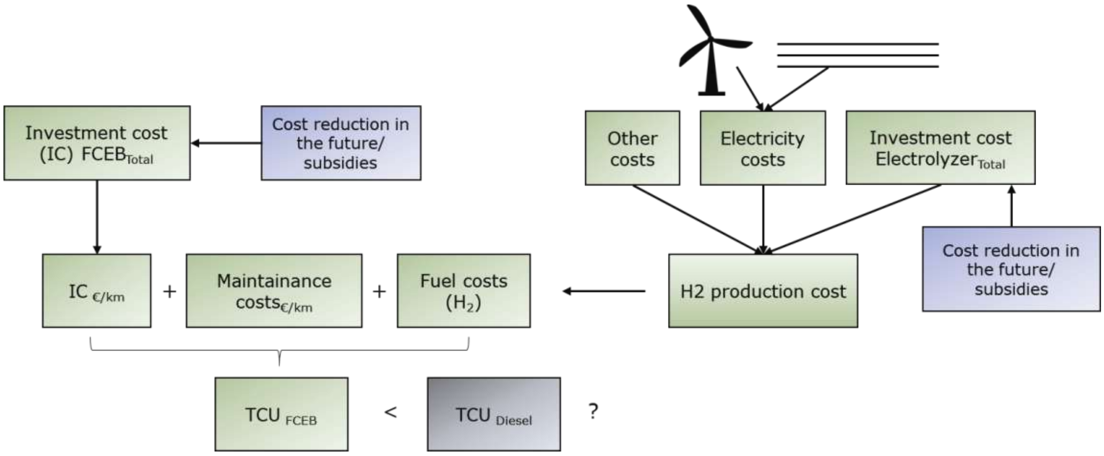

Figure 54: Overview of the method of approach and the aim of the analysis

The TCU per year are calculated using the investment cost (IC_{0_t}, in €), the capital recovery factor (α), the yearly operating, maintenance and repair costs ($C_{O\&M_t}, in$ €$/yr$)[9] and the annual fuel costs (C_{fuel_i}, in €$/yr$):

$$TCU = IC_{0_t} \cdot \alpha + C_{O\&M_t} + C_{fuel_t} \qquad (€/\text{yr}) \qquad (19)$$

and the calculation of α with discount rate (r) and service life (n)

$$\alpha = \frac{(1+r)^n \cdot r}{(1+r)^n - 1} \qquad (20)$$

The annual fuel costs are calculated from the average fuel consumption ($fc_i, in\ kg\ H_2\ per\ 100\ km\ or\ l\ per\ 100\ km$), the fuel price ($p_{fuel_i}, in$ €$/kg\ H2$ or €$/l$) and the annual distance traveled ($d, in\ km$). The index i refers to diesel or FCEB, depending on the technology of the bus for which the TCU analysis is performed:

$$C_{fuel_i} = fc_i \cdot p_{fuel_i} \cdot d \qquad (€/\text{yr}) \qquad (21)$$

Second, we conduct a sensitivity analysis on important influencing factors of the electrolyzer, namely the size of the electrolyzer, to indicate potential economies of scale and the influence of the operating hours (FLH) on the electrolyzer plant. For this, we use the direct investment (IC_{Ely}, in €$/kW$) and other project costs (e.g., compressor, installation, analysis and infrastructure) (IC_{Other}, in €$/kW$) of the electrolyzer, the capital recovery factor (α) with the discount rate (r) and depreciation period (n), the operation and maintenance costs

[9] We do not include labor costs for bus drivers as they are the same for both bus types.

($C_{o\&m}, in\ €/kW$), the electricity costs ($C_{Ele}, in\ €/kWh$) and the efficiency of the electrolyzer (η). The hydrogen production costs (C_{H2}) by an electrolyzer are calculated as:

$$C_{H2} = \frac{(IC_{Ely}+IC_{Other})\cdot\alpha + C_{o\&m}}{FLH/\eta} + \frac{C_{Ele}}{\eta} \quad (€/kWh) \quad (22)$$

In addition, in a third step, we define three operation models to identify the most economical production method for the power-to-gas system. In order to calculate the required power (P_{Ele}) of the electrolyzer, we must first calculate the amount of hydrogen (Q_{H2}) needed to run the 15 FCEBs (Q_{FCEB}):

$$Q_{H2} = Q_{FCEB} * fc_i * d \quad (kgH_2/yr) \quad (23)$$

$$P_{Ele} = \frac{Q_{H2}}{FLH/\eta} \quad (kW) \quad (24)$$

The required power of the electrolyzer depends on the operation model since wind energy is not available to the same extent every day. If the wind energy alone is to be used to operate the electrolyzer without additional grid electricity backup, the electrolyzer must be dimensioned larger.

For each model, the hydrogen production costs were calculated and the respective input factors were utilized depending on the operation mode. Since, in some cases, the wind energy is supplied directly by the wind farm, the electricity does not have to be purchased on the market. However, we take into account the lost profit since the electricity could otherwise have been sold on the market. This is factored into the hydrogen price. The calculations do not include refueling stations, possible grid expansion and long-term storage options. The model assumes that the hydrogen can be stored 24 hours after production. This means that the required amount of hydrogen must be produced each day.

To identify the possible future investment cost reductions of the FCEB and the electrolyzer, the technological learning approach is being applied as explained in Section 4.1.2.

6.3. Results

In this section, the TCU of FCEB and hydrogen production via electrolysis, without taking the specific hydrogen production with wind power into account, are analyzed. This served to identify major barriers and challenges in terms of cost development.

6.3.1. Cost analysis of fuel cell electric buses and electrolyzers

The input data used for the TCU calculations are displayed in Table 21. The investment costs, the values for the maintenance and repair costs, as well as the required travel distance of each bus are based on the experience of bus operator Postbus (Postbus, 2019). The diesel price used corresponds to the official average price in 2019 in Austria (BMK, 2022b). As a comparison, the average diesel price in 2018 amounted to 1.25 €/l, 1.05 €/l in 2020 and 1.24 €/l in 2021. Hence, we can say the data for calculation is well in that price range. The average fuel consumption values of the diesel bus, as well as the FCEB, come from literature, as do the acquisition costs of the diesel bus (Grütter Consulting, 2015; Müller et al., 2017; Potkány et al., 2018; Stempien and Chan, 2017). Further specifics on the FCEB are that the overall efficiency lies between 51-58%, with a maximum output of 100 kW and a storage tank of 45 kg with hydrogen at 350 bar (Roland Berger, 2017). The hydrogen purchase price applies to Germany but is assumed to be representative of all of Europe (H2.LIVE, 2021).

Table 21: Input data of the TCU calculation of the FCEB and the Diesel Bus

Type	FCEB	Diesel Bus
Investment costs (complete bus)	625 000 €	234 000 €
Maintenance and repair costs	0.20 €/km	0.27 €/km
Fuel costs	9.50 €/kg H_2	1,21 €/l Diesel
Fuel consumption	9 kg H_2/100km	35 L Diesel/100km
Discount rate	5 %	5 %
Analyzed period	10 years	10 years
Distance travelled	45 000 km	45 000 km

The major result of the economic analysis is that the investment costs of the FCEB have a very large influence on the TCU due to its share of 63% of the overall TCU. The results of the TCU analysis are presented in Figure 55 and Table 22. It is apparent that the FCEB is not yet competitive with the diesel bus. Table 22 shows the TCU results with the cost shares. Today – in 2022 – the TCU for the FCEB is more than twice more expensive with 128 415 €/yr, considerably higher than the diesel bus with 61 512 €/yr.

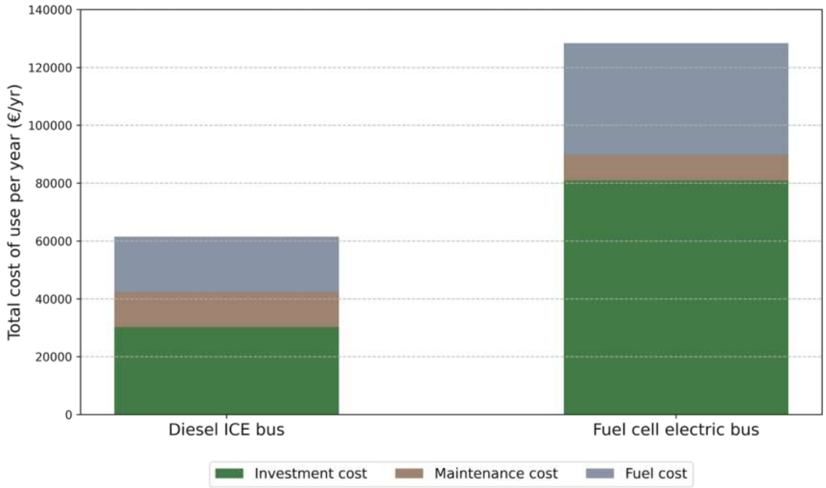

Figure 55: TCU of a diesel bus and an FCEB in comparison

Table 22: Results of the TCU calculation of the FCEB and the Diesel Bus

	Costs of Diesel Bus	Costs of FCEB
TCU per year	61 512 €/yr	128 415 €/yr
TCU: investment cost share	49 %	63 %
TCU: fuel cost share	31 %	30 %
TCU: maintenance cost share	20 %	7 %

In a further investigation, a sensitivity analysis has been carried out with the variation of different input parameters for the profitability calculation, which are summarized in Figure 56 in order to analyze their influence. As a first step, the hydrogen price has been varied. It can be seen that the hydrogen price has a very large impact on the O&M costs (operating, maintenance and repair costs). When the hydrogen price decreases, the fuel costs of the FCEB decrease drastically. When comparing the overall O&M costs with a hydrogen price of 5 €/kg hydrogen, the costs of the FCEB are slightly lower than those of the diesel bus due to its lower maintenance cost share. The next analysis varies the CO_2 prices, displayed for a very high CO_2 price of 1000 € per t CO_2. We assume CO_2 emissions of 2.63 kg CO_2/l diesel. For the FCEB bus, it is assumed that the electricity for hydrogen production is generated purely from renewable sources. Therefore, the effect can be seen in the fuel cost share of the diesel bus. Only from the assumed high CO_2 price, a noticeable difference is to be recognized. Due to the relatively high hydrogen fuel cost, when varying the driven distance per year, the difference between the diesel bus and FCEB increases. Finally, the investment costs are varied. Figure 56 shows the results for investment costs of 300000 € of the FCEB, where the investment cost-share comes quite close to the one of the diesel bus.

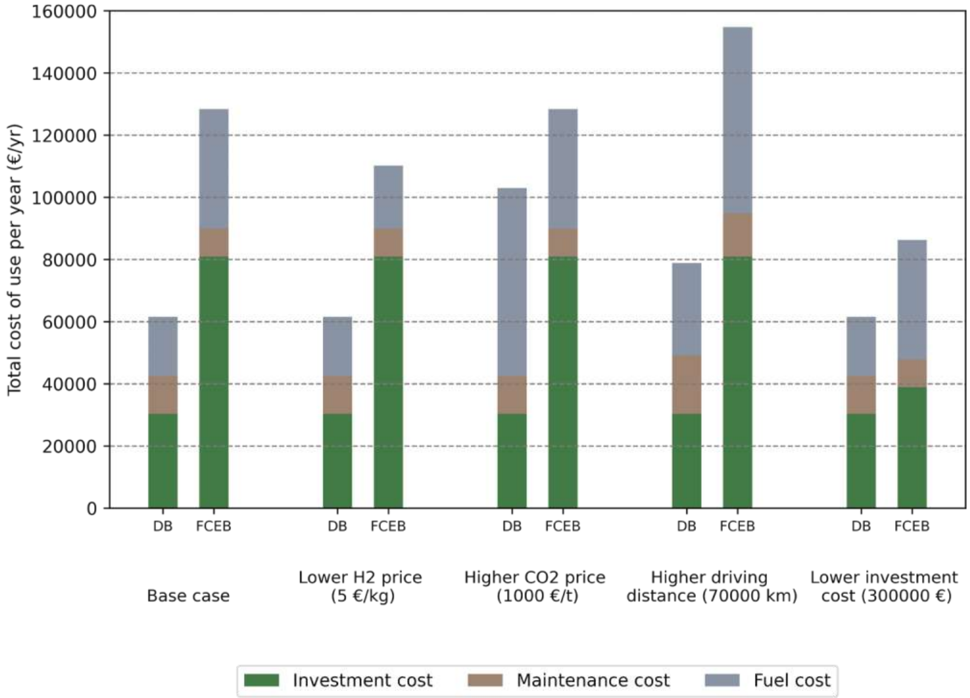

Figure 56: Sensitivity analysis of a lower hydrogen price (5 €/kg), a higher CO_2 price (1000 €/t), a higher driving distance (70000 km) and a lower investment cost of the FCEB (300000 €)

Overall, it is evident from the results of the sensitivity analysis that the high hydrogen price and the high investment cost of the FCEB in combination are the major barriers to market penetration. If both the acquisition costs could be reduced to around €300000 in the long term and if the hydrogen price were to fall to €5/kg H_2, the FCEB would become economical.

Another important factor for FCEB to become competitive is hydrogen production. There are different hydrogen production ways and currently, the most widely used is SMR of natural gas. To date, only 0.03% of the overall hydrogen is produced with an electrolyzer (IEA, 2021). However, a shift to more sustainable production methods is inevitable. Hence, the focus in this analysis lies on hydrogen production via alkaline water electrolysis and PEM electrolysis, as the most mature electrolysis technologies.

In an economic analysis of the electrolyzer costs, there are two main aspects to be considered (Haas et al., 2022a), namely the scale of the plants as well as the overall operation hours. In this analysis, we first want to consider potential economies of scale that result from the installation of a larger electrolyzer plant. In Figure 57, the investment costs of alkaline and PEM electrolyzers depending on the module size with data from a thorough literature research are displayed. It is important to note that there are hardly any recent and reliable figures for investment costs in the literature. This results from two problems, namely that there is often no precise information on the plant size in general and if this is indicated whether it refers to kW_{ele} or kW_{H2}, as well as the year of the data and the parts of the overall system included. Secondly, the cost of electrolysis depends on the manufacturer and is therefore subject to company secrets in order not to gain a competitive disadvantage. The mentioned points make a direct comparison difficult. However, we have attempted to do so in Figure 57. The main message of this graphic is that economies of scale are very much evident. These can be seen especially from an electrolyzer size of 2 MW. According to IRENA (2020b), these cost reductions are mainly due to the "balance of plant" cost component. This includes power supply, deionized water circulation, hydrogen processing and cooling. Compared to the stack, where no significant cost reductions can be achieved due to leakage, manufacturing limitations, mechanical instability issues for large-scale components, the maximum area of the cell and others, large economies of scale can be achieved by installing a larger compressor, for example. This finding is taken into account in the further analysis for the selection of a suitable electrolyzer.

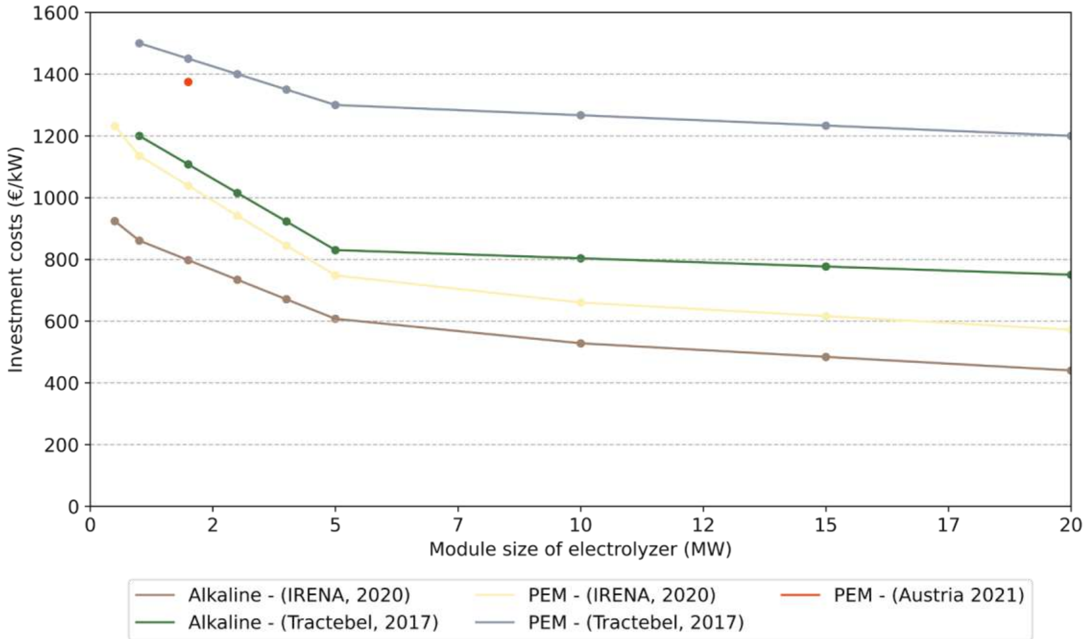

Figure 57: *Investment cost of the electrolyzer depending on the module size, 0,5-20 MW (ENEA, 2016; IRENA, 2020b; Tractebel, 2017)*

Due to the high investment costs of the electrolysis plants, the production costs of renewable hydrogen depend significantly on the full-load hours and the resulting annual operating time (BEE, 2013). Figure 58a shows the total costs of electrolysis as a function of full-load hours for a large (5 MW) and a small (500 kW) system indicating, that the costs are lowest, starting from about 4500 full-load hours per year. In this analysis we assumed a different depreciation time of the electrolyzer depending on the number of full-load hours, starting with 30 years for 500 full-load hours and constantly decreasing until 10 years for 8000 full-load hours. Figure 58b depicts the costs of the large electrolyzer in a more detailed way considering capital-, operation and maintenance as well as energy costs. Again, it can clearly be seen that higher full-load hours lead to an overall cost reduction. This is also taken into account in further analysis.

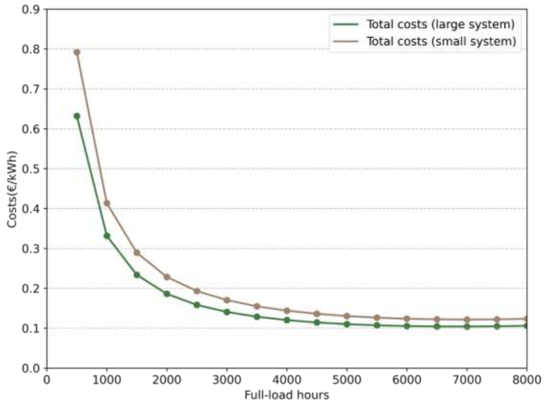

Figure 58a: Total hydrogen production costs of a small (500 kW) hydrogen production of a and a large (5 MW) size electrolysis plants in relation to full-load hours with a decreasing depreciation time (15-30 years)

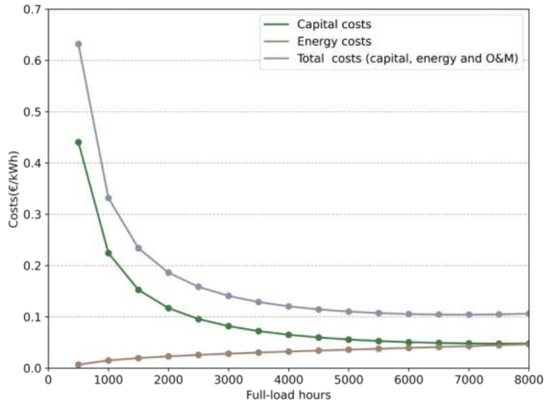

Figure 69b: Cost structure of large 5 MW electrolyzer, including capital-, operation and maintenance- and energy costs with a decreasing depreciation time (15-30 years); (Energy costs are based on the prices of the Austrian wholesale market over the year 2020)

A PEM electrolyzer is used for this analysis. The advantage of this technology is the good partial load behavior of the electrolyzer, which is particularly beneficial in the case of fluctuating feed-in, e.g., from wind turbines. To better illustrate the different costs depending on the capacity of the electrolyzer, a sensitivity analysis is performed. In each case, the total costs of an electrolyzer with 500 kW, 2 MW and 5 MW are shown in Figure 59. Besides the capital costs of the electrolyzer, costs of eration mode, the electrolyz 500 m³ storage and other costs were included. Other costs include all additional relevant costs like compressor, installation, analysis and infrastructure.

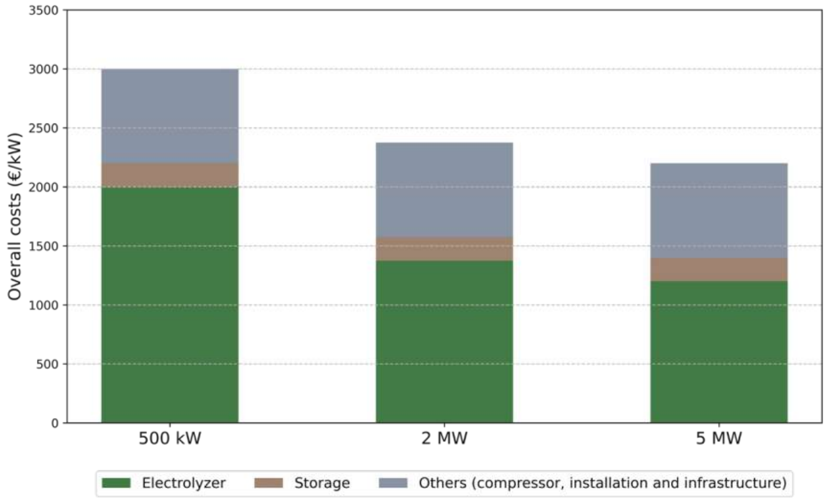

Figure 59: *Overall investment cost with different capacities of the electrolyzer*

6.3.2. Analysis of electrolyzer operation modes

In this section, three possible strategies for hydrogen production were analyzed:

1. *Direct line*

In this operation mode, the wind farm is connected to the electrolyzer via a "direct line" and not connected to the high-voltage grid. In Figure 60, the electricity consumed by the electrolyzer over time is shown in purple and the wind power generated is shown in green. It can be seen that all power for which the electrolyzer is designed is fed directly from the wind farm to the electrolyzer. If the wind power generated is less than the maximum power of the electrolyzer, the electrolyzer is ramped down (and correspondingly, less hydrogen is generated). Compared to the other variants, this results in a higher capacity of electrolyzer needed.

2. *Direct purchase from the electricity grid*

For the second operation mode, the electrolyzer draws constant electricity directly from the high voltage grid, independent of the generation capacity of the wind farm. Thus, the electrolyzer is operated at a continuous load, see Figure 60. The dimensioning of the electrolyzer is "smaller" here but it is in addition dependent on the market price.

3. *Market-driven*

In the third market-driven operation mode, the electricity consumed by the electrolyzer over time is shown in purple and the electricity price on the electricity exchange (in €) is shown in orange in Figure 60. The system works similarly to a PSH power plant. The spot market price determines whether the generated wind power is fed into the high-voltage grid or consumed by the electrolyzer. At low spot market prices, the electrolyzer is ramped up and produces hydrogen from the generated wind power. In contrast, when spot market prices are high, all electricity is sold on the spot market.

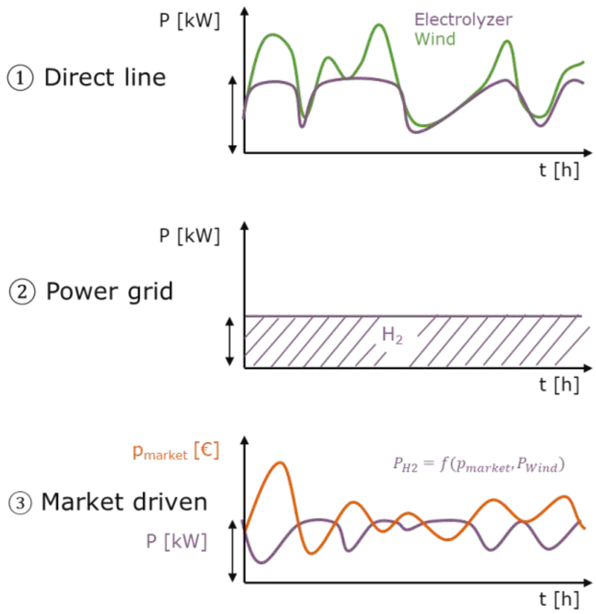

Figure 60: *Three operation models of the power-to-gas system*

The operation model analysis has been conducted based on wind data from a large wind park in Austria. Generation data from 102 wind turbine generators for the period from the beginning of September 2016 to the end of August 2019 were available for analysis. Figure 61 plots the sum of wind energy generation output of all relevant wind turbines over the 2018/2019 period. As is usual for fluctuating renewable energy sources, the generation capacities fluctuate strongly over the year and over the day.

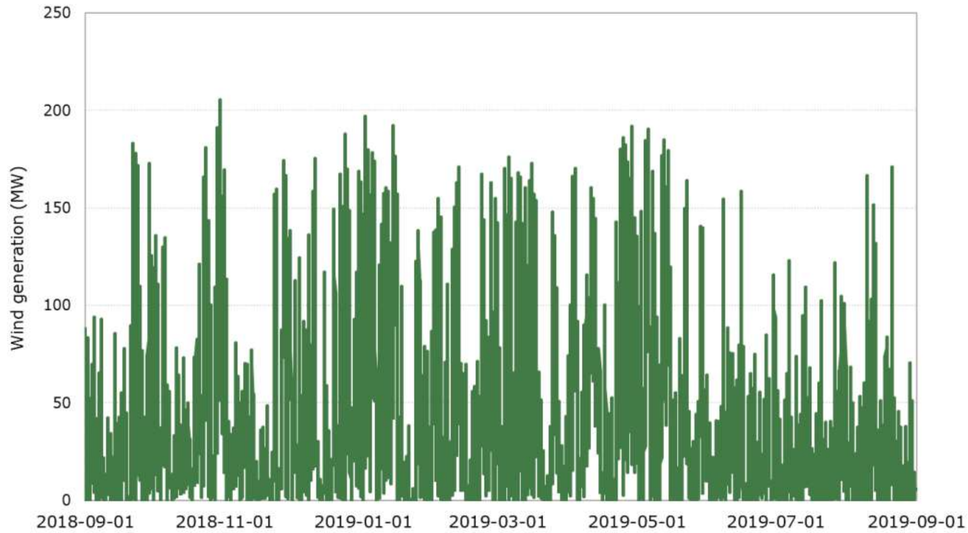

Figure 61: *Total wind power generation capacity for the year 2018/2019 of the relevant wind power generation plants*

These generation outputs can be ordered by magnitude to obtain an ordered wind power duration curve to see the overall wind availability for the whole year, as shown in Figure 62 for three different years.

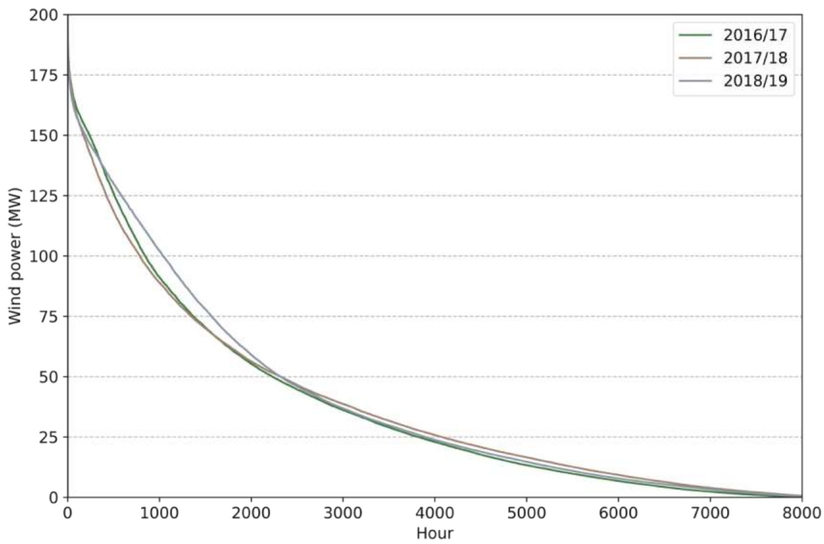

Figure 62: *Classified wind power curve for Burgenland for three different years*

To calculate the required amount of hydrogen, a hydrogen consumption of 9 kg H_2 per 100 km was taken in accordance with the range in the literature of 8.5-10.5 kg H_2 per 100 km (NOW, 2018). A driven distance of 45000 km/yr is assumed, which corresponds to the specific use case of the bus operator as already indicated earlier (Postbus 2019).

For all further calculations, we assume a minimum production quantity of hydrogen of 60750 kg H_2/yr for the operation of 15 buses. It is pointed out in the literature to use at least a maximum value for further calculations since the consumption can vary depending on the season and driving behavior. The quantity is therefore increased by 10% to 66825 kgH_2/yr. The required daily quantity is thus 183 kgH_2 on average.

The following data are used for the calculation:

Table 23: Calculation data

Data for PEM Electrolyzer	
Efficiency (LHV)	0.65
Investment costs	500 kW: 2000 €/kW$_{Ele}$
	1 MW: 1600 €/kW$_{Ele}$
Storage costs	200 €/kW$_{Ele}$
Other costs	801 €/kW$_{Ele}$
Operation and maintenance costs	60 €/kWEle/yr
Interest rate	5 %
Depreciation period	15 years

Wind generation data from the 2018/19 billing period and electricity price data from EPEX Spot Austria for the same period were used.

With the exception of two days per year, based on the data of the 2018/19 billing period, the required amount of hydrogen for the 15 FCEB buses could be provided by the wind park alone. However, the cost of hydrogen production in the *direct line* operation mode, is higher than in the other operation modes, as the size of the electrolyzer must be matched to the wind production in order to be able to produce sufficient amounts of hydrogen during hours with high wind speed. The required electrolyzer size is 1 MW and the calculated cost per kg of hydrogen is 6.41 €/kgH_2. For this calculation, we used equations described in Section 6.2, which take into account the total investment, operation, maintenance and energy costs. Since all the electricity required in this case is supplied directly by the wind farm, the losses incurred by hydrogen production instead of electricity sales are included in the hydrogen production costs for better comparability. In the model, hydrogen is assumed to be produced daily starting at hour one, according to the capacity of the electrolyzer. If the required amount of hydrogen is already produced before hour 24, in the case of high wind energy availability on that day, the electrolyzer is switched off until the next day. Besides the costs, when considering this operation model, an increase in hydrogen production in the future should be considered, resulting in an even higher electrolyzer capacity and further days where an additional backup is needed. Another aspect that has not been investigated in this analysis is a possible grid overload when high amounts of electricity have to be transported to the electrolyzer and possible additional costs due to the construction of a power cable from the wind park to the electrolyzer.

In the second operation mode, through the constant electricity availability and operation of the electrolyzer, its capacity could be dimensioned with 500 kW, resulting in the lowest investment cost share of all three analyzed models. However, this makes electricity costs a relatively large part of the total production costs and it is not possible to adjust production in this model. Nevertheless, the total production costs were calculated to be 4.77 € kg/H_2, which is the lowest of all three models. It can therefore be seen very clearly that the investment costs of the electrolyzer, as well as the operating hours, have a very strong influence. In the future, should the electricity prices remain at the current high level, an optimization of the production times adapted to the electricity price will certainly become more important and the investment costs of the electrolyzer will be reduced in the future due to technological learning.

The third operation mode envisages a market-driven approach. Similar to PSH, hydrogen is produced when prices on the electricity exchanges are low or negative in order to be able to produce more cost-effectively. In this use case, this means that the electric utility owning wind power sells the wind in times of high prices on the market and produces hydrogen himself when these are low. This is certainly a very helpful approach in the long run, also from an electricity market point of view, because if it works optimally, prices are low when there is enough surplus electricity available. In this model, optimization takes place on a daily basis, i.e., the daily required quantity is produced in each case. In order to be able to achieve this, the electrolyzer must be dimensioned larger. A compromise between optimization of the electricity price and too high investment costs with a 1 MW electrolyzer was chosen. The resulting hydrogen production costs are 6.27 € kg/H_2, which is a little lower than in the first model. Again, it is expected that higher arbitrage opportunities will be available in the electricity market in the future and thus there will be a greater opportunity for optimization. All results can be found in Table 24 and Figure 63.

Table 24: Comparison of hydrogen production costs of each operation model (OM)

	Direct line (Wind-electrolysis), OM1	Power grid-electrolysis, OM2	Wind-market driven-electrolysis, OM3
Size of electrolyser	1 MW	500 KW	1 MW
Hydrogen cost	6.41 € kg/H_2	4.77 € kg/H_2	6.27 € kg/H_2

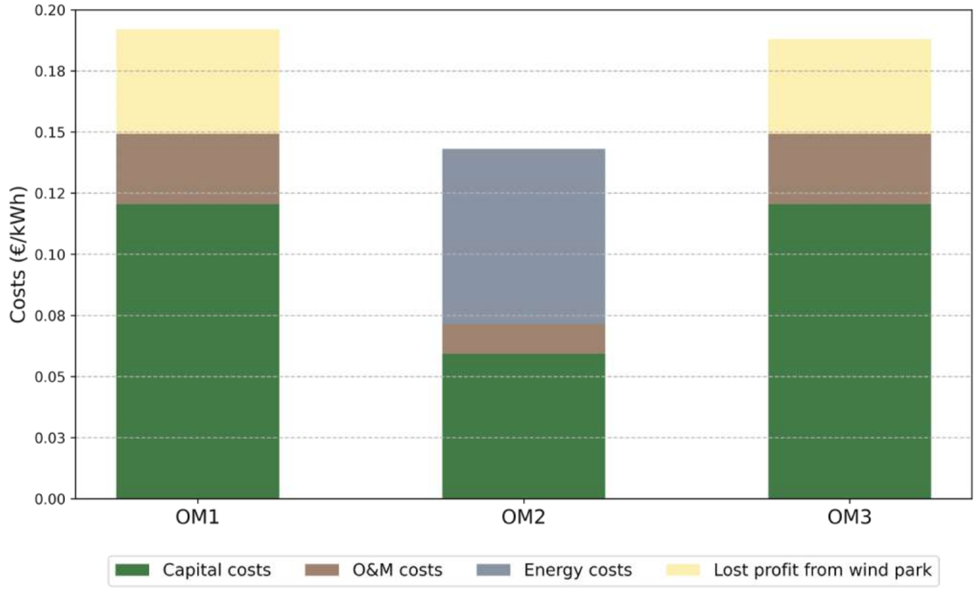

Figure 63: Overall hydrogen production costs for each operation model (OM), including capital-, operation and maintenance- and energy costs and the cost of wind energy that was used for electrolysis instead of market sale (lost profit) for better comparison

6.3.3. Future prospects

Finally, the future prospects of the overall system are analyzed. The development of investment costs of FCEB compared to the diesel bus was modeled until 2050 based on the technological learning approach. Learning rates of 15% were assumed for the FCEB. No further learning is expected for the diesel bus, as it is already a mature technology. Significant learning effects can be expected for FCEB, see Figure 64. In 2040, the cost of an FCB will already be very close to that of a diesel bus.

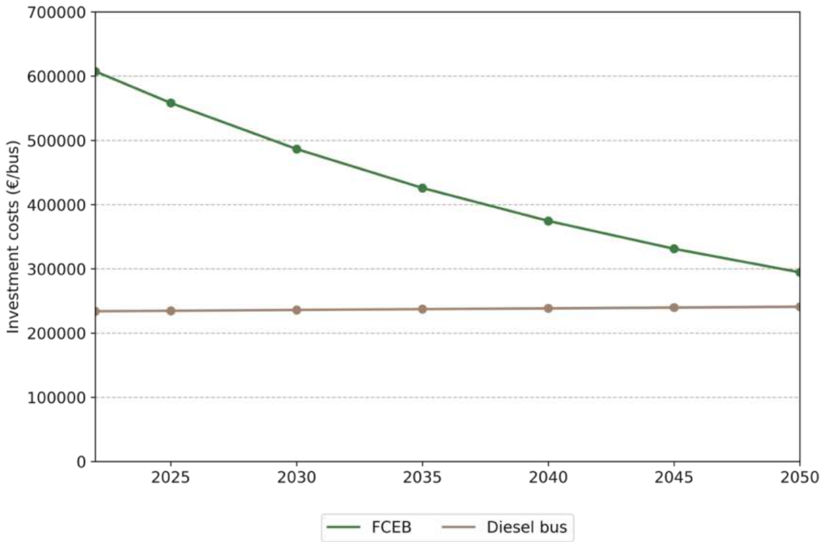

Figure 64: *FCEB and diesel bus investment costs development until 2050 (own calculations with data from (IEA, 2020b; Samsun et al., 2021)*

In order to be able to specifically address the future investment cost development of electrolysis, the learning effects were modeled for a 2 MW and a 500 kW PEM electrolyzer in Figure 65. A learning rate of 18% is assumed in each case (IEA, 2020a). In summary, it can be said that there is definitely a high learning potential for electrolyzers.

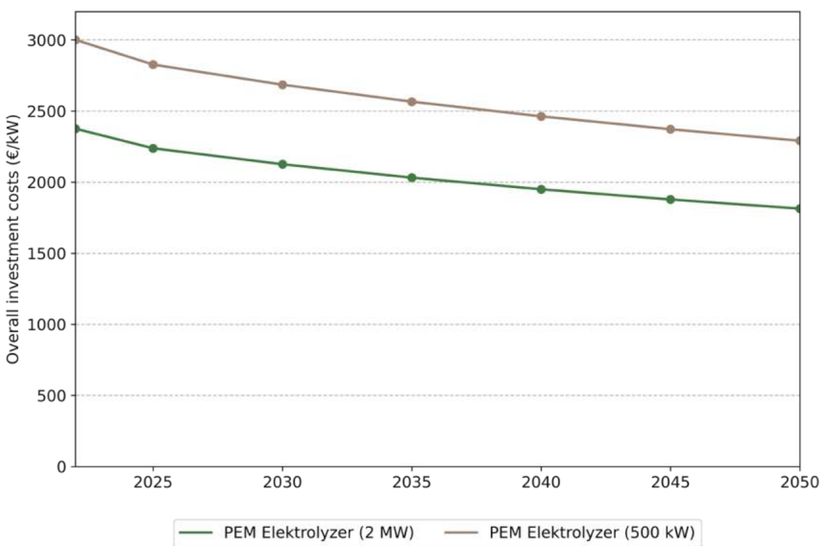

Figure 65: *Development of overall investment costs (including storage and others) of PEM electrolysis technologies of 500 kW and 2 MW until 2050 (own calculations with data from (IEA, 2021, 2020a; Krishnan et al., 2020; Schmidt et al., 2017a))*

7. General conclusions and outlook

In the first part of this work, addressing research question one, based on Sayer et al. (2024a), three different scenarios—*policy (A), renewables and electrification (B)* and *efficiency (C)*—were examined to cover some possible future outlooks for the decarbonization of Austria's electricity system using high shares and varying degrees of renewable generation and storage capacity expansion. Despite certain scenarios and model calculations being available until 2030 in the literature, policies (100% renewable electricity) and conditions regarding emission reductions (carbon neutrality) are changing, necessitating calculations with new scenarios and models. This requires a more detailed view of storage systems, with a focus on the dynamics and capacity utilization of different storage technologies. Specifically, battery storage is utilized for short-term daily balancing due to its high power ratio and efficiency, but limited energy capacity due to high investment costs, according to the model design. PSH appears relevant primarily for short- to medium-term storage needs, but it also exhibits a seasonal component due to Austria’s large reservoir capacities and seasonal water inflows. Hydrogen storage is required for seasonal balancing. Additionally, a focus has been set on long-term development, aiming for a fully transitioned electricity system using renewable technologies and increased electrification on the demand side. These scenarios were optimized through the analysis of optimal dispatch strategies under certain assumptions.

The analysis has shown that a fully decarbonized energy system is feasible, provided that policy goals are implemented accordingly and generation expansion occurs to the extent shown in the present model. The future energy system will significantly differ from the current one, with the main distinction being the absence of fossil fuel generation, which must be replaced by a combination of renewable generation and long-term storage. As neighboring countries are also facing the decarbonization of their energy systems, sourcing imports of renewable energy from these countries could become more challenging (and costly) in the future, especially during winter months, as coal power capacities are phased out. These potential assumptions are accounted for in two of the scenarios presented here, with import/export exchanges being more strictly limited (modeled in this case as artificial storage) to demonstrate that a transition would still be possible even with more restrictive assumptions.

Another significant finding of this work is the influence of weather patterns on renewable electricity generation and consequently, on the utilization of storage technologies and dispatchable generators. Using weather data from different years results in significant differences in capacity utilization of storage and the required integration of additional dispatchable renewable capacities. These weather patterns can be categorized into seasonal trends, such as higher PV and run-of-river hydroelectricity generation in summer compared to winter and extreme events. Extreme events include prolonged low wind events (five consecutive days with an average capacity factor of less than 10% according to Ohlendorf and Schill (2020)), low PV generation, low water levels and natural inflows coupled with low temperatures and increased use of HPs, which are integrated into the model using data from weather year 2017. Consequently, we treat the two weather trends separately and define their implications and requirements on the energy system, as achieving climate neutrality requires a significant increase in generation from wind and PV sources compared to current levels in electricity systems. This amplifies the impact of weather fluctuations and additionally, no flexibilities are available from fossil flexible power plants.

Regarding the general trend, once fossil generation is no longer available, seasonal balance can only be achieved through long-term storage (storing the negative residual load). An initial trend is already evident in Austria, where the massive expansion of PV has led to generation reaching peak levels, but flexibility is still insufficient. Consequently, run-of-river hydroelectricity plants have been massively curtailed on those exemplary days (Fraunhofer ISE, 2024a). Although this is a crucial flexibility, it is not sustainable in the long term if the ultimate goal is complete decarbonization. Short-term solutions like battery storage, improved DSM and grid expansion could mitigate PV peaks during the day, but long-term storage is necessary for storing this surplus for winter periods. Despite Austria having significant PSH capacities, they are insufficient for this purpose. This task is fulfilled in the present model by underground hydrogen storage. Power-to-gas, underground hydrogen storage and re-electrification through CCGT provide seasonal balancing options for the electricity system.

The model demonstrates that in the assumed scenarios, hydrogen storage (or electrolysis facilities) can offer the required flexibility to store significant amounts of this negative residual load as hydrogen. For the seasonal storage of electricity surpluses or hydrogen, existing underground hydrogen storage capacities must be utilized. Domestic natural gas storage capacities (94 TWh_{NG}, equivalent to approximately 25 TWh_{H}) are more than sufficient for balancing a renewable electricity system seasonally, as demonstrated in the current model based on hydrogen storage levels. The regional aspect of expanding power-to-gas/electrolysis facilities, including storage, becomes essential here. If well-planned and located in close proximity to surplus electricity generation sites, coupling electricity to gas provides the electricity system not only with additional temporal but also spatial balancing options through the coupled gas infrastructure, further alleviating strain on the electricity system. The magnitude of the electricity surplus should be the primary criterion for site selection. Reconversion facilities should be situated near demand centers for the same reason.

Currently, hydrogen storage and seasonal PSH (such as the Limberg facility in Austria (Hunt et al., 2020)) are the two most discussed technologies for long-term energy storage. Due to the low efficiencies of hydrogen and topographical constraints associated with PSH, requiring vast reservoirs, other technologies for seasonal storage are increasingly under discussion, such as gravity energy storage (Hunt et al., 2023), pumped heat energy storage (Smallbone et al., 2017), or general seasonal thermal storage (Yang et al., 2021). Integrating additional technologies for seasonal storage, along with their respective technical characteristics, into future models will be important.

The second important conclusion regarding climatic conditions pertains to extreme years. In these years, capacities of storage and renewable generators such as biomass and biomethane are necessary, which are scarcely needed in other average years as the load can be covered by storage technologies. Biomethane, to give an example, in the model with the target year 2050 in all scenarios examined, is dispatched only in the weather year 2017 (extreme year) and is thus a pure backup capacity for the occurrence of such an event. The capacities included in the modeling are essential. With lower system flexibility capacities, there would be hours of undercoverage if the other model parameters remained the same. The use of biomethane is only an example in the model; this capacity could just as well be covered by additional capacities of hydrogen re-electrification, but it exemplifies the problem of low to no utilization of some flexible capacities in a fully renewable electricity system. There is already much discussion in the literature on how operators of such storage or power plants should be remunerated, whether this should be market-based with very high scarcity prices so that the operators can earn enough in the few hours to keep these technologies available or whether it should be done through capacity markets or other ideas. What is certain, however, is that this requires strategic planning to ensure that the expansion of renewable generation goes hand in hand with planning the necessary flexibilities to prevent stranded assets that can no longer be used and to maximize the utilization of installed storage capacities. The scenarios defined in this work provide a first insight into how a distribution of capacities under the chosen boundary conditions might look. Through previous sensitivity analysis, in all scenarios, only as many capacities of storage and dispatchable renewable generations were implemented as required to ensure system reliability even in extreme weather years.

The second part of this work, based on Sayer et al. (2024b), answers research question two and provides a detailed analysis of storage costs using a techno-economic approach and the method of technological learning, both for the current period and for a future decarbonized energy system in Austria. Through an extensive literature review on storage investment costs, all cost components of the entire storage system were incorporated into the analysis. The assessment of future investment cost trends for storage technologies offers a comprehensive insight into potential developments.

Among all the various storage technologies analyzed, cost reductions are observed except for PSH, which, as a mature technology, shows minimal or negative learning effects, resulting in stagnant or increased costs. Conversely, lithium-ion batteries demonstrate significant cost reductions, becoming the dominant technology for short-term storage due to expected capacity expansions and high learning rates. Hydrogen storage, encompassing electrolyzers, underground storage and hydrogen turbines, shows the most substantial investment cost reductions. Electrolyzers, in particular, benefit from significant expansion plans and a relatively homogeneous nature. Despite initial higher costs, underground hydrogen storage is projected to achieve investment cost parity with PSH by the 2030s. Nevertheless, hydrogen storage still experiences higher energy losses during the whole storage process, thus leading to higher total costs of storage per kWh discharged. The future use of underground hydrogen storage will depend significantly on the need for seasonal storage, as it may not be competitive with other storage technologies based solely on cost considerations. Nonetheless, in scenarios prioritizing fossil-free electricity systems, hydrogen storage could emerge as a critical option for providing electricity during periods of insufficient renewable generation, provided no other seasonal storage technology becomes competitive by then.

In summary, the technological learning approach suggests that for future reductions in investment costs of storage technologies, several key factors must be considered:

- Technologies should remain homogeneous over the technology's lifespan (without changes or adaptations in functionality), which is rarely achievable in practice.
- Modularity and homogeneity are crucial factors for significant cost reductions, as evidenced by lithium-ion batteries. Complex designs typically achieve lower cost reductions (for example, underground hydrogen storage consists of different components that must interact and whether individual components like electrolyzers will achieve significant cost reductions remains to be seen).
- The technology should not be so widely deployed that there is no potential for capacity doubling, as is the case with PSH. Due to topographical constraints, additional expansion is limited, resulting in a decrease in the driving force for technological learning. Additionally, doubling the stock becomes more challenging and time-consuming as deployed quantities increase.

Identifying future investment costs presents several challenges:

- Obtaining reliable data from the literature is generally difficult. Data is often either outdated or lacks information on plant sizes and system boundaries of the analysis (whether the entire system is considered or possibly only the battery pack).
- For the analysis of new types of storage not yet available in the market, obtaining public cost data is nearly impossible.
- Estimations typically rely on market prices rather than costs and market prices may temporarily rise or be volatile due to short-term scarcities. This also poses challenges in conducting accurate cost analyses.

However, from an economic standpoint, costs remain one of the key indicators, making transparent public access to cost data, including the listing of different components, crucial.

The analysis confirmed the specific applications of the integrated storage technologies in the modeling. Battery storage is best suited for short-term storage and cannot compete with long-term storage technologies due to high energy-related costs. PSH is clearly intended for medium to long-term storage but remains competitive for short-term storage in the medium run. Underground hydrogen storage is distinctly suitable for long-term storage use. The energy-related costs are extremely low, meaning that especially in depleted gas reservoirs, a significant amount of hydrogen can be stored at minimal cost. The high total costs lie in the conversion technology, re-electrification and the high energy losses due to the low conversion efficiency.

The calculations demonstrate that, in addition to investment cost development and the previously mentioned roundtrip efficiency of each technology, the cost of electricity used for charging and the number of full-load hours strongly influence storage costs. Key points include:

- Different scenarios have shown that an optimal ratio of electricity demand, renewable generation expansion and storage deployment leads to the most cost-effective results. Excessive storage deployment, compared to renewable generation, results in lower storage utilization and overall higher costs. This could be seen with all technologies and can be referred to as 'self-cannibalism' of storage (Ehlers, 2011).
- The influence of full-load hours is most significant for underground hydrogen storage, where total costs of storage vary by a factor of five between 500 and 2500 full-load hours per year.
- Full-load hours in the range of 1500 are necessary for the profitable operation of all storage systems.

- With the complete decarbonization of the electricity grid, electricity costs decline over time due to the diminishing reliance on expensive fossil fuels. This was demonstrated in the modeling, leading to a reduction in costs from 2030 to 2050 in all scenarios. However, optimal storage deployment remains pivotal to realizing these benefits.

This underscores the significance of strategic planning, which is essential for optimizing utilization and minimizing overall costs. It's essential to also consider other flexibility measures, such as demand-side options, demand response, sector coupling, or grid expansion, as these factors compete with each other to some extent. However, the applied cost calculation method can only assess electricity-to-electricity storage options. Therefore, it is advisable to extend the analysis to include additional flexibility options in future studies.

The third part of this work, based on Sayer et al. (2024c), addresses research question three by investigating the economic and environmental aspects of four defined hydrogen production chains (grey, blue, yellow, green) and, in the case of a production site outside the designated Austrian hydrogen hub, the two main hydrogen transport options (pipeline and ship) from North Africa to Europe, from today's perspective.

The major conclusions are:

- First, production cost calculations show that grey hydrogen production has the lowest total cost, but this changes when externalities such as greenhouse gas emissions are considered by means of a CO_2 price. Only in grey hydrogen production investment costs play a minor role, whereas for yellow and green hydrogen, they are significant. This is because grey hydrogen has been and still is the dominant production method, with large-scale SMR plants already in place and high economies of scale achieved. Blue hydrogen production is in-between since SMR technology is mature, but the process of CCUS is still under development, with some uncertainty regarding the storage aspects of carbon. In the case that emissions are considered by means of a carbon tax, both technologies experience some cost increase, as those production methods cause the largest amount of emissions.
- Second, when assuming fully green hydrogen production, the full-load hours of the electrolyzer are lower as the production depends on the climatic conditions of the region of operation of the renewable power plant. In more favorable regions, higher operation hours of renewable electricity, hence green hydrogen production can be achieved at lower costs. Green hydrogen from wind is cheaper than PV-powered hydrogen, even when considering the most suitable production sites for both.

- Third, with yellow hydrogen production, the costs decrease further, as the same utilization rates as grey and blue hydrogen production can be achieved since electricity from the power grid is always available. In this case, however, emissions increase. Depending on the electricity mix of the respective country, substantial increases in emissions can occur. The sensitivity analysis showed that if the EU electricity mix is used for hydrogen production instead of the Austrian electricity mix, emissions will increase threefold. Thus, the electricity mix has a strong impact on hydrogen production emissions and yellow hydrogen cannot be used in a fully carbon-neutral energy system. CO_2 emissions can only be reduced overall when hydrogen is produced using green electricity. Therefore, a rapid expansion of renewable electricity generation should be one of Europe's greatest efforts and go hand in hand with a sustainable hydrogen economy.
- Fourth, the analysis indicates that pipeline transport is generally cheaper than ship transport and, therefore, preferable, but transport costs depend on distance, making it location-specific. As this work focuses on the current perspective and assumes the transportation of small-medium volumes of hydrogen, the cost savings from imports from North Africa under these specific conditions are limited. However, cost reductions can be anticipated for higher volumes of hydrogen and with further infrastructure expansion.

In general, green hydrogen is expected to play an important role in the transition to a fully renewable energy system, as outlined in the REPowerEU plan (European Commission, 2022a). However, it has been shown that some challenges remain, such as the higher costs compared to conventional hydrogen production, the integration of emissions into adequate pricing mechanisms and the expansion of transport infrastructure, including cost reduction. In addition to focusing on hydrogen imports, equal importance should be given to building hydrogen production capacity within Europe. With this, supply chains can be shortened and a lower energy dependency can be achieved. For hydrogen imports, fossil gas pipelines should be converted when possible since the construction of new pipelines, especially transport by ship, is more expensive. In any case, it should be ensured that fully green hydrogen is imported. When considering blue hydrogen, it is essential to also include methane emissions, which already occur upstream and thus cannot be fully captured.

The final part of this work answers research question four, based on Sayer et al. (2022), by analyzing the total costs of use for fuel cell electric hydrogen buses. The findings indicate that today, the investment costs of the FCEB, with a share of 63%, have a very large influence on the TCU. Currently, the TCU for the FCEB is more than two times higher than that of diesel buses.

With regard to hydrogen production costs, the analysis shows that high utilization of the electrolyzer and low electricity costs are the most important cost factors. Constant utilization of the electrolyzer, shown under the analyzed operation model *power grid,* is the most favorable option. In this specific case, due to the high investment costs of the electrolyzer, the resulting costs of hydrogen are 4.77 € per kg/H_2, compared to 6.27 € per kg/H_2 in the operation model *market-driven* and 6.41 € per kg/H_2 in the *direct line* case.

Additionally, the costs of electricity used in the electrolyzer are important for the economics of the FCEB. It can be concluded that the higher the electricity prices on the market are, the more unfavorable conditions are for the economics of hydrogen from electrolyzers. An optimization regarding electricity costs was carried out in the analyzed market-driven model. In this case, hydrogen is produced only when the market price for wind power is very low or negative, as selling wind power on the wholesale market otherwise yields higher revenues than producing hydrogen.

It is important to note that only the costs associated with hydrogen production, excluding CO_2 costs, were considered in the analysis. Environmental restrictions (e.g., a requirement of a certain amount of green fuel to be used or restrictions on only green hydrogen use) were neglected. If it were decided to produce only green hydrogen, the market-driven model would be preferred, as in that case, hydrogen is being produced at times with low or even negative electricity prices. But if we assume a constant operation of the electrolyzer, purely green hydrogen production will not be possible as grey electricity from the power grid will be used.

In the future, cost reductions due to learning effects are expected to take place for the FCEB as well as for the electrolyzer. This means that investment costs are expected to decrease gradually for both technologies with increasing numbers of FCEB and installed electrolyzer capacity over the next decades. However, the corresponding conclusion is that it will take some time until these cost reductions are reached. In the short term, investment subsidies could further reduce investment costs and accelerate the number of both, buses and electrolyzers deployed. One example of such incentives is the 45% investment cost reduction for a newly installed electrolyzer, as introduced in the EAG in Austria.

In addition, in the future, the introduction of a higher CO_2 price will make hydrogen as a fuel more competitive with diesel. However, given the current electricity market design, the electricity price is also likely to increase. This is due to the fact that marginal costs of fossil generation will remain the price-setting power plant during periods of peak residual load. However, higher electricity market prices make it more attractive for the electric utility owning wind power to sell the wind electricity on the wholesale market rather than use it for hydrogen production.

Regarding the market uptake of FCEBs, in addition to a decrease in investment costs due to technological learning, investment subsidies and a higher CO_2 price for fossil fuels, the implementation of higher environmental and emission standards and additional policies for emission reductions, such as emission-free zones or diesel bans, is very important. The major final conclusion of this part is, however, that today severe policy interferences, such as subsidies for FCEB as well as electrolyzers and restrictions on fossil energy, are necessary to make FCEBs competitive with conventional buses in the coming years.

Given the broad scope of possibilities, this thesis concentrated on selected aspects concerning storage of electricity. The methodologies and modeling framework introduced can be further refined and expanded to incorporate new developments and research in this area. In the first part of the thesis, which focuses on energy system modeling, other flexibility measures are only indirectly addressed. However, it is important to consider other flexibility measures, such as demand-side options, demand response, or grid expansion, as these factors partly compete with each other. Additionally, in future model extensions, bidirectional coupling with other sectors should be integrated to utilize potential surpluses for purposes beyond the hydrogen integration included in this work (for example for other power-to-x solutions). In this case, this coupling would affect parts of the electricity not needed in the electricity system, thus not unlocking additional storage opportunities but aiming for the most cost-effective and efficient utilization of negative residual load and potential consumption shifting. Further extensions could also be made on the demand side, with specific strategies for mobility demand management (e.g., better load management, vehicle-to-grid, etc.) as well as increased flexibility of small scale HPs, although the opportunities here tend to be more limited (Schöniger et al., 2024).

In this work, variable renewable generation profiles were developed based on historical profiles. Although the input data were based on different weather years, the model assumes perfect foresight for optimizing storage and dispatchable generators. In future work, including forecasting would be important to make the modeling more realistic. Prediction, especially for wind and over longer time horizons using weather forecast models, is challenging due to rapid atmospheric changes. However, the electricity market relies heavily on such forecasts. Therefore, integrating such models into electricity model analyses would be advantageous. Additionally, the influence of climate change on the electricity system is increasingly significant and coupling climate models with electricity system models will also be essential in the future, albeit with significant challenges due to the enormous volume of data involved.

Given the ongoing dynamic and often unpredictable developments in the energy market, as well as the general uncertainties associated with long-term forecasts, it is further recommended to continuously update cost calculations. The one-factor approach used in this work for future cost calculation could be expanded in future research to a two-factor model. In two-factor models, not only is cumulative production/installed capacity considered, but also research and development expenditures, which can contribute to cost reduction (Kouvaritakis et al., 2000). Neglecting the influence of research and development can lead to an overestimation of the impact of production in one-factor approaches, especially for technologies in early market phases. Consequently, there is a relatively low elasticity regarding the learning effects of research expenditures and capacity expansion, leading to the conclusion that research expenditures cannot be substituted by production and vice versa (Jamasb, 2006). However, this increases the problem of already challenging data collection for cumulative production with regard to research expenditures, leading to further significant uncertainties. Extending the component-based approach to all technologies would also be another possibility, although a comparison of the results of the component-based approach with the one-factor learning rate approach by Böhm et al. (2019) found both approaches to be appropriate.

Furthermore, it is recommended to include additional storage technologies in future works, such as pumped heat energy storage for long-term storage or gravity energy storage, as mentioned in the literature. This approach allows for adaptation to unforeseen technological breakthroughs or shifts, potentially favoring emerging, more efficient technologies. Another potential method extension could involve integrating a metric for the manufacturing emissions of each technology, allowing for an assessment not only based on technical and economic criteria but also on environmental considerations. The availability of raw materials, especially for battery technologies, is expected to play a significant role in future developments, with cobalt-free batteries already being developed due to extraction conditions and cost considerations (European Commission, 2024; MIT, 2024). Therefore, incorporating indicators reflecting these aspects and raw material availability could additionally provide valuable insights into future trends.

In order to include all external costs of hydrogen production, further research is needed, especially regarding the differences between green and yellow hydrogen. Additionally, a strong emphasis should be placed on greening the electricity mix worldwide. Some other lower carbon hydrogen production methods also need further research, especially on upstream emissions of natural gas and its influence on the overall emissions of blue and turquoise hydrogen.

Lastly, in future research, it should be analyzed how hydrogen storage could impact the economic performance of FCEB. In this work, it was assumed that the amount of hydrogen produced per day is constant for all modes analyzed, as the buses need to be refueled regularly and the small storage capacity is only used for a short period, typically one to two days. In the future, it should be analyzed whether hydrogen production could be optimized on a weekly basis using storage to better respond to longer periods of low electricity prices.

However, it should also be noted that significant developments have occurred in hydrogen applications since the work on the case study was completed. In general, hydrogen applications face the challenge that the efficiencies of the entire chain, from production to end-use technologies, are relatively low. Specifically in the transportation sector, good EV alternatives have been developed, largely due to the rapid improvements in battery range and costs. In these cases, direct electricity applications offer higher efficiencies and lower energy consumption, making them more suitable. While the debate between batteries and fuel cells was still open a few years ago, it now seems that batteries are regarded as the better alternative. This is especially true for passenger cars, based on user and production perspectives, as well as at the European Union level (with some exceptions). Plötz (2022) argues that it is already too late to create a viable market for hydrogen-powered passenger cars. Even in the case of trucks, which are still frequently cited as a potential application for hydrogen, a decision must be made soon regarding whether the niche is substantial enough to justify further development (Plötz, 2022). Meanwhile, battery technologies are making significant advancements in the freight sector, leaving hydrogen as a feasible option primarily for transporting very heavy loads to remote areas.

Regarding the development of the classification for green hydrogen, the European Commission's first Delegated Act defines the conditions under which hydrogen can be considered a renewable fuel of non-biological origin. The Act specifies the "additionality" principle for hydrogen. To qualify as renewable, hydrogen production using electrolyzers must be linked to new sources of renewable electricity. This requirement is designed to ensure that generating renewable hydrogen contributes to an overall increase in the amount of renewable energy supplied to the grid, exceeding the current levels. This aspect was considered in the calculations of this thesis, assuming that new additional PV or wind generation capacities would be built for green hydrogen production. However, there remains an ongoing debate between industry stakeholders, who argue that this rule is too stringent and makes green hydrogen too costly and non-governmental organizations, who criticize it as insufficiently strict. An initial study on this topic by Brandt et al. (2024) finds that permitting a diverse electricity mix does not automatically result in higher emission intensity.

Another aspect not addressed in this work due to time lags in publications is the energy crisis that has dominated European Union policy over the past two years, particularly with respect to energy security amid rising energy prices. In terms of energy security, a critical concern is that many countries continue to rely heavily on fossil fuels, particularly natural gas. An increased expansion of renewable energy sources would address this issue and also provide a long-term solution to the energy price problem. The surge in energy prices could not be accounted for in the present work, but it has undoubtedly further complicated the energy transition. The European Union and its member states face the challenge of advancing the energy transition while balancing economic, environmental and social considerations. The energy crisis has exacerbated energy poverty, with high energy prices disproportionately affecting low-income households. Addressing this issue requires targeted interventions to ensure that the energy transition is equitable and inclusive. In this context, energy communities are seen as a promising development. However, simply establishing energy communities will not be sufficient. It is also crucial to ensure energy justice by including lower-income households through reduced membership fees and collaboration with social housing providers and social services (Kerneïs, 2023).

List of papers

Ajanovic, A., Sayer, M., Haas, R., 2024. On the future relevance of green hydrogen in Europe. Appl. Energy 358, 122586. https://doi.org/10.1016/j.apenergy.2023.122586

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List of Figures

List of Tables

Appendices

A. Nomenclature

See Table 25.

Table 25: Nomenclature (if not otherwise specified then MW_{el} and MWh_{el})

	Units	Description
Sets:		
$i \in I$	Fossil, waste, biomas, biomethane	Dispatchable power plants
$sto \in STO$	PSH, SH, battery and hydrogen storage	Storage technologies
$t \in T$	Hours	Time
Parameters:		
c	€/MWh	Variable costs
c_{CO2}	€/MWh	CO_2 costs
c_{fuel}	€/MWh	Fuel costs
$c_{O\&M}$	€/MWh	Operation and maintenance costs
$E_{bat,fin}$	MWh	Final energy stored in the battery
$E_{bat,init}$	MWh	Initial energy stored in the battery
$E_{H2,init}$	MWh	Initial energy stored in the hydrogen storage
$E_{inflow,t}$	MWh	Hourly natural water inflow into the hydro reservoir
$E_{sto}max$	MWh	Maximum energy capacity of the storage unit
$E_{trans,fin}$	MWh	Final virtual import export storage capacity
$E_{trans,init}$	MWh	Initial virtual import export storage capacity
f_{DoD}	Between 0 and 1	Depth-of-discharge (DOD) rate
f_{grid}	Between 0 and 1	Curtailment factor due to grid congestion
$f_{inj/wit}$	Between 0 and 1	Injection to withdawl factor
$f_{PV,t}$	Between 0 and 1	Hourly historical power factor of PV dependent on the climatic conditions of the chosen year
$f_{wind,t}$	Between 0 and 1	Hourly historical power factor of wind dependent on the climatic conditions of the chosen year
$P_{EV,t}$	MW	Hourly load of EVs
P_{exp_max}	MW	Maximum export power
$P_{H2,injection\_max}$	MW_{H2}	Maximum hydrogen injection capacity
$P_{H2,withdrawal\_max}$	MW_{H2}	Hydrogen storage withdrawal capacity
$P_{HP,t}$	MW	Hourly load of HPs

P_{i_max}	MW	Installed capacity of dispatchable generation
P_{imp_max}	MW	Maximum import power
$P_{load,t}$	MW	Hourly load/demand dependent on the chosen year
$P_{other,t}$	MW	Hourly load of historical load
P_{PV_max}	MW	Installed capacity of PV generation
$P_{PV,t}$	MW	Hourly generation power of PV
P_{RE_max}	MW	Installed capacity of renewable generation
$P_{RE,t}$	MW	Hourly generation power of renewable electricity
$P_{river,t}$	MW	Hourly generation power of run-of-river hydroelectricity
$P_{RSL,t}$	MW	Hourly residual load
P_{sto,in_max}	MW	Maximum storage charging power
P_{sto,out_max}	MW	Maximum storage discharging power
P_{wind_max}	MW	Installed capacity of wind generation
$P_{wind,t}$	MW	Hourly generation power of wind
$\eta_{sto,in}$	Between 0 and 1	Efficiency of storage charging
$\eta_{sto,out}$	Between 0 and 1	Efficiency of storage discharging
Variables:		
$E_{sto,H2,fin}$	MWh	Final energy stored in the hydrogen storage
$E_{sto,t}$	MWh	Hourly energy stored in storage technology
$E_{trans,t}$	MWh	Hourly energy exported (modeled as virtual storage plant)
$P_{curt,grid,t}$	MW	Hourly power of curtailment due to grid congestion
$P_{curt,t}$	MW	Hourly power of curtailment
$P_{exp,t}$	MW	Hourly power of exports
$P_{i,t}$	MW	Hourly power by dispatchable power plants
$P_{imp,t}$	MW	Hourly power of imports
$P_{sto,in,t}$	MW	Hourly power consumption of storage technologies charging
$P_{sto,out,t}$	MW	Hourly power output of storage technologies discharging

B. Formal description of the model

The following section is an addition to Section 3.1.1 and provides a more detailed explanation of the model description.

The load variable (electricity demand) includes separate hourly time series for HPs ($P_{HP}, in\ MW$) and EVs ($P_{EV}, in\ MW$), which were modeled as electric loads through the AIT load generator (AIT, 2023a, 2023b) and other load ($P_{other}, in\ MW$), based on historical data of representative weather years:

$$P_{load,t} = P_{HP,t} + P_{EV,t} + P_{other,t} \qquad \forall t \in T \qquad (MW) \qquad (B.1)$$

The power of renewable electricity includes run-river hydro ($P_{river}, in\ MW$), wind ($P_{wind}, in\ MW$) and PV ($P_{PV}, in\ MW$):

$$P_{RE,t} = P_{river,t} + P_{wind,t} + P_{PV,t} \qquad \forall t \in T \qquad (MW) \qquad (B.2)$$

The calculation of electricity generation from wind and PV sources involves multiplying the hourly historical power factors ($\mathrm{f_{wind/PV}}, in\ MW/MW$) of different weather years by the installed capacities of wind and PV systems ($\mathrm{P_{wind/PV}}max, in\ MW$), which vary across different scenarios. Enhanced wind turbine efficiency has been considered in this calculation.

$$\mathrm{P_{wind,t}} = \mathrm{f_{wind,t}}\ \mathrm{P_{wind\_max}} \qquad \forall t \in T \qquad (MW) \qquad (B.3)$$

$$\mathrm{P_{PV,t}} = \mathrm{f_{PV,t}}\ \mathrm{P_{PV\_max}} \qquad \forall t \in T \qquad (MW) \qquad (B.4)$$

Hydroelectric power plants are aggregated into run-of-river hydroelectricity, SH and PSH capacities. Run-of-river hydroelectricity is included in the must-feed renewable capacities, while SH and PSH capacities are modeled as dispatchable storage of electricity, restricted by natural inflows derived for different meteorological conditions and the filling levels of water reservoirs.

Some constraints define that the hourly generation of all aggregated dispatchable power plants and storage technologies has to be lower or equal to the installed capacity ($\mathrm{P_i}max, in\ MW$) and the maximum storage charging ($\mathrm{P_{sto,in}}\,max, in\ MW$) and discharging power ($\mathrm{P_{sto,out\_max}}, in\ MW$):

$$\sum_{i \in I}(\mathrm{P_{i,t}} - \mathrm{P_i}max) \leq 0 \qquad \forall t \in T \qquad (MW) \qquad (B.5)$$

$$\sum_{sto \in STO}(\mathrm{P_{sto,in,t}} - \mathrm{P_{sto,in}}\,max) \leq 0 \qquad \forall t \in T \qquad (MW) \qquad (B.6)$$

$\sum_{sto \in STO}(\mathrm{P}_{\mathrm{sto,out,t}} - \mathrm{P}_{\mathrm{sto,out}} max) \leq 0 \qquad \forall t \in T \qquad \text{(MW)} \qquad \text{(B.7)}$

The parameter definition of the hydrogen storage system is composed of different components and is therefore explained in more detail. The parameter maximum storage charging ($\mathrm{P}_{\mathrm{H2,in}}\, max, in\ MW$) consists of the installed electrolyzer capacity for each scenario. The maximum hydrogen injection capacity ($\mathrm{P}_{\mathrm{H2,injection}}\, max, MW_{H2}$) is accordingly reduced by the overall efficiency of the conversion step and compression ($\eta_{\mathrm{H2,in}}$) and results in the maximum amount of hydrogen that can be stored in the storage tank every hour.

$$\mathrm{P}_{\mathrm{H2,injection}}\, max = \mathrm{P}_{\mathrm{H2,in}}\, max\ \eta_{\mathrm{h2,in}} \qquad (\mathrm{MW_{H2}}) \qquad \text{(B.8)}$$

The withdrawal capacity of the hydrogen storage facility was selected according to current data from gas storage facilities in depleted gas fields from RAG, as no data is yet available for hydrogen storage facilities (RAG, 2023). The maximum injection and withdrawal capacity of natural gas storage sites of RAG Austria is currently 26.6/31.9 GW. In this relationship, referred to as injection/ withdrawal factor ($\mathrm{f}_{\mathrm{inj/wit}}$), the hydrogen storage withdrawal capacity ($\mathrm{P}_{\mathrm{H2,withdrawal}}\, max, MW_{H2}$) has been set up. To further derive the ($\mathrm{P}_{\mathrm{H2,out}}\, max, in\ MW$) of the hydrogen storage system the withdrawal capacity has to be multiplied by the overall efficiency of the re-electrification process ($\eta_{\mathrm{H2,out}}$).

$$\mathrm{P}_{\mathrm{H2,withdrawal}}\, max = \mathrm{P}_{\mathrm{H2,injection}}\, max\ \ \mathrm{f}_{\mathrm{inj/wit}} \qquad (\mathrm{MW_{H2}}) \qquad \text{(B.9)}$$

$$\mathrm{P}_{\mathrm{H2,in}}\, max\ = \mathrm{P}_{\mathrm{H2,withdrawal}}\, max\ \eta_{\mathrm{H2,out}} \qquad \text{(MW)} \qquad \text{(B.10)}$$

The upper limits of the energy stored in the storage capacity are restricted by the maximum energy capacity ($E_{sto} max, in\ MWh$) and the lower limits by the depth-of-discharge (DOD) rate ($\mathrm{f}_{\mathrm{DOD}}$), of the respective technology and are considered as follows:

$$\sum_{sto \in STO}(\mathrm{E}_{\mathrm{sto,t}} - \mathrm{E}_{\mathrm{sto\_max}}\,(1 - \mathrm{f}_{\mathrm{DOD}}) \leq 0 \quad \forall t \in T \qquad \text{(MWh)} \qquad \text{(B.11)}$$

$$\sum_{sto \in STO}(\mathrm{P}_{\mathrm{sto,out,t}} 1 - E_{sto,t-1}) \leq 0 \qquad \forall t \in T \qquad \text{(MWh)} \qquad \text{(B.12)}$$

The non-negativity constraints for dispatchable power plant generation, storage charging and discharging, load and energy stored are given as follows:

$$\sum_{i \in I} \mathrm{P}_{\mathrm{i,t}} \geq 0 \qquad \forall t \in T \qquad \text{(MW)} \qquad \text{(B.13)}$$

$$\sum_{sto \in STO} \mathrm{P}_{\mathrm{sto,t}}\ \geq 0 \qquad \forall t \in T \qquad \text{(MW)} \qquad \text{(B.14)}$$

$$P_{load,t}\ \geq 0 \qquad \forall t \in T \qquad \text{(MW)} \qquad \text{(B.15)}$$

$$\sum_{sto \in STO} \mathrm{E}_{\mathrm{sto,t}} \geq 0 \qquad \forall t \in T \qquad (\mathrm{MWh}) \qquad (\mathrm{B.16})$$

Battery systems are subject to the constraint that their energy stored at the beginning of the regarded year ($\mathrm{E}_{\mathrm{bat,init}}, in\ MWh$) has to be equal to their energy stored at the end of this year ($\mathrm{E}_{\mathrm{bat,fin}}, in\ MWh$):

$$\mathrm{E}_{\mathrm{bat,init}} = \mathrm{E}_{\mathrm{bat,fin}} \qquad (\mathrm{MWh}) \qquad (\mathrm{B.17})$$

Since hydrogen storage facilities offer the biggest energy storage capacities and hydrogen should also be produced for use in other sectors, hydrogen storage facilities are limited to the constraint that at least the energy stored from the beginning of the year ($\mathrm{E}_{\mathrm{H2,init}}, in\ MWh$) must be available at the end of the year ($\mathrm{E}_{\mathrm{H2,fin}}, in\ MWh$). The storage facility remains open at the top in order to be able to show what quantities of hydrogen can be produced for use in other sectors with the given production capacities:

$$\mathrm{E}_{\mathrm{H2,init}} \leq \mathrm{E}_{\mathrm{H2,fin}} \qquad (\mathrm{MWh}) \qquad (\mathrm{B.18})$$

The utilized climate data restrict SH and PSH start and end filling levels.

Cross-border electricity exchanges are modeled using a virtual storage capacity. They are limited by means of an overall import and export (transport) possibility ($\mathrm{E}_{\mathrm{trans,}}, in\ MWh$) in addition to the respective maximum import and export power capacities:

$$\mathrm{E}_{\mathrm{trans,t}} - \mathrm{E}_{\mathrm{trans,t-1}} - \mathrm{P}_{\mathrm{exp,t}}\, 1 + \mathrm{P}_{\mathrm{imp,t}} 1 = 0\ \forall t \in T \qquad (\mathrm{MWh}) \qquad (\mathrm{B.19})$$

$$\mathrm{E}_{\mathrm{trans,init}} = \mathrm{E}_{\mathrm{trans,fin}} \qquad (\mathrm{MWh}) \qquad (\mathrm{B.20})$$

$$\mathrm{P}_{\mathrm{exp,t}} - \mathrm{P}_{\mathrm{exp}} max \leq 0 \qquad \forall t \in T \qquad (\mathrm{MW}) \qquad (\mathrm{B.21})$$

$$\mathrm{P}_{\mathrm{imp,t}} - \mathrm{P}_{\mathrm{imp}} max \leq 0 \qquad \forall t \in T \qquad (\mathrm{MW}) \qquad (\mathrm{B.22})$$

Since the model does not consider regional specifics of the grid, a restriction was implemented that automatically curtails a share of the generation ($\mathrm{f}_{\mathrm{grid}}$) in the event of very high fluctuating feed-in from renewable generation. This is intended to take potential grid overload into account.

$$\mathrm{P}_{\mathrm{curt,grid,t}} = \begin{cases} \mathrm{P}_{\mathrm{RE,t}}\, \mathrm{f}_{\mathrm{grid}} & \text{if } P_{RE,t} \geq \mathrm{P}_{\mathrm{RE}}\, max(1 - \mathrm{f}_{\mathrm{grid}}) \\ 0 & \text{if } P_{RE,t} < \mathrm{P}_{\mathrm{RE}}\, max(1 - \mathrm{f}_{\mathrm{grid}}) \end{cases} \qquad \forall t \in T \quad (\mathrm{MW}) \qquad (\mathrm{B.23})$$

Overall curtailment ($P_{curt}, in\ MW$) is restricted to the power of renewable generation in each hour.

$P_{curt,t} - P_{RE,t} \leq 0$ $\forall t \in T$ (MW) (B.24)

Residual load ($P_{RSL}, in\ MW$) in this work is defined by subtracting all renewable must-feed generators (run-river hydro, wind and PV) from the load (electricity demand of the public grid) for each timestep:

$P_{RSL,t} = P_{load,t} - P_{RE,t}$ $\forall t \in T$ (MW) (B.25)

C. Variable costs and efficiency

See Table 26.

Table 26: Variable costs and efficiency of included power plants and storage technologies

	Variable costs		Efficiency	Source
	(€/MWh$_{th}$)	(€/MWh$_{el}$)		
CCGT fossil	45.04/		0.60	(IEA, 2023b, 2020c; Umweltbundesamt, 2022) Net Zero Emissions by 2050 Scenario
OCGT efficient	65.64		0.41	
OCGT inefficient			0.31	
Biomethane plant	41.00		0.4	(BIP Europe, 2023)
Biomass plant	31.73		0.39/ 0.4	(EU, 2018; Schill and Zerrahn, 2018)
Waste	5.99		0.34	(EU, 2018) and own assumption
PSH		0.95	0.79	(Schill and Zerrahn, 2018; Webb, 2018)
Lithium-ion battery		1.09	0.90	(Lovegrove et al., 2018; Schill and Zerrahn, 2018)
Hydrogen storage		2.02	0.37/ 0.46	(European Commission. Directorate General for Energy. et al., 2023; Lovegrove et al., 2018; MIT, 2022; Welder et al., 2019)

D. Details on the scenario outline and assumptions

This section describes the assumptions underlying the model-based analysis. Sections D a-c each present the respective scenario.

a. Policy scenario (A)

The *policy* scenario *(A)* specifically incorporates existing policy objectives, encompassing the targets outlined in the EAG and the Integrated National Energy and Climate Plan for Austria

(Federal Ministry for Sustainability and Tourism, 2019b). The specific parameters included in the model for the respective scenario are outlined in Table 27.

Table 27: Scenario data policy

Parameter	Unit	2030	2050	Source
Electricity demand:				
Total load/demand incl. grid losses (excluding storage consumption)	TWh	70	80	Own assumptions based on (Haas et al., 2017; Krutzler et al., 2016)
Of which: HPs [10]	TWh	2.7	6.2	(AIT, 2023a; Kranzl et al., 2018)
Of which: EVs	TWh	1.4	5	(AIT, 2023b; SECURES, 2023)
Electricity generation capacities:				
Run-of-river hydroelectricity	MW	6100	7000	(ENTSO-E, 2022; Österreichisches Parlament, 2021)
Wind	MW	7000	10000	(Österreichisches Parlament, 2021)
PV	MW	12000	20000	(Österreichisches Parlament, 2021)
Biomass	MW	650	1000	(Österreichisches Parlament, 2021; Platzenbecker et al., 2019)
Waste	MW	100	500	(Haas et al., 2017; SECURES, 2023)
CCGT Fossil	MW	3000	0	(ENTSO-E, 2022)
CCGT Biomethane	MW	500	1000	Assumption
Storage:				
PSH capacity (turbining/pumping)	MW	5000/4300	6043/ 5206	(ENTSO-E, 2022; SECURES, 2023)
SH capacity	MW	2489	2489	(ENTSO-E, 2022)
Storage charge/discharge capacity grid-scale battery	MW	534	3000	(Porada et al., 2023)
Storage in/out capacity hydrogen	MW	1000/440	5000/ 2200	(BMK, 2022a; RAG, 2023)
Other:				
Import/export capacities	MW	2500	2500	APG assumption

In the context of the *policy* scenario *(A)*, electricity demand (from the public grid) is expected to increase to 73 TWh by 2030 and 83 TWh by 2050. This growth is predominantly due to the ongoing shift from fossil energy sources to EVs and HPs (electric boilers are included in the overall load profile). In this scenario, EVs are anticipated to contribute 1.8 TWh and 6 TWh to

[10] The HP electricity demand for households is estimated to be 2349 GWh in 2030 and 3748 GWh in 2050 according to Kranzl (Kranzl et al., 2018); industry demand according to the AIT load profile generator.

electricity consumption in 2030 and 2050, respectively, while HPs are projected to contribute 3.5 TWh and 9 TWh in the corresponding years. By 2030, approximately 650000 HPs are envisioned to be deployed in Austria, according to the findings of (Suna et al., 2022). The detailed HP input data according to categories for heating and cooling in this scenario is provided in Table 28.

Table 28: Detailed HP input data (AIT, 2023a)[11]

Heat pump categories	Energy (GWh_{th}/a)	Energy (GWh_{el}/a)	Max. Output (MW_{th})	Max. Output (MW_{el})	SCOP
2030:					
Heating - air-to-air Heat Pumps	95.90	36.60	43.90	27.20	2.62
Heating - air-to-water Heat Pumps	3751.40	1311.60	1714.50	1051.60	2.86
Heating - geothermal Heat Pumps	3592.20	888.60	1641.20	338.80	4.04
Hybrid Heat Pumps	1250.50	430.20	571.50	165.60	2.91
Air-Conditioning - air-to-air Heat Pumps	8.50	2.30	14.40	4.40	3.65
Air-Conditioning - air-to-water Heat Pumps	493.90	132.10	838.00	225.90	3.74
Air-Conditioning - geothermal Heat Pumps	337.60	63.90	572.90	86.10	5.28
Sanitary Water - air-to-water Heat Pumps	764.90	253.40	165.60	66.00	3.02
Sanitary Water - geothermal Heat Pumps	235.80	80.00	51.00	17.30	2.95
Industry	1696.50	339.30	193.70	38.70	5.00
2050:					
Heating - air-to-air Heat Pumps	315.30	107.70	157.10	93.30	2.93
Heating - air-to-water Heat Pumps	10073.60	3182.60	5017.20	2973.60	3.17
Heating - geothermal Heat Pumps	2371.60	518.20	1181.60	213.10	4.58
Hybrid Heat Pumps	3357.80	1039.70	1672.40	429.80	3.23
Air-Conditioning - air-to-air Heat Pumps	37.10	9.40	63.00	18.00	3.93
Air-Conditioning - air-to-water Heat Pumps	1753.60	438.50	2975.60	749.60	4.00
Air-Conditioning - geothermal Heat Pumps	302.80	54.10	513.70	72.90	5.59
Sanitary Water - air-to-water Heat Pumps	2350.00	735.90	508.60	202.40	3.19
Sanitary Water - geothermal Heat Pumps	294.50	93.00	63.70	20.10	3.17
Industry	12285.00	2457.00	1402.40	280.50	5.00

[11] For the weather year 2015

As of the end of November 2023, Austria has a cumulative total of 152,122 exclusively electric-powered passenger cars, representing 2.9% of the total national passenger car fleet (BEO, 2023). Future projections within this scenario assume that the EV stock in Austria will comprise around 1 million by 2030 (Suna et al., 2022) and 3 million by 2050. The profiles are divided into user types private and business. For private usage, it is assumed that the average effective usage is 36.25 km/EV/day for weekdays and 26.77 km/EV/day for weekends, with an average energy consumption of 15.75 kWh/100 km. In the car stock for primarily business usage, it is assumed that the average effective usage is 53 km/EV/day for weekdays and 21.07 km/EV/day for weekends, with an average energy consumption of 16.72 kWh/100 km. It is assumed that fast charging can be applied to approximately 80% of the car stock. Beyond meeting heating and mobility needs, additional electricity consumption arises from the ongoing decarbonization efforts in various industries. Additionally, Austria has observed a consistent upward trajectory in total gross electricity consumption across all sectors since 2005, with exceptions during the crises of 2009 and 2020 (BMK, 2023b). This increase is mainly due to economic and population growth, which is also expected in the coming years.

The projections for increases in generation capacity align with the targets of the EAG in this scenario. Water storage capacity expansion is according to the PECD (ENTSO-E, 2022) and a battery storage capacity of 0.5 GW is assumed by 2030, only including large-scale batteries that can operate on the spot market as needed (Porada et al., 2023). Self-consumption-optimized prosumer batteries are not considered in this context. Assumptions about hydrogen production capacities (electrolyzers) are in line with the Austrian national hydrogen strategy (BMK, 2022a). Technical details for hydrogen storage, such as injection and withdrawal capacities, align with the specifications of RAG's overall natural gas storage capacities (RAG, 2023). The DOD rates are 90% for SH, PSH and batteries in line with (IRENA, 2020). This scenario employs assumptions from the APG based on TYNDP 2020 simulations for cross-border electricity exchange capacities. This includes a maximum foreign storage volume of 420 GWh, which corresponds to the assumption of a total export or import capacity of 2.5 GW over 7 days and is being implemented due to the occasional unavailability of import capacities when needed.

b. Renewables and electrification scenario (B)

The *renewables and electrification* scenario *(B)* considers an ambitious expansion of renewable and hydrogen capacities and assumes a high degree of electrification. This anticipates a significant rise in electricity demand for space heating, cooling and electromobility. In order to achieve this, it is assumed that the acceptance of the population and local politicians with regard to renewable power plants in the immediate vicinity has improved. With this, the potential of national renewable resources is being used to their maximum. The generated electricity, coupled with electrolysis capacities, enables hydrogen production to decarbonize sectors that cannot be electrified. The scenario assumes a substantial expansion of the power grid to transport the produced electricity to consumers efficiently. To support this, emphasis is placed on regionally optimizing the distribution of renewable generators and electrolysis capacities. Further details on the specific parameters incorporated into the model for this scenario are provided in Table 29.

Table 29: Scenario data renewables and electrification

Parameter	Unit	2030	2050	Source
Electricity demand:				
Total load/demand incl. grid losses (excluding storage consumption)	TWh	70	80	Own assumptions based on (Haas et al., 2017; Krutzler et al., 2016)
Of which: HPs[12]	TWh	2.7	6.2	(AIT, 2023a; Kranzl et al., 2018)
Of which: EVs	TWh	1.4	5	(AIT, 2023b; SECURES, 2023)
Electricity generation capacities:				
Run-of-river hydroelectricity	MW	6100	7000	(ENTSO-E, 2022; Österreichisches Parlament, 2021)
Wind	MW	7000	10000	(Österreichisches Parlament, 2021)
PV	MW	12000	20000	(Österreichisches Parlament, 2021)
Biomass	MW	650	1000	(Österreichisches Parlament, 2021; Platzenbecker et al., 2019)
Waste	MW	100	500	(Haas et al., 2017; SECURES, 2023)
CCGT Fossil	MW	3000	0	(ENTSO-E, 2022)
CCGT Biomethane	MW	500	1000	Assumption
Storage:				
PSH capacity (turbining/pumping)	MW	5000/4300	6043/ 5206	(ENTSO-E, 2022; SECURES, 2023)
SH capacity	MW	2489	2489	(ENTSO-E, 2022)
Storage charge/discharge capacity grid-scale battery	MW	534	3000	(Porada et al., 2023)
Storage in/out capacity hydrogen	MW	1000/440	5000/ 2200	(BMK, 2022a; RAG, 2023)
Other:				
Import/export capacities	MW	2500	2500	APG assumption

In the *Renewables and electrification* scenario *(B)*, there is a projected increase in electricity demand from the public grid, reaching 79 TWh by 2030 and 95 TWh by 2050. This increase is driven, in part, by the ambitious expansion of electromobility. According to the Environment Agency Austria's WAM scenario, an estimated 1.5 million EVs are anticipated by 2030 (UBA,

[12] The HP electricity demand for households is estimated to be 2349 GWh in 2030 and 3748 GWh in 2050 according to Kranzl (Kranzl et al., 2018); industry demand according to the AIT load profile generator.

2017), resulting in a power requirement of 3 TWh. The 2030 target aligns closely with the annual growth rate observed between 2022 and 2023, rising from 110225 to 152122 units (BEO, 2023). By 2050, 4.4 million vehicles are expected to be on the road, with an electricity demand of 10.3 TWh, reflecting the continued significance of motorized individual transport in this scenario (AIT, 2023b). This is due to the continuing urban sprawl in rural areas and fewer attractive alternatives. However, longer ranges and falling costs mean that the majority of vehicles will be electrically powered. Furthermore, the scenario anticipates a shift towards HPs for space heating and cooling, coupled with a rising demand for living space, evident in a 20% per person rise from 2005 to 2021 (BMK, 2023b). Collectively, these dynamics contribute to heightened demand for electricity for HPs, expected to reach 8 TWh in 2030 and surge to 16 TWh by 2050. These factors together are leading to a higher demand for electricity for HPs.

On the generation side, the *renewables and electrification* scenario *(B)* for 2030 incorporates the ENTSOE's wind capacity projections of 9 GW (ENTSO-E, 2022), aligned with SECURES assumptions (SECURES, 2023). By 2050, this capacity will be expanded to 20 GW, consistent with the AURES project's development trajectory (AURES, 2022). PV capacities in 2030 remain identical to those of the *policy* scenario *(A)*. However, in 2040, based on the integrated Austrian network infrastructure plan's (NIP) Transition scenario, they are augmented to reach 40 GW (BMK, 2023b). The capacity for biomethane CCGT stays constant throughout this scenario at 0.5 GW. In addition, a higher balancing through import and export capacities is also permitted. Electrolysis capacities are concurrently increased to enhance the system's ability to absorb available electricity and potentially distribute hydrogen to other sectors if a surplus exists. As the currently tradable border capacities of 9.1 GW (export) and 8.6 GW (import) represent a theoretical potential and cannot necessarily be called up at the same time, this scenario assumes 6 GW for both available import and export capacities (Suna et al., 2022). All other capacities remain consistent with the *policy* scenario *(A)*.

c. Efficiency scenario (C)

In the *efficiency* scenario *(C)*, it is assumed that conventional electricity consumption decreases gradually through increased efficiency measures. The integration of efficiency measures, coupled with decreased demand in areas such as heating, mobility and other appliances, results in lower electricity demand compared to the previous scenarios, see Table 30.

Implementing energy-efficient practices and conservation initiatives is forecasted to maintain consistent refurbishment rates in the building sector, thereby contributing to a diminishing energy demand within residential spaces. Assumptions underlying this scenario emphasize a proactive environmental consciousness among the population and industries, catalyzing concerted efforts toward electricity-saving initiatives. Essential measures to reduce consumption and enhance efficiency are introduced.

Table 30: Scenario data efficiency

Parameter	Unit	2030	2050	Source
Electricity demand:				
Total load/demand incl. grid losses (excluding storage consumption)	TWh	70	80	Own assumptions based on (Haas et al., 2017; Krutzler et al., 2016)
Of which: HPs[13]	TWh	2.7	6.2	(AIT, 2023a; Kranzl et al., 2018)
Of which: EVs	TWh	1.4	5	(AIT, 2023b; SECURES, 2023)
Electricity generation capacities:				
Run-of-river hydroelectricity	MW	6100	7000	(ENTSO-E, 2022; Österreichisches Parlament, 2021)
Wind	MW	7000	10000	(Österreichisches Parlament, 2021)
PV	MW	12000	20000	(Österreichisches Parlament, 2021)
Biomass	MW	650	1000	(Österreichisches Parlament, 2021; Platzenbecker et al., 2019)
Waste	MW	100	500	(Haas et al., 2017; SECURES, 2023)
CCGT Fossil	MW	3000	0	(ENTSO-E, 2022)
CCGT Biomethane	MW	500	1000	Assumption
Storage:				
PSH capacity (turbining/pumping)	MW	5000/4300	6043/ 5206	(ENTSO-E, 2022; SECURES, 2023)
SH capacity	MW	2489	2489	(ENTSO-E, 2022)
Storage charge/discharge capacity grid-scale battery	MW	534	3000	(Porada et al., 2023)
Storage in/out capacity hydrogen	MW	1000/440	5000/ 2200	(BMK, 2022a; RAG, 2023)
Other:				
Import/export capacities	MW	2500	2500	APG assumption

[13] The HP electricity demand for households is estimated to be 2349 GWh in 2030 and 3748 GWh in 2050 according to Kranzl (Kranzl et al., 2018); industry demand according to the AIT load profile generator.

The total electricity demand in 2030 in this scenario is 70 TWh, resulting from significant efficiency improvements and a slower market uptake for EVs and HPs. By 2050, the electricity demand is projected to rise to 80 TWh, slightly surpassing the estimate provided in the renewable energy scenario by the Environment Agency Austria (78.7 TWh) (Haas et al., 2017; Krutzler et al., 2016). Regarding HP development, the trajectory from (Kranzl et al., 2018) heating scenario is followed. The total electricity demand for HPs rises from 1.45 TWh in 2015 to 2.35 TWh in 2030 and 3.75 TWh in 2050 for buildings. Based on the AIT load profile generator, the corresponding industrial HP demand adds up to a total demand of 2.7 TWh in 2030 and 6.2 TWh in 2050 (AIT, 2023a). It is noteworthy that the overall electricity consumption for heating in the heat scenario is decreasing. This is a consequence of the phasing out of direct electric heating and the reduced heating load of buildings with HPs, primarily in newly constructed or thermally renovated existing structures. Additionally, a lower heat demand is anticipated due to expected climate change. All mentioned factors are incorporated into the overall demand within the *efficiency* scenario *(C)*.

Regarding EVs, a lower market penetration (700000 units in 2030 and 2500000 in 2050) is projected within this scenario. Consequently, the electricity demand for EVs is anticipated to be only 1.4 TWh in 2030 and 5 TWh in 2050. The lower electricity demand is also attributed to enhanced efficiency, with an average energy consumption decreasing to 12 kWh/100 km compared to 15.75 kWh/100 in other scenarios. The adoption of smaller vehicles also influences this efficiency gain.

On the generation side, renewable capacities are slightly reduced compared to the preceding scenarios due to lower electricity demand. The only exception is 2030, where the same expansion assumptions as in the *policy* scenario *(A)* are adopted, as the EAG goals have already been finalized. Otherwise, the assumptions remain consistent with those in the other scenarios.

E. Detailed results

This section contains tables providing supplementary information to Section 3.2. Tables 34-39 display the detailed modeling results (generation and consumption) for the three analyzed weather years (weather year 2015-2017).

Table 31: Modeling results for electricity generation of the three scenarios and the weather year 2015 in TWh

Parameter	A 2030	B 2030	C 2030	A 2050	B 2050	C 2050
Demand (including HPs, EVs and grid losses)	73.05	79.02	70.11	83.20	94.93	80.38
PSH consumption	4.19	2.14	5.19	8.25	15.30	5.85
Battery consumption	0.33	0.25	0.39	1.55	2.22	1.44
Power-to-gas (Hydrogen)	3.93	4.66	4.34	18.63	38.63	15.49
Export	1.19	2.09	1.31	0.97	3.48	0.51
Curtailment	0.55	0.00	1.23	0.40	7.87	0.12
Total	83.24	88.16	82.57	112.99	162.43	103.78

Table 32: Modeling results and initial assumptions by demand type (including charging losses) of the three scenarios and the weather year 2015 in TWh

Parameter	A 2030	B 2030	C 2030	A 2050	B 2050	C 2050
Demand (including HPs, EVs and grid losses)	73.05	79.02	70.11	83.20	94.93	80.38
PSH consumption	4.19	2.14	5.19	8.25	15.30	5.85
Battery consumption	0.33	0.25	0.39	1.55	2.22	1.44
Power-to-gas (Hydrogen)	3.93	4.66	4.34	18.63	38.63	15.49
Export	1.19	2.09	1.31	0.97	3.48	0.51
Curtailment	0.55	0.00	1.23	0.40	7.87	0.12
Total	83.24	88.16	82.57	112.99	162.43	103.78

Table 33: Modeling results for electricity generation of the three scenarios and the weather year 2016 in TWh

Parameter	A 2030	B 2030	C 2030	A 2050	B 2050	C 2050
PV	13.28	13.28	13.28	25.57	46.50	23.25
Wind	17.71	22.77	17.71	30.58	50.96	25.48
Run-of-river hydroelectricity	31.18	31.18	31.18	35.78	35.78	35.78
Generation from PSH	8.12	5.91	8.57	11.39	16.34	9.48
Generation from SH	2.03	2.03	2.03	2.03	2.03	2.03
Generation from batteries	0.30	0.22	0.31	1.33	2.18	1.23
Biomass	2.61	2.73	2.39	0.65	0.00	0.67
Waste	0.39	0.41	0.35	0.30	0.00	0.31
Biomethane	1.68	1.76	1.51	0.00	0.00	0.00
Gas turbine	4.14	3.97	2.81	0.00	0.00	0.00
Hydrogen turbine	1.21	1.89	1.30	3.57	1.93	4.63
Import	1.40	2.61	1.48	0.83	3.77	0.57
Total	84.05	88.76	82.92	112.03	159.49	103.43

Table 34: Modeling results and initial assumptions by demand type (including charging losses) of the three scenarios and the weather year 2016 in TWh

Parameter	A 2030	B 2030	C 2030	A 2050	B 2050	C 2050
Demand (including HPs, EVs and grid losses)	73.10	79.26	70.45	83.59	95.37	80.73
PSH consumption	4.36	1.57	4.93	8.49	14.74	6.08
Battery consumption	0.33	0.24	0.35	1.48	2.43	1.37
Power-to-gas (Hydrogen)	3.26	5.07	3.51	17.44	37.29	14.62
Export	1.40	2.61	1.48	0.83	3.77	0.57
Curtailment	1.60	0.00	2.21	0.21	5.89	0.06
Total	84.05	88.76	82.92	112.03	159.49	103.43

Table 35: Modeling results for electricity generation of the three scenarios and the weather year 2017 in TWh

Parameter	A 2030	B 2030	C 2030	A 2050	B 2050	C 2050
PV	13.07	13.07	13.07	25.17	45.75	22.88
Wind	21.15	27.20	21.15	36.51	60.85	30.43
Run-of-river hydroelectricity	30.28	30.28	30.28	34.74	34.74	34.74
Generation from PSH	8.78	6.72	9.17	10.23	16.55	8.52
Generation from SH	1.91	1.91	1.91	1.91	1.91	1.91
Generation from batteries	0.37	0.24	0.38	1.39	2.71	1.30
Biomass	2.05	1.84	1.78	1.22	0.68	1.24
Waste	0.31	0.28	0.26	0.61	0.33	0.62
Biomethane	1.18	1.14	1.12	1.11	0.29	1.03
Gas turbine	4.21	4.08	3.23	0.00	0.00	0.00
Hydrogen turbine	1.18	2.03	1.17	2.88	2.52	3.36
Import	1.45	2.42	1.26	1.42	3.70	1.01
Total	85.94	91.21	84.79	117.19	170.04	107.04

Table 36: Modeling results and initial assumptions by demand type (including charging losses) of the three scenarios and the weather year 2017 in TWh

Parameter	A 2030	B 2030	C 2030	A 2050	B 2050	C 2050
Demand (including HPs, EVs and grid losses)	73.36	79.96	70.97	84.02	96.52	81.00
PSH consumption	5.70	3.09	6.18	7.53	15.50	5.37
Battery consumption	0.41	0.27	0.42	1.55	3.01	1.44
Power-to-gas (Hydrogen)	4.13	5.46	4.32	22.29	43.01	18.11
Export	1.45	2.42	1.26	1.42	3.70	1.01
Curtailment	0.90	0.00	1.63	0.39	8.30	0.10
Total	85.94	91.21	84.79	117.19	170.04	107.04

F. Background on hydrogen

This section, which is based on the review papers by Ajanovic et al. (2022) and Ajanovic et al. (2024), provides an in-depth overview of hydrogen. The structure is as follows: Section a presents the history of hydrogen, while Section b details its current status. Section c examines hydrogen production within the European Union as well as the global market. In Section d, various hydrogen production technologies (the different colors of hydrogen) are discussed, including grey, blue, turquoise, green, purple and others. Finally, Section e explores the potential applications of hydrogen across different sectors.

a. History of hydrogen

Hydrogen was first identified as a distinct element by Henry Cavendish in 1766. It was later given its name by Antoine Lavoisier in 1788, derived from the Greek words meaning "water" and "born of." In 1800, William Nicholson and Sir Anthony Carlisle discovered that applying electric current to water produced hydrogen and oxygen gases, which became known as "electrolysis." In 1807, Isaac de Rivas created the first hydrogen gas-powered vehicle using internal combustion power, although it was an unsuccessful design. The fuel cell effect was discovered in 1838 by the Swiss chemist Christian Friedrich Schoenbein, which involves combining hydrogen and oxygen gases to produce water and an electric current. One year later, William Grove constructed a gaseous voltaic battery based on Schoenbein's findings (Trubin, 2018).

Since more than a century ago, hydrogen has been discussed as a major energy carrier in the energy system. In the book "The Mysterious Island," published already in 1874, hydrogen and oxygen were seen by the French science-fiction writer Jules Verne as the core energy carriers of the future energy system. Jules Verne's vision preaches to transform the energy system from coal, which was at that time the dominant fossil energy (Adolf and Fischedick, 2017), to hydrogen, produced through breaking down water (using electrolysis). The substantial difference between coal and hydrogen is that the latter is an energy carrier, not a primary energy source.

Hydrogen was subsequently used in industrial processes for ammonia synthesis, starting around 1920. Furthermore, until the 1960s, the so-called town gas, which consisted of 50% hydrogen, was used in many cities for street lighting and households (Ball and Weeda, 2015). Since 1958, hydrogen was used in NASA's space program, primarily for rocket propulsion and as a fuel for fuel cells. However, also other applications for hydrogen were being researched at the same time and the first PEM fuel cell was produced. The term hydrogen economy emerged in the 1970s and was first used by General Motors to push hydrogen in the transportation sector (Ball and Weeda, 2015). In general, the rediscovery of hydrogen for usage in sectors other than industrial feedstocks was due to the oil crises with the rising prices and the greater awareness of environmental issues that started around that time. In the mid-1980s, the idea of a hydrogen economy in the energy sector was further developed by the German Center for Aeronautics and Space (DLR), which proposed a realistic way of using various primary energy sources to generate electricity and then producing hydrogen by electrolysis (Groll, 2023).

The call for hydrogen re-started again at the beginning of the 21st century based on the technological developments achieved in the 1990s (e.g., the first proton-exchange membrane fuel cell (PEMFC) car in 1993). In 2002, Rifkin (2003) discussed hydrogen as an environmentally benign energy carrier to be used universally, bringing the world closer to a sustainable energy system. In his seminal contribution, "The Hydrogen Economy," Rifkin envisions the dawn of a new economy powered by hydrogen that will fundamentally change the nature of our market, political and social institutions, just as the switch to coal and steam power did at the beginning of the industrial age. Around that time, the public attention on fuel cell vehicles (FCVs) peaked and in 2021 the global FCVs stock was approximately 51000 vehicles worldwide (IEA, 2022a). The major hydrogen and fuel cell developments from the discovery of the fuel cell effect in 1839 to the current European hydrogen strategy for a climate-neutral Europe can be seen in Figure 66.

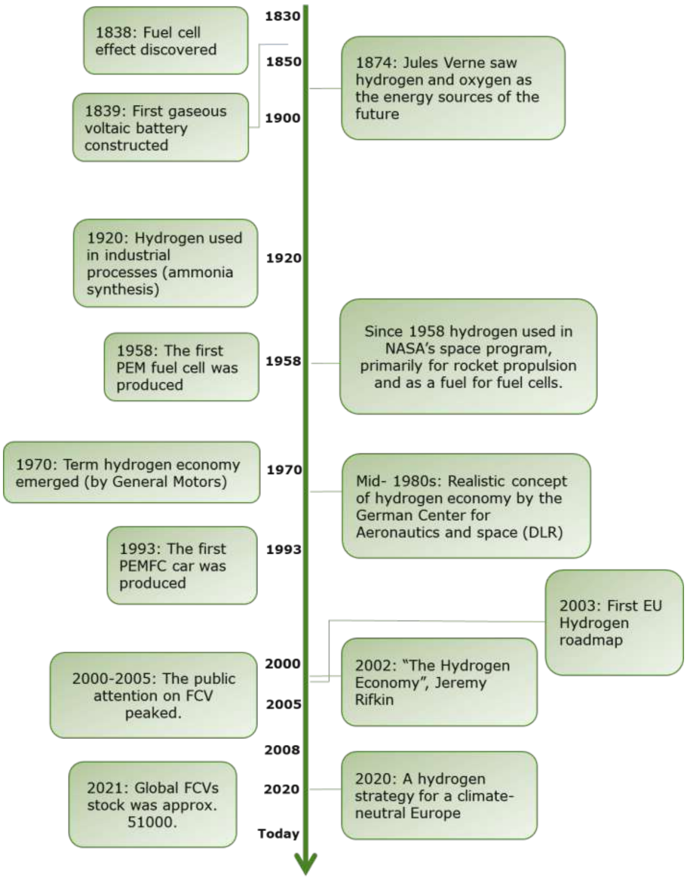

Figure 66: The major milestones in the development of hydrogen and its use

Hydrogen is oft seen as a solver for many problems related to energy use and resulting emissions. The EU pursues an ambitious policy regarding energy and climate change mitigation, reducing air pollution and energy efficiency. The possible benefits of hydrogen to realizing these goals have been recognized by European policymakers and stakeholders already in the early 2000s (European Commission, 2003). The EU strategies for changing the prevailing coal-based fossil energy system towards a more environmentally benign and sustainable one consist of ongoing technological R&D using and converting renewable sources into easily storable energy carriers like hydrogen and implementing corresponding promotion strategies.

In 2003, the European Commission presented a roadmap for an integrated energy system based on hydrogen and fuel cells to look up to 2050 (European Commission, 2003). However, neither the goals regarding hydrogen production and dissemination technologies, envisaged in the early 2000s nor the targets regarding fuel cells and hydrogen systems have been met so far.

One year earlier, in the United States a document named, "A National Vision of America's Transition to a Hydrogen Economy" was published by the United States Department of Energy ((DOE, 2002), where all key areas including the transition to a hydrogen economy were discussed. It is interesting that none of the previously listed hydrogen visions prominent and explicitly mentioned the technologies and the primary energy sources from which hydrogen should be produced. This is still not yet decided although some further work on hydrogen has been published.

Some years ago, the IEA issued a hydrogen technology roadmap analyzing the relevance of hydrogen for several stakeholders and providing an action plan to bring about a transition towards a worldwide energy system based on the energy carrier hydrogen (IEA, 2015). This was followed by another comprehensive assessment of the current status of hydrogen, including an outlook into the future (IEA, 2019a). Currently, a comprehensive hydrogen review is issued each year by the IEA (IEA, 2022a).

b. Status quo of hydrogen

The current share of primary energy carriers in global hydrogen production is depicted in Figure 67. Globally, 71% of hydrogen is produced by SMR as this is the most mature and cheapest way of hydrogen production. 27% are produced by gasification of coal, with slightly higher production costs but easier access and storage of the primary fuel. Nevertheless, with the rise of renewable electricity production and the resulting surplus of electricity, hydrogen production from electrolysis will become more economically competitive in the future.

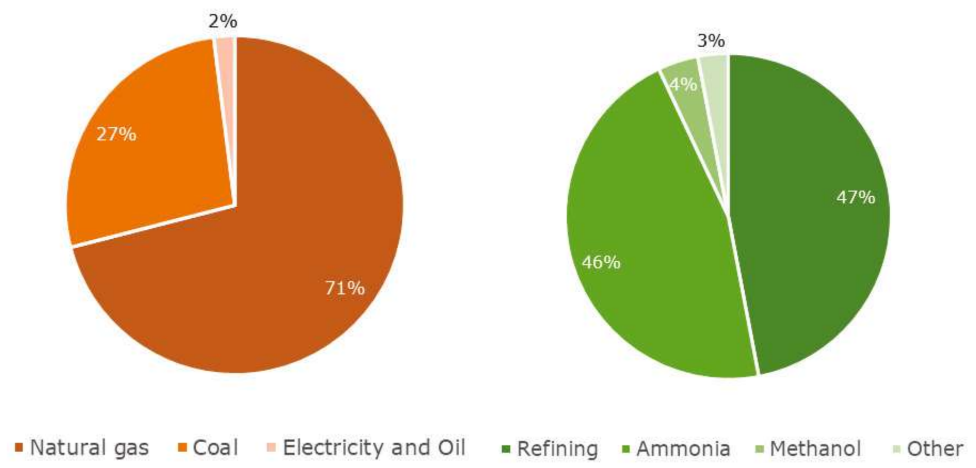

Figure 67: Share of energy carriers in hydrogen production (left) (IEA, 2019a) and share of hydrogen use for different purposes (right) (IEA, 2019a; Sterner and Stadler, 2019)

Regarding the use of hydrogen currently various industrial as well as chemical processes are prevailing. Ammonia processing presents about 46% of worldwide hydrogen use and 47% in refineries dominate, 4% adds up for methanol and only 3% is dedicated to other applications, such as the production of metals, mobility, inputs to the electronics and food conversion, see Figure 67.

As shown, since all hydrogen currently used is produced from fossil resources, green hydrogen offers enormous benefits in the above-mentioned areas. Replacing fossil (grey) hydrogen with green hydrogen can avoid emissions. Another advantage of the future use of hydrogen is that there are almost no emissions at the point of use (except nitrogen oxides (NOx) during combustion). Furthermore, hydrogen can be used flexibly for different end uses (feedstock, storage, transport, etc.). Especially concerning storage, hydrogen has the advantage that large amounts of energy (TWh) can be stored e.g., underground in former natural gas reservoirs or salt caverns for a long time with little losses. The problems are the high conversion losses and the low volumetric energy density of hydrogen.

The efficiencies of hydrogen as a fuel are 33% (42% in the future), which is lower than direct electrification with 77% (81% in the future) but higher than the use of conventional fuels such as fossil petrol (engine efficiency for cars 30%) and fossil diesel (engine efficiency for cars 36%) (Transport&Environment, 2020). Hydrogen also has a higher conversion efficiency than otherwise frequently mentioned synthetic fuels such as power-to-liquid (petrol in the future 18% and diesel in the future 22% (Transport&Environment, 2020).

Until now, hydrogen was mostly produced using the cheapest production processes without consideration of the impact on the environment. Since SMR is the most developed and cheapest commercial method for hydrogen production, the largest amount of hydrogen is produced in this way. Overall, around 900 Mt of CO_2 emissions per year are released into the atmosphere by worldwide hydrogen production (IEA 2021c). With the pressing environmental problems, interest in low-carbon hydrogen production is increasing. However, this increase is still very slow due to higher hydrogen production costs.

c. Hydrogen production in the EU and a worldwide market for hydrogen

With the REPowerEU plan, published in March 2022, the European Union is trying to reduce the consumption of fossil fuels in Europe. Concerning hydrogen, it states that 10 million t/yr of renewable hydrogen should be produced in the EU in 2030 and a further 10 million t/yr should be imported (European Commission, 2022a). The planned production volumes approximately align with the hydrogen volumes produced in the EU in 2020 (11.4 million t)

(European Partnership, 2022). However, 96% of the mentioned quantities were produced by SMR (European Commission, 2023c). In order to substitute these quantities with renewable hydrogen, an enormous expansion of electrolysis capacities will be necessary. In 2022, 80 MW of electrolysis capacities were installed, corresponding to a doubling of the previous year. Subsidies of 5.4 billion euros were awarded in July 2022 for the first hydrogen project within the Project of Common European Interest for electrolysis incentives (IEA, 2023d). The hydrogen consumption within the EU amounted to 8.6 million t in 2020 (European Partnership, 2022).

The market ramp-up of electrolysis will be a key factor in achieving these goals. Odenweller et al. (2022) show that although project announcements are increasing exponentially, green hydrogen is likely to continue to be scarce (<1% of final energy demand) until 2030 in the European Union and until 2035 worldwide. This can be explained by the concept of exponential growth, where, due to the flat start, even high annual growth rates take time to develop into really high growth rates. However, once the breakthrough has been achieved, the market can develop very quickly, as seen with PVs, for example. Electrolysis capacities, however, are more complex. Due to the currently very low installation volumes, on the one hand, there is uncertainty as to whether the market will develop as planned. On the other hand, there must be a simultaneous development of supply, demand and infrastructure, which is associated with high costs. Furthermore, there is the risk that the potential of green hydrogen is overestimated (Odenweller et al., 2022). Another problem with the European expansion of electrolysis capacities is the necessary input of green electricity. An increase in the use of electricity for the production of green hydrogen must lead to a higher expansion of renewable electricity generation capacities due to the possible lower utilization of renewable generation.

Apart from the availability of renewable electricity and electrolysis plants, the cost of green hydrogen production in Europe will also be important. As discussed before, the availability of low-cost renewable electricity, the lowest possible investment costs of the electrolysis plants and a high annual utilization rate are necessary for cost-effective production. Infrastructure availability in terms of transport options, also at the distribution level and storage of hydrogen are also of great importance (Matthes et al., 2020).

The mentioned bottlenecks of green hydrogen being produced locally within the European Union imply that there should also be a discussion on hydrogen imports into the European Union. An important question will be how this hydrogen import will look like. Will there be a worldwide hydrogen market or bilateral agreements as long-term contracts between countries?

Currently, hydrogen is not traded on a large scale, as most of it is produced for consumption in industrial areas. Even where hydrogen is traded, there is usually one supplier who then supplies the various industries in the vicinity (IRENA, 2022c). However, according to the IEA (2022a), a large number of hydrogen export projects are planned by 2030, amounting to 12 Mt H_2/yr. Broken down by world region, this amounts to 3 Mt H_2/yr from Latin America, 2.7 Mt H_2/yr from Australia, 1.79 Mt H_2/yr from Europe (to other European countries), 1.7 Mt H_2/yr from Africa, 1.1 Mt H_2/yr from North America 1.0 Mt H_2/yr from the Middle East and 0.7 Mt H_2/yr from Asia. The main focus is on hydrogen production from electrolysis (88% of export volumes) and the hydrogen produced is either to be exported directly or, with the help of ammonia as a carrier, to be exported over long distances by ship (IEA, 2022a). According to the IEA, synthetic liquid fuels, LOHC, liquefied hydrogen, or compressed hydrogen play a subordinate role. Building onto these planned export volumes so that hydrogen can be produced in regions where the conditions for renewable electricity are at their best, resulting in low hydrogen production costs, having hydrogen as a worldwide traded commodity would simplify this effort. This could be done in the beginning, differentiated for production technologies, as already done for the Netherlands hydrogen hub, as seen in Figure 68. They distinguish between the electrolyzer technologies, alkaline and PEM and SMR, with and without CSS and report those prices.

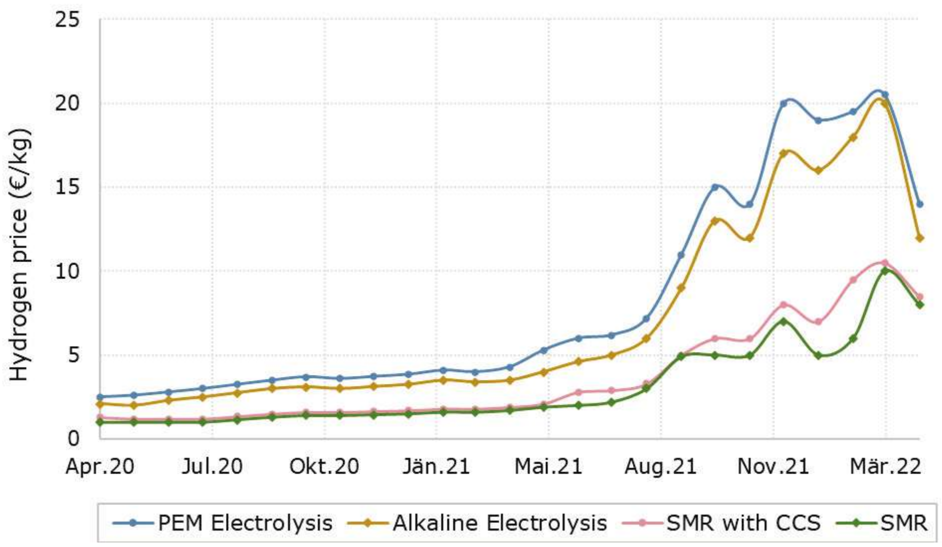

Figure 68: The market price of hydrogen for PEM and Alkaline Electrolysis, SMR with CCS and SMR technologies for the Netherlands production hub: Data from Platts Hydrogen Assessment.

Nevertheless, in the medium run, aiming for a single hydrogen market that includes the external cost of all hydrogen production methods would be preferable. In order to implement this in the future, some measures are mentioned that should be implemented. These are the development of trade infrastructure, demand creation and off-take, World Trade Organization (WTO) rules clarifications and standards, regulations and certifications (IEA, 2022a). The latter is classified as an important condition in this context and its importance is also outlined by IRENA (2023c) through a publication on the creation of a global hydrogen market. It is crucial that all market participants can distinguish which emissions have occurred in each case in the production process, also with regard to laws concerning the use of renewable hydrogen certifications (IEA, 2022a).

d. Hydrogen production technologies – colors of hydrogen

Hydrogen can be produced from different primary energy sources. Depending on the production process and kind of energy used, hydrogen costs and related emissions could be very different. This is the reason that hydrogen generation technologies are often classified based on different colors, e.g., grey, blue, turquoise, green, purple and yellow. Within this work, all hydrogen production methods that rely on fossil fuel inputs without CCUS are considered as grey hydrogen, as this is done in the majority of scientific literature, e.g., (Ji and Wang, 2021; Newborough and Cooley, 2020). Noussan et al. (2021) also summarise all the mentioned production methods into grey hydrogen but also acknowledge that also brown or black is in use. While the scientific literature focuses on grey hydrogen for all fossil fuels, some sources explicitly mention brown hydrogen for coal gasification (Bridges and Merzian, 2019; Droege, 2021) or (Dodgshun, 2020) with brown hydrogen when brown coal and black hydrogen when black coal is used. As we found those classifications to be the minority, we will continue with the more common classification of grey hydrogen.

Some of the production technologies are well-developed and mature technologies, but there are also some methods (e.g., photochemical and biological methods), which are under fundamental research. Conventional production methods use natural gas, coal, or oil as feedstock and then convert them by steam reforming or gasification to hydrogen, which emits CO_2 unless it is captured and stored (CCS) or used (CCU). Another mature but not widely developed technology is the thermal cracking of methane under the exclusion of oxidizing reaction partners such as oxygen, water vapor or, carbon dioxide called methane pyrolysis (Schneider et al., 2020). Additionally, biomass can be used as feedstock for pyrolysis. This method is then CO_2-neutral however has the major disadvantage of varying hydrogen content due to feedstock impurities (Nikolaidis and Poullikkas, 2017). Another method with also relatively high efficiencies is dark fermentation, having the advantage of high energetic density being produced through microbial conversion of waste biomass (Sarangi and Nanda, 2020). Though, it has a quite low technology maturity level (1-3) (Dawood et al., 2020). The method mostly referred to when talking about renewable hydrogen is electrolysis, with renewable electricity as input. Another option to produce hydrogen from renewable energy sources is to do it via steam reforming from biomass. The biomass-hydrogen-based processes are promising options that contribute to hydrogen production in the future but require improvements to produce larger competitive volumes (Lepage et al., 2021). Hydrogen production from nuclear electricity is not very promoted in the European hydrogen strategies, however, it may become a practical alternative in other world regions, such as China and Russia (Baker McKenzie, 2020; El-Emam et al., 2020; Strategy&, 2020; Woody and Carlson, 2020). However, if the electricity for hydrogen production with electrolysis is taken from the grid, then this hydrogen cannot be classified as green, since the electricity is largely produced with fossil fuel power plants (except Norway and Iceland). Electrolysis with electricity inputs from the grid is called yellow hydrogen (Dodgshun, 2020). According to Dawood et al. (2020), there are also other emerging hydrogen production technologies with efficiencies of up to 90%, for example, a membrane reactor or anion exchange membrane. Together with Nikolaidis et al. (2017), they give the most comprehensive overview of all existing hydrogen production technologies to date, including technology maturity.

The main colors are grey, green, blue, turquoise and purple, which will be discussed in more detail in the following.

Grey Hydrogen

Currently, the largest amount of hydrogen is grey hydrogen. The grey hydrogen represents hydrogen produced by SMR or coal gasification without CCUS. More than 40 % of grey hydrogen is a by-product of other chemical processes (Woody and Carlson, 2020). Hydrogen produced as a by-product has also been unofficially classified by the North American Council for Freight Efficiency as white hydrogen (Roeth, 2021). Grey hydrogen is mostly used in the petrochemical industry and for ammonia production (Yukesh Kannah et al., 2021). The demand for hydrogen for those two applications increased substantially over the past 70 years, see Figure 69. In general, around 6% of the worldwide extracted natural gas and 2% of coal are used for the production of grey hydrogen per year (Newborough and Cooley, 2020).

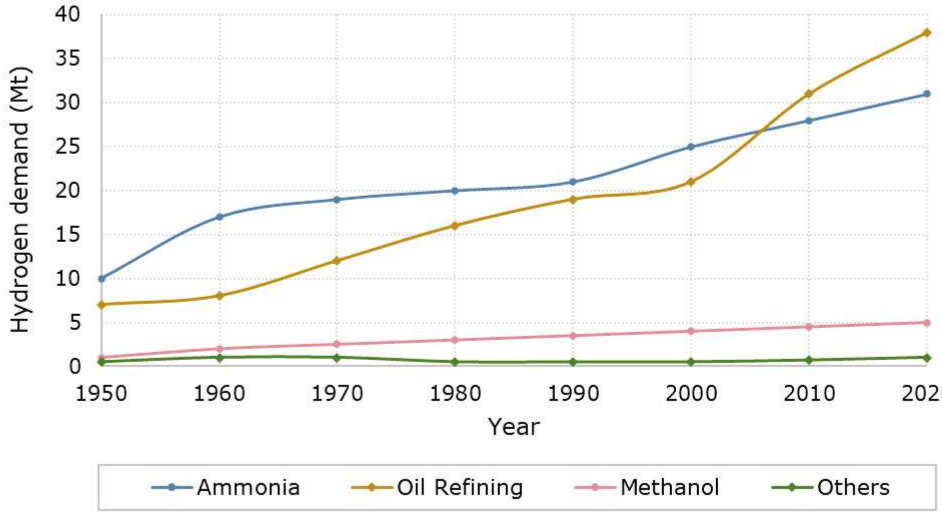

Figure 69: Development of worldwide hydrogen demand over the last 70 years (Yukesh Kannah et al., 2021)

The major disadvantage of grey hydrogen is associated with significant CO_2 emissions generated during hydrogen production, which are estimated to be around 830 Mt CO_2 per year (Newborough and Cooley, 2020). Yet, SMR without CCUS is a well-established process, resulting in low hydrogen costs. In the process, the natural gas undergoes a pre-treatment and the water is heated. The methane is then split up in the reformer with steam into syngas (Eq. 25), having CO and H_2 as the main components. This is then converted by the water gas shift reaction (Eq. 26) into CO_2 and H_2, CO_2 is separated and the H_2 is purified, see Figure 70 (Ji and Wang, 2021; Ratnakar et al., 2021). The size of the SMR plants is usually in the range of 50 – 1000 MW (Newborough and Cooley, 2020).

$$CH_4 + H_2O \rightarrow CO + 3H_2 \tag{25}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{26}$$

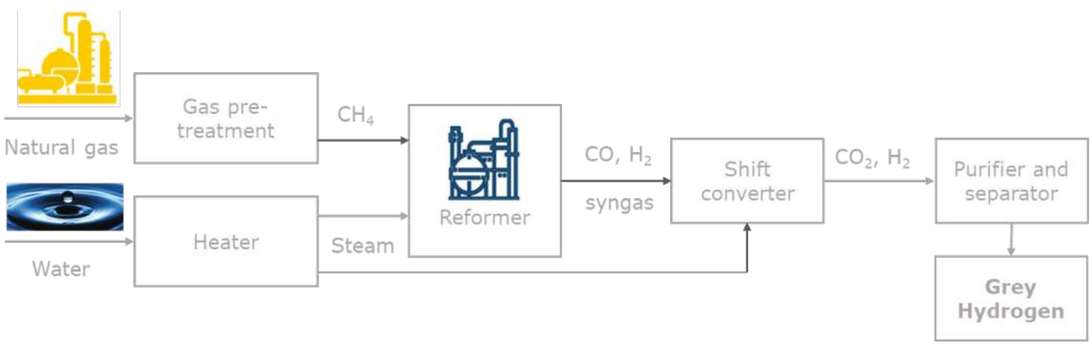

Figure 70: Schematic production process of steam methane reforming (SMR)

Another major production process resulting in grey hydrogen is coal gasification, which in some literature might be considered brown hydrogen. Since coal is the fossil energy source with the largest reserves worldwide, this is also a highly used production method. Especially China produces a large amount of hydrogen with coal gasification due to high natural gas prices and large coal reserves (Ji and Wang, 2021). Four distinct types of coal, namely lignite (low rank), sub-bituminous coal (low rank), bituminous coals (medium rank) and anthracites (high rank), are commonly used as gasification feedstock (Midilli et al., 2021). Besides the different coal types specific gasification methods can be distinguished (fixed bed-, moving bed-, fluidized bed-, entrained flow- and plasma gasification), all operating at temperatures over 900 °C (Midilli et al., 2021). In this work, we do not cover all specifics but focus on the main process, as also seen in Figure 71. In general, the dry coal and pulverized is inserted in the gasifier, where it is reacts under high temperatures with oxygen and steam into syngas with the main components of CO_2 and H_2. This can be separated into two phases. First, the air is fed into the gasifier and oxidizes a fraction of the coal into CO_2 (Eq. 27) while storing the heat in the fuel layer. In the second stage, the air inflow is cut and steam is injected. The steam, together with part of the coal, reacts to CO_2 and H_2 (Eq. 28). Once the heat has been depleted to a particular point, some air is once again fed into the gasifier. Those are the two main reactions that alternate and are used in most gasification methods (Ji and Wang, 2021).

$$C + O_2 \rightarrow CO_2 \tag{27}$$

$$C + H_2O \rightarrow CO_2 + H_2 \tag{28}$$

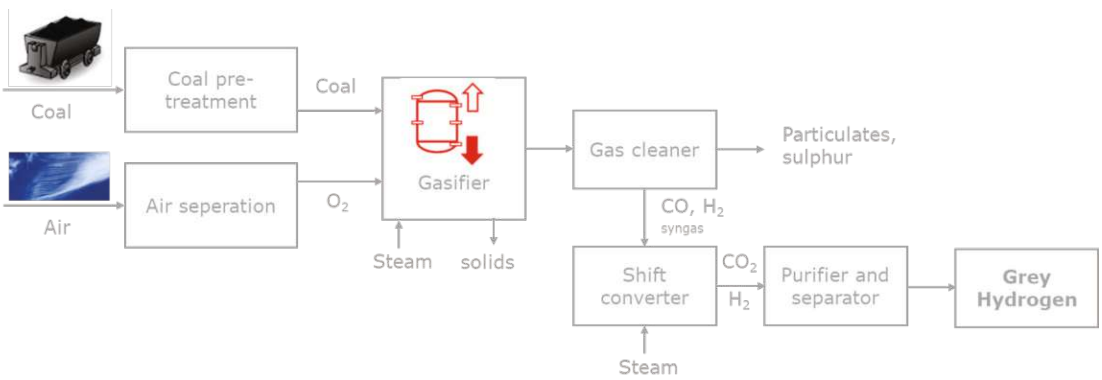

Figure 71: Schematic production process of coal gasification

Both SMR and coal gasification are fully mature technologies with a process efficiency of 60 – 85% for SMR and 74 – 85% for coal gasification (Dawood et al., 2020). Additional production methods are partial oxidation of methane, partial oxidation of oil products and autothermal reforming (Ji and Wang, 2021). In the literature, for grey hydrogen also the colors brown and black are used.

Blue Hydrogen

Blue hydrogen is hydrogen produced by SMR with CCUS, using natural gas or biomass. According to Newborough and Cooley (2020), a hydrogen production facility only has to install a CCUS device in order to be counted as blue hydrogen. The certain amount that needs to be captured has not been defined. When applied to the SMR process, up to 90% capture rates, also including capturing post-combustion CO_2 (without 70%), were reported (Newborough and Cooley, 2020). Currently, blue hydrogen is considered a bridging technology before a full transition to green hydrogen (Woody and Carlson, 2020) and carbon capture and sequestration were being promoted heavily a few years back. As a result, the European Union largely subsidized carbon capture and sequestration demonstration projects added to fossil power plants with 587 million EUR (Teffer, 2017), with none of them being implemented to date (Mulligan, 2020). Recently, also an increasing number of scientists have taken a critical look at CCS technology in view of blue hydrogen production, e.g., (Bauer et al., 2021; Howarth and Jacobson, 2021; Newborough and Cooley, 2020).

Despite resulting in lower emissions, the technology is still far from being climate-neutral (Dawood et al., 2020). The environmental impact has been calculated by different authors and largely depends on which parts of the hydrogen production process are included. Even when the CCS operations were powered by renewable electricity, substantial fugitive methane emissions occurred upstream from producing and transporting natural gas. When taking those into account, blue hydrogen only halves the emissions of grey hydrogen (Burgess, 2021). This has also been supported by a recent paper by Alvarez et al. (2018), finding that methane leaks in the production of natural gas and oil are largely underestimated even by Environmental protection agencies. The problem of substantial atmospheric methane growth should not be underestimated as a substantial acceleration has been reported in the last few years (Nisbet et al., 2019).

Another problem that arises is finding adequate storage sites for the captured carbon that cannot be utilized. In some cases, in which carbon is stored underground, considerable capital costs could be required. Due to CCUS, total hydrogen costs could be significantly higher compared to grey hydrogen. Further, it is also not yet regulated who bears the responsibility for the CO_2 and the cost of storage (Newborough and Cooley, 2020).

The whole process and required steps for CCUS after SMR can be seen in Figure 72. The overall process efficiency of the SMR (60 – 85%) decreases by 5-14 % when the carbon capture unit is integrated (Noussan et al., 2021).

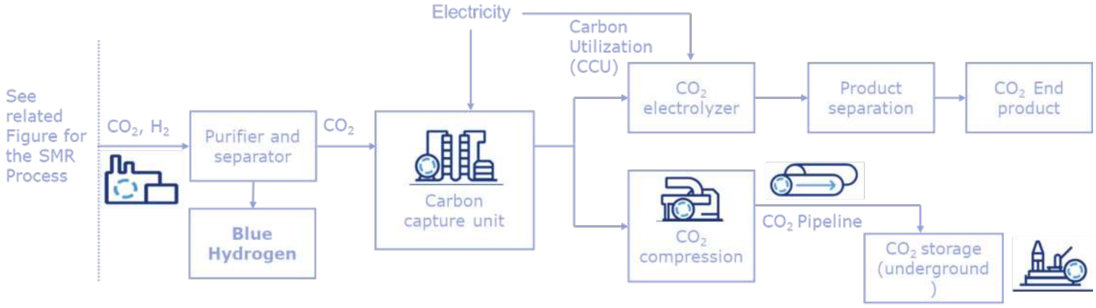

Figure 72: Schematic production process of carbon capture and utilization (CCU) and carbon capture and storage (CCS) (Amin et al., 2011)

Recently also new technologies for CCUS of hydrogen are emerging, with chemical looping reforming being the only one tested on a pilot scale, according to Antzaras and Lemonidou (2021). CLR offers a less energy-intensive alternative approach to partial oxidation. Also promising is sorption enhanced reforming, aiming to produce and separate CO_2 in one step and also being able to operate at a lower temperature (Antzaras and Lemonidou, 2021).

Turquoise Hydrogen

Contrary to the mentioned conventional production methods, the by-product of turquoise hydrogen via methane-pyrolysis is solid carbon in the form of filamentous carbon or carbon nanotubes (Amin et al., 2011), which can be used for the further production process or might be easier to store, hence having a lower carbon footprint. The solid carbon can be sold depending on its type for 150-400 EUR per t for coke, 500-1000 EUR per t for carbon black, 1500-1800 EUR per t for activated carbon and up to 1 Mio. EUR per t for carbon filaments (Leal Pérez et al., 2021).

Methane-pyrolysis, which can be divided into three process categories, namely, (i) thermal decomposition, (ii) plasma decomposition (Kvaerner process) and (iii) catalytic decomposition, has been known for decades and technically realized in several processes. However, only in recent years has it raised the interest to produce hydrogen mostly via thermal decomposition as the furthest developed process (Schneider et al., 2020). Pyrolysis has not yet been commercialized from the point of view of hydrogen production. Only the thermal process (Eq. 29) is being further developed by BASF to produce hydrogen in larger quantities (Schneider et al., 2020).

$$CH_4 \rightarrow 2H_2 + C \tag{29}$$

Green Hydrogen

Green hydrogen is hydrogen produced from water by electrolysis using electricity from renewable energy sources. This kind of hydrogen is of special interest in the transition toward a more sustainable energy and transport system. In literature, for green hydrogen, also expressions like “clean hydrogen,” “renewable hydrogen,” or “low-carbon hydrogen” are used. Dawood et al. (2020) criticize that the definition for low carbon hydrogen, meaning up to which emission level hydrogen is classified as green, clean, or renewable hydrogen is not universal and introduces a hydrogen cleanness index model.

Currently, there are three major electrolysis technologies, alkaline water electrolysis, PEM electrolysis and SOEC. Alkaline water electrolysis is the most mature technology, already been used since 1920, with a market share of about 70% (Strategy&, 2020). This technology benefits from the low costs and long operational life. A disadvantage is that the alkaline electrolysis process needs to be run continuously to avoid damage so ld and platinum-coated titanium material), which account for a large proportion of the stack cost and shortervariable renewable energy should not be a single source of power. Additionally, they have problems with low current densities and corrosive conditions (Holm et al., 2021). PEM has been in operation since 1960 and is more suitable for urban areas due to the smaller system size. Furthermore, it is more efficient and can respond faster, making it suitable for capturing an oversupply of renewable electricity (Holm et al., 2021). When hydrogen is later needed in pressurized form for use or storage, “high pressure” PEMs can already deliver the required pressure without another conversion step, leading to higher overall efficiency. However, this technology is associated with higher capital costs due to expensive electrode catalysts and membrane materials, for example, for producing bipolar plates (gold and platinum-coated titanium material), which account for a large proportion of the stack cost and shorter lifetime (IRENA, 2022d). Furthermore, rare metals (iridium) are used for the core of the stack to make it more robust, which also adds some costs. However, at the system level, this accounts for only 10% of the total cost (IRENA, 2022d). 45% of the system costs are caused by system power equipment. Minke et al. (2021) find that in a mature PEM market, supply problems might occur due to the socioeconomic and geographical conditions of reserves, not the size of the reserves themselves. They suggest recycling and a more efficient PEM technology (Minke et al., 2021). Hodges et al. (Hodges et al., 2022) recently announced their finding of a capillary-fed electrolysis cell with high efficiencies. In that new design, the electrolysis cell can directly produce both gases, as the liquid electrolyte is being taken up through the capillary effect from a reservoir.

A technology that is associated with great expectations due to low expected capital costs and high efficiency (Ozturk and Dincer, 2021) is the SOEC, which has recently become available on the market with about 150 kW of capacity installed so far (Zhao et al., 2020). The operating temperatures of high-temperature steam electrolysis in SOEC range from 700 to 1000 °C, which should help in using less electricity as the thermodynamic conditions of the reaction are better under these conditions and also heat can be supplied into the process (Motazedi et al., 2021). Some drawbacks of the technology are instability and delamination of electrodes and safety problems (Ozturk and Dincer, 2021). When CO_2 is added to the electrode as an additional fuel in SOEC electrolysis, co-electrolysis of CO_2/H_2O can occur. In this process, both water vapor and carbon dioxide are split in parallel, resulting in the formation of a mixture of CO and H_2 (syngas) on one side and the formation of oxygen on the opposite side, which can be further used to produce useful chemicals. Since both CO_2 and H_2 from H_2O electrolysis are present, it undergoes a methanation reaction (Błaszczak et al., 2022). Co-electrolysis of water and CO_2 is an important manufacturing process for power-to-chemicals and power-to-fuel (CORDIS, 2023).

Some other challenges must be considered: electrolyzers have relatively low efficiency and remain costly, with typical capacities ranging from 1 kW to 1 GW. Additionally, raw materials such as platinum (for PEM) and cobalt (for alkaline) are required (European Commission. Directorate General for Energy. et al., 2023). Table 37 shows the efficiency and maturity of each electrolysis technology. An overall benefit of hydrogen produced with electrolysis instead of other means is the high purity of >99.95% (Newborough and Cooley, 2020).

Table 37: *Electrical efficiencies (as lower heating value (LHV)), Technology maturity level (TML)* and general maturity assessment of the three main electrolyzer technologies*

Technology	Electrical Efficiency, Technology maturity level (TML), Maturity	Source
Alkaline electrolysis	63 – 70%, 9-10, Mature and commercial	(IEA, 2019a), (Dawood et al., 2020), (Zhao et al., 2020)
Proton exchange membrane electrolysis (PEM)	56 – 60%, 7-9, Commercial (earlier stage of development)	(IEA, 2019a), (Dawood et al., 2020), (Zhao et al., 2020)
Solid oxide electrolyzer cell (SOEC)	74 – 81%, 3-5, Commercially available (150kW)	(IEA, 2019a), (Dawood et al., 2020), (Zhao et al., 2020)

(*TML has been introduced by Dawood et al. (2020) and is a combination of the commonly known Technology readiness level (TRL) and the Commercial readiness index (CRI) of the Australian Renewable energy; the reported electrical efficiencies for SOEC are substantially higher as they use additional thermal energy.)

The general schematic electrolysis process can be seen in Figure 73. For electrolytes, either liquid solutions (e.g., polymeric or alkaline) for PEM or alkaline or solids (e.g., solid oxide/ceramic) for SOEC electrolyzer can be used. The latter works at higher temperatures, as already discussed earlier. The specific process for alkaline (Eq. 30 and 31) and PEM (Eq. 32 and 33) electrolyzer works through electricity being transmitted, the water creating hydrogen ions, which are positively charged together with oxygen at the anode. This then flows through the liquid electrolytes and merges with the electrons from the external circuit, producing hydrogen gas. When the electrolyte is solid, as in the case of SOEC (Eq. 34 and 35), the water dissociates and produces hydrogen (H_2) and negatively charged oxygen (O_2) at the cathode through merging with electrons from the external circuit. The O_2 permeates across the membrane and gives up electrons at the anode to generate oxygen gas (Ratnakar et al., 2021).

It is also important to mention that all electricity needed for the described processes has to be solely from renewable energy sources in order to be regarded as green hydrogen.

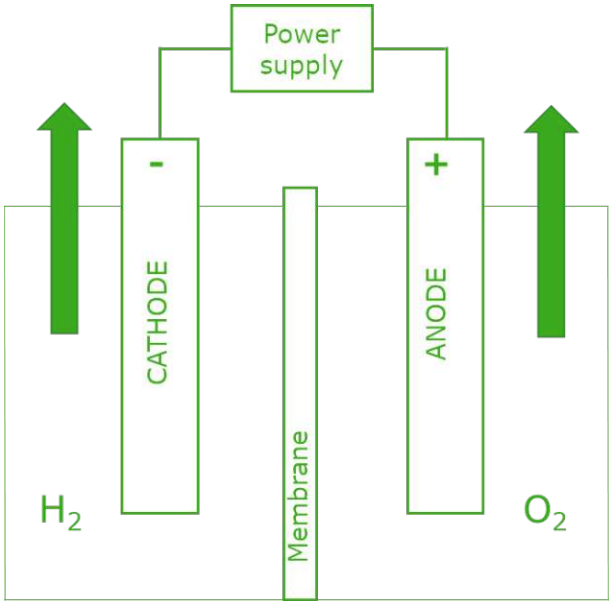

Figure 73: Schematic electrolysis process

Alkaline: Cathodic Reaction $\quad 2H_2O + 2e^- \rightarrow H_2 + 2OH^-$ (30)

Alkaline: Anodic Reaction $\quad 2OH^- \rightarrow H_2O + \frac{1}{2}O_2 + 2e^-$ (31)

PEM: Cathodic Reaction $\quad 2H^+ + 2e^- \rightarrow H_2$ (32)

PEM: Anodic Reaction $\quad H_2O \rightarrow 2H^+ + \frac{1}{2}O_2 + 2e^-$ (33)

SOEC: Cathodic Reaction $\quad H_2O + 2e^- \rightarrow H_2 + O^2$ (34)

SOEC: Anodic Reaction $\quad O^2 \rightarrow \frac{1}{2}O_2 + 2e^-$ (35)

According to projections by the IEA (IEA, 2022a), the majority of manufacturing capacities for electrolysis technology are expected to be dominated by alkaline electrolyzers, accounting for 64% by the year 2030. Meanwhile, PEM and SOEC are expected to account for 22% and 4%, respectively. An alternative technology, known as anion exchange membrane electrolyzers, has mainly been utilized for demonstration purposes thus far. However, Enapter has announced to manufacture 280 MW by 2023 (IEA, 2022a).

In one recent study on green hydrogen production, IRENA (IRENA, 2020b) divides the historical development into five generations (see Figure 74), with the first generation from 1800-1950, where alkaline technologies were used for ammonia production, causing health hazards due to the use of asbestos as gas separators. This was followed by the second generation from 1950-1980, in which PEM technologies were invented and deployed, driven mainly by spaceship programs and military applications in submarines. In the third generation, from 1980-2010, they were substantially simplified to find other business opportunities besides the two mentioned earlier. From 2010 until 2020, the business case has been improved due to the drastic expansion of variable renewables, with more installments and resulting lower capital costs. The fifth generation will be the most important one in terms of economies of scale. Electrolysis has to evolve from niche application (MW) to mainstream (GW). According to IRENA (IRENA, 2020b), around one GW/yr of production capacity per industry has the largest benefits for economies of scale, which several manufacturers claim to have reached.

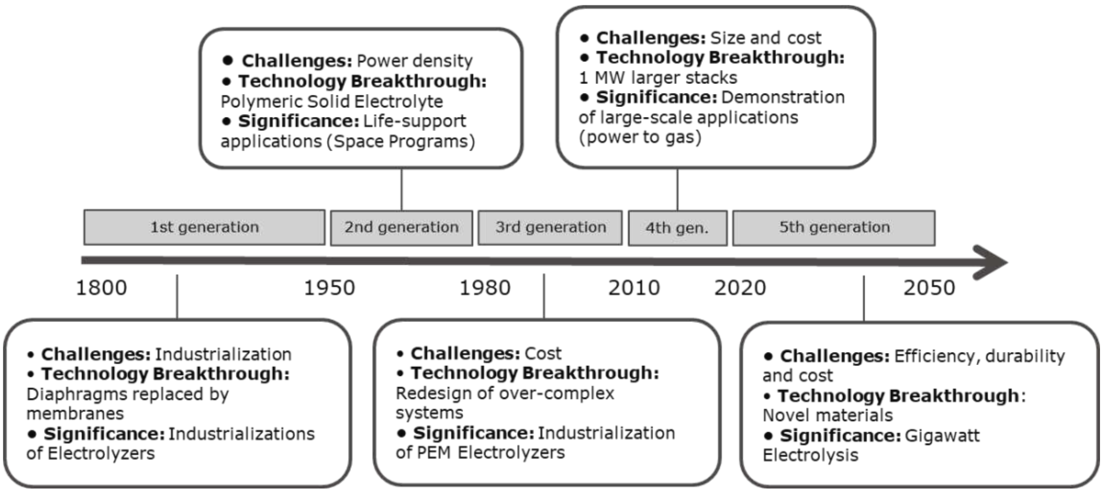

Figure 74: Historical development of electrolyzers (IRENA, 2020b)

The largest worldwide operating production capacity is a 150 MW alkaline Electrolyzer in Ningxia, China, which started operation in December 2021, with parts (30 MW) already being operational in April 2021 (FuelCellsWorks, 2022). Before that, the largest electrolyzer worldwide was in Béancour, Canada, with a production capacity of 20 MW (PEM technology) at the Air Liquide hydrogen production facility, inaugurated in 2020 and primarily powered by hydropower (Platts, 2021). Additionally, an alkaline electrolyzer with a 10 MW capacity has been operational in Fukushima, Japan, since 2020 (IRENA, 2020b). The largest European electrolysis production capacities are located in Germany (Shell Rhineland Energy and Chemicals Park in Wesseling (REFHYNE, 2022) and Energiepark Mainz (Kopp et al., 2017)) and Austria. In 2019, a 6 MW electrolyzer for industrial purposes in iron and steel production was launched at the Voestalpine industrial site in Linz, Austria (H2FUTURE, 2021). The largest SOEC electrolyzer with 2.6 MW is being constructed in a Neste refinery in the Netherlands and another SOEC project is supposed to begin construction in 2023 with a 25 MW capacity (IEA, 2022b).

Table 38: *Electrolysis plants in operation (European Commission, 2022b; FuelCellsWorks, 2022; H2FUTURE, 2021; IRENA, 2020b; Kopp et al., 2017; Platts, 2021; REFHYNE, 2022)*

Project and country	Capacity (MW)	Year of completion
Ningxia, China	30	2021
Cachimayo Plant, Peru	25	1965
Air Liquide Becancour, Canada	20	2020
Refhyne, Germany	10	2021
Fukushima Hydrogen Energy Research Field, Japan	10	2020
H2Future, Austria	6	2019
Energiepark Mainz, Germany	6	2015
Plant Svartsengi, Iceland	6	2011
H&R Ölwerke Schindler	5	2018
Hybrit (Luleå)	4.5	2021
BIG HIT, Orkney, Scotland	1.5	2022

Overall only 0.03% of global hydrogen production is done via electrolysis, also including yellow and purple hydrogen (IEA 2021b). This means green hydrogen to date is still very much a niche product.

Purple Hydrogen

Hydrogen production from nuclear electricity is not very promoted in the European hydrogen strategies, however, it may become a practical alternative in other world regions, such as China and Russia (El-Emam et al., 2020; Ping et al., 2018; Pinsky et al., 2020; Zhiznin et al., 2020). Purple hydrogen is obtained by electrolysis through an atomic current. Attaching a hydrogen production facility might help to reduce the curtailment of nuclear plants (Scamman and Newborough, 2016) and provide a further energy storage possibility once seasonal storage is required. Milewski et al. (2021) analyze the operation of high-temperature electrolysis SOEC in combination with nuclear power plants and find that the available steam is beneficial to the energy use efficiency of the whole operation. One other benefit mentioned in the literature is the combination of electrolysis with micro nuclear reactors, constructed, for example, by Rolls-Royce (Newborough and Cooley, 2020).

In the literature, purple hydrogen is also sometimes also called yellow hydrogen. We, however, use the more common description of yellow hydrogen for electrolysis with grid electricity.

A summary of all discussed hydrogen production methods is provided in Figure 75.

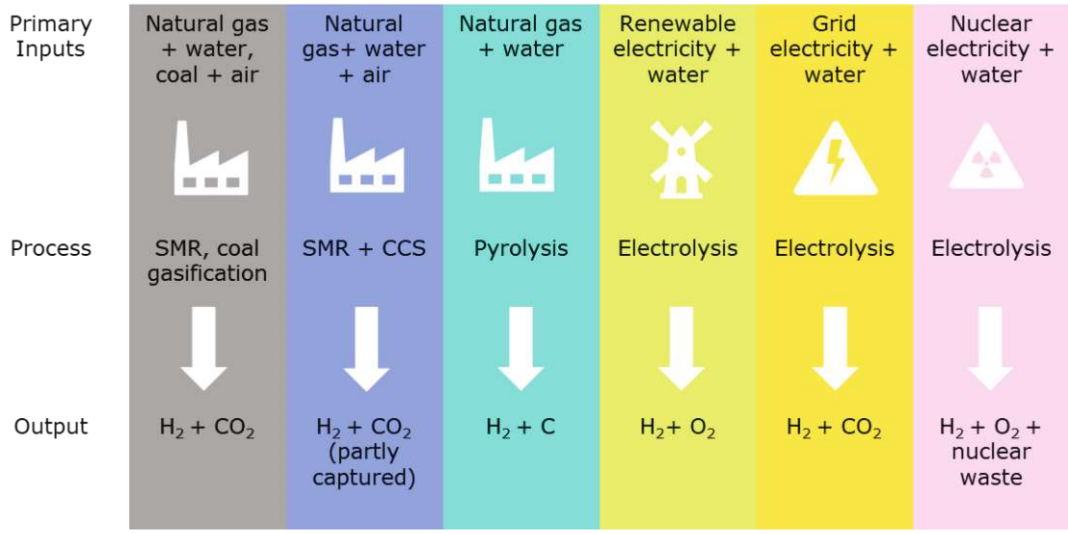

Figure 75: Summary of hydrogen production pathways and colors

Other hydrogen production methods

Another hydrogen production method is using biomass as feedstock through different processes. The maturest biomass process today is thermochemical conversion, with gasification being the most researched biomass hydrogen technology (Aziz et al., 2021; Lepage et al., 2021). However, also biological technologies are under research for example, microbial electrolysis (Yun et al., 2021) and dark fermentation (Sanchez et al., 2020). Pal et al. (2021) provide the most comprehensive review of hydrogen production from biomass. Using biomass as feedstock always implies that it stands in competition with other use cases like biogas production or other fuels. To date, there is only a very small fraction of hydrogen produced through biomass which is, according to Newborough and Cooley (2020), the reason that no individual color is assigned for the process. It is not clear if they should be clustered into green hydrogen production, as done by Noussan et al. (2021) and Dincer (2012).

Two new colors were introduced in the literature, namely aqua and white hydrogen. Aqua hydrogen is, according to Yu et al. (2021), produced from oil sands and oil fields with a new method developed by the University of Calgary, emitting no carbon emissions. The color has been selected as it is between blue and green, produced with fossil feedstock (blue) but not emitting carbon (green). The authors claim that no emissions occur since the conversion from oil reservoirs or oil sands to hydrogen should take place in the reservoirs below the earth and only hydrogen is extracted in a final step. The technology is currently being tested in Saskatchewan, Canada. The main mentioned obstacles to this new technology are the scale-up and concerns for the environment. The color aquamarine has also been used by Boretti (2021a), who uses it for the pyrolysis of natural gas, powered by concentrated solar energy, producing solid carbon and hydrogen as an end product. As white, he classifies the direct splitting of water molecules by means of concentrated solar energy (Boretti, 2021b) Both proposed colors are still under fundamental research and are meant to be tested and applied in Saudi Arabia (Boretti, 2021a). Some other processes under fundamental research were analyzed by Dincer and Acar (2017) and they rank all technologies according to emissions (photonic H2 production lowest, thermolysis highest), costs (thermochemical processes lowest cost, photoelectrochemical systems highest), efficiencies (thermolysis highest, photocatalysis lowest). When all three factors are included in the evaluation, thermochemical hydrogen generation seems to be the most appropriate production method, with photofermentation second and artificial photosynthesis third. The least suited according to this analysis are photoelectrochemical systems, photocatalysis and thermolysis (Dincer and Acar, 2017).

d. Use of hydrogen in different sectors

This section aims to analyze the opportunities for hydrogen use and applications in different end-use sectors, analyzing the overall efficiency of the different conversion hydrogen use chains, mainly to show the efficiency.

There are at least five major possibilities to use hydrogen produced from renewable electricity:

(i) Re-electrification: The first one is to use hydrogen as storage for surplus electricity and according to needs to convert them to electricity again.

(ii) A different option is to blend hydrogen produced from electrolysis with natural gas as well as transform them towards methane. Within this opportunity, the existing gas grid can be used as storage.

(iii) Another opportunity is to transform electricity to hydrogen, to be an essential input as feedstock for various specific industry processes, which currently use hydrogen produced by SMR (e.g., ammonia production). Additionally, hydrogen can also be used in industry to further decarbonize processes where high temperature heat is required, e.g., the iron and steel sector.

(iv) The fourth opportunity, of specific interest for the transport sector is the possibility of using hydrogen in trucks, ships, or in aviation as a clean fuel

(v) Another option is to use hydrogen for domestic heating in buildings.

The mentioned applications can be seen in Figure 76, ranging in principle from transport to industry and the power sector and finally in buildings for producing electricity and heat.

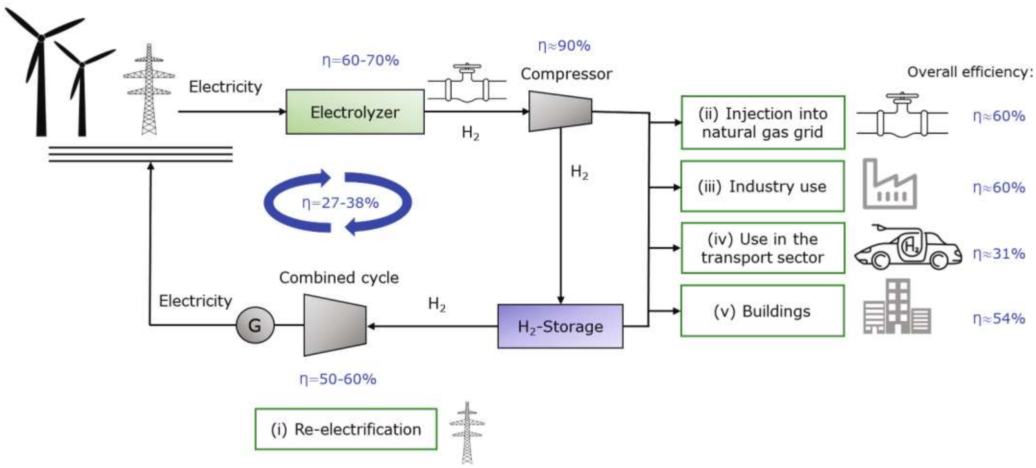

Figure 76: Possible future applications of hydrogen in the energy system

As can be seen from Figure 76, the efficiencies of the chains up until the end-use technologies are relatively low. For some of the possibilities mentioned, very advanced direct electricity applications are already available, such as for passenger cars, where electric vehicles are fully mature and experience a substantial increase in driving ranges. In these cases, the direct electricity applications have higher efficiencies and lower power consumption and are, therefore, more suitable. According to Plötz (2022), it is already too late to establish a market for hydrogen passenger cars. Even with trucks, which are still often mentioned as a hydrogen application today, the decision as to whether the niche is large enough to support further development in this direction must be made as soon as possible (Plötz, 2022). Battery applications are also catching up significantly in the freight sector and at the moment, only very heavy loads to remote areas can be handled with hydrogen technologies. When comparing the overall efficiency of electric passenger cars (77%) and hydrogen (33%), it is evident that hydrogen should be better used in sectors where no real alternatives exist so far (Transport&Environment, 2020).

Another example is the storage and re-electrification of hydrogen, with a total conversion efficiency in the range of 27% to 38%. With many necessary steps, every conversion process in the energy supply chain is leading to lower total efficiency of the system. Nevertheless, when considering seasonal/long-term storage of electricity, hydrogen underground storage is currently seen as the only option and additionally, variable renewables are supposed to increase capacity (Egeland-Eriksen et al., 2021). More information can be found in Section 2.1.3, where hydrogen storage has been explained in more detail.

Fewer conversion steps can be reached when the produced hydrogen can be used directly, for example, as feedstock, which substitutes hydrogen that is now being used from SMR. Oil refining and ammonia production are often named production processes where hydrogen should be substituted. This is relatively straightforward, especially when considering that grid electricity can be used for production, as the Haber Bosch process needs a constant energy inflow. The only shortcoming is that for Urea production, which is the most commonly used fertilizer, CO_2 inputs are needed. Those are in traditional production processes taken from the natural gas used in the SMR process but must be taken from elsewhere in the case of green hydrogen (Dolci, 2018). In steelmaking, the hydrogen route is often discussed as an alternative. Nevertheless, all industry applications in which hydrogen is not being used as feedstock must be well selected, as various alternatives for direct electrification already exist (Madeddu et al., 2020). The paper by Madeddu et al. (2020) calculates that 78% of industrial heat in Europe could be decarbonized with clean power and existing commercial technologies. This rises to as much as 99 % if technologies that are currently still in the development phase are also included.

One application considered unsuitable in most of the literature is hydrogen for space heating in buildings. For one thing, it has a very low maturity compared to other alternatives, such as HPs and much lower efficiency (IRENA, 2022e). Rosenow (2022) analyzes 32 "independent" (indicated by the author as not carried by or on behalf of a specific industry like gas, oil, electricity, HPs, or boiler manufacturers) studies and finds that none of them attribute a meaningful role to space heating in the Energy Transition. Here, separating independent papers from reports sponsored by the gas, gas grid and heating industries is hugely important (Liebreich, 2022). Even in the recently published future scenarios by Schell, hydrogen is assumed to have a share of only 0.4% in the space heating sector (Shell Global, 2023).

A special case is the possible blending of hydrogen into the existing natural gas network. In this case, an attempt is being made to add quantities of green hydrogen in order to reduce the overall emissions from gas consumption. According to a study by the Fraunhofer Institute (Bard et al., 2022), however, the technical effort of this blending (up to 20 Vol-% of natural gas) is in no relation to the possible GHG savings, which are between 6-7% due to the lower calorific value of hydrogen compared to natural gas. This finding has also been supported by IRENA (2022b) in their technology review of hydrogen carriers report. Another problematic factor mentioned in the Fraunhofer study is the limited quantities of green hydrogen available in the near future. It is emphasized that applications with high CO_2 reduction potential should be replaced by hydrogen instead of limited emission reductions by blending, which is in direct competition with the direct use of hydrogen (Bard et al., 2022). An overall overview of the efficiencies of the different conversion steps for all discussed applications can be found in Table 39.

Table 39: Efficiencies of hydrogen use chains

Use case	Efficiency η						End product
	Electrolysis	Compre-ssion	Storage	Transport	Conver-sion	Total	
Re-electrification (large electrolyzer) via CCGT	0.7	0.9	0.98	0.97	0.6	0.36	Electricity
Re-electrification (small electrolyzer) via CCGT	0.63	0.9	0.98	0.97	0.6	0.32	Electricity
Feed in gas grid	0.7	0.9	0.98	0.97	1	0.60	-
Feedstock use in industry for ammonia production (replacement of SMR)	0.7	0.9	0.98	0.97	1	0.60	Hydrogen as feedstock
Transport cars	0.7	0.9	0.98	0.97	0.51	0.31	Mobility
Transport trains	0.7	0.9	0.98	0.97	0.85	0.51	Mobility
Buildings	0.7	0.9	0.98	0.97	0.9	0.54	Electricity and heat

From a European perspective, today, most of the hydrogen within the EU is used by the chemical industry to produce plastics and fertilizers (European Commission, 2023c). Other applications are primarily in the pilot project phase.

It would be important to prioritize hydrogen in end-use applications for which there are no suitable alternatives. The paradox, however, is that in terms of business scenario, the potential profit margins are in transport and not in the industry. Sectors such as steel and chemicals will need enormous quantities of hydrogen, but at the same time, they are the most price-sensitive industries and are exposed to global competition (van Renssen, 2020). In the transportation sector, price levels are already higher and thus, higher profit margins are possible (Ajanovic, 2013).