Evaluating the Infrastructure Requirements of a Low-Carbon Hydrogen Supply Chain in Germany and the Gulf Coast

by

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Abstract

The increasing political momentum advocating for decarbonization efforts, in Europe and elsewhere, has led many governments to unveil national hydrogen strategies. Hydrogen is viewed as a potential enabler of deep decarbonization, notably in hard-to-abate sectors such as the industry. A novel optimal low-carbon hydrogen network algorithm was developed to assess the supply chain requirements of systems with increasing electrolytic hydrogen production levels. This model was used to investigate the low-carbon hydrogen procurement strategies of Germany and the Gulf Coast, with a focus on industrial demand.

An initial case explored a self-sufficiency scenario in which the studied region would domestically procure hydrogen with electrolytic production. Results show important synergies between electrolytic production powered by a mix of renewables, large-scale hydrogen storage in the form of salt caverns, and hydrogen pipelines. The optimal power mix in the Gulf Coast consists of a majority of wind turbines, while Germany deploys a larger share of solar panels. The levelized cost of hydrogen, which includes storage and transport, totals ~\$5.5-6.2kgH_2 in the Gulf Coast (2025), and 4.9-6.1 €/kgH_2 in Germany (2025). Replacing salt caverns with compressed and liquid tank storage drastically changes the system, which deploys more renewable capacity to avoid storage needs but ultimately increases curtailment, driving costs up by ~\$1/kgH_2 in the Gulf Coast and 1.0-2.2 €/kgH_2 in Germany. This calls for a centralized approach to building out the supply chain, requiring extensive stakeholder collaboration. Furthermore, optimal electrolytic production requires low capacity factors (40-70%) to truly achieve low-carbon status with renewable electricity at all times, which impacts the levelized cost of hydrogen and keeps it high (>\$4 (and €)/kgH_2) even in 2050. It was found that electricity storage is not economical to increase electrolytic capacity factors at times of low renewable production.

Natural gas-derived production was found to be significantly impacted by upstream supply chain emissions of electricity and natural gas. Maintaining such production will require important reductions of the methane leakage rate and electricity carbon footprint, alongside a high carbon capture rate at the process level. Finally, in the case of Germany, pipeline imports from neighboring countries were found to have important systemic benefits and provide a viable pathway to decarbonization, but the local large-scale storage of these potentially variable imports should not be overlooked.

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Chapter 1

Introduction

1.1. Introduction

The threat of climate change has spurred efforts to decarbonize all corners of our society. Its increasing pace commands greater efforts to be undertaken before 2050. A major contributor to climate change is the energy sector, which is responsible for 75% of Green House Gas (GHG) emissions today [1]. Currently, energy systems are dominated by fossil fuels. These are ubiquitous from industrial processes to basic materials, transport, and residential heating. A widely agreed upon consensus states that reducing fossil fuels use and increasing the role of electricity and power systems as a whole can lead to significant emissions reduction [1]–[5]. Such pathways lead to significant deployment of low-carbon electricity generation technologies, such as wind turbines and solar panels. These will provide the backbone for the procurement of electricity to current demand as well as to the electrifying sectors such as transportation and the industry. However, electrification may not be sufficient to enable deep decarbonization. Several sectors are likely to continue requiring fuels to power their processes. This has triggered growing attention towards fuels with the potential to be low carbon. Among those, hydrogen has emerged as one of the most promising. The versatility of hydrogen, which can theoretically be used in a range of applications such as industrial processes, power production, and transport, has been a determining factor in its rise on the geo-political agenda.

Hydrogen has historically been used in the industry [6] – the main applications being oil refining, ammonia, and methanol production. While demand for ammonia and methanol will likely increase, the quantity of oil will depend on the trajectories of countries concerning their fossil fuel strategies but is expected to remain significant in the 2030s. This translates into an immediate need for low-carbon hydrogen to decarbonize the industry sector. However, its role in the economy may be expanded. Hydrogen is viewed as an alternative fuel in the transport sector, especially long haul, heavy freight, using fuel cells to power vehicles [7]. Further uses include district heating, for which several pilots are underway [8], [9], steel manufacturing [10], and electricity storage with potential reconversion into electricity using natural gas turbine retrofits [11] or fuel cells.

Hydrogen production is dominated by a single process – Steam Methane Reforming (SMR), which uses natural gas as a fuel. The carbon intensity of this process is ~10 tCO_2/tH_2 [12], [13]. To date, few SMR plants have been fitted with CCS technologies – only two have reached the demonstration scale, while two others are at the pilot scale [14]. Retrofitting them with CCS technologies can be achieved at a 50% capture rate rather inexpensively, but reaching higher rates (~85%) requires significant additional investments [15]. Another process, Autothermal Reforming (ATR), can be fitted with CCS. ATR plants are characterized by a similar carbon intensity to SMR at the process level. However, while both generate carbon dioxide in the process gas, SMR also emits flue gases from natural gas combustion that contains carbon dioxide [16]. As such, ATR facilities only need CCS technologies to be fitted at a single exhaust, allowing higher capture rates potentially more economically than SMR [15], [17]. This is exacerbated by the fact that most SMR plants are integrated into facilities where hydrogen is not the end product, and thus are specifically designed for their respective application.

Alternatively, hydrogen can be produced through the electrolysis of water. This highly energy-intensive process can be low-carbon granted that the input electricity comes from low-carbon sources. There are currently three main electrolytic production technologies: Alkaline, Proton Exchange Membrane (PEM), and Solid Oxide (SOE). The former is an established process notably in the Chlor-Alkaline industry to produce chlorine and sodium hydroxide, with an installed capacity surpassing 20 GW. However, Alkaline electrolyzers dedicated to hydrogen production only reached 400 MW in 2022. The two latter are relatively immature technologies, with negligible deployed capacity worldwide. Comparative advantages between technologies revolve around the efficiency, ramp-up ability, and stack size, to name a few. Despite their cost, several countries have placed electrolyzers at the center of their strategy, with a few stating deployment targets [18]–[21].

Electrolytic hydrogen production requires low-carbon power sources to deliver low-carbon hydrogen. Several technologies can deliver low-carbon electricity such as Renewable Electricity Sources (RES), nuclear production, or conventional production fitted with CCS. RES, excluding hydropower, are characterized by their non-dispatchability, where their power output is dictated by the natural resource they harness. This leads to varying power curves throughout the day. As a result, the operation of electrolyzers power by non-dispatchable RES should be flexible and will cause varying hydrogen outputs.

In a broader decarbonization effort, several countries around the world have released national hydrogen strategies. These strategies and roadmaps differ among countries. Those that have access to ample resources suited for renewable electricity production envision becoming major exporters of electrolytic hydrogen. This includes Australia, Chile, and Saudi Arabia [18], [20], [21]. In contrast, countries with insufficient resources but a potentially significant demand such as much of Europe, Japan, and Korea are likely to become importers. Those that benefit from ample natural gas resources may resort to hydrogen production with CCS [22]. The present analysis investigates Germany and the Gulf Coast, both major hydrogen demand centers with radically different accesses to natural resources.

1.2. Challenges ahead of the decarbonization of hydrogen

The ambitious targets laid out in the strategy are likely to face several challenges. An initial hurdle is the sheer scale of electrolyzer capacity deployment envisioned. In 2020, global electrolyzer capacity dedicated to hydrogen production reached 0.3 GW [23]. In Europe, Germany stands with the largest capacity at 59 MW [6]. Reaching Germany's target corresponds to a 67% compound annual growth rate until 2030. In comparison, between 2000 and 2020, the annual growth rate of renewable reached 7% [24], even though the ramp-up has accelerated in the last five years. The electrolyzer manufacturing market is currently dominated by a small number of firms, which have almost all unveiled plans to gradually increase their manufacturing capacity, totaling several GWs [25]–[30]. Depending on the electrolyzer production technology these will need to tap into critical material resources, notably iridium and platinum, which, while currently available, may become scarce as manufacturing increases [31]. Furthermore, Germany's electrolyzer capacity ambition has been matched by several neighboring countries such as France, the UK, Spain, and Italy [32]–[35]. At the European level, it is targeted to reach 40 GW of capacity by 2030, complemented by 40 GW in peripherical countries that are well endowed with renewable resources [36]. These objectives, when added to similar ambitions in several countries around the world, may be difficult to attain, potentially due to supply chain constraints.

Current German production relies on natural gas, which is 95% imported [37]. A large share is imported from Russia, followed by Norway [38]. This gas is reformed into hydrogen in SMR plants, which are large and expensive assets. There is therefore a risk of stranded SMR assets in Germany. Investing in new ATR plants may also not align with Germany's strategy which only views electrolytic hydrogen as sustainable in the long term and could become uneconomical compared with electrolysis. Even with the continued use of natural gas, Germany is looking to diversify its supply due to the Ukrainian war, which is an ambition shared at the European level. Concurrently to a decrease in consumption, it is highlighted that supply needs to be diversified via liquefied natural gas or pipeline imports from non-Russian suppliers [39]. The Gulf Coast has larger access to domestic natural gas thanks to ample resources. However, supply chain emissions in the region are notably high [40], which conflicts with a move towards low-carbon production.

The cost of producing decarbonized hydrogen may be expensive, notably in the short- to medium-term. Electrolyzers, even though being a relatively established technology, have not yet been deployed at scales comparable to that of SMR plants. The cost of electrolytic hydrogen is thus more expensive, sitting around \$5-6/kg-H_2 [41], compared with ~\$1.3/kg-H_2 for unabated SMR [42]. These high costs may prove uncompetitive in the industrial sector, but economical in other sectors such as transportation, for which a cost of \$4/kg-H_2 is estimated to be sufficient to reach cost parity for 50% of transport energy demand [17], [43]. However, immediate demand is solely provided by the industry – most electrolytic hydrogen is thus likely to compete with cheap hydrogen from natural gas. Future demand in other sectors is characterized by large uncertainties. Even though the German national strategy states a doubling in demand from green steel by 2030, this application has barely passed the pilot stage, with a first-of-its-kind plant operational in 2020 and targeting full commercial production by 2026 [44].

Electrolytic production requires low-carbon electricity to deliver carbon-free hydrogen. This positions electrolyzers in competition with other electrifying sectors. The expected power demand increase will require extensive addition of renewable energy in the German electricity grid, which is currently characterized by a relatively large carbon intensity [45]. This is further exacerbated by the governmental decision to proceed with the decommissioning of nuclear power plants [46], and the requirement to be less reliant on natural gas in the power system due to the aforementioned issues. The opportunity cost of powering electrolyzers with renewable energy instead of delivering this electricity to the power system is thus non-negligible [47], notably considering the lack of ample solar irradiance and wind exposure in Germany compared to other well-endowed countries. The Gulf Coast, on the other hand, is very well endowed with ample solar irradiance and wind potential. However, the greatest wind potential is in the Northwest of Texas, which is usually complicated to transmit to demand centers due to transmission capacity constraints.

The creation of a more holistic hydrogen supply chain will also likely require transmission pipelines and large-scale storage. Making use of the existing natural gas pipeline network is envisaged, but the feasibility of retrofit remains unclear [48] – only a single project has been completed [49]. Likewise, while storage in tanks is well established, a more inexpensive form of storage in salt caverns or depleted gas wells is considered, but not yet fully understood.

Finally, beyond a purely technical standpoint, several socio-political considerations inherent in the German context must be accounted for. Most notably, the German population dislike for CCS technologies [50], which is reflected institutionally [51] – the German Environment Agency considers CCS' potential 'limited'. This could jeopardize plans to pursue blue hydrogen. To this must be added the aversion for nuclear.

1.3. An optimization model to evaluate a low-carbon hydrogen supply chain

Such ambitions will require the extensive development of a hydrogen supply chain. As opposed to the status quo in which most hydrogen is produced on-site, a more versatile use of hydrogen will likely spur the deployment of an integrated network of production, transmission, and storage technologies. To evaluate the feasibility of such an effort, several modeling algorithms have been developed. These intend to locate the location of production and the required transmission network to fulfill hydrogen demand. In many instances, they target hydrogen for light-duty mobility [52]–[57].

This study describes the development of an optimal low-carbon hydrogen network, created within the SESAME group at MIT. The model intends to evaluate the regional infrastructure deployment required to fulfill a prescribed industrial demand from the year 2025 until the year 2050. Each node represents a region in the considered system. Each region, or node, is associated with a hydrogen demand according to its industrial activity. In each region, the model optimizes the required infrastructure to be deployed. The model also optimizes infrastructure to be built between nodes, namely hydrogen and electricity transmission. The technologies considered are laid out in Table 1. All infrastructure is assumed to be greenfield.

Table 1: List of optimized technologies in the study

Power	Production	PV, Onshore and Offshore Wind
	Storage	Li-Ion
	Transmission	Transmission Lines
Hydrogen	Production	PEM Electrolysis, ATR with CCS, SMR with CCS
	Storage	Salt Caverns, Liquid Tank, Compressed Tank
	Transport	Pipelines

The model intends to fulfill hydrogen demand at all times during an entire year. The temporal granularity is hourly. Furthermore, to evaluate the growth of the required supply chain, the model is run for multiple years. To avoid computational intractability, the model is run for the years 2025, 2030, 2040, and 2050. It is formulated entirely linearly, thus avoiding binary constraints that would further exacerbate complexity. The inputs and outputs of the model are laid out in Table 2. For most technologies, a single cost was considered for all years due to the limited scope for cost decreases. Renewable technologies and electrolyzer costs are however expected to decrease – data was obtained for the four considered years. PEM electrolyzers were chosen thanks to their shorter ramp-up time compared with other production technologies, making them more adequate when paired with non-dispatchable RES.

Table 2: List of inputs and outputs in the model

Inputs	Cost and Technology Parameters, Capacity Constraints (Solar PV, Wind Turbines, Salt Caverns), Renewable Generation Profiles, Demand by Regions

Outputs	Hourly Flows of Electricity and Hydrogen Between and Within Regions, Technology Capacities, CO_2 Emissions

This model is primarily used to assess the influence of electrolytic production in an increasingly decarbonized hydrogen supply chain. For both assessed regions, it evaluates the infrastructure deployment needed if production were to come entirely from electrolyzers powered by renewables. This provides an understanding of the scale of decarbonizing the industry with low-carbon hydrogen. Another case study models the supply chain under a system-wide carbon constraint. This enables the assessment of the relative merits of electrolytic production and ATR production with CCS. Finally, in the case of Germany, a scenario in which production targets are set for both technologies as well as for pipeline imports from Norway, Spain, and North Africa is investigated. This intends to match a potential decarbonization avenue for the country which is in line with the efforts outlined in the national strategy.

Chapter 2 presents the model in its extensive shape. It then describes the results for the Gulf Coast region. Chapter 3 investigates the German case in depth.

Chapter 2

A Novel Optimal Low Carbon Hydrogen Network

2.1. Introduction

Despite the ratification of the Paris Agreement by 189 countries in 2015, carbon emissions have remained fairly constant and above 30 Gt per year [58]. This has incited calls for further action, which resulted in several countries pledging to attain carbon neutrality by mid-century [2]. An advocated decarbonization pathway promotes a reduction of carbon emissions from electricity generation and the electrification of several end-uses that currently rely on several incumbent fuels [2-3]. The former objective is deemed to be attainable using low-carbon electricity generation technologies, notably solar panels, wind turbines, and nuclear. The latter targets sectors such as transport and the industry. Overall, this would increase electricity's share in the global consumed energy from 21.3% (27,000 TWh) to 65-70% (115,000 TWh) in 2050 [59]. However, electrification may be impaired by feasibility or cost-effectiveness issues in several applications, notably in the industry sector. Among alternatives, a portfolio of low-carbon fuels such as hydrogen and biofuels is considered. Hydrogen's versatility is deemed to make it suitable for various end-uses such as industrial processes, long-haul transport, or renewable energy storage [60]. This has incited several countries to release national hydrogen strategies, which highlights the potential future role of hydrogen in the decarbonization effort [61].

Hydrogen's role in a future decarbonized energy system is contingent upon its environmental impact. However, it is currently predominantly produced from SMR, which is associated with substantial Green House Gas (GHG) emissions, both at the process level as well as upstream the supply chain. Globally, this accounts for 2% of global carbon emissions. Alternatively, hydrogen can be produced through the electrolysis of water. This process, which is highly energy-intensive, can be low-carbon granted that the input electricity comes from low-carbon sources. There are currently three main production technologies: Alkaline, Proton Exchange Membrane (PEM), and Solid Oxide (SOE). The former is established, but not for dedicated hydrogen production. The two latter are relatively immature and expensive, with negligible deployed capacity worldwide. Despite their cost, several countries have placed electrolyzers at the center of their strategy, with a few stating deployment targets [18]–[21].

Electrolytic hydrogen production requires low-carbon power sources to deliver low-carbon hydrogen. Several technologies can deliver low-carbon electricity such as Renewable Electricity Sources (RES), nuclear production, or conventional production fitted with CCS. RES, excluding hydropower, are characterized by their non-dispatchability, where their power output is dictated by the natural resource they harness. This leads to varying power curves throughout the day. As a result, the operation of electrolyzers power by non-dispatchable RES should be flexible and will cause varying hydrogen outputs.

Historically, hydrogen has been used in the industry, primarily for oil refining, ammonia, and methanol production. These industrial processes require a constant hydrogen inflow, which was achieved with the constant operation of SMRs. The varying output of electrolyzers will require the deployment of hydrogen storage to balance low production periods and ensure constant delivery. Furthermore, production and consumption sites may now be separated since industrial sites are not necessarily co-located with adequate renewable production regions. This is likely to cause the spur of hydrogen supply chains that will encompass production, storage, and transmission at large scales.

The evolution of these novel supply chains as well as hydrogen's envisioned greater participation in several industries has spurred the interest of energy modelers. This has led to an increase in the number of hydrogen models at various scales, aiming to provide insights regarding future supply chain feasibility and cost. However, the versatility of hydrogen and the potential it offers in terms of sector coupling has led to a variety of models for which there is currently no consensus [62]. This versatility would, in theory, require a large pool of modeled uses such as in mobility, industry, storage, and long-haul transport. A satisfactory spatial resolution also aids in understanding the decoupling of production and consumption/storage. Additionally, an appropriate level of temporal resolution enables capturing certain short-term operations notably of electrolyzers, over an extended period to model the long-term operation of large-scale storage.

This requirement to maintain accuracy across these three dimensions comes at the expense of computational tractability. This is particularly felt when binary decision variables or integer variables are introduced [52]. While they may appear essential to represent behaviors such as economies of scale or decide upon a transmission network, certain assumptions enable to bypass these constraints by introducing linear relaxation [63]. Most notably, it is argued that even though production units commonly exhibit economies of scale that would require non-linear cost relations, assuming that a large number of units are built is sufficient to justify that cost relations remain linear [64]. In the subsequent model, all cost relationships and constraints are maintained linear, which enables a finer spatial and temporal resolution. The use of representative weeks defined using clustering algorithms is therefore not needed – a full year of resource data can be utilized.

Within the literature, most analysis target mobility, with exogenous demand constraints that are dictated by an assumption on the market penetration of fuel cell battery vehicles [52]–[57]. Considering hydrogen's versatility, restricting analyses to a single sector may overshadow the synergies with other sectors that could result in cost savings. Surprisingly, only a few analyses target the industry sector [65], which currently is the overwhelming consumer of hydrogen. Since the production of ammonia and methanol is not expected to decrease, this sector provides a sound basis for analysis, with a demand that can be reasonably forecasted. Finally, among existing supply chain models, few consider the optimization of both hydrogen pipelines and electricity transmission. Including both means of transport of energy can yield the relative merit of moving energy as electrons as opposed to chemically and vice-versa.

To provide insights regarding the least cost scenario for a developed hydrogen supply chain, an optimization model has been developed. Using a linear approach, a multi-nodal system representing regions within a country optimizes for electricity generation, hydrogen generation, transmission, and storage. Several power generation, hydrogen production, and storage options are considered. This model aims to provide insights regarding the development of a hydrogen supply chain realistically. It has been developed as a part of MIT's Sustainable Energy System Analysis Modeling Environment (SESAME) [66] and will be accessible through the software's User Interface.

2.2. Hydrogen Supply Chain Model

The model presented in this report is a multi-nodal system that seeks to optimize a hydrogen supply chain comprising power and hydrogen production, transmission, and storage. It is developed from a macroeconomic modeler's perspective, thus optimizing for social welfare by minimizing the overall costs. Each node in the system can represent a geographical area of any size. The model optimizes for a set of adjacent years (i.e. four years between 2025 and 2050) to analyze the expansion of the supply chain as demand grows. While the system presented here analyzes the US Gulf Coast, the model is location agnostic as long as the right input data is used, which captures the geographical area of interest. Within all nodes, capacities of renewable generation from solar and wind, electrolyzers, ATR with CCS, SMR with CCS, and hydrogen and electricity storage are optimized. PEM electrolyzers were chosen thanks to their shorter ramp-up time compared with other production technologies, making them more adequate when paired with non-dispatchable RES. The optimized technologies are laid out in Table 1:

Table 3: Optimized technologies in the hydrogen supply chain

Power	Production	PV, Onshore and Offshore Wind
	Storage	Li-Ion
	Transmission	Transmission Lines
Hydrogen	Production	PEM Electrolysis, ATR with CCS, SMR with CCS
	Storage	Salt Caverns, Liquid Tank, Compressed Tank
	Transport	Pipelines

The flows within a node are displayed in Figure 1. The capacity of all technologies displayed is optimized. Figure 2 shows the flows of hydrogen outside a node and within a node. Transmitted hydrogen can either enter a node to be consumed or continue to flow to other nodes.

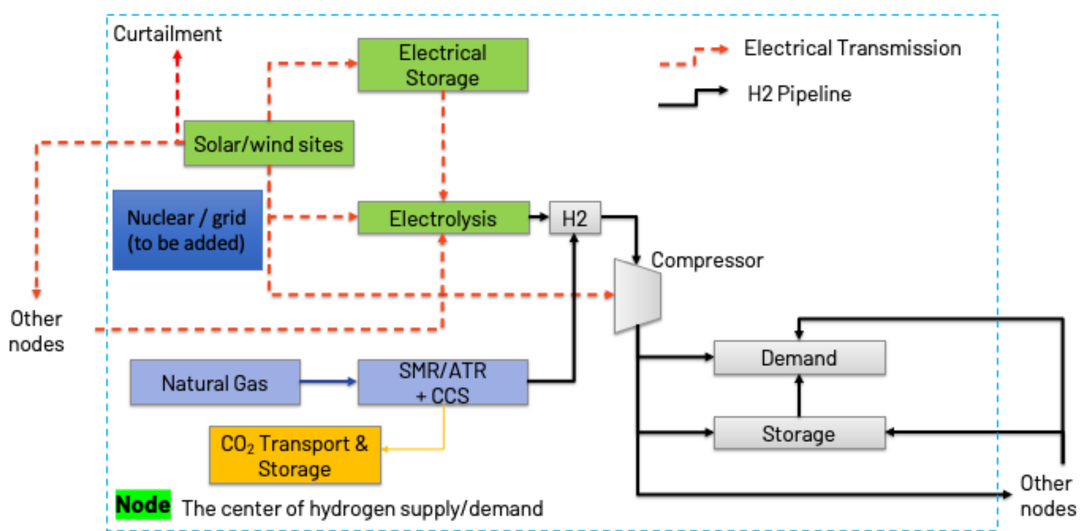


Figure 1: Main flows between regions

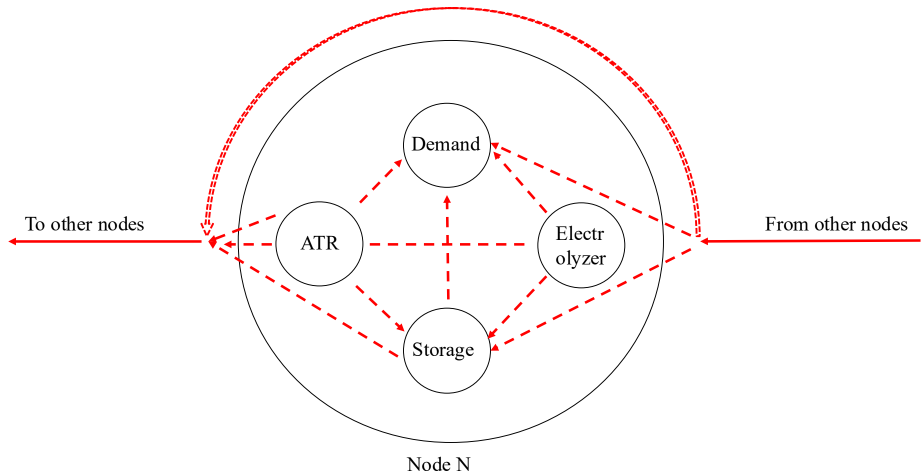


Figure 2: Nodal flows

The data used in this model are renewable electricity profiles, cost factors, emission factors, and technology parameters. The variables relate to the capacities of all considered technologies (c), electricity and hydrogen flows (f), and electricity and hydrogen storage levels (l). Capital superscripts relate to capacities, lowercase subscripts relate to the origin and destination of flows, and capital abbreviation describe parameters. Finally, several sets are introduced. These are all laid out in table 2:

Table 4: Index and sets, capacities, flows, technological parameters, and emission factors

SETS	
t, T	Index and set of hours in a year
n, N	Index and set of nodes in the model
y, Y	Index and set of years in the model
n_{off}, N_{off}	Index and set of offshore nodes in the model
n_{on}, N_{on}	Index and set of onshore nodes in the model
r, R	Index and set of renewable generation technologies
c, C	Index and set of compressors
f, F	Index and set of natural gas-derived production technologies
k, K	Index and set of transmission technologies
s, S	Index and set of hydrogen storage technologies

CAPACITIES – Uppercase Superscripts (set) and lower-case subscripts (index)	
REN: sol, $w(on)$, $w(off)$	Renewable capacities. sol=solar, w, on=onshore wind, w, off=offshore wind
$CMPR$: $h_{2,sc}, h_{2,ct}, h_{2,lt}$	Compressor capacities. $h_{2,sc}$=salt cavern, $h_{2,ct}$=compressed tank, $h_{2,lt}$=liquid tank
INV	Inverter capacity.
$ETLZ$	Electrolyzer capacity.
NGP: atr, smr	Natural gas-derived hydrogen production capacities. atr = ATR, smr=SMR
TRA: e, h_2	Transmission capacities. e=electrical transmission, h_2=domestic hydrogen pipeline

STO: $e(p), e(\ e), h_{2,sc}, h_{2,ct}, h_{2,lt}$	Storage capacities. $e(p)$=electrical power capacity, $e(e)$=electrical energy capacity, $h_{2,sc}$=salt cavern capacity, $h_{2,ct}$=compressed tank capacity, $h_{2,lt}$=liquid tank capacity
$TECH$	All technologies excluding transmission assets.
INJ	Injection rate of the salt cavern

FLOWS – Uppercase superscripts (set) and lowercase subscripts (index)

H_2: $etlzprod$	Electrolytic production
H_2, E: $etlz$	To/From electrolyzer
H_2: $ngprod$	Natural gas-derived production
H_2: ng	To/From natural gas-derived production
H_2: H_2prod	All production (both electrolytic and fossil-based)
H_2: dem	To demand
H_2: ${h_2}_{sc}$	To/From salt cavern
H_2: ${h_2}_{ct}$	To/From compressed tank
H_2: ${h_2}_{lt}$	To/From liquid tank
H_2, E: $trans$	To/From transmission
H_2: $cont$	Transmitted hydrogen that continues to be transmitted
H_2: nor	From Norway
E: gen	Electricity generation
E: cu	To curtailment
E: cs	To storage compressor
E: $stor$	To/From storage

PARAMETERS

$CAPEX_i$	Capital expenditure of technology i
$OPEX_i$	Operational expenditure i
AF_i	Annuity Factor of technology i
DF_i	Depreciation Factor of technology i
${H_{2dem}}_n$	Hydrogen demand at node n
EFF_i	Efficiency of technology i
HE	Hourly storage efficiency of the battery
CE	Charging efficiency of the battery
DE	Discharging efficiency of the battery
BSD	Battery storage duration
TDT	Total discharge time of the salt cavern
CF_r	Capacity factor of renewable technology r
$LOSSES_k$	Losses of transmission technology k
DF_k	Detour factor of transmission technology k
$COMP_c$	Compression requirement for either salt cavern, compressed or liquefied tank
$REQ_{el,f}, REQ_{ng,f}$	Electricity and natural gas requirement of natural gas-derived production technology f
CF_f	Capacity factor of fossil-based hydrogen production f
$DIST_{n\rightarrow n'}$	Distance between regions n and n'

$A_{n,n'}$	Incidence matrix, 0 or 1 depending on whether regions are neighbors
$DIST_{CO_2}$	Typical distance covered by a CO_2 pipeline
$COST_{CO_2,t}$	Cost of CO_2 transport
$COST_{CO_2,s}$	Cost of CO_2 storage
$HOURS$	Hours in a year
YHD_y	Yearly hydrogen demand in year y
MCI_y	Maximum carbon intensity in year y
CT	Carbon Tax

EMISSIONS	
$E_{up,y}$	Upstream emissions from natural gas supply chain
$E_{grid,y}$	Typical emissions from the grid
$E_{r,f}$	Released process emissions of natural gas-derived production technology f
$E_{capt,f}$	Captured process emissions of natural gas-derived production technology f

2.2.1. Equations

2.2.1.1. Objective Function

The objective function is composed of several components. It aims to minimize the annualized costs of the various components in the system. It is composed of the capacity, fuel, and emissions costs. All capacity values are multiplied linearly by an annualized cost. This comprises a Capital Expenditure (CAPEX) cost that is divided by the lifetime of the asset. This CAPEX is multiplied by an Operational Expenditure (OPEX) cost expressed as a percentage of the CAPEX, added to an annualized factor (AF) that is a function of the cost of capital (WACC) and of the asset's lifetime, and a Depreciation Factor (DF). The fuel costs encompass the cost of the natural gas procured for the ATRs. Finally, the emissions costs are accounted for by multiplying the total emissions by a carbon tax. The objective function is thus expressed as the sum of the capacity costs (CC), fuel costs (FC), and emissions costs (EC). It contains the sum of infrastructure costs for a set of prescribed years (2025, 2030, 2040, 2050):

$$OF = CC + FC + EC \tag{1}$$

The capacity costs are broken down into technologies that are optimized for within nodes, and those in between nodes (transmission). These boil down to:

$$\mathrm{CC} = \mathrm{CC}_{in,nodes} + \mathrm{CC}_{between,nodes} \tag{2}$$

In turn, these equal:

$$CC_{in,nodes} = \sum_{y\in Y}\sum_{n\in N}\sum_{TECH} c_{n,y}^{TECH} \times CAPEX_y^{TECH} \times (AF_y^{TECH} + OPEX_y^{TECH}) \tag{3}$$

$$CC_{between,nodes} = \sum_{TRA} CAPEX^{TRA} \times (AF^{TRA} + OPEX^{TRA}) \times \sum_{y\in Y}\sum_{n\in N}\sum_{n'\in N} DIST_{n\to n'} \times c_{n\to n',y}^{TRA} \tag{4}$$

For a few technologies such as wind turbines, solar panels, and electrolyzers, costs change through the years, which is reflected in the objective function. The fuel costs consist of natural gas for hydrogen production, as well as the electricity required to power the process and carbon capture. Fossil hydrogen production is assumed to be constant throughout the year, accounting for a certain capacity factor:

$$FC = \sum_{y \in Y} \sum_{f \in F} \sum_{n \in N} c_{n,f,y}^{NGP} \times HOURS \times (REQ_{ng,f} \times CF_f \times COST_{ng,y} + REQ_{el,f} \times CF_f \times COST_{el,y}) \tag{5}$$

The emission cost encompasses all sources of carbon emissions, including methane, which is translated into carbon equivalent using its 100-year global warming potential. Upstream emissions are quantified in a single factor, decreasing over the years. The electricity required to power the carbon capture process for ATRs and SMRs is also quantified. It is assumed that the grid provides the required power input and is therefore linked to a typical emission intensity. The remaining process emissions after carbon capture are also accounted for. These are multiplied by a carbon tax. Captured CO_2 is quantified and added as a cost for its transmission and storage.

$$\begin{aligned} EC = \sum_{y \in Y} \Big(& \sum_{f \in F} \sum_{n \in N} c_{n,f,y}^{NGP} \times HOURS \times CF_f \times REQ_{e,f} \times E_{grid,y} \\ & + \sum_{f \in F} \sum_{n \in N} c_{n,f,y}^{NGP} \times HOURS \times REQ_{ng,f}^{NGP} \times CF_f \times E_{up,y} \\ & + \sum_{f \in F} \sum_{n \in N} c_{n,f,y}^{NGP} \times HOURS \times CF_f \times E_r \Big) \times CT \\ & + \sum_{f \in F} \sum_{n \in N} c_{n,f,y}^{NGP} \times HOURS \times CF_f \times E_{capt,f} \times (DIST_{CO_2} \times COST_{CO_2,t} + COST_{CO_2,s}) \end{aligned} \tag{6}$$

2.2.1.2. Electricity Constraints

Electricity flows model the generation of electricity from renewable and its dispatch throughout the supply chain to power electrolyzers and compressors. A portion of the electricity that cannot be used is therefore curtailed, not sent into the grid. As such, all the infrastructure considered in this analysis is greenfield − a cap on the amount of renewable installable in each region is defined from a land eligibility analysis.

The relative share of each technology capacity is optimized in each node. The generation curve at each node and each hour is determined differently depending on whether the considered node is offshore or onshore. If offshore, the generation curve is:

$$f_{gen,n,t,y}^{E} = c_{w(off),n,y}^{REN} \times CF_{w(off),n,t,y} \ \forall \ \ n_{off} \in N_{off}, \forall \ t \in T, \forall \ y \in Y \tag{7}$$

If onshore, the generation curve is:

$$f_{gen,n,t,y}^{E} = c_{w(on),n,y}^{REN} \times CF_{w(on),n,t,y} + c_{sol,,n,y}^{REN} \times CF_{sol,n,t,y} \ \forall \ n_{on} \in N_{on}, \forall \ t \in T, \forall \ y \in Y \tag{8}$$

These constraints optimize the required renewable capacity in each node. In turn, the dictated hourly flow of electricity is dispatched among several pathways to power electrolyzers and compressors within the node or outside the node for electrolyzer production, and compressed and liquid tank operation. Unused electricity can be sent to electrical storage or curtailed:

$$f^{E}_{gen,n,t,y} = f^{E}_{gen\rightarrow h_{2_{sc}},n,t,y} + f^{E}_{gen\rightarrow h_{2_{ct}},n,t,y} + f^{E}_{gen\rightarrow h_{2_{lt}},n,t,y} + f^{E}_{gen\rightarrow etlz,n,t,y} + f^{E}_{gen\rightarrow curt,n,t,y} + f^{E}_{gen\rightarrow stor,n,t,y} + \sum\nolimits_{n'\in N} f^{E}_{gen\rightarrow trans\rightarrow etlz,n,n',t,y} + f^{E}_{gen\rightarrow trans\rightarrow h_{2_{ct}},n,n',t,y} + f^{E}_{gen\rightarrow trans\rightarrow h_{2_{lt}},n,n',t,y} \;\forall\; n\in N, \forall\, t \in T, \forall\; y\in Y \tag{9}$$

Compressors' operations are dictated by the incoming electricity flows and the electricity consumption necessary to reach ~100 bar, for both storage and pipelines. Compression for storage for salt caverns is defined as such:

$$f^{E}_{gen\rightarrow h_{2_{sc}},n,t,y} \times COMP_{sc} = f^{H_2}_{ng\rightarrow h_{2_{sc}},n,t,y} + f^{H_2}_{etlz\rightarrow h_{2_{sc}},n,t,y} + f^{H_2}_{trans\rightarrow h_{2_{sc}},n,t,y} \;\forall\; n\in N, \forall\; t\in T, \forall\; y\in Y \tag{10}$$

Compression for compressed and liquid storage tanks are defined, respectively, as such:

$$\left(f^{E}_{gen\rightarrow h_{2_{ct}},n,t,y} + \sum\nolimits_{n'\in N} f^{E}_{gen\rightarrow trans\rightarrow h_{2_{ct}},n,n',t,y}\right) \times COMP_{ct} = f^{H_2}_{ng\rightarrow h_{2_{ct}},n,t,y} + f^{H_2}_{etlz\rightarrow h_{2_{ct}},n,t,y} + f^{H_2}_{trans\rightarrow h_{2_{ct}},n,t,y} \;\forall\; n \in N, \forall\; t\in T, \forall\; y\in Y \tag{11}$$

$$\left(f^{E}_{gen\rightarrow h_{2_{lt}},n,t,y} + \sum\nolimits_{n'\in N} f^{E}_{gen\rightarrow trans\rightarrow h_{2_{lt}},n,n',t,y}\right) \times COMP_{lt} = f^{H_2}_{ng\rightarrow h_{2_{lt}},n,t,y} + f^{H_2}_{etlz\rightarrow h_{2_{lt}},n,t,y} + f^{H_2}_{trans\rightarrow h_{2_{lt}},n,t,y} \;\forall\; n \in N, \forall\; t\in T, \forall\; y\in Y \tag{12}$$

2.2.1.3. Hydrogen Constraints

Hydrogen production can be either electrolytic or fossil based. Electrolytic production is powered by renewables, which are optimized for in the model. This gives rise to a supply curve, from which a portion can be directed to electrolyzers. These flows can stem from production within a node, or come from transmission from other nodes. Additionally, electricity stored in batteries can be used to provide additional power. Electrolytic production is thus defined as follows:

$$\left(f^{E}_{gen\rightarrow etlz,n,t,y} + f^{E}_{stor\rightarrow etlz,n,t,y} + \sum\nolimits_{n'\in N} f^{E}_{gen\rightarrow trans\rightarrow etlz,n,n',t,y} \times LOSSES^{TRA}_{n,n',el}\right) \times EFF_{etlz,y} = f^{H_2}_{etlzprod,n,t,y} \;\forall\; n \in N, \forall\; t\in T, \forall\; y\in Y \tag{13}$$

The resulting flow can either be sent to demand or storage within node n, or to transmission:

$$f^{H_2}_{etlzprod,n,t,y} = f^{H_2}_{etlzprod\rightarrow dem,n,t,y} + f^{H_2}_{etlzprod\rightarrow,n,t,y} + f^{H_2}_{etlzprod\rightarrow trans,n,t,y} \;\forall\; n\in N, \forall\; t\in T, \forall\; y\in Y \tag{14}$$

The other production source is natural gas-derived production. The two considered technologies are ATRs and SMRs, both with carbon capture. They are assumed to produce a constant output of hydrogen throughout the year, even though a capacity factor remains accounted for:

$$f^{H_2}_{ngprod,n,t,y} = \sum\nolimits_{f\in F} c^{NGP}_{n,f,y} \times CF_f \quad \forall\; n\in N, \forall\; t\in T, \forall\; y\in Y \tag{15}$$

The resulting flow is similarly sent to either demand, storage, or transmission, as in equation 12.

Hydrogen demand fulfilment must be complied with in each node at every hour. It is assumed that demand is constant throughout the year, which is typical of an industrial operation. Furthermore, it must always be complied with – there is no cost of non-served hydrogen. It can be fulfilled from either local electrolytic or natural gas-derived production, local storage, or transmission from other regions. The model is standardized so as to fulfil a unitary demand at every hour (i.e., $\sum_{n\in N} H_{2dem_n} = 1$) across the country for computational efficiency. It is then split across regions according to their relative hydrogen consumption. During post-processing, the system is scaled back to the required size.

$$H_{2dem_{n,y}} = f^{H_2}_{etlz\rightarrow dem,n,t,y} + f^{H_2}_{ng\rightarrow dem,n,t,y} + f^{H_2}_{h_{2_{sc}}\rightarrow dem,n,t,y} + f^{H_2}_{h_{2_{ct}}\rightarrow dem,n,t,y} + f^{H_2}_{h_{2_{lt}}\rightarrow dem,n,t,y} + f^{H_2}_{trans\rightarrow dem,n,t,y} \ \forall\ n \in N, \forall\ t \in T, \forall\ y \in Y \tag{16}$$

2.2.1.4. Transmission

Transmission is optimized for both electricity and hydrogen. Hydrogen pipelines are allowed to be built between neighboring regions only, while electricity transmission lines can be built between any regions. Hydrogen, though, can be transmitted between several regions across the country from production or storage towards demand through these regional pipelines. While line packing can be a convenient process to store hydrogen in pipelines, it is not considered in this study.

Electricity transmission accommodates for electrolytic production and compressor operations, which were described in equations 9, and 11. Hydrogen transmission is modelled differently – instead of assigning flows with a prescribed destination as with electricity, transmitted hydrogen flows are destination agnostic. They are bundled in a flow called $f^{H_2}_{trans}$. To enable hydrogen to flow from a region to another distant region through consecutive pipelines connecting all intermediate regions, a flow called $f^{H_2}_{cont}$ is introduced. This conveniently avoids requiring binary variables for hydrogen pipelines, reducing the computational burden.

Constraints on incoming and outgoing transmitted hydrogen are required. Incoming hydrogen can either be dispatched to demand, storage, or continue its transmission. Transmission is modelled using a four-dimensional array. The first index represents the node from which hydrogen is sent, the second is the receiving node, and the third is the hour of the year, and the fourth is the year. In this case, the summation of the transmitted flows occurs over the first dimension, representing the sending nodes. An incidence matrix filled with 0 and 1 dictates whether two regions are neighbors, constraining pipelines to be built between neighboring regions only:

$$f^{H_2}_{trans\rightarrow dem,n,t,y} + f^{H_2}_{trans\rightarrow h_{2_{sc}},n,t,y} + f^{H_2}_{trans\rightarrow h_{2_{ct}},n,t,y} + f^{H_2}_{trans\rightarrow h_{2_{lt}},n,t,y} + f^{H_2}_{trans\rightarrow cont,n,t,y} = \sum_{n'\in N} f^{H_2}_{trans,n',n,t,y} \times A_{n.n'} \ \ \forall\ \ n \in N, \forall\ t \in T, \forall\ y \in Y \tag{17}$$

Hydrogen coming out of node consists of that hydrogen which continues to other nodes, and hydrogen from the nodal electrolyzers, ATR, and storage. The summation is operated over the second dimension, which represents the receiving nodes:

$$f^{H_2}_{trans\rightarrow cont,n,t,y} + f^{H_2}_{etlz\rightarrow trans,n,t,y} + f^{H_2}_{ng\rightarrow trans,n,t,y} + f^{H_2}_{h_{2_{sc}}\rightarrow trans,n,t,y} + f^{H_2}_{h_{2_{ct}}\rightarrow trans,n,t,y} + f^{H_2}_{h_{2_{lt}}\rightarrow trans,n,t,y} = \sum_{n'\in N} f^{H_2}_{trans,n,n',t,y} \times A_{n.n'} \ \ \forall\ \ n \in N, \forall\ t \in T, \forall\ y \in Y \tag{18}$$

Importing regions can also send imported hydrogen to other regions. The model must be further constrained for the flows in between two regions – the total flow should be calculated with a proxy variable that calculates the net transmission:

$$f^{H_2}_{transnet,n,n',t,y} = f^{H_2}_{trans,n,n',t,y} - f^{H_2}_{trans,n',n,t,y} \;\forall\;\; n \in N, \forall\;\; n' > n \in N, \forall\; t \in T, \forall\; y \in Y \tag{19}$$

This net flow can either be positive or negative, indicating the direction of the flow. It is an upper triangular matrix.

2.2.1.5. Storage

Both electricity and hydrogen can be stored. Electricity storage is assumed to come from Li-Ion batteries. Its operation accounts for the hourly storage efficiency of the asset as well as the charging and discharging efficiency:

$$l^E_{n,t,y} = l^E_{n,t-1,y} \times HE + f^E_{gen\to stor,n,t,y} \times CE - \frac{f^E_{stor\to etlz,n,t,y}}{DE} \;\forall\;\; n \in N, \forall\; t \in T, \forall\; y \in Y \tag{20}$$

Hydrogen storage can be filled from electrolyzer, fossil-based production, or transmission, and sent to demand or transmission. The model considers storage from salt caverns, compressed tanks, and liquid tanks. It is assumed that the storage losses in salt caverns are minimal and are therefore unaccounted for:

$$l^{H_2}_{h_{2_{sc}},n,t,y} = l^{H_2}_{h_{2_{sc}},n,t-1,y} + f^{H_2}_{etlz\to h_{2_{sc}},n,t,y} + f^{H_2}_{ng\to h_{2_{sc}},n,t,y} + f^{H_2}_{trans\to h_{2_{sc}},n,t,y} - f^{H_2}_{h_{2_{sc}}\to dem,n,t,y} - f^{H_2}_{h_{2_{sc}}\to trans,n,t,y} \;\forall\; n \in N, \forall\; t \in T, \forall\; y \in Y \tag{21}$$

Injection rates are accounted for. All positive flows in equation 21 must be lower than the injection rate of the cavern, which is defined as a variable:

$$f^{H_2}_{etlz\to h_{2_{sc}},n,t,y} + f^{H_2}_{ng\to h_{2_{sc}},n,t,y} + f^{H_2}_{trans\to h_{2_{sc}},n,t,y} \le c^{INJ}_n \;\forall\; n \in N, \forall\; t \in T, \forall\; y \in Y \tag{22}$$

The equations for compressed and liquid tanks are similarly defined, with the addition of a loss term that characterizes the hourly loss rate of stored hydrogen.

2.2.1.6. Capacity Constraints

The capacities of all the infrastructure considered are the main drivers of the cost to be minimized. Renewable technologies' capacities are optimized in equation 7 – they dictate the energy curve. Similarly, fossil-based technologies' capacities are optimized in equation 14, in which they set a constant production output. Most other technologies' capacities are constrained to equal the maximum flow/inventory that they must be able to accommodate at any given time.

Compressors' capacities are optimized as follows:

$$f^E_{gen\to c,n,t,y} + \sum\nolimits_{n' \in N} f^E_{gen\to trans\to c,n,n',t,y} \le c^{COMP}_{c,n,y} \quad \forall\; c \in C, \forall\; n \in N, \forall\; t \in T, \forall\; y \in Y \tag{23}$$

Electrolyzers' capacities are likewise bound by the maximum flows of electricity they intake at any hour during the year:

$$\frac{f^{H_2}_{etlzprod,n,t,y}}{EFF_{etlz,y}} \leq c^{ETLZ}_{n,y} \quad \forall\ n \in N, \forall\ t \in T, \forall\ y \in Y \tag{24}$$

Transmission technologies are bound by the maximum flow they must transport between two regions at any given hour of the year. Electricity transmission capacity is defined as such:

$$f^{E}_{gen\to trans\to etlz,n,n',t,y} + f^{E}_{gen\to trans\to h_{2_{ct}},n,n',t,y} + f^{E}_{gen\to trans\to h_{2_{lt}},n,n',t,y} \leq c^{TRA}_{e,n,n'}, \quad \forall\ n \in N, \forall\ n' \in N, \forall\ t \in T, \forall\ y \in Y \tag{25}$$

Hydrogen transmission capacity is bound by the net flow of hydrogen between regions:

$$f^{H_2}_{transnet,n,n',t,y} \leq c^{TRA}_{h_2,n,n',y} \quad \forall\ n \in N, \forall\ n' \in N, \forall\ t \in T, \forall\ y \in Y \tag{26}$$

Similarly, imported hydrogen is assumed to be carried by pipeline. The maximum flow of imported hydrogen thus also defines the capacity of the importing pipeline.

Hydrogen and electricity storages are capped by their maximum level throughout the year. Hydrogen storage capacity is defined as such:

$$l^{H_2}_{s,n,t,y} \leq c^{STO}_{s,n,y} \quad \forall\ s \in S, \forall\ n \in N, \forall\ t \in T, \forall\ y \in Y \tag{27}$$

The injection rate and the maximum storage capacity of each hydrogen storage technology are related by a total discharge time (TDT), which quantifies the time required to fill the storage technology from empty to full at the maximum injection rate:

$$c^{STO}_{s,n,y} \leq c^{INJ}_{s,n,y} \times TDT \quad \forall\ s \in S, \forall\ n \in N, \forall\ y \in Y \tag{28}$$

The resulting capacity captures the working capacity of the technology. It does not account for the total capacity, which would also include enough cushion gas to maintain a safe operation of the technology.

The energy capacity of the battery is capped to the maximum energy level throughout the year:

$$l^{E}_{n,t,y} \leq c^{STO}_{e(e),n,y} \quad \forall\ n \in N, \forall\ t \in T, \forall\ y \in Y \tag{29}$$

The energy capacity of the battery is tied to the power capacity. The power capacity is bound to accommodate for the maximum flow of incoming electricity:

$$f^{E}_{gen\to stor,n,t,y} \times CE \leq c^{STO}_{e(p),n,y} \quad \forall\ n \in N, \forall\ t \in T, \forall\ y \in Y \tag{30}$$

It must also accommodate for a discharge of electricity:

$$\frac{f^{E}_{stor\to etlz,n,t,y}}{DE} \leq c^{STO}_{e(p),n,y}\ \forall\ n \in N, \forall\ t \in T, \forall\ y \in Y \tag{31}$$

Both power and energy capacities are tied by the battery storage duration (BSD):

$$c^{STO}_{e(p),n,y} \times BSD = c^{STO}_{e(e),n,y} \ \forall\ n \in N, \forall\ y \in Y \tag{32}$$

2.2.1.7. Land Constraints

To ensure that a node does not install an unrealistic amount of renewable capacity within its potentially constrained land, a land eligibility analysis was performed to evaluate the technical potential of each region for solar PV and wind turbines. Offshore wind and salt caverns are also considered. At each node, the optimized capacity relating to these technologies is capped by a parameter defining the maximum installable capacity in a certain region.

2.2.1.8. System Constraints

Total system constraints are required to ensure that a certain technology does not overtake the system due to its cost benefits compared with other technologies. To ensure that electrolyzers are build, a percentage of total production can be enforced to stem from electrolyzers. This is particularly insightful to assess national strategies that include targets for electrolytic production. For fossil-based production, a relative share of newly built ATR and retrofitted SMR can be set, reflecting the fact that retrofits are more expensive than new plants, but SMR plants are already built. A final system constraint consists of a maximum carbon intensity over the entire system, which lets all technologies free to compete and provides a system for which the average hydrogen carbon intensity is under a threshold. It considers process and upstream emissions, from natural gas and electricity:

$$\begin{aligned}\Big(\sum\nolimits_{f\in F} REQ_{e,f} \times E_{grid,y} \times \sum\nolimits_{n\in N} c^{NGP}_{n,f,y} \times HOURS \times CF_f \\ + \sum\nolimits_{f\in F} \big((E_{r\&P,y} + E_{ngt,y} \times DIST_{ng}) \times LR + E_{iu}\big) \times \sum\nolimits_{n\in N} c^{NGP}_{n,f,y} \times HOURS \times REQ^{NGP}_{ng,f} \times CF_f \\ + \sum\nolimits_{f\in F} E_{r,f} \times \sum\nolimits_{n\in N} c^{NGP}_{n,f,y} \times HOURS \times CF_f\Big) / YHD_y \le MCI_y \ \forall\ y \in Y\end{aligned} \tag{33}$$

2.2.1.9. Account of Existing Infrastructure

The model optimizes for infrastructure deployment over a large period (25 years), by considering four years from 2025 until 2025, namely: 2025, 2030, 2040, and 2050. Accounting for such intervals enables to capture the cost decrease of certain technologies such as electrolyzers and renewables. It also allows for the consideration of increasing hydrogen demand. The analysis of the expanding supply chain requires constraints on the deployed infrastructure. The model enforces any infrastructure in the system in a given year to be more or equal than the infrastructure at the previous considered year, to account for the fact that built infrastructure cannot be discarded. This effectively captures the risk of stranded assets, which is an important feature in hydrogen supply chains [67]:

$$c_{y+1} \ge c_y \ \forall\ y \in Y \tag{34}$$

2.2.1.10. Policies

Hydrogen has recently benefited from governments' attention, which has translated in several forms of subsidies, notably in the United States through the Inflation Reduction Act (IRA). This legislation provides hydrogen producers with Production Tax Credits (PTC) commensurate with the life cycle emissions of their product. The largest subsidy totals \$3/kgH_2 if life cycle emissions remain below 0.45kgCO_2/kgH_2. The model thus adds a discount for each kilogram of hydrogen produced, with varying tax credits depending on the origin of the production. Other legislation beyond the IRA can reduce the cost of producing hydrogen. Production tax credits for renewable electricity production total $25/MWh, thus lowering the cost of electricity. Hydrogen production from natural gas can benefit from the 45Q tax credit, which provides $85 for each ton of CO_2 captured.

These tax credits are available to the producers for a period of ten years after starting operation. The last year to claim these policies is 2033, meaning that they will extend until 2043. Quantifying the amount of hydrogen produced that qualifies for tax credits throughout the years in the model is complex – optimized electricity and hydrogen flows in each considered year do not distinguish between electrolytic capacity built at different time frames. To obtain the most accurate estimation of qualifying hydrogen production, the total hydrogen production added at a certain time frame is calculated, both for electrolytic and natural gas-derived production:

$$\sum_{n\in N}\sum_{t\in T} f^{H_2}_{etlzprod,n,t,y} - \sum_{n\in N}\sum_{t\in T} f^{H_2}_{etlzprod,n,t,y-1} = F_{etlz,y} \ \forall\ y \in Y \tag{35}$$

$$\sum_{n\in N}\sum_{t\in T} f^{H_2}_{ngprod,n,t,y} - \sum_{n\in N}\sum_{t\in T} f^{H_2}_{ngprod,n,t,y-1} = F_{ng,y} \ \forall\ y \in Y \tag{36}$$

The PTC for electrolytic and natural-gas derived production can be claimed by facilities whose construction begins before 2033. For the two first considered years, 2025 and 2030, it is assumed that all hydrogen can benefit from the tax credit, which is then discounted from the objective function as such:

$$-\sum_{y=2025}^{y\leq year} F_{etlz,y} \times \Delta_{etlz} \times PTC_{etlz} \ \forall\ year \in [2025, 2030] \tag{37}$$

Δ_{etlz} accounts for the lifetime of the PTC, which is shorter than the lifetime of the electrolyzer, and is calculated as:

$$\Delta_{etlz} \tag{38}$$

For the year 2040, subsidies from the year 2030 as well as the production added between 2030 and 2033 should be accounted for. To estimate the production added during that time frame, a simple linear interpolation was adopted, yielding the following PTC:

$$-F_{etlz,2030} \times \Delta_{etlz} \times PTC_{etlz} - 0.3 \times F_{etlz,2040} \times \Delta_{etlz} \times PTC_{etlz} \tag{39}$$

The tax credit benefits for natural gas-derived production were calculated similarly. Renewable electricity production was calculated more straightforwardly. Since the PTC time horizon evolves and is regularly being updated, it was assumed that only the years 2025 and 2030 will receive PTC. The total renewable generation was therefore not broken down into generation added at each time step, but simply aggregated, with the discount of the generation to curtailment, which does not qualify for PTC:

$$\sum_{n\in N}\sum_{t\in T} f^{E}_{gen,n,t,y} - \sum_{n\in N}\sum_{t\in T} f^{E}_{gen\to curt,n,t,y} = F_{elec,y} \ \forall\ y \in Y \tag{40}$$

This generation thus benefits from tax credits for the years 2025 and 2030. Δ_{elec} also captures the different lifetime of the PTC and the generation assets:

$$-F_{elec,y} \times \Delta_{elec} \times PTC_{elec} \;\; \forall \; y \in [2025, 2030] \tag{41}$$

The captured carbon emissions, which qualify for 45Q tax credits, are calculated similarly to electrolytic and natural gas-derived production:

$$\sum_{f \in F} E_{capt,f} \times \sum_{n \in N} c^{NGP}_{n,f,y} \times HOURS \times CF_f - \sum_{f \in F} E_{capt,f} \times \sum_{n \in N} c^{NGP}_{n,f,y-1} \times HOURS \times CF_f = F_{emissions,y} \;\; \forall \; y \in Y \tag{42}$$

These emissions benefit from a similar treatment as hydrogen under 45V, which is reflected in the model as such:

$$-\sum_{y=2025}^{y \leq year} F_{emissions,y} \times \Delta_{emissions} \times PTC_{emissions} \;\; \forall \; year \in [2025, 2030] \tag{43}$$

And for the year 2040:

$$-F_{emissions,2030} \times \Delta_{emissions} \times PTC_{emissions} - 0.3 \times F_{emissions,2040} \times \Delta_{emissions} \times PTC_{emissions} \tag{44}$$

2.3. Case Study & Data

While the model can capture any region, this analysis considers Texas and Louisiana. These two states represent a large share of the current hydrogen demand, which is located around the Gulf Coast. The two states were split into 15 regions – 12 inland and 3 offshore. This arrangement of regions was established to reflect the location of hydrogen demand hubs around the coast while capturing regions with high renewable electricity generation potential West and North of Texas.

The yearly renewable resource profiles were extracted from the Zero-emissions Electricity system Planning with HourlY operational Resolution (ZEPHYR)[68]. It provides spatially granular hourly power generation profiles for wind turbines and solar panels, obtained by converting weather data using physical models. Each region contains an array of nodes, each with an associated profile. For each region, they were aggregated by averaging to obtain a single regional profile. Offshore wind data was obtained from NREL Wind Integration National Dataset (WIND)[69]. Three offshore regions were defined, and a single curve was obtained for each using the same averaging methods as onshore nodes. The weather year studied was 2010.

Hydrogen demand is assumed to stem from industrial activities. The baseline in 2025 was set at 217 TWh, with a projected demand reaching 276 TWh/year in 2050. This demand was calculated from the postprocessing of the MIT U.S. Regional Energy Policy (USREP) model [70]. Land eligibility for solar panels and wind turbines was performed using NREL's Renewable Energy Potential (ReV) tool [71] and Lopez et. al. [72] Offshore wind potential was also determined using NREL's assessment [73]. The regional salt cavern potential was derived from Lackey et. al. [74]. The Weighted Average Cost of Capital (WACC) was set to 10% for all technologies, and the depreciation factor is equal to 9.3%. All parameters, system characteristics, and cost assumptions are laid out in the Appendix.

Several case studies were examined to illustrate costs and infrastructure requirements for different scenarios. To provide an edge case of full decarbonization, a case in which all the production would come from electrolytic production was considered. This aims to illustrate the potential infrastructure build-out and gain an understanding of the magnitude of deployment required as well as the total cost. The baseline scenario will consider a high but realistic cost of electrolyzers. Another scenario will be provided with a more optimistic outlook on the cost of electrolyzers. Policy levers such as the 45V PTC as well as the renewable electricity production tax credits are illustrated. Finally, three other cases are analyzed: low cost of offshore wind, no pipelines allowed, and no salt caverns. This aims to display synergies of the variety of infrastructure necessary to develop an extensive hydrogen supply chain. These are performed with the optimistic outlook on the cost of electrolyzers.

Another case study delves into a system dictated by a carbon constraint. Two main scenarios are considered – a business-as-usual case (BAU), and an accelerated decarbonization case with more aggressive targets (AD). Both incorporate the policy levers. For each case, two analyses are performed, each with either a baseline or optimistic outlook on the cost of electrolyzers. Here, electrolytic and natural-gas-derived production are allowed to compete, yielding a system with a blend of technologies.

2.4. Results

2.4.1. 100% Electrolytic Production

The results of the initial case study with 100% electrolytic production can be mapped out to visualize the transmission capacities between regions, as well as the technologies' capacities within regions. The base case scenario was plotted in Figure 3. It displays the capacity build out from 2025 to 2050.

The optimized supply chain shows extensive infrastructure build-out throughout the state. Even though most of the demand is located around the Gulf Coast, hydrogen is mainly produced in the Northwest. A combination of wind turbines and solar PVs is deployed in all power-producing regions, displaying the synergies existing between the two technologies. However, the mix is dominated by wind – this highlights the benefits of a more consistent production curve, limiting the required size of electrolyzers and storage.

An important hub of electrolytic production coupled with a mix of wind turbines and solar PVs thus emerges in the Northwest. The scale of required capacity deployment is significant, reaching 30.8 GW of electrolyzers, 50.9 GW of wind turbines, and 8.3 GW of solar panels in this region alone. The remaining electrolytic capacity is spread around the state, with two major production centers around the Coast, close to demand. There, significant renewable capacity is also deployed, alongside electricity transmission from the Northwest to increase electrolyzers' capacity factors. In total, 7 GW of electricity transmission is dedicated to electrolytic production by 2050. In the western part of the state, the relatively small demand is mostly filled by local electrolytic production, alongside a small amount of hydrogen transmission from northern regions.

A significant amount of hydrogen pipelines is being deployed, totaling 61.5 GW by 2050. This mostly delivers hydrogen from the production hub in the northwest down to Louisiana and to a lesser extent to the central Gulf Coast. A large pipeline from the southern part of the Gulf Coast up to the center is also deployed. Hydrogen pipelines' capacity outweighs that of electricity transmission lines, demonstrating that producing electrolytic hydrogen within the power production regions instead of at the location of demand may be more cost-effective.

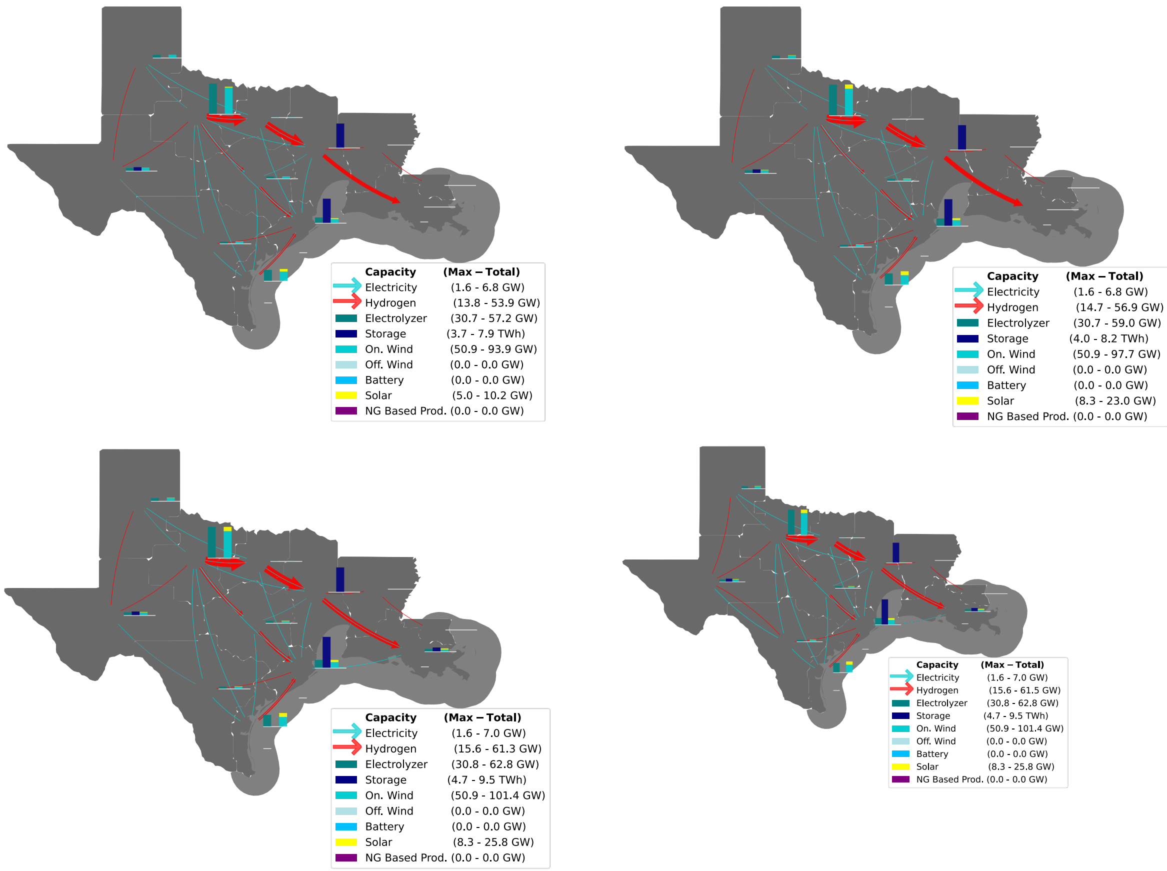


Figure 3: Illustration of the infrastructure expansion for a 100% electrolytic production scenario. Vertical bars within regions represent capacities of infrastructure. Each technology has been scaled by the maximum capacity deployed in a single region for that specific technology. To relate the bar size to actual capacity, refer to the legend which states two values – Max: maximum capacity in a single region, and Total: total capacity in the entire system, for each technology. Top Left: 2025, Top Right: 2030, Bottom Left: 2040, Bottom Right: 2050.

Hydrogen storage in the form of salt caverns is also deployed. Unsurprisingly, salt caverns are preferred to compressed or liquid storage due to large cost benefits. Storage capacities reach 9.5 TWh in 2050. These are conveniently located close demand centers. The yearly inventory is displayed for both regions with the largest capacities in Figure 4. A similar seasonal pattern emerges in which caverns reach their fullest capacities during the summer months, indicating large renewable production leading to high electrolyzer utilization. Due to lower renewable production in the winter months, hydrogen demand is being fulfilled in parts by hydrogen stored on a large scale. This highlights the benefits of a cheap storage resource to balance production throughout the year and adequately deal with seasonal variations in power production. This also indicates that collaboration between producers and consumers should occur due to the large-scale operation required of salt caverns.

An illustration of the power curve, both from a generator perspective as well as a dispatch point of view, is provided in Figure 5 for the first seven days of the year in the largest power-producing region. Even though solar production is low due to winter weather, the power curve remains large, upwards of 40 GW at peak times. During the largest production periods, electricity is sent to other regions for electrolytic production as well as to compressors, highlighting surplus hydrogen produced being stored. Finally, despite the potential advantages of offshore wind as a more constant power source for electrolyzers, no capacity is deployed due to the prohibitive costs, notably from the offshore electricity transmission cables.

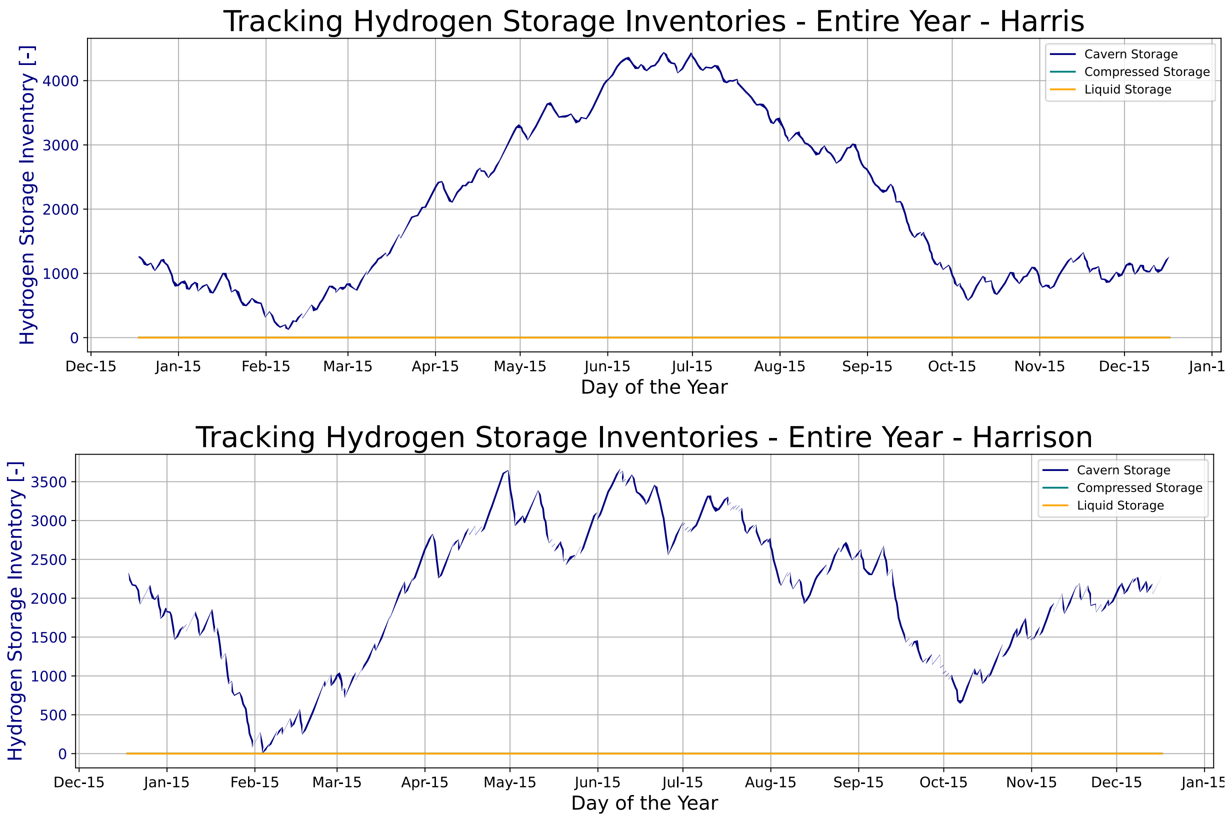


Figure 4: Hydrogen storage inventories in the two regions with the largest capacities.

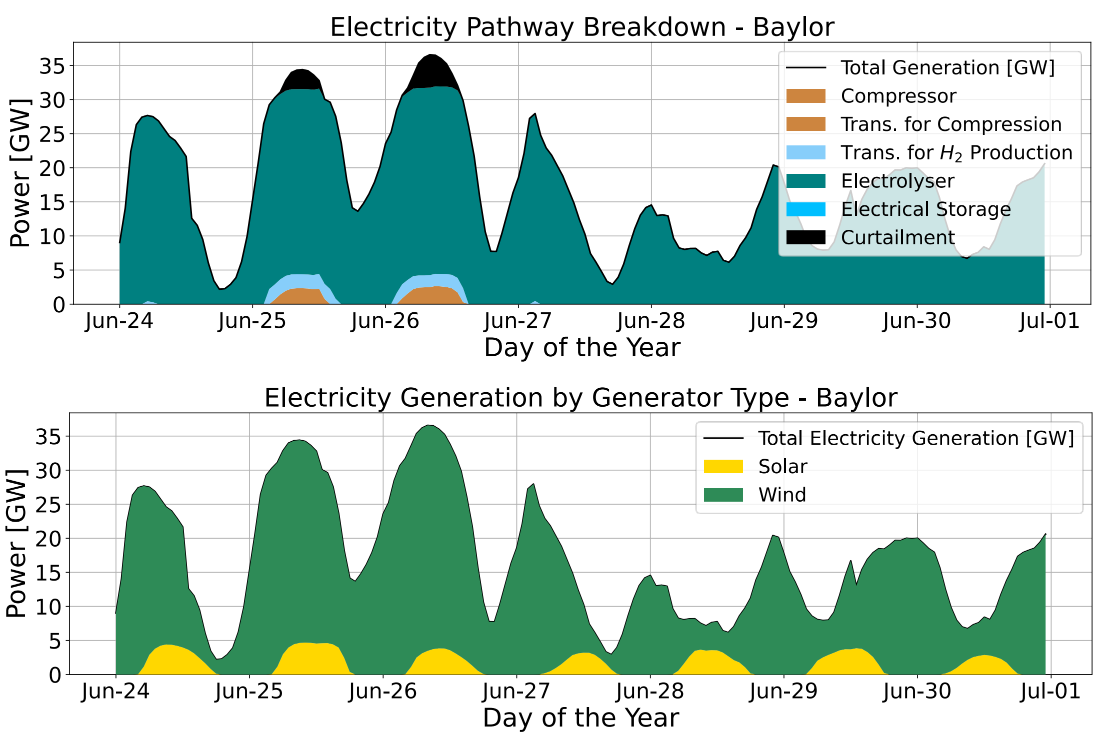


Figure 5: Electricity production during the last week of June in the largest power producing region.

The cost of hydrogen is displayed in Figure 6. It displays both the Base and Optimistic outlooks on electrolyzer costs, as well as the resulting levelized cost post-IRA tax credits applied. The levelized cost shown represents the average cost of the system – as such, the costs account for infrastructure deployed in all considered years. This explains why the drop in the contribution of electrolyzers to the levelized cost is not as steep as the cost projection of electrolyzers through the years since infrastructure deployed in previous years with more expensive capital and operating costs still needs to be repaid. This is also displayed in the small remaining cost decrease from IRA tax credits in 2040, stemming from infrastructure built between 2030 and 2033 which still benefits from the subsidy.

Most of the costs are dominated by electrolyzers and power production technologies. The third greatest cost contributor comes from pipelines. This cost is also exacerbated by the fact that this system operates flexibly, dictated by varying power production curves, meaning that pipelines are used below their maximum capacity factor and are sized to accommodate large flows during peak production hours. Electricity transmission represents a smaller part of the levelized cost due to lower deployed capacity. Finally, despite their practicality as a buffer between production and demand, salt caverns represent a very small portion of the levelized cost of hydrogen.

The difference in cost between the base and optimistic scenarios is more pronounced in 2025 than in 2050. This is again caused by the averaging of the cost of infrastructure deployed throughout the years. Since the considered demand projection goes from 217 TWh in 2025 to 296 TWh in 2050, most of the infrastructure is already built in 2025. This is exacerbated by the increase in electrolyzer efficiency, which requires less deployment at equal production levels. In reality, hydrogen production will not be 100% electrolytic in the near-term, due to the scale of infrastructure required and resulting supply chain bottleneck issues. As such, lower system-level levelized cost of hydrogen could be observed in the longer term as electrolyzers are deployed further into the future at a lower cost than today. Interestingly, less electricity transmission is deployed in the optimistic scenario, showing that lower electrolyzer cost enables them to run at lower capacity factors than in an expensive scenario.

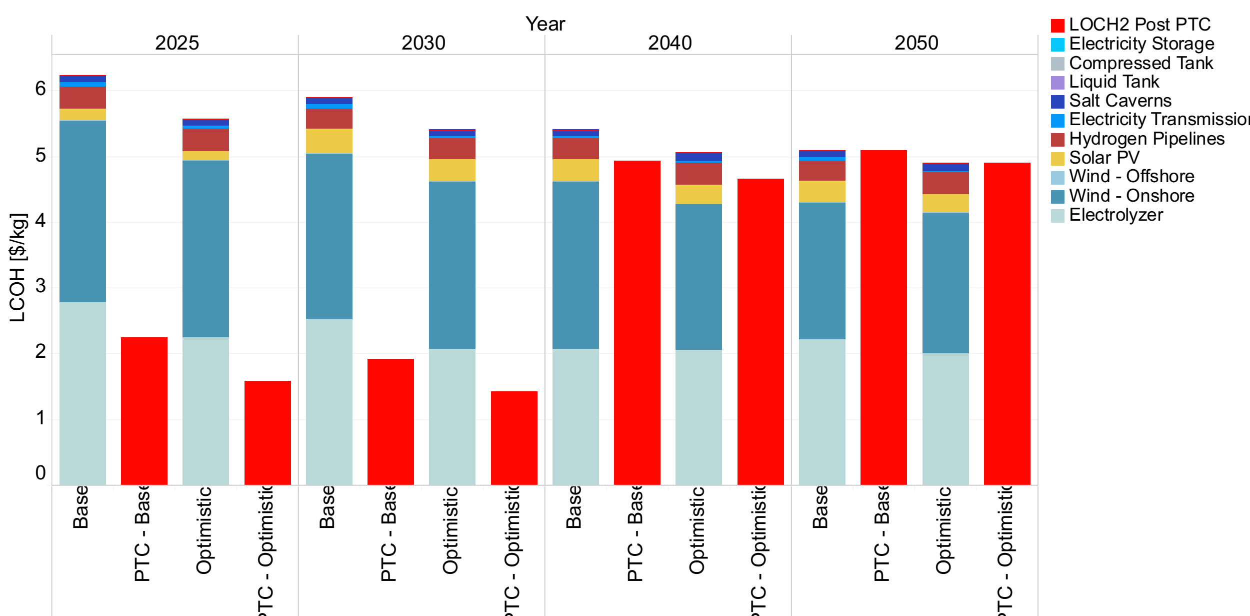


Figure 6: Levelized cost of hydrogen for the base and optimistic scenarios for electrolyzer costs, alongside the cost of hydrogen once the IRA tax credits are applied.

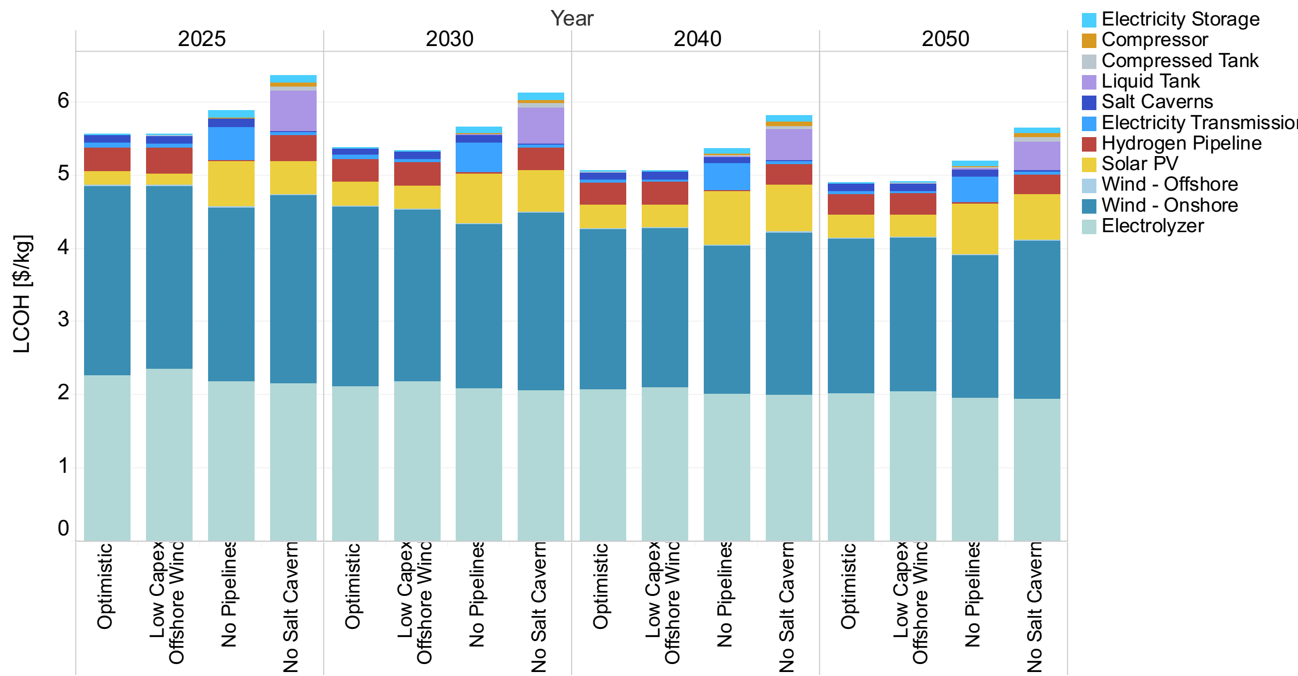


Figure 7: levelized cost for three sensitivity cases alongside a base case - low cost of offshore wind, no pipelines, and no salt caverns. All four cases assume optimistic electrolyzer cost.

Finally, the influence of IRA tax credits as well as renewable production tax credits is observed. Beyond 45V tax credits, the renewable tax credits add a subsidy of ~$1.10/kg$H_2$. This drives down the cost of electrolytic hydrogen below $2/kg$H_2$ with an optimistic outlook on electrolyzer costs, which significantly closes the gap with hydrogen from natural gas.

A sensitivity analysis was performed to evaluate the influence of a lower cost for offshore wind, no pipelines, and no salt caverns. The resulting levelized costs are displayed in Figure 7, and infrastructure capacities in 2050 are shown in Table 4.

Table 5: Capacity per technology for the four cases studied (in 2050): base case, low capex for offshore wind, no hydrogen pipelines, and no salt caverns

Technology	Base Case	Low Capex Off. Wind	No Pipelines	No Salt Caverns
Onshore Wind. [GW]	107.7	107.7	98	110
Offshore Wind [GW]	0	0	0	0
Solar PV [GW]	25	25	54	49
Total Renewables [GW]	132.7	132.7	152	159
Electrolyzer [GW]	72	72	70	69.5
Salt Caverns [TWh]	10.6	10.6	9.6	0

Compressed Tanks [TWh]	0	0	0.03	0.13
Liquid Tanks [TWh]	0.02	0.02	0.08	1.75
Battery Storage [GW]	0	0	3.9	3.9
Elec. Transmission [GW]	5.6	5.6	37.5	3.4
H_2 Transmission [GW]	60.5	60.5	0	59.1
$LCOH_2$ [€/kg]	4.9	4.9	5.2	5.6

In the base scenario, offshore wind turbines are not deployed, despite their increased capacity factor over their onshore counterpart. In terms of the cost, their current capital costs are twice greater, as well as their operational expenses. Furthermore, offshore transmission lines are much more expensive than onshore transmission lines. Even with a 50% decrease in capital and operational cost of both offshore wind turbines and transmission lines, these technologies are not deployed. Indeed, the offshore capacity factor in the Gulf Coast does not exceed 34%, while onshore capacity factors reach upward of 40% in certain regions in the Northwest. Offshore wind is thus unlikely to play an important role in hydrogen production around the Gulf Coast.

Hydrogen storage has an important systemic impact. It is a main driver of the interplay occurring between the required capacity of renewable compared with electrolytic capacity, hereafter termed the renewable oversize and expressed in GW of renewable per GW of electrolytic capacity, displayed in Table 5 alongside the average electrolyzer capacity factor and the percentage of electricity curtailment. Inexpensive storage allows for a lower renewable oversize since hydrogen demand can be fulfilled from storage at times of low electricity production leading to low electrolytic hydrogen production. Systems with the most intermittent sources of electricity benefit the most from inexpensive storage. Higher capacity factors lead to a lesser requirement for storage, as illustrated by the case with inexpensive offshore wind. This renewable oversize in turn impacts the percentage of electricity curtailed. Expensive storage such as compressed and liquid storage tanks drive up the renewable oversize, which leads to an increased percentage of electricity curtailed at times of high production. In all cases, the electrolyzer capacity factor does not surpass 80%. The systemic optimum does not align with the objective of an electrolytic hydrogen producer, which is likely to target upwards of 90% asset utilization. However, this is unlikely to be achievable with dedicated renewable generation. Drawing electricity from the grid would be associated with large carbon emissions, defeating the purpose of low-carbon electrolytic production.

Table 6: Renewable oversize, average electrolyzer capacity factor and electricity curtailment in all cases

	Base Case	**Low Capex Off. Wind**	**No Pipelines**	**No Salt Caverns**
Renewable Oversize [GW/GW]	1.84	1.84	2.18	2.3

Average Electrolyzer Capacity Factor [%]	70.6	70.6	73.1	73.1
Electricity Curtailment [%]	3.2	3.2	7.3	16.3

A scenario with no pipeline forces the system to rely on electricity transmission between regions. It also has the effect of forcing each region to locally produce electrolytic hydrogen. The optimal solution introduces battery storage to smooth out the renewable generation curve and enable a more constant electrolytic production to fulfill demand. It is notably prevalent in regions that do not have any salt cavern potential. In these regions, electrolytic production must be always constant to fulfill demand. Introducing more expensive forms of hydrogen storage such as compressed or liquid tanks would expectedly be chosen as the alternative, due to their lower cost of storage over batteries. The required electricity transmission capacity is significant. Accounting for current bottlenecks in transmission to other applications would likely further raise costs and operational hurdles, further highlighting the need for pipeline transmission as the decarbonization of hydrogen production reaches a significant size above a few GW of electrolyzers.

2.4.2. System under Carbon Constraint

Another scenario considered the system under a carbon constraint, stipulating that the average carbon intensity of hydrogen produced cannot surpass a threshold which is increasingly stringent over time. This average is calculated over the entire system – thus, a production technology can have a carbon intensity larger than the threshold and still be used in the system if another technology with a lower carbon intensity counterbalances it. Four cases were considered: two carbon constraint limits were considered, and each was run with either the base or optimistic electrolytic cost outlook. The resulting shares of electrolytic versus natural gas derived production through the years were obtained, displayed in Figure 8. Despite the upstream supply chain emissions of RES, these are not accounted for to follow the methodology stipulated by the IRA.

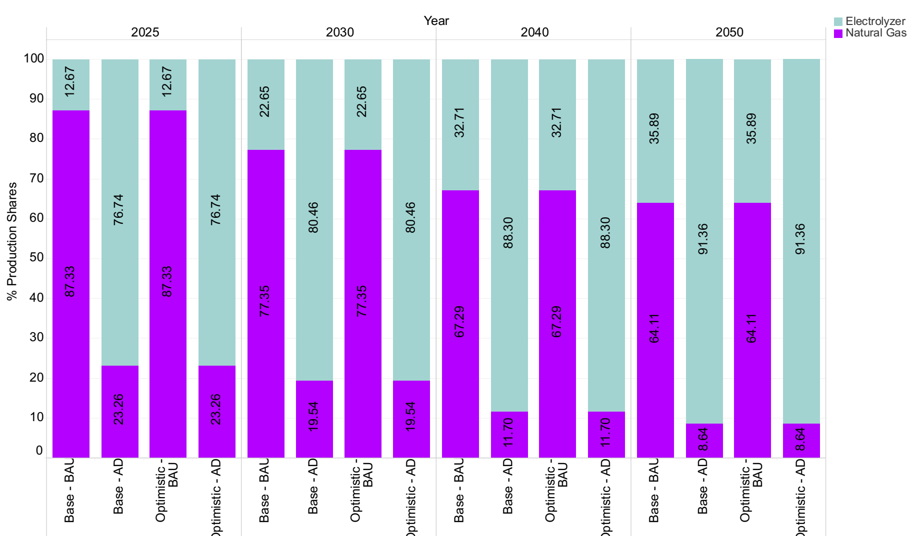


Figure 8: percentage production share of electrolytic versus natural gas derived production for four scenarios: Business As Usual (BAU) carbon constraint, Advanced Decarbonization (AD) scenario, both with a base and optimistic electrolytic cost outlook.

Both cases show a downward trend in natural-gas-derived production through the years, dictated by a decreasing carbon constraint limit. However, the relative shares importantly differ between both cases. The AD case shows a greater share of electrolytic production even in 2025. Interestingly, while the BAU average carbon intensity is equal to the maximum threshold in all considered years, in the AD case the average carbon intensity is below the threshold for all years but 2050. This indicates that achieving meaningful emissions abatement requires early, large-scale deployment of electrolytic production, alongside the retirement of natural gas-derived production plants. Maintaining and continuing to develop SMR and ATR plants, whose asset life surpasses 20 years, would therefore not drive sufficient emission reduction by 2050, even with a reduction in upstream methane leakage.

The costs are outlined in Figure 9. The cost drop for electrolyzers is more significant in this case compared with the previous baseline scenario. This stems from the fact that less electrolyzer capacity is deployed in the early years. Further added capacity is proportionally more significant than in the baseline, which reduces the overall levelized cost of hydrogen for electrolyzers. As such, the cost of subsidized (45V and VRE PTC) electrolytic hydrogen in the 2030s becomes lower than the cost of natural gas-derived production, even with the application of 45Q.

Electrolytic hydrogen production is thus likely to be competitive with natural gas-derived production in the 2030s with significant governmental subsidies. This may result in important deployment in the coming decade, as electrolyzer and renewable cost reduction materialize. However, in the absence of subsidy, electrolytic production is likely to remain more expensive than current production methods, requiring careful planning from developers and policymakers to avoid stranded assets.

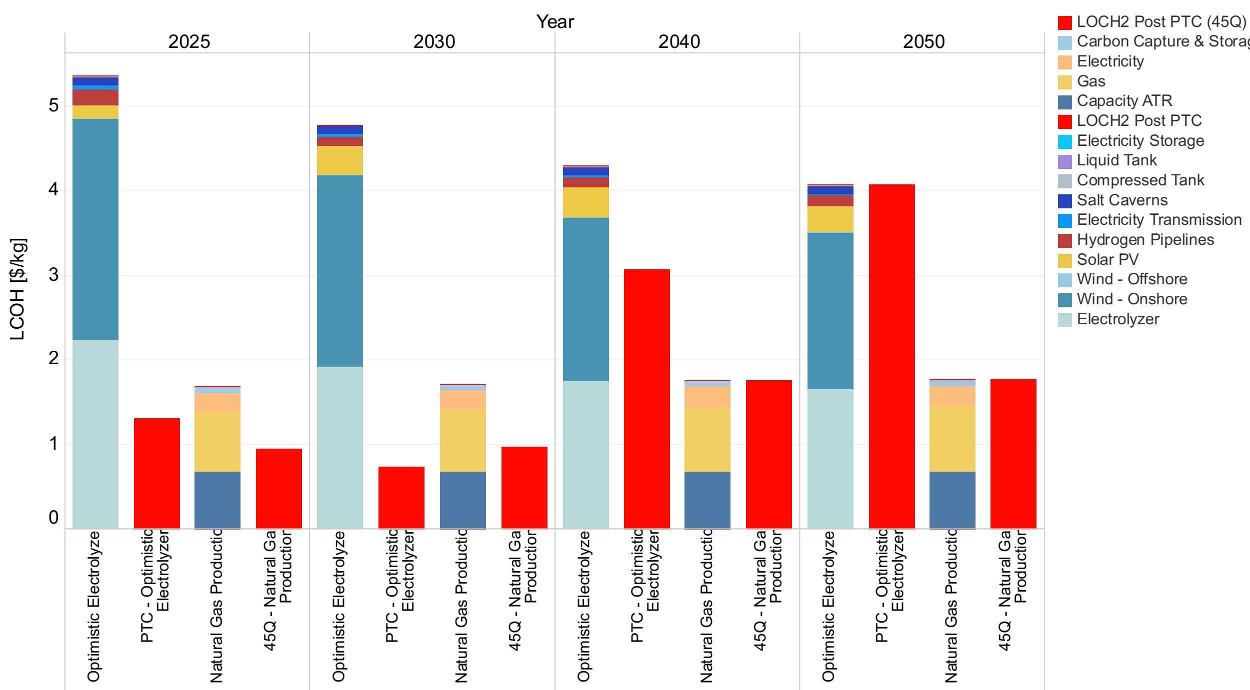


Figure 9: Levelized costs of electrolytic hydrogen before and after subsidies (45V and VRE PTC), and ATR production before and after subsidies (45Q).

2.5. Conclusion

The presented model is a multi-nodal hydrogen supply chain optimization system. It seeks to lower the overall cost of a system that encompasses renewable generation with solar PV and wind turbines, hydrogen production with electrolyzers, SMR and ATR, transmission with pipelines or transmission lines, and electricity and hydrogen storage. The variable production of renewable electricity requires a high granularity, which is captured at an hourly level using annual supply curves. This intends to faithfully represent the hourly operation of all technologies, shedding light on the synergies between electricity production, hydrogen production, transmission, and storage granularly. The considered hydrogen demand was assumed to stem from industrial applications, thus requiring constant hydrogen input. The model can also handle more variable demand in other case scenarios.

A case study considered the decarbonization of current hydrogen demand in Texas and Louisiana (217 TWh/yr in 2025) using electrolytic production only. The resulting levelized cost of hydrogen totaled 5.5 €/kgH_2 in 2025, decreasing to 4.9 €/kgH_2 in 2030 in an optimistic electrolytic cost outlook. This cost is mainly composed of the capacity costs of renewables and electrolyzers, and the cost in 2050 reflects added capacity in previous years, explaining the relatively low decrease. Inexpensive storage was found to be central to coping with the flexible operation of electrolyzers dictated by the power generation curve in order to fulfill constant demand. The absence of salt caverns in the system increases the renewable generation capacity to rely less on storage, leading to increased electricity curtailment. The benefit of large underground storage is greater in concurrence with pipeline transmission. It enables regions that do not have the required geological formation to benefit from this inexpensive form of storage, instead of producing hydrogen locally with either tanks or batteries, both of which importantly increase the levelized cost. Finally, the current cost of offshore wind seems unfavorable for its introduction into the system. Reducing the capital cost of offshore wind as well as that of undersea transmission lines may lead to benefits in certain regions of the US, but did not show advantages in the Gulf Coast due to the larger capacity factors of onshore wind compared with offshore.

Another scenario considered the supply chain in the Gulf Coast under a carbon constraint, limiting the system-wide emissions allowed for hydrogen production. Two cases were analyzed – a business-as-usual case and an accelerated decarbonization case, with both decreasing thresholds through the years but with a more aggressive approach in the later scenario. Results show that lax carbon constraints lead to a continued reliance upon hydrogen produced from natural gas, especially if upstream emissions can be decreased. With tighter constraints, the system primarily relies on electrolytic hydrogen. Sending early signal to the industry of tight carbon constraints would thus accelerate the deployment of electrolytic hydrogen.

The model provides an overview of the optimal system under different scenarios. Grounding the analysis with greater information on existing infrastructure, such as natural gas pipelines that are candidates for retrofit or the location and capacity of operating SMR plants, would provide a more realistic outcome. Hydrogen's potential end uses are numerous – capturing more applications as well as the concurrent supply chain of its derivative such as ammonia would be beneficial. Finally, including more import options with several hydrogen carriers would provide insights regarding the current import discussions.

2.6. Appendix

2.6.1. Technical Potential of wind turbines, solar panels, salt caverns, and hydrogen demand

Region	Wind – Onshore [MW]	Wind – Offshore [MW]	Solar [MW]	Salt Caverns [TWh]	Hydrogen Demand [TWh] - 2050
Dallas	27591	-	748053	0	8.5
Baylor	107759	-	1726158	0	2.8
Harrison	26203	-	1522704	4	11.8
Harris	10772	-	268810	8	101.7
Nueces	18031	-	346563	0	22.0
Austin	65040	-	1610652	0	9.9
Bexar	156880	-	2620741	0	12.
Lubbock	166803	-	1795271	0	7.6
Midland	291039	-	3091781	1	12.3
Caddo	18555	-	642859	1	8.2
Ascension	9661	-	198846	8	77.1
Livingston	1584	-	161489	0	1.0
Texas West Offshore	-	63633	0	0	0
Texas East Offshore	-	63633	0	0	0
Louisiana Offshore	-	134090	0	0	0

2.6.2. Constants

Name	Model Name	Value	Unit	Source
Electrolyzer Efficiency - 2025		60	%	Assumption
Electrolyzer Efficiency - 2030		63	%	Assumption
Electrolyzer Efficiency - 2040		69	%	Assumption
Electrolyzer Efficiency - 2050		76	%	Assumption
ATR Capacity Factor		90	%	[15]
Battery Storage Duration		8	Hours	[75]
Compressor Req. – Salt Cavern		93	$kWhH_2/kWh_{el}$	[76]
Compressor Req. – Comp. Tank		33	$kWhH_2/kWh_{el}$	[77]
Compressor Req. – Liquid Tank		11	$kWhH_2/kWh_{el}$	[77]
Transmission Losses %		6.25	%/1000km	Expert Elicitation
Charging and Discharging Eff.		96	%	[75]
Detour Factor		1.4	-	[78]

Total Charge Time – Salt Cavern	608	Hours	[79]
Total Discharge Time – Salt Cavern	122	Hours	[79]
Total Charge Time – Compressed Tank	203	Hours	Expert Elicitation
Total Discharge Time – Compressed Tank	41	Hours	Expert Elicitation
Total Charge Time – Liquid Tank	203	Hours	Expert Elicitation
Total Discharge Time – Liquid Tank	41	Hours	Expert Elicitation
Electricity Req. – ATR	0.123	kWh/kWhH2	Expert Elicitation
Natural Gas Req. – ATR	1.38	kWhNG/kWhH2	Expert Elicitation
Distance CO_2 Pipeline	100	Miles	Assumption
Production Tax Credit – Electrolytic Hydrogen	3	\$/kgH_2	[80]
Delta – Electrolyzer	0.962	[-]	Calculated
Production Tax Credit – Natural Gas Hydrogen	0.6	\$/kgH_2	[80]
Delta – Natural Gas	0.869	[-]	Calculated
Production Tax Credit – 45Q	85	\$/tonCO_2	[80]
Delta – PTC 45Q	0.964	[-]	Calculated
Renewable PTC	27.5	\$/MWh	[80]
Delta – Renewable PTC	0.869	[-]	Calculated

2.6.3. System Characteristics

Name	Model Name	Value	Unit	Source
Yearly Hydrogen Demand – 2025		217	TWh	Expert Elicitation
Yearly Hydrogen Demand – 2030		245	TWh	Expert Elicitation
Yearly Hydrogen Demand – 2040		282	TWh	Expert Elicitation
Yearly Hydrogen Demand – 2050		296	TWh	Expert Elicitation
Grid Electricity Price – 2025		55.8	\$/MWh	Expert Elicitation
Grid Electricity Price – 2030		56.6	\$/MWh	Expert Elicitation
Grid Electricity Price – 2040		58.6	\$/MWh	Expert Elicitation
Grid Electricity Price – 2050		57.5	\$/MWh	Expert Elicitation
Grid Electricity Emissions – 2025		0.265	kgCO_2/kWh	Expert Elicitation

Grid Electricity Emissions – 2030	0.162	$kgCO_2/kWh$	Expert Elicitation
Grid Electricity Emissions – 2040	0.134	$kgCO_2/kWh$	Expert Elicitation
Grid Electricity Emissions – 2050	0.119	$kgCO_2/kWh$	Expert Elicitation
Maximum Carbon Intensity BAU - 2025	3.00	$kgCO_2/kgH_2$	Assumption
Maximum Carbon Intensity BAU - 2030	2.40	$kgCO_2/kgH_2$	Assumption
Maximum Carbon Intensity BAU - 2040	1.54	$kgCO_2/kgH_2$	Assumption
Maximum Carbon Intensity BAU - 2050	0.98	$kgCO_2/kgH_2$	Assumption
Maximum Carbon Intensity AD – 2025	3.00	$kgCO_2/kgH_2$	Assumption
Maximum Carbon Intensity AD – 2030	1.50	$kgCO_2/kgH_2$	Assumption
Maximum Carbon Intensity AD – 2040	0.38	$kgCO_2/kgH_2$	Assumption
Maximum Carbon Intensity AD - 2050	0.09	$kgCO_2/kgH_2$	Assumption

2.6.4. Costs

Name		Value	Unit	Source
Weighted Average Cost of Capital		10	%	Assumption
Wind - Onshore	Lifetime	30	Years	[81]
	CapEx – 2025	1,206	$/kW	[81]
	OpEx – 2025	3.4	% of CapEx/yr	[81]
	CapEx – 2030	956	$/kW	[81]
	OpEx – 2030	4.1	% of CapEx/yr	[81]
	CapEx – 2040	908	$/kW	[81]
	OpEx – 2040	4.1	% of CapEx/yr	[81]
	CapEx – 2050	765	$/kW	[81]
	OpEx – 2050	4.3	% of CapEx/yr	[81]
Wind - Offshore	Lifetime	30	Years	[81]
	CapEx	2,734	$/kW	[81]
	OpEx	3	% of CapEx/yr	[81]
Solar	Lifetime	30	Years	[81]
	CapEx – 2025	982	$/kW	[81]
	OpEx – 2025	1.85	% of CapEx/yr	[81]
	CapEx – 2030	754	$/kW	[81]
	OpEx – 2030	2.02	% of CapEx/yr	[81]
	CapEx – 2040	687	$/kW	[81]

	OpEx – 2040	2.07	% of CapEx/yr	[81]
	CapEx – 2050	620	\$/kW	[81]
	OpEx – 2050	2.1	% of CapEx/yr	[81]
Transmission Lines - Onshore	Lifetime	25	Years	Expert Elicitation
	CapEx	1.867	\$/kW-km	Expert Elicitation
	OpEx	1.5	% of CapEx/yr	Expert Elicitation
Transmission Lines - Offshore	Lifetime	25	Years	Assumption
	CapEx	7.67	€/kW-km	[82]
	OpEx	2	% of CapEx/yr	Assumption
Electrical Storage	Lifetime	30	Years	[75]
	CapEx – Power	235	€/kW	[75]
	Capex - Energy	148	€/kWh	[75]
	OpEx	3.82	% of CapEx/yr	[75]
Electrolyzer – Pessimistic Scenario	Lifetime	20	Years	Expert Elicitation
	CapEx – 2025	2000	\$/kW	Expert Elicitation
	OpEx – 2025	3.5	% of CapEx/yr	Expert Elicitation
	CapEx – 2030	1760	\$/kW	Expert Elicitation
	OpEx – 2030	3.7	% of CapEx/yr	Expert Elicitation
	CapEx – 2040	1410	\$/kW	Expert Elicitation
	OpEx – 2040	4.2	% of CapEx/yr	Expert Elicitation
	CapEx – 2050	1150	\$/kW	Expert Elicitation
	OpEx – 2050	5	% of CapEx/yr	Expert Elicitation
Electrolyzer – Optimistic Scenario	Lifetime	20	Years	Expert Elicitation
	CapEx – 2025	1600	\$/kW	Expert Elicitation
	OpEx – 2025	4.25	% of CapEx/yr	Expert Elicitation
	CapEx – 2030	1232	\$/kW	Expert Elicitation
	OpEx – 2030	5.28	% of CapEx/yr	Expert Elicitation
	CapEx – 2040	846	\$/kW	Expert Elicitation
	OpEx – 2040	7.09	% of CapEx/yr	Expert Elicitation
	CapEx – 2050	575	\$/kW	Expert Elicitation
	OpEx – 2050	9.91	% of CapEx/yr	Expert Elicitation
ATR with 96% Carbon Capture - Greenfield	Lifetime	30	Years	[83]
	CapEx	1004	\$/kW	[83]
	OpEx	0.044	% of CapEx/yr	[83]
Compressor - Storage	Lifetime	15	Years	[84]
	CapEx	1,303	$\$/kW_{el}$	[84]
	OpEx	5	% of CapEx/yr	[84]
Cavern	Lifetime	30	Years	[76]
	CapEx	0.6874	$\$/kWhH_2$	[76]
	OpEx	2	% of CapEx/yr	[76]
Compressed Tank	Lifetime	20	Years	Expert Elicitation
	CapEx	23	$\$/kgH_2$	Expert Elicitation
	OpEx	2	% of CapEx/yr	Expert Elicitation
Liquid Tank	Lifetime	20	Years	Expert Elicitation

	CapEx	13.83	$/kgH_2$	Expert Elicitation
	OpEx	2	% of CapEx/yr	Expert Elicitation
Onshore Pipeline	Lifetime	30	Years	Expert Elicitation
	CapEx	0.87	$/kW/km	Expert Elicitation
	OpEx	0.57	% of CapEx/yr	Expert Elicitation
CO_2 Storage & Transport	Transport	0.1	\$/tonCO_2/mile	Expert Elicitation
	Storage	8	\$/tonCO_2	Expert Elicitation
Natural Gas Cost	Cost – 2025	0.015258599	$/kWhNG	Expert Elicitation
	Cost – 2030	0.015739331	$/kWhNG	Expert Elicitation
	Cost – 2040	0.016567071	$/kWhNG	Expert Elicitation
	Cost – 2050	0.016882994	$/kWhNG	Expert Elicitation

2.6.5. Emissions

Name	Value	Unit	Source
Upstream Emissions – 2025	0.03947	kgCO_{2eq}/kWhNG	Expert Elicitation
Upstream Emissions – 2030	0.03033	kgCO_{2eq}/kWhNG	Expert Elicitation
Upstream Emissions – 2040	0.01815	kgCO_{2eq}/kWhNG	Expert Elicitation
Upstream Emissions – 2050	0.01105	kgCO_{2eq}/kWhNG	Expert Elicitation
ATR – Captured	0.27	kgCO_2/kWhH_2	Expert Elicitation
ATR – Released	0.016	kgCO_2/kWhH_2	Expert Elicitation

Chapter 3

The Procurement of Low-Carbon Hydrogen in Germany

3.1. Introduction

The threat of climate change has spurred efforts to decarbonize all corners of our society. Its increasing pace commands greater efforts to be undertaken before 2050. A major contributor to climate change is the energy sector, which is responsible for 75% of Green House Gas (GHG) emissions today [1]. Currently, energy systems are dominated by fossil fuels. These are ubiquitous from industrial processes to basic materials, transport, and residential heating. A widely agreed upon consensus states that reducing fossil fuels use and increasing the role of electricity and power systems as a whole can lead to significant emissions reduction [1]–[5]. Such pathways lead to significant deployment of low-carbon electricity generation technologies, such as wind turbines and solar panels. These will provide the backbone for the procurement of electricity to current demand as well as to the electrifying sectors such as transportation and industry. However, electrification may not be sufficient to enable deep decarbonization. Several sectors are likely to continue requiring fuels to power their processes. This has triggered growing attention towards fuels with the potential to be low carbon. Among those, hydrogen has emerged as one of the most promising. The versatility of hydrogen, which can theoretically be used in a range of applications such as industrial processes, power production, and transport, has been a determining factor in its rise on the geo-political agenda.

In a broader decarbonization effort, several countries around the world have released national hydrogen strategies. These strategies and roadmaps differ among countries. Those that have access to ample resources suited for renewable electricity production envision becoming major exporters through the electrolytic production of hydrogen, in which water molecules are split into hydrogen and oxygen in an electricity-intensive process [85]. This includes Australia, Chile, and Saudi Arabia [18], [20], [21]. In contrast, countries with insufficient resources but a potentially significant demand such as much of Europe, Japan, and Korea are likely to become importers. Those that benefit from ample natural gas resources may resort to hydrogen production with Carbon Capture and Storage (CCS) [22].

In Europe, the current largest consumer of hydrogen is Germany. It possesses a total nominal production capacity of 60.8 TWh/yr [86], which fulfills an annual demand of 54.7 TWh/yr [87]. The production is dominated by a single process – Steam Methane Reforming (SMR), which uses natural gas as a fuel. Among production sites that are captive (consumed on-site) or merchant (manufactured to be sold), 93% come from SMR. The remaining parts are Chlor-Alkali production (6%) and electrolysis (<1%), both of which are merchant. Germany imports 4.7 GWh/yr of hydrogen, mainly from the Netherlands and France [88], and exports 4.3 GWh/yr in measurable quantities to France, Austria, and the Netherlands [89] – these flows are negligible compared with the national production and demand capacity. By 2020, hydrogen in Germany was manufactured in 113 production sites [87]. Captive production, which is dedicated to consumption on-site, represented 67% of the supply capacity, entirely provided by SMR plants. Merchant production, usually intended to be sold to a single large consumer, consisted of 17% of the supply capacity, dominated by SMR plants. The remaining capacity stems from by-product processes, notably from coke oven gas and ethylene. This predominant SMR production is undertaken in 44 plants around the country. The carbon intensity of this process is ~10 tCO_2/tH_2 [12], [13]. To date, few SMR plants have been fitted with CCS technologies – only two have reached the demonstration scale, while two others are at the pilot scale [14]. Retrofitting them with CCS technologies can be achieved at a 50% capture rate rather inexpensively, but reaching higher rates (~85%) requires significant additional investments [15]. Another process, Autothermal Reforming (ATR), can be fitted with CCS. ATR plants are characterized by a similar carbon intensity to SMR at the process level. However, while both generate carbon dioxide in the process gas, SMR also emits flue gases from natural gas combustion that contains carbon dioxide [16]. As such, ATR facilities only need CCS technologies to be fitted at a single exhaust, allowing higher capture rates potentially more economically than SMR [15], [17]. This is exacerbated by the fact that most SMR plants are integrated into facilities where hydrogen is not the end product, and thus are specifically designed for their respective application. While the long lifetime of SMR plants (~20 years) [90] may pose risks of stranded assets, the subsequent analysis will consider only ATR plants, assuming that higher capture rates coupled with incentives such as a carbon tax are likely to spur investments in ATR with CCS.

Electrolytic hydrogen is manufactured in a power-intensive process, whose carbon intensity reflects that of the input electricity [91]. If powered by the grid, German electrolytic hydrogen would emit 17 tCO_2/tH_2 [6], much more than unabated SMR. Low-carbon electricity production is therefore a requirement. However, producing the current hydrogen demand solely with electrolyzers would result in the electricity consumption of 3,600 TWh, more than the current annual generation in Europe [12]. This highlights the challenge of shifting to complete electrolytic production without resorting to natural gas reforming.

In Germany and beyond, hydrogen has historically been used in the industry [6] – the main applications being oil refining, ammonia, and methanol production. While demand for ammonia and methanol will likely increase, the quantity of oil will depend on the trajectories of countries with regard to their fossil fuel strategies but is expected to remain significant in the 2030s. This translates into an immediate need for low-carbon hydrogen to decarbonize the industry sector. However, its role in the economy may be expanded. Hydrogen is viewed as an alternative fuel in the transport sector, especially long haul, heavy freight, using fuel cells to power vehicles [7]. Further uses include district heating, for which several pilots are underway [8], [9], steel manufacturing [10], and electricity storage with potential reconversion into electricity using natural gas turbine retrofits [11] or fuel cells. This has triggered plans for a possible European hydrogen backbone, a major network of hydrogen pipelines that would deliver hydrogen trans-nationally [92] using 75% retrofitted natural gas pipelines and 25% new installations. The rollout is expected to be slow in the 2020s, and gain momentum in the 2030s to reach 23,000 km by 2040.

To comply with the amendment to the Climate Change Act stating a net-zero target by 2045 [93], Germany has produced a national hydrogen strategy, released in 2020 [19] and recently updated. It recognized hydrogen as a potential energy storage medium, an enabler for sector coupling, and a requirement in certain industries to decarbonize. The government only considers electrolytic hydrogen produced from renewable electricity to be sustainable in the long term – it stated that it can rely on carbon-free hydrogen produced from natural gas reforming with Carbon Capture and Storage (CCS) or methane pyrolysis only temporarily. It intends to provide seven billion euros to speed up the rollout of hydrogen and two additional billions to foster international partnerships. The focus is directed to areas that are close to commercial viability and those which cannot be decarbonized in other ways, citing the steel and chemical industries. It expected 90-

110 TWh of hydrogen demand in 2030, revised upward to 95-130 TWh due to forecasted demand in hydrogen for gas peakers. Setting a target of 10 GW of electrolyzers in 2030, Germany is aware that this will not be sufficient to meet the entire demand. Even a planned rollout of 5 GW of additional electrolyzers by 2035 at the earliest would fall short of production independence. As such, Germany has viewed imports as crucial, which was reiterated in the revised version with an expectation of 50-70% of imports in 2030. In a stated desire to safeguard the attractivity of its industrial sector, several policy measures such as waiving the EEG surcharge to electricity that will power electrolyzers alongside carbon Contracts for Difference (CfDs) were considered. The policy landscape continues to evolve rapidly – the recent strategy update expands subsidies to hydrogen from natural gas with CCS.

The ambitious targets laid out in the strategy are likely to face several challenges. An initial hurdle is the sheer scale of electrolyzer capacity deployment envisioned. In 2020, global electrolyzer capacity reached 0.3 GW [23]. In Europe, Germany stands with the largest capacity at 59 MW [6]. Reaching Germany's target corresponds to a 67% compound annual growth rate until 2030. In comparison, between 2000 and 2020, the annual growth rate of renewables reached 7% [24], even though the ramp-up has accelerated in the last five years. The electrolyzer manufacturing market is currently dominated by a small number of firms, which have almost all unveiled plans to gradually increase their manufacturing capacity, totaling several GWs [25]–[30]. Depending on the electrolyzer production technology these will need to tap into critical material resources, notably for iridium and platinum, which, while currently available, may become scarce as manufacturing increases [31]. Furthermore, Germany's electrolyzer capacity ambition has been matched by several neighboring countries such as France, the UK, Spain, and Italy [32]–[35]. At the European level, it is targeted to reach 40 GW of capacity by 2030, complemented by 40 GW in peripherical countries that are well endowed with renewable resources [36]. These objectives, when added to similar ambitions in several countries around the world, may be difficult to attain, potentially due to supply chain constraints.

Current German production relies on natural gas, which is 95% imported [37]. A large share is imported from Russia, followed by Norway [38]. This gas is reformed into hydrogen in SMR plants, which are large and expensive assets. There is therefore a risk of stranded SMR assets in Germany. Investing in new ATR plants may also not align with Germany's strategy which only views electrolytic hydrogen as sustainable in the long term and could become uneconomical compared with electrolysis. Even with a continued use of natural gas, Germany is looking to diversify its supply due to the Ukrainian war, an ambition shared at the European level. Concurrently to a decrease in consumption, it is highlighted that supply needs to be diversified via liquefied natural gas or pipeline imports from non-Russian suppliers [39].

The cost of producing decarbonized hydrogen may be expensive, notably in the short- to medium-term. Electrolyzers, even though being a relatively established technology, have not yet been deployed at scales comparable to that of SMR plants. The cost of electrolytic hydrogen is thus more expensive, within \$5-6/kg-H_2 [41], compared with ~\$1.3/kg-H_2 for unabated SMR [42]. These high costs may prove uncompetitive in the industrial sector, but economical in other sectors such as transportation, for which a cost of \$4/kg-H_2 is estimated to be sufficient to reach cost parity for 50% of transport energy demand [17], [43]. However, immediate demand is solely provided by the industry – most electrolytic hydrogen is thus likely to compete with cheap hydrogen from natural gas. Future demand in other sectors is characterized by large uncertainties. Even though the German national strategy states a doubling in demand from green steel by 2030, this application has barely passed the pilot stage, with a first-of-its-kind plant operational in 2020 and targeting full commercial production by 2026 [44].

Electrolytic production requires low-carbon electricity to deliver carbon-free hydrogen. This positions electrolyzers in competition with other electrifying sectors. The expected power demand increase will require extensive addition of renewable energy into the German electricity grid, which is currently characterized by a relatively large carbon intensity [45]. This is further exacerbated by the governmental decision to proceed with the decommissioning of nuclear power plants [46], and the requirement to be less reliant on natural gas in the power system due to the aforementioned issues. The opportunity cost of powering electrolyzers with renewable energy instead of integrating it into the power system is thus non-negligible [47], notably considering the lack of ample solar irradiance and wind exposure in Germany compared to other well-endowed countries.

The creation of a more holistic hydrogen supply chain will also likely require transmission pipelines and large-scale storage. Making use of the existing natural gas pipeline network is envisaged, but the feasibility of retrofit remains unclear [48] – only a single project has been completed [49]. Likewise, while storage in tanks is well established, a more inexpensive form of storage in salt caverns or depleted gas wells is considered, but not yet fully understood.

Finally, beyond a purely technical standpoint, several socio-political considerations inherent in the German context must be accounted for. Most notably, the German population dislike for CCS technologies [50], which is an institutionally reflected concern [51] – the German Environment Agency considers CCS' potential 'limited'. This could jeopardize plans to pursue blue hydrogen. To this must be added the aversion for nuclear.

Such ambitions will require the extensive development of a hydrogen supply chain. As opposed to the status quo in which most hydrogen is produced on site, a more versatile use of hydrogen will likely spur the deployment of an integrated network of production, transmission, and storage technologies.

To evaluate the feasibility of such an effort, several modeling algorithms have been developed. These intend to locate the location of production and the required transmission network to fulfil hydrogen demand. In many instances, they target hydrogen for light-duty mobility [52]–[57].

The subsequent results are provided by an optimal low carbon hydrogen network developed by the SESAME group at MIT [66]. The entire model description and methodology is extensively described in Chapter 2. It provides insights regarding the least cost scenario for a developed hydrogen supply chain while addressing the various concerns aforementioned. Using a linear approach, a multi-nodal system representing Germany's regions optimizes electricity generation, hydrogen generation, transmission, and storage. A scenario in which hydrogen is produced in Norway, Spain, and North Africa and sent through pipelines is evaluated. Several power generation, hydrogen production, and storage options are considered. This model aims to provide insights regarding the development of a hydrogen supply chain realistically by implementing several objectives laid out in the German hydrogen strategy.

3.2. Case Study & Data

The optimal low-carbon hydrogen network model used to perform the analysis intends to evaluate the regional infrastructure deployment required to fulfill a prescribed industrial demand from the year 2025 until the year 2050. This study captures the entire country of Germany. The country's regions are mapped into nodes in the model. The smaller regions of Hamburg, Berlin, Bremen, and Saarland have been respectively grouped within their larger neighbors. Two additional regions are captured in the North Sea, which represent regions with offshore wind potential. This provides a total of 14 nodes. Each region, or node, is associated with a hydrogen demand according to its industrial activity. In each region, the model optimizes the required infrastructure to be deployed. The model also optimizes infrastructure to be built between nodes, namely hydrogen and electricity transmission. The technologies considered are laid out in Table 7. All infrastructure is assumed to be greenfield. PEM electrolyzers were chosen thanks to their shorter ramp-up time compared with other production technologies.

Table 7: List of optimized technologies in the study

Power	Production	PV, Onshore and Offshore Wind
	Storage	Li-Ion
	Transmission	Transmission Lines
Hydrogen	Production	PEM Electrolysis, ATR with CCS, SMR with CCS
	Storage	Salt Caverns, Liquid Tank, Compressed Tank
	Transport	Pipelines

The model intends to fulfil hydrogen demand at all times during an entire year. The temporal granularity is hourly. Furthermore, to evaluate the growth of the required supply chain, the model is run for multiple years. To avoid computational intractability, the model is run for the years 2025, 2030, 2040, and 2050. It is formulated entirely linearly, thus avoiding binary constraints that would further exacerbate complexity. The inputs and outputs of the model are laid out in Table 8. For most technologies, a single cost was considered for all years due to the limited scope for cost decreases. Renewable technologies and electrolyzer costs are however expected to decrease – data was obtained for the four considered years.

Table 8: List of inputs and outputs in the model

Inputs	Cost and Technology Parameters, Capacity Constraints (Solar PV, Wind Turbines, Salt Caverns), Renewable Generation Profiles, Demand by Regions
Outputs	Hourly Flows of Electricity and Hydrogen Between and Within Regions, Technology Capacities, CO_2 Emissions

To ensure that renewable capacity deployment remains realistic, a Land Eligibility Analysis (LEA) was performed. It consists of a geographical analysis in which usable land for renewable power generation is defined for each region based on a certain set of constraints. To achieve so, the open source glaes framework [94] has been used, harnessing its convenient exclusion criteria compiled from a variety of European data sources. Considered constraints include societal and policy preferences, physical boundaries, and protected areas. These are subsequently listed for both wind turbines and solar panel, closely mirroring assumptions from Welder et. al. [62] and the IRENA [95]. While in agreement on most of the constraints, a more conservative value of terrain slope greater than 20 degrees for wind turbines was advocated by Jarvis et. al. [96] compared with 30 degrees for Welder et. al., and was subsequently used. Solar panels exclusion criteria were equal to those for wind turbines with the addition of the exclusion of arable and heterogeneous agriculture, and terrain slope greater than 5 degrees [96]. The constraints are tabulated in the subsequent table:

Table 9: Exclusion criteria for the land eligibility analysis

Excluded zone	Buffer distance [m]

Urban and industrial areas	500
Roads and railways	100
Power lines	120
Airport	5,000
Protected bird areas	200
Protected flora and fauna areas	0
Forest and bodies of water	0
Elevations above 2,000 m	0
Slopes above 20 degrees	0
Arable and heterogenous agriculture (solar only)	0
Slopes above 5 degrees (solar only)	0

Once the constraints have been defined, a heuristic placement algorithm was implemented to calculate the number of turbines potentially installable in the eligible zones. A minimal distance of 500 m between turbines was used, similarly to Welder et. al. [52]. For solar panels, the specifications of a First Solar Series 6 FS-6450 were employed [97], which is rated at 450W for a 2.47 m^2 area. Assuming a space between panels equal to 1 m, the potential power in a 400x400m area is 18 MW. The same algorithm was thus used with a 400 m distance.

Performing the analysis for each region output the number of wind turbines and solar panels installable, which were then converted into total power. In the case of wind turbines, the already installed capacity was compiled [98] and subtracted from the calculated potential. Solar panels installed capacity was not accounted for since it was assumed that most of the current infrastructure was rooftop solar. After the technical potential was defined, only 10% of it was kept as an upper limit for the model, to remain realistic about the prospect of using renewable generation solely for hydrogen production. This is contrary to Welder et. al. [52], who filtered the technical potential to keep turbines with a Levelized Cost of Electricity (LOCE) lower than €60/MWh. Results of this analysis are provided in the Appendix.

The yearly renewable resource profiles were extracted from the RE-Europe dataset [99]. It provides granular and hourly power generation profiles for wind turbines and solar panels, obtained by converting weather data using physical models. Each German region contained an array of RE-Europe nodes, each with an associated profile. For each region, they were aggregated by averaging to obtain a single regional profile. Offshore wind data was obtained from Grothe et. al. [100]. Two nodes representing offshore areas were arbitrarily drawn, one in the North Sea and one in the Baltic Sea. A similar methodology as that followed for the RE-Europe dataset was applied, in which the resource data for the nodes contained in each area were averaged and aggregated. The weather year studied was 2010.

Demand data was obtained from the data compiled by Neuwirth et. al [101]. The dataset provides hydrogen demand potential for both existing demand and maximum projected demand in energy-intensive industrial activities. Two demand scenarios were constructed to account for the uncertainty regarding future hydrogen needs in the industry. Both start at the same baseline in 2025 and consider that all steel plants resort to hydrogen by 2030. While hardly conceivable in practice, the obtained total demand corresponds to the forecasted industrial demand highlighted in the national hydrogen strategy. Then the low-demand scenario considers that by 2040, 50% of olefin-producing plants switch to hydrogen, with a 100% switch by 2050. The high-demand scenario considers that by 2040 100% of olefin-producing plants switch to hydrogen and that by 2050, other industries which include non-ferrous and non-metallic minerals and pulp and paper also switch to hydrogen. The dataset contains locational data for all plants in Germany, enabling the mapping of demand to the considered regions. The scenarios are outlined in the Appendix.

The model considers carbon emissions from the natural gas supply chain and the ATR process emissions. These are taxed according to forecasted carbon tax prices. The cost of capital is assumed to be 10% for all technologies.

The model contains a set of assumptions. Renewable electricity is assumed to be solely used for electrolyzers and compressors – any unused electricity is thus curtailed. ATR plants are assumed to have a constant hourly output. Hydrogen storage is allowed in salt caverns in regions with a cavern potential, otherwise in compressed or liquid tanks in regions with no potential.

Several case studies were analyzed to obtain various viewpoints on a future hydrogen supply chain in Germany. The first case study considers a system in which 100% of the demand is fulfilled by domestic electrolytic hydrogen. This represents an edge case of the decarbonization of hydrogen production and provides an estimation of the required infrastructure deployment for an autarkic scenario. Both the low and high demand scenarios are considered. A sensitivity analysis of the cost of offshore wind was performed to analyze its influence on the system. Another case prevented hydrogen pipelines to be built, to gain greater insights into the electricity transmission system and the relative cost benefits of moving energy using electricity or hydrogen. One case prevented salt caverns in the system, replacing them with storage tanks. A final scenario looked at a more pessimistic cost of electrolyzers. Indeed, the future cost of electrolyzers is highly uncertain, and while projections are optimistic, there are accounts that the actual cost of electrolyzers in 2023 paid by developers is well upwards of 1,000 €/kW [102].

Another case delved into an optimal system under an increasingly stringent carbon constraint. In this case, electrolyzers and ATR production are allowed to compete – the average hydrogen carbon intensity must not surpass a certain threshold, expressed in $kgCO_2/kgH_2$. Two base scenarios are considered – a business as usual (BAU), and an Advanced Decarbonization (AD) case, with more aggressive targets. Sensitivity analyses are performed on the cost of natural gas and the methane leakage rate.

A final case considers a system in which imports from Norway, Spain, and North Africa through pipelines are allowed. Due to the winner-takes-all nature of a linear algorithm, production technologies are not allowed to compete but are fixed according to the national strategy targets. This case intends to provide a more realistic overview of the potential future supply chain. Both demand scenarios are analyzed. A sensitivity analysis delved into imports from either Norway, Spain, or North Africa, to map out the required network infrastructure in all cases.

3.3. Results

3.3.1. 100% Electrolytic Production

Electrolytic hydrogen production is viewed by the German government as the most viable production technology in the long term. To ensure a low carbon intensity, electrolyzers must be powered by renewable electricity. The non-dispatchable nature of renewable thus forces electrolyzers to follow the production curve dictated by fluctuating natural resources.

This implies that electrolyzers may not be able to reach 100% capacity factors. This gives rise to an interplay in the sizing of renewable capacity against the sizing of electrolyzer capacity, which is hereafter termed the renewable oversize. A greater oversize leads to an increased electrolyzer capacity factor but generates more curtailment at times of high electricity production. Conversely, a small oversize decreases curtailment but also the electrolyzer capacity factor. Access to renewable generation in high production regions helps reducing the cost of hydrogen production. However, these sites may not be close to demand centers. Large scale, inexpensive storage can also benefit the supply chain. Designing for a hydrogen supply chain increasingly dominated by large-scale electrolytic production thus requires evaluating the trade-offs between electrolytic production potentially far from demand centers with pipeline transmission or electricity transmission to electrolyzers located close to demand. It also evaluates the role of large-scale storage and its importance in such a system.

3.3.1.1. Low Demand Scenario

The initial and base scenario considers a low industrial demand through 2050, with a limited and slow replacement of incumbent fuels with hydrogen in the steel and then olefin industries. The optimized system is displayed in Figure 10.

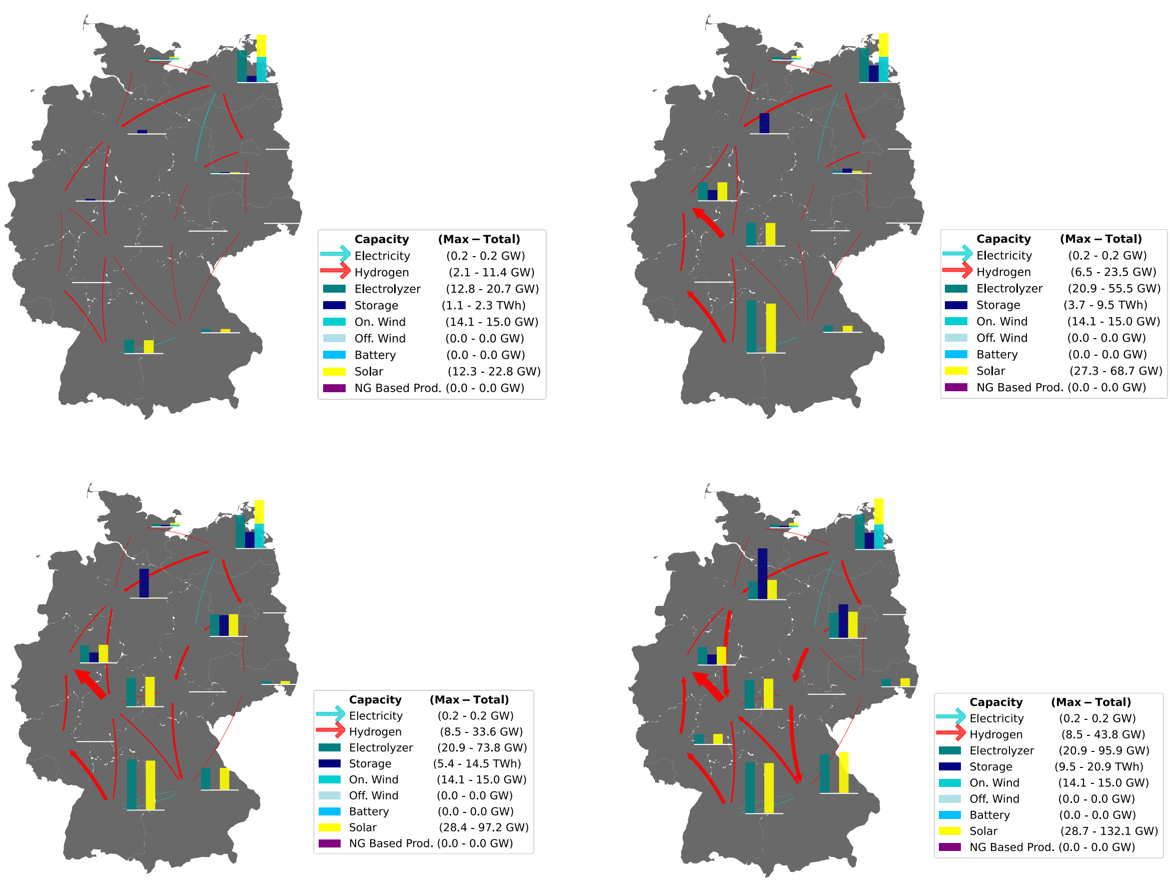


Figure 10: Illustration of the infrastructure expansion for a 100% electrolytic production scenario. Vertical bars within regions represent capacities of infrastructure. Each technology has been scaled by the maximum capacity deployed in a single region for that specific technology. To relate the bar size to actual capacity, refer to the legend which states two values – Max: maximum capacity in a single region, and Total: total capacity in the entire system, for each technology. Top Left: 2025, Top Right: 2030, Bottom Left: 2040, Bottom Right: 2050.

The supply chain visibly evolves through the years as hydrogen demand increases. The initial iteration represents the required supply chain infrastructure to decarbonize current demand (~50 TWh). It is visible that most of the production is located in Northwest Germany in the region of Mecklenburg-Vorpommern, despite the absence of hydrogen demand in this region. Electricity production comes from a mix of solar panels and wind turbines. It is the only state in the system that significantly deploys wind turbines, even extending up to 2050. This stems from the increased wind capacity factors in this region, which reach almost 30% compared with ~13% in the Southern regions. The maximum deployable capacity in this region is attained in the first time step, with 14 GW. All other years see the co-deployment of solar panels and electrolyzers. The system does not include offshore wind turbines or electricity storage, nor liquid hydrogen tanks.

The obtained electricity curve is illustrated in Figure 11. Renewable sources result in variable electricity production, dependent on the weather conditions. This forces electrolyzers to follow the curve at all times. It is visible that during peak production hours the generation exceeds to electrolyzer capacity, resulting in curtailment. Overall, 7.9% of electricity production is curtailed in the 2025 system, increasing up to 12.4% in 2050 due to the increased prevalence of solar panels.

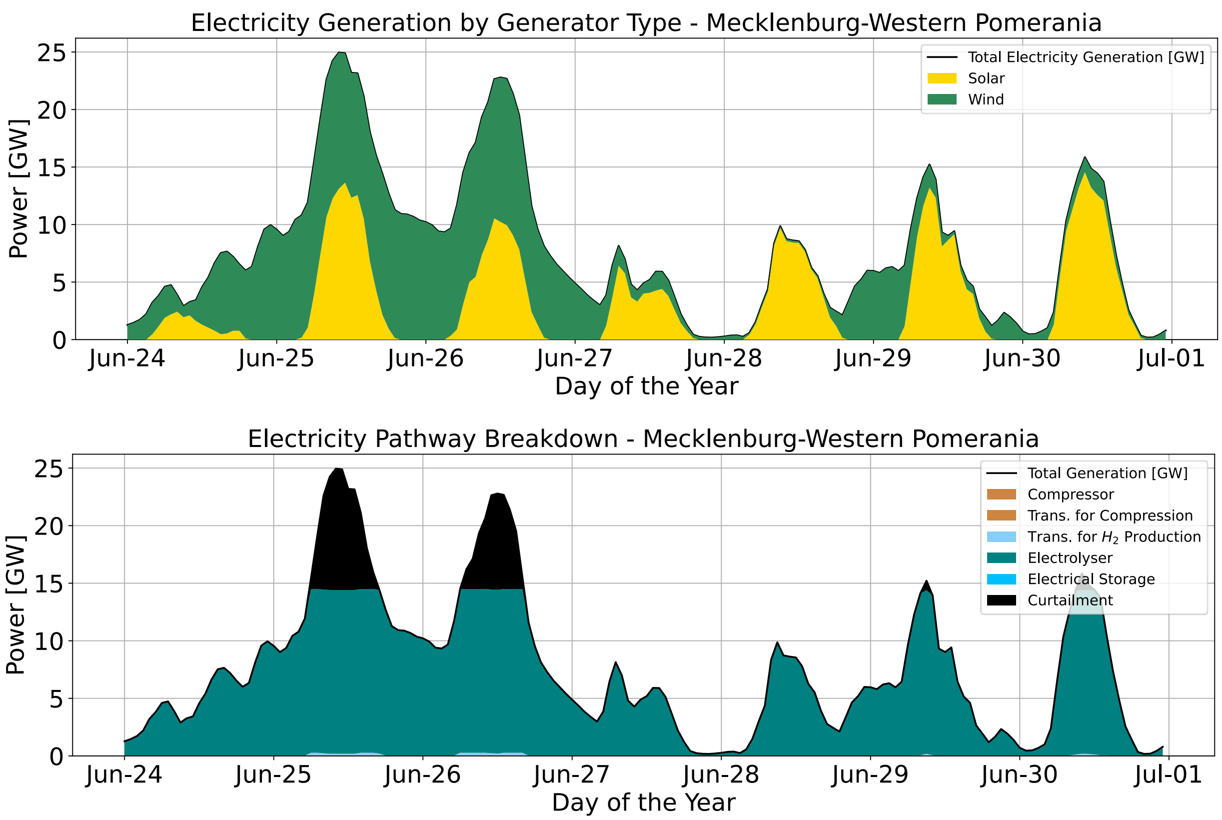


Figure 11: Electricity generation by generator type and electricity pathway breakdown for the region of Mecklenburg-Western Pomerania during a week in June.

This indicates that from a systemic cost perspective, curtailment can benefit the operation of electrolyzers. An important assumption of the model is that electricity production is considered from a cost perspective but not its value, which changes with time due to market mechanisms. The algorithm aims to reduce annualized capital and operational costs in a system that does not interact with other sectors. In practice, a hydrogen developer that builds renewable capacity to power electrolyzers may also want to be integrated into the grid to generate revenues during peak electricity prices. This will lead to a different renewable oversize. However, such an operation would also result in a reduced electrolyzer capacity factor, requiring a thoughtful balance between power revenues and electrolyzer utilization.

In light of this model assumption, the system is always optimal with a significant renewable oversize. In 2025 in Mecklenburg-Vorpommern, the oversize reaches 2.04 $GW_{renewable}/GW_{electrolyzer}$. This results in a 47% electrolyzer capacity factor. In future years with added solar panels the oversize decreases, usually between 1.5 and 2. The oversize is not higher since solar production is concentrated around peaks which usually represent production at 100% capacity factor for a few hours, as illustrated in Figure 12 for the region of Baden-Württemberg. An important oversize would thus translate into large curtailment during these short production hours. This is unlike wind, for which a greater oversize can be justified based on greater electrolyzer utilization when wind production fluctuates between 20-70% capacity factor, a much more frequent occurrence than for solar production. Despite a smaller renewable oversize than in the region of Mecklenburg-Vorpommern, the electrolyzer capacity factor is ~30% due to the absence of nightly production.

To balance variable hydrogen production with constant demand, hydrogen storage is deployed in the system. The bulk of storage deployed is in the form of salt caverns thanks to the technology's low capital and operational costs. By 2050, a total of 20.9 TWh are deployed throughout the country, as opposed to 0.072 TWh of compressed tanks. This represents 11% of the yearly hydrogen demand in 2050 (187 TWh). Salt caverns play an important role in dealing with the seasonal variation of renewable production. They display a strong seasonal pattern, with an increase in inventory during the warmer months and a slow depletion during the colder months. Beyond this seasonal balance, they also dispatch hydrogen at a shorter timescale, typically within a day, to fulfill immediate demand. This is visible in the short and continuous fluctuation throughout the year.

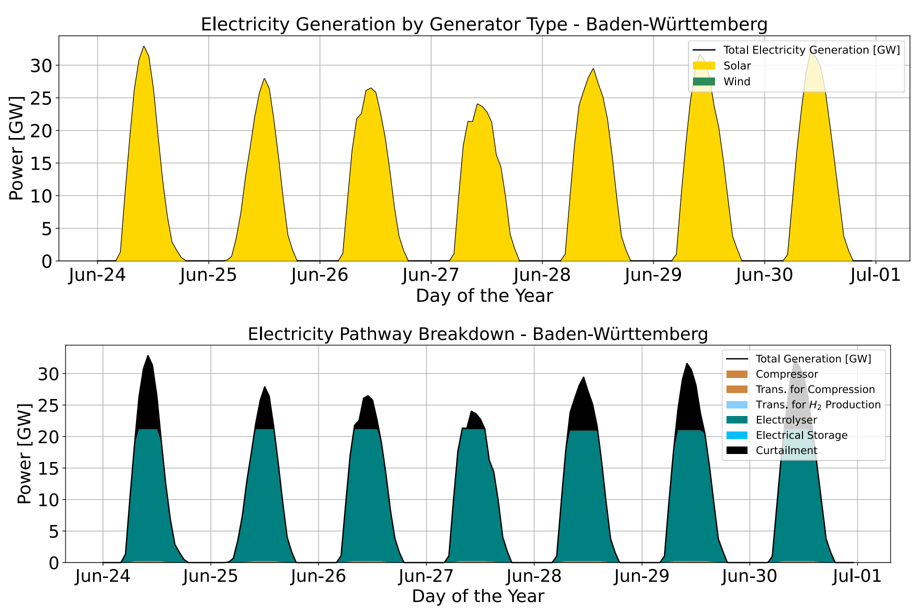


Figure 12: Electricity generation by generator type and electricity pathway breakdown in Baden-Württemberg. The shape of the production curve is peaky due to the absence of wind turbines in the region. This results in periods of high electrolytic production with curtailment, with absence of production during nighttime.

The co-location of salt caverns with good renewable resources is an advantage for Germany. It enables keeping production and storage together and minimizes the need for expensive tank storage or electricity storage. The first salt caverns are deployed in Mecklenburg-Vorpommern and in Lower Saxony. It then increases in Lower Saxony to become the region with the largest cavern by 2050 with 9.5 TWh. This large increase is concurrent with electrolyzer and solar panel deployment in the region. A similar phenomenon is observed in Saxony-Anhalt. These two regions display an almost sinusoidal hydrogen storage inventory, as opposed to Mecklenburg-Vorpommern where the inventory fluctuates less predictably due to the presence of wind. This is illustrated in Figure 4. Southern regions also see the deployment of hydrogen storage, albeit minimal compared to Northern regions, and in the form of compressed tanks. This is caused by the absence of salt cavern potential in this part of the country. Tanks fulfill a buffer role for daily fluctuations in production only, as opposed to caverns that handle both daily and seasonal fluctuations. Inventories in the regions of Mecklenburg-Vorpommern, Lower Saxony, and Baden-Württemberg are displayed in Figure 13.

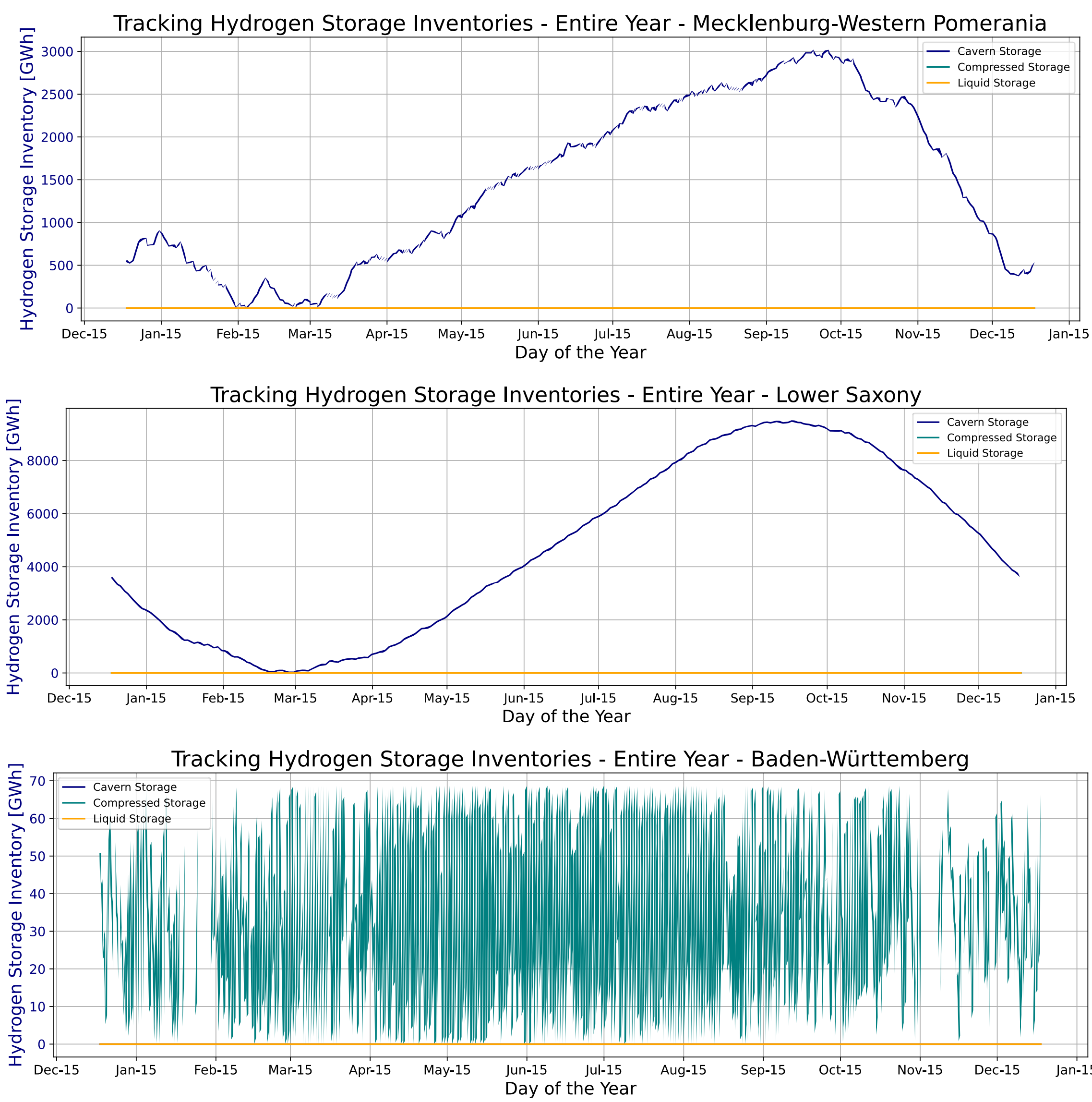
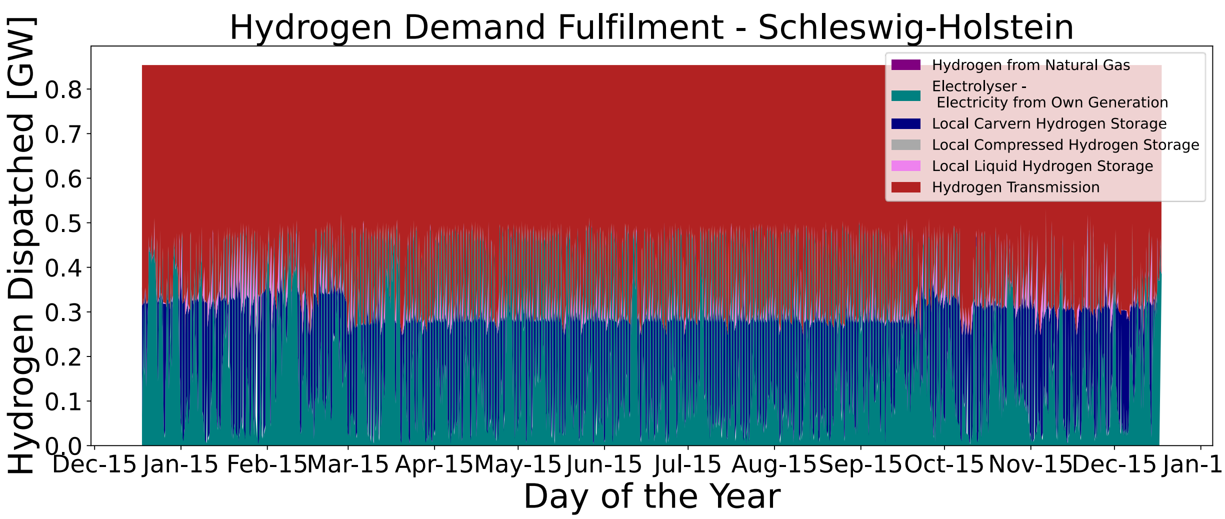


Figure 13: Hydrogen storage inventories in the regions of Mecklenburg-Western Pomerania, Lower Saxony and Baden-Württemberg over an entire year. Salt cavern storage provides seasonal as well as daily buffer, while compressed tank storage only provides daily flexibility.

The convenience of the salt cavern location results in the important reliance on hydrogen transmission in the system. Decarbonizing current demand requires 11.4 GW of pipelines, increasing up to 43.8 GW in 2050. The initial network is composed of pipelines connecting the North and the South to the central region, most notably North-Rhine Westphalia, which has the greatest hydrogen demand. This pattern remains throughout the years – the notable difference comes from added capacity among the existing routes. Hydrogen transmission is prevalent against electricity transmission – only 0.2 GW are deployed throughout the years. This indicates that despite the distance between regions well-endowed with natural resources and demand, production occurs far from demand centers instead of close to demand centers and is complemented by electricity transmission. Another factor that is likely to buoy hydrogen transmission is the availability of low-cost hydrogen storage. Storing hydrogen instead of electricity is very cost-effective, especially with salt caverns that boast low capital and operational cost as well as relatively low compression requirements. A hydrogen system that heavily relies on electrolytic production is thus likely to benefit from large-scale hydrogen transmission to capture the synergies between production, storage, and demand, and their relative distance.

This is reflected in the hydrogen demand fulfillment of most regions. Several regions see their demand fulfilled by hydrogen transmission from other regions. The region of Schleswig-Holstein has a low hydrogen demand but deploys both solar panels and wind turbines to power a local electrolyzer. It does not export hydrogen or electricity to other regions. As such, most electrolytic production is sent to the local demand, while another portion of hydrogen comes from salt cavern storage. The remaining demand requirement is fulfilled by hydrogen transmission from Mecklenburg-Vorpommern. The fulfillment pattern in a region without salt caverns is somewhat different. For example, in Bavaria, electrolytic production powered by solar panels results in daily spikes that flow directly to demand. A portion of demand is then fulfilled with expensive compressed tank storage during the nighttime, complemented with hydrogen transmission. These are displayed in Figure 14.



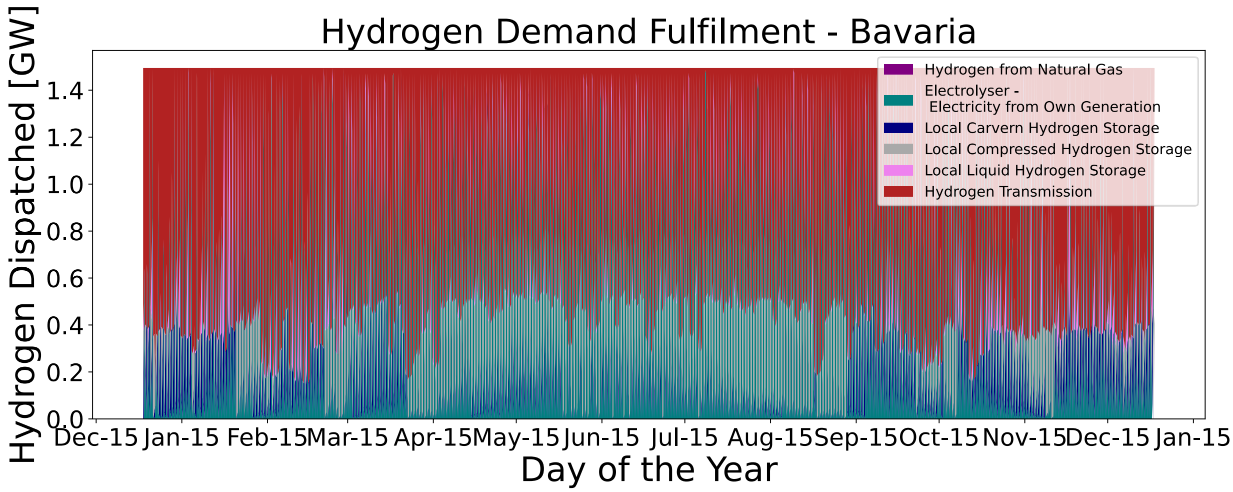


Figure 14: Hydrogen demand fulfilment in the regions of Schleswig-Holstein and Bavaria. Schleswig-Holstein hosts a mix of wind turbines and solar panels, enabling electrolytic production during nighttime, which can then fulfil demand. The region of Bavaria relies on compressed storage to fulfil a portion of nighttime demand, almost entirely provides itself with local electrolytic production during the day (seen in the daily peaks) and heavily relies on transmission during the night.

3.3.1.2. High Demand Scenario

A scenario with higher demand assumptions leads to a very large infrastructure deployment. By 2050, 176 GW of electrolyzers would be required. Similar to the previous case, onshore wind is not extensively deployed – a total of 15 .7 GW is added, which does not represent an increase compared to the low-demand scenario. Solar deployment is large, topping 250 GW. Storage in Lower Saxony and Saxony-Anhalt is also significant. It provides an important buffer to dispatch hydrogen through large pipelines to the Southern regions. The largest pipeline requirement between two regions is 12.1 GW, with a total of 75 GW over the entire system.

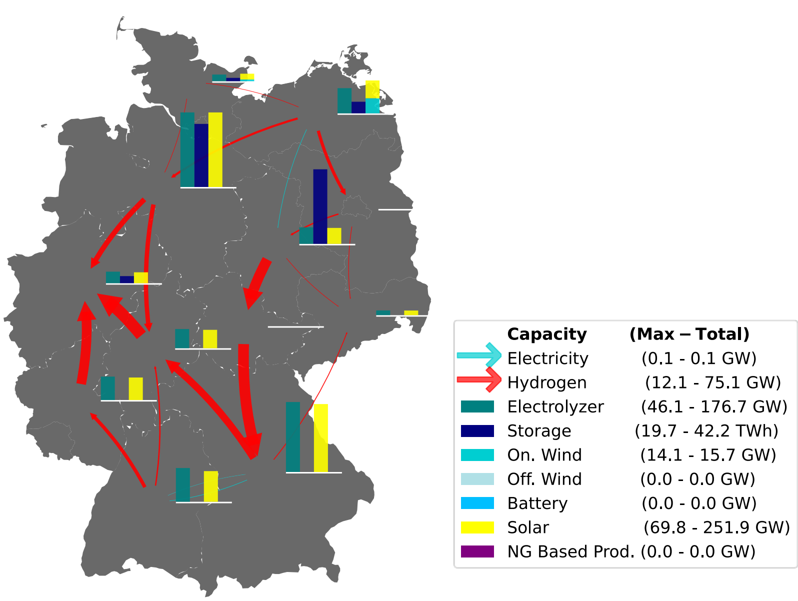


Figure 15: Illustration of the supply chain requirements in the high demand scenario in 2050.

This case illustrates the scale of the challenge in decarbonizing industrial demand with domestic electrolytic production. Both the low-demand and high-demand scenarios require technology deployments that are unlikely to be achievable in such a short time span. By 2021, solar and wind capacities totaled 58 GW and 64 GW respectively [103]. Electrolytic production would therefore monopolize a large share of renewable capacity, thus competing with other sectors needing low-carbon electricity. This highlights the need for imports and potential retrofit of existing fossil-based production assets.

3.3.1.3. Sensitivity Analysis

A system relying on electrolytic production displays strong synergies between technologies of production, storage, and transmission. A sensitivity analysis was performed to understand the synergies in greater depth. One case analyzed the system with a reduced cost of offshore wind turbines, which are not deployed in the base case. Two other cases considered the system in the absence of pipelines and salt caverns respectively. Finally, a scenario investigated a higher electrolyzer cost. The levelized costs of hydrogen are displayed in Figure 16.

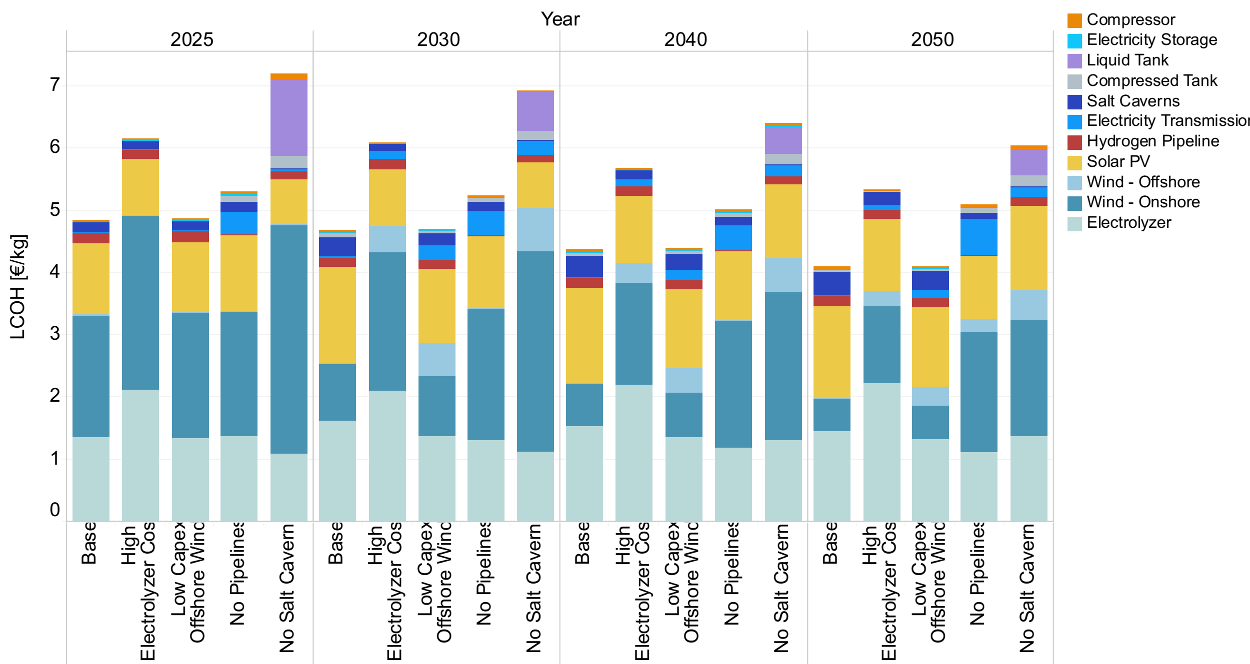


Figure 16: Levelized cost of hydrogen for the base scenario as well as the sensitivity scenarios. The vertical ordering of the legend entries matches that of the stacked bars.

The levelized cost in the base scenario is initially ~4.8€/kgH_2. An important majority of the cost stems from renewable capacity. The cost of electrolyzers is relatively low compared with renewables – the capital cost of electrolyzers in the base scenario is below 1,000 €/kW, which may be unrealistic in the short term. The levelized cost decreases through the years to reach ~4.0€/kgH_2. The levelized cost captures infrastructure deployed all throughout the years – technologies deployed in 2025 are more expensive than in the next time steps (especially electrolyzers, wind turbines, and solar panels) which is reflected in the cost. Therefore, the system in 2050 and its associated cost captures infrastructure built in previous years – the displayed LCOH thus do not represent the levelized cost for infrastructure built in 2050 only.

In this base scenario, while onshore wind surpasses solar panels in cost, the trend is reversed in the next time steps. This rise in solar panel proportion in the cost is associated with a rise in salt cavern storage cost, which is deployed in greater quantities in a solar-dominated system than in a system with both solar and wind. Hydrogen pipelines are the final significant contribution to the cost, which remains relatively low. Electricity transmission, compressed and liquid tanks, electricity storage, and compressors are negligible.

A doubling in electrolyzer cost significantly increases the levelized cost, but also has system-wide implications in the technology rollout. The renewable oversize differs from that of the base scenario. Greater electrolyzer costs require increased capacity factors, which forces increased renewable capacity buildout. To further maximize electrolyzer capacity factors without requiring extensive renewable deployment, 3.5 GW of offshore wind are deployed in 2030. While more expensive than other renewables, they reach almost 50% capacity factor thanks to ample wind resources. The relative cost of electrolyzers and renewables thus shifts the optimal oversize and influences the share of renewable technologies deployed.

Decreasing the cost of offshore wind by 50% while keeping the cost of electrolyzers equal also results in offshore wind deployment. Compared to the base case, this results in less renewable capacity deployed – by 2050, 136 GW for the low offshore wind capex case as opposed to 147 GW for the base case. Electricity curtailment in 2050 decreases to 11%, and the electrolyzer capacity factors increase by 2-3% in Northern regions. However, even with such a cost decrease, the overall system cost does not significantly decrease from the base case. One important factor is the cost of offshore transmission lines which starts becoming consequential in the system.

A scenario with no pipelines forces the system to rely on electricity transmission. By 2050, 43.6 GW of transmission lines are built throughout the country. Onshore wind is deployed in greater quantities in this system (56 GW) compared to the base case (15 GW), once again to reduce curtailment and increase electrolyzer capacity factors. 3.8 GW of offshore wind are deployed in the year 2050. In this case, all regions that consume must produce their own hydrogen locally. This forces regions without salt cavern potential to deploy compressed and liquid tanks (119 GWh and 45 GWh respectively in 2050). Since salt caverns can only be used to provide buffer to a single region, only 5.9 TWh are deployed. In this scenario, the cost of hydrogen does not significantly decrease through the years – systemic synergies with hydrogen pipelines and salt cavern storage cannot be achieved which results in an outsized need for renewable and electricity transmission deployment.

A final scenario delved into a system without salt cavern storage. This scenario is by far the most expensive among all others. The cost of liquid and compressed tanks particularly stands out, as well as the cost of onshore wind. By 2050, 1.1 TWh of liquid tanks are deployed, as well as 0.27 TWh of compressed storage. 7 GW of offshore wind is also installed, even more than in the low CapEx case. In total, 192 GW of renewable capacity is built, corresponding to an average oversize of 2.1 $GW_{renewable}/GW_{electrolyzer}$. This highlights the benefits of inexpensive large-scale storage in a system dominated by electrolytic production. Interestingly, while the scenario with no pipelines introduces compressed storage in the system, this scenario sees more liquid storage being deployed. Indeed, while liquid tanks have a lower capital cost than their compressed counterparts, the electricity compression requirements are much greater, representing almost 30% of hydrogen's energy content. However, since electrolytic production occurs concurrently with storage, an important share of electricity that would have been curtailed anyway is not used to compress hydrogen, which reduces curtailment while benefitting from lower capital costs.

Decarbonizing Germany's hydrogen production with domestic electrolyzers only thus represents a significant challenge regarding the scale of technology deployment required. Beyond technological hurdles, the cost of production is greater than current production methods, especially since Germany is not well endowed with natural resources.

3.3.2. System under Carbon Constraint

The scale of infrastructure deployment required to reach low carbon production with electrolyzers only thus seems unattainable in the timeline up to 2050. Therefore, Germany is likely to rely on other production technologies to fulfill its industrial demand. Since current production is ensured by processes based on natural gas, pursuing this avenue by decreasing emissions using carbon capture is considered.

To ensure that this complies with the decarbonization ambitions of Germany, the overall carbon emissions of the system must be kept within reasonable bounds. An important factor to consider, beyond the remaining carbon emissions of the process after carbon capture, are the upstream emissions of the natural gas supply chain. In this case, the overall carbon emissions of the system were set as a constraint. Electrolytic and ATR production were left to compete. An initial scenario considered a BAU scenario, under which the average carbon intensity of hydrogen produced in the system cannot exceed the threshold defined by the European Commission for low-carbon fuels [104] all throughout 2050, equal to 3.38 $kgCO_{2eq}/kgH_2$. An AD scenario adopts a more aggressive target, starting with 3.38 $kgCO_{2eq}/kgH_2$ with a final threshold of 1 $kgCO_{2eq}/kgH_2$ by 2050. Sensitivities on the cost of natural gas and the methane leakage rate were also performed.

3.3.2.1. Base Case

Under both scenarios, the system is wholly dominated by ATR production. Indeed, emissions remain below the threshold, even in the AD case. The resulting emissions are outlined in Table 10.

Table 10: Life-cycle emissions from ATR production in all considered years.

Emissions [$kgCO_{2,eq}/kgH_2$]	2025	2030	2040	2050
Process (91% capture for ATR)	0.62	0.62	0.62	0.62
Leaks and venting from transport	1.45	0.97	0.48	0.29
Electricity	0.65	0.43	0.14	0.07
Total	**2.72**	**2.02**	**1.25**	**0.98**

The calculation of life cycle emissions of natural gas-derived products is notably complex due to the lack of data available to accurately quantify upstream emissions. It notably depends on a main factor, the methane leakage rate. This factor is highly location dependent and importantly varies throughout the world. Ladage et. al. [40] compiled sources stating leakage rates for Germany, its neighbors, and strategic partners. While the leakage rate for domestic production is low, that of Russia is much more uncertain, ranging from 0.3% to 1.5%. Before the Ukrainian war, Russia provided an important share of natural gas to Germany. The model conservatively assumes a leakage rate of 1.5% in the first time step. It is then decreased down to 0.3% by 2050. This reflects the likely import shift away from Russia and towards other partners that may work towards reducing supply chain emissions. A sensitivity on the leakage rate is performed and subsequently described, where the leakage rate remains at 1.5%.

Another important factor in the life cycle assessment of ATR production is the emissions stemming from electricity. It is assumed that electricity is drawn from the grid. The adopted grid emissions in this study come from projections for the EU27, taking conservative estimates from a number of scenarios compiled by Ember [105]. However, Germany's grid remains dominated by fossil fuels leading to a high carbon intensity nearing 400 gCO_2/kWh [106]. Decarbonizing the electricity grid is therefore paramount to reducing the carbon intensity of natural gas-derived hydrogen, alongside the tightening of supply chains.

Finally, process emissions are importantly reduced compared to the unabated case. However, there are currently very few plants operating with carbon capture at scale. Reaching a high capture rate is costly – it increases capital costs between 50-100% [15], [83]. This may affect the economics of conventional hydrogen production, further exacerbated by potentially volatile carbon pricing.

3.3.2.2. Sensitivity: Cost of Natural Gas

The cost of ATR production heavily relies on the cost of natural gas and will be increasingly affected by carbon pricing. A sensitivity analysis on the cost of natural gas was thus performed. Cost projections from Fraunhofer were adopted [107], and the base case was compared with a 30% cost decrease, and a 30% and 100% cost increase, reflecting the volatility of this commodity. While during modeling the carbon price is applied to all fugitive emissions, only the cost of emissions from the process is reflected in Figure 17.

ATR production with CCS is characterized by high levelized capital costs, in excess of 1€/kgH_2. Beyond capital costs, the cost of electricity and natural gas are the main drivers of the levelized cost, of which natural gas is the most significant. It is visible that the levelized cost of ATR is particularly sensitive to gas costs. Also, while the projected gas costs decrease through the years, the cost differential is partially filled with the carbon tax. Production costs even in the optimistic case are upwards of 2€/kgH_2. However, all cases remain less expensive than the base electrolytic case. An important factor is the cost of infrastructure needed beyond production in the electrolytic case – storage and transmission become significant in the levelized cost. Large, constant ATR production does not require extensive adjacent infrastructure beyond a natural gas pipeline since it is usually co-located with demand. The costs beyond production are usually overlooked in an electrolyzer-dominated system and should be more carefully considered.

3.3.2.3. Sensitivity: Methane Leakage Rate

The methane leakage rate is a determining factor regarding the life cycle emissions of natural gas-derived products. Its potency as a greenhouse gas raises concerns and increasingly spurs policy advocacy and action. Recently, the European Union developed a Methane Strategy in 2020, later strengthened by an Action Plan in 2022 [108]. It calls for greater scrutiny of measurements, reporting, and verification, alongside immediate reduction of emissions through fast repairs of detected leaks. This has formed the basis of the model assumption regarding decreasing methane leakage rate through the years. If efforts are not pursued, upstream emissions will remain significant for all products derived from natural gas. The relative share of ATR and electrolytic production in a scenario in which the leakage rate remains constant is investigated, using the AD carbon constraint. These are displayed in Figure 18.

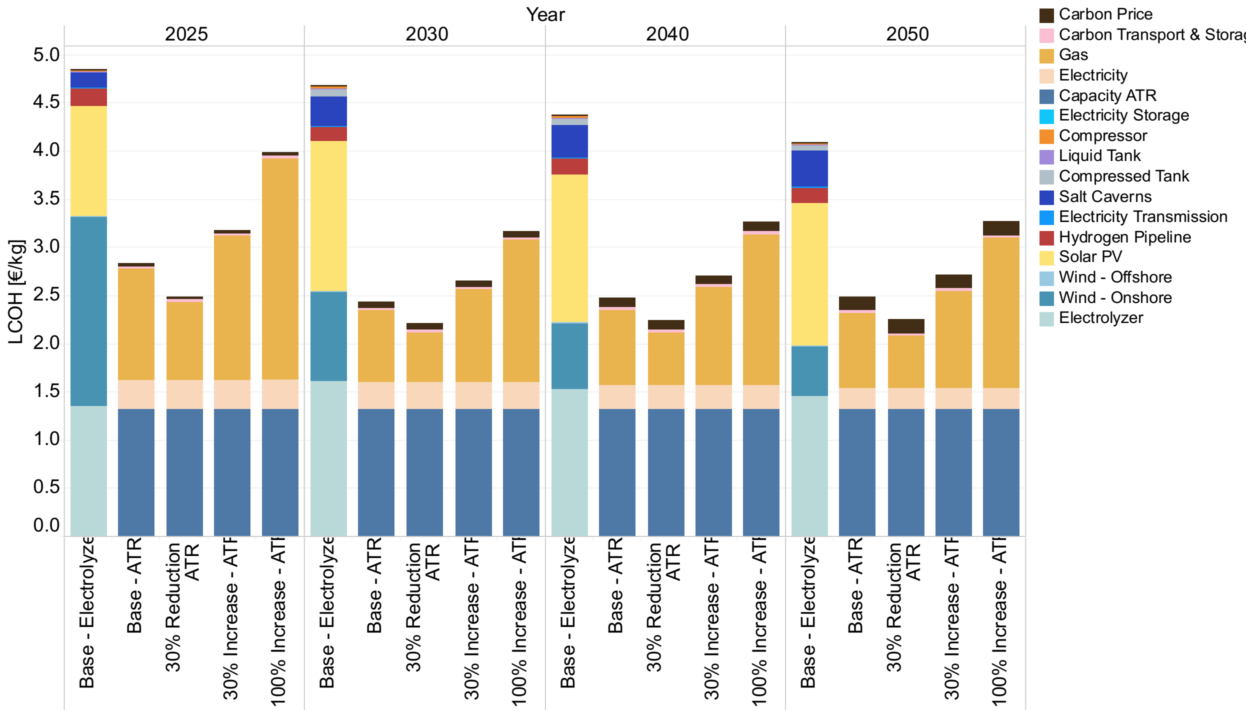


Figure 17: Levelized cost of hydrogen for the base case as well as the natural gas sensitivities for ATR production. The bottom part of the legend entries vertically match that of the electrolytic production cost, while the five top entries of the legend vertically match the ATR production stack bars.

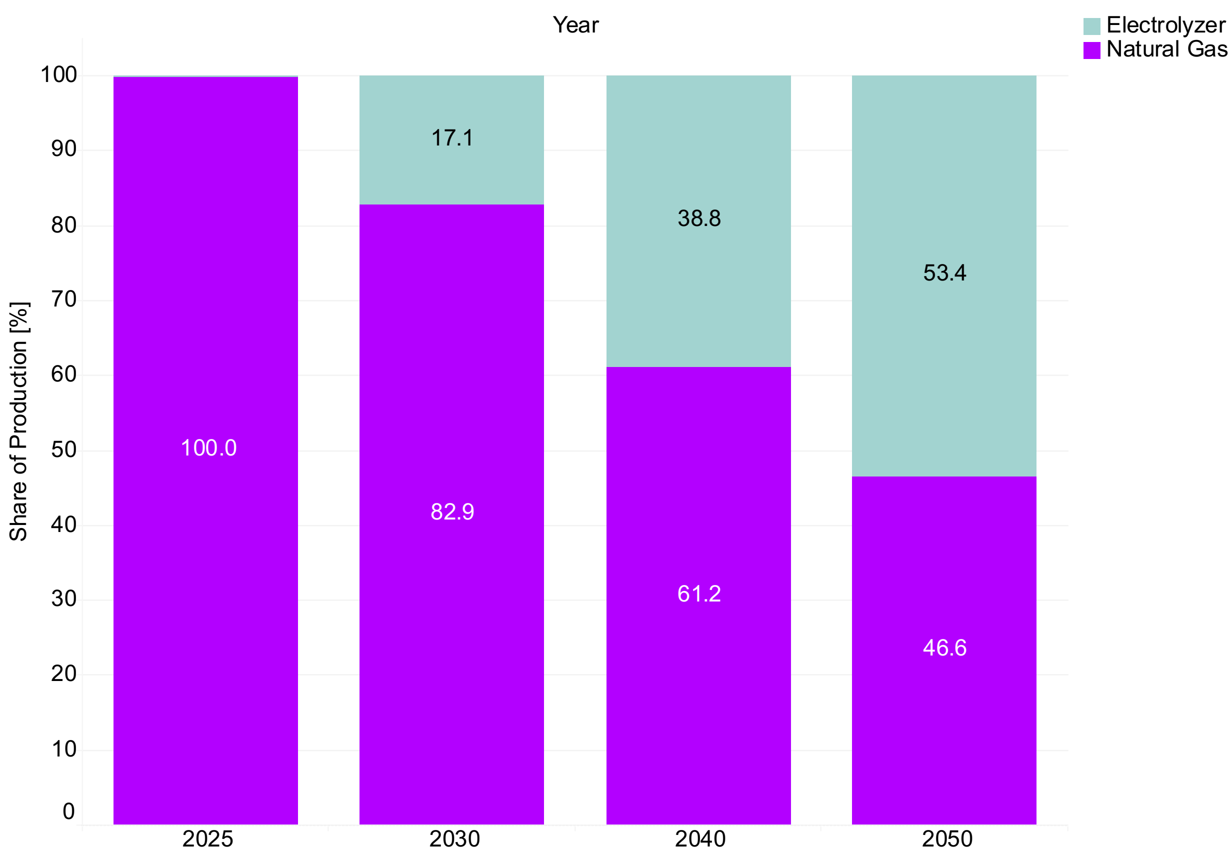


Figure 18: Relative share of electrolytic vs. ATR production in the AD scenario, considering that natural gas supply chain leakage does not ameliorate with time.

Maintaining a high level of leakage throughout the supply chain results in a overtake of electrolytic hydrogen as the carbon constraint is tightened. Furthermore, this analysis considers the average emissions over the entire system – owing to the higher cost of electrolytic production, its introduction in the system indicates that ATR emissions are above the defined threshold and need to be counterbalanced. In reality, if the definition of the carbon emission threshold of low-carbon gases changes and future policy mechanisms prohibit the use of fuels that surpass that threshold, natural gas-derived production faces the risk of stranded assets. To be a viable pathway in a future hydrogen supply chain, natural gas-derived production will require the appropriate tightening of upstream supply chain, decarbonization of electricity consumption, and high carbon capture rates.

3.3.3. Scenario with Imports, Binding Targets

Decarbonizing hydrogen demand in Germany is therefore likely to require imports to alleviate the otherwise large renewable and electrolytic capacity demand. Several avenues are being investigated by the German government, leading to a number of memoranda of understanding with potential partner countries. These avenues consist of a few transportation pathways such as hydrogen pipelines and ships, or transport via other molecular forms such as Liquid Organic Hydrogen Carriers (LOHC) or ammonia to fulfil existing demand. Overall, imports are forecasted to represent 50-70% of demand fulfilment by 2030 [19]. Given that large distance ship transport of hydrogen does not yet occur on a large scale, the most likely pathway in the short term is in the form of pipelines from adjacent countries. The final case of this study delves into a system in which pipelines from Norway, Spain, and North Africa deliver hydrogen to Germany. These countries are chosen due to the relative maturity of the plans to build pipelines compared with other countries, for which the capacity for collaboration remains unclear.

The objective is to evaluate a system that blends policy objectives stated by the German government. The initial objective relates to electrolytic production – 10 GW are planned to be constructed by 2030. To ensure that the model provides electrolytic production, production targets (instead of capacities) were thus mapped to the considered years and enforced as constraints. It was assumed that 10% of hydrogen demand will be fulfilled with ATR production with CCS domestically. For imports, 40% of hydrogen was assumed to be fulfilled with Spanish and North African hydrogen, each in equal amounts. The remaining hydrogen demand was assumed to be imported from Norway. Imported hydrogen is assumed to be always available. While there is a lot of uncertainties regarding the actual amount of hydrogen to be imported from each country, the analysis provides an overview of the systemic synergies between imports and electrolytic production from an operational point of view.

3.3.3.1. Low Demand Scenario

The initial system delves into the low demand scenario, which reaches 187 TWh by 2050. The obtained optimized system is displayed in Figure 19.

Domestically, the system differs from the first case with 100% electrolytic production. The production region in the Northwest powered by a mix of wind turbines and solar panels is not present anymore – there is no onshore wind remaining in the system. Only solar production remains in the system with almost 40 GW deployed mostly in the Southern and Western regions of the country. By 2050, 50 TWh were assumed to be required from electrolytic hydrogen, resulting in 28.6 GW of electrolyzer.

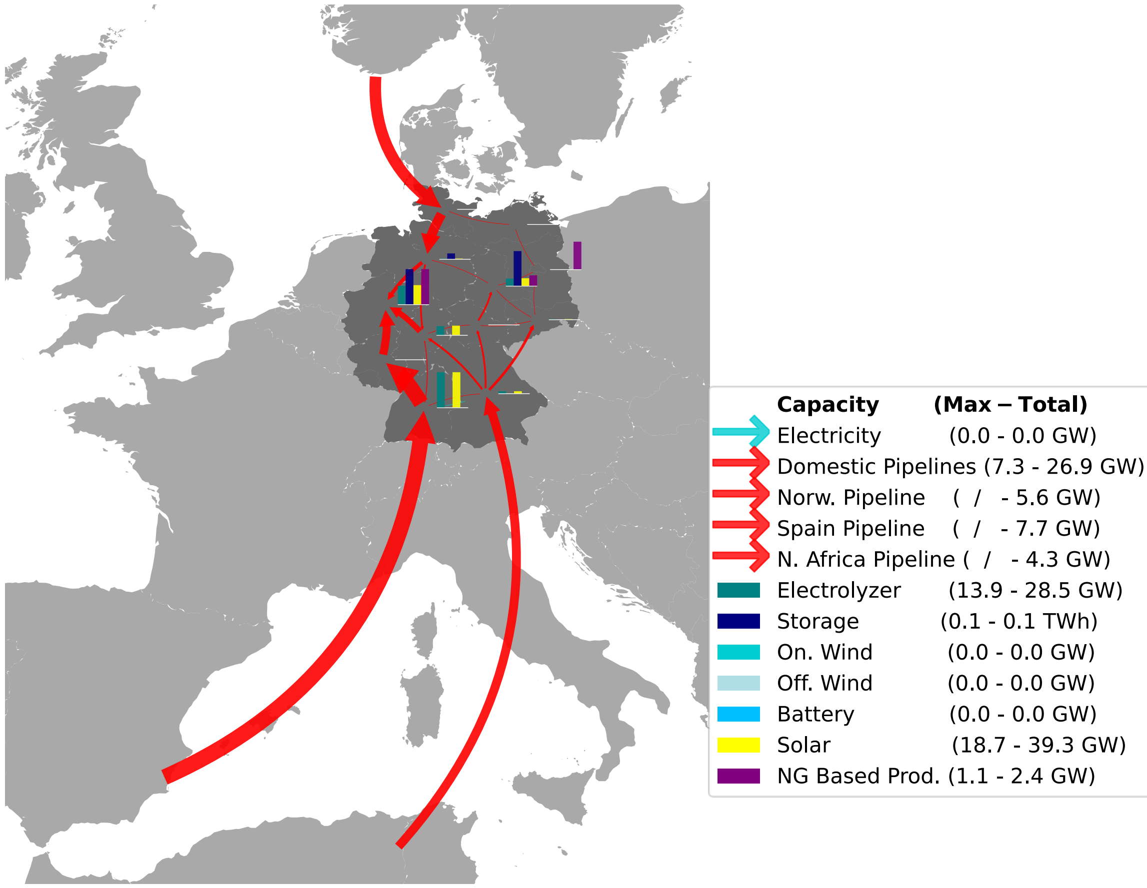


Figure 19: Illustration of the supply chain requirements with imports from Norway, Spain, and North Africa in 2050, in the low demand scenario. Fixed amounts of production were fixed: 50 TWh/year of electrolytic production, 10% of demand from ATR, 20% of demand from Spain, 20% of demand from North Africa, and the rest from Norway.

Hydrogen pipelines are prevalent in the Western part of Germany. The bulk of pipelines provide hydrogen to this industrial hub. Interestingly, the region of North Rhine-Westphalia (with the largest hydrogen demand) fulfils its demand with a mix of electrolytic production with salt cavern storage, ATR production, and imports. All ATR production is not installed in this region, despite its large demand. Almost half of ATRs are deployed in Brandenburg – having a constant production in this region avoids the need for storage and pipeline connections, saving on costs from a system perspective.

Very little storage is deployed in the system – less than 0.1 TWh. This stems from the assumption that imported hydrogen is available at all times, thus ensuring a stable output to fulfill demand. In reality, if imported hydrogen comes from electrolytic production from renewables, there will be a need for storage either in the importing or exporting country. Such an optimistic assumption likely leads to an underestimation of storage capacities and associated pipelines. While Norway exports its hydrogen to North Germany which is well endowed with salt caverns, Spain and North Africa are connected to the South of the country, a region that does not have significant salt caverns potential. This may require pipelines extending all the way to large-scale storage, increasing costs.

Such a system displays capacity deployments that are more reasonable than the 100% electrolytic case. The important addition to the system consists of the importing pipelines. The capacities required are as high as 7.7 GW for imports from Spain. Even though both Spain and North Africa both deliver 20% of hydrogen demand, Spain's pipeline is much larger than North Africa's (4.4 GW) since it fulfills demand from regions that produce hydrogen electrolytically and thus have peaky demand profiles when there is limited electrolytic production. This system has a strong emphasis on hydrogen transmission to transport imported hydrogen to demand centers.

3.3.3.2. Sensitivity: Norway, Spain, and North Africa Only

To compare such a diverse system with one in which only one partner country delivers hydrogen, scenarios were run in which import constraints were set. The system capacities in 2050 are outlined in Table 11. Connection to Norway and Spain are the cheapest options in levelized terms – the distance of the North African connection increases the pipeline cost, which is ~0.20€/kgH_2 more expensive than its counterparts. Only the Norwegian case deploys significant amounts of salt cavern storage (~390 GWh) – this decreases the international pipeline size since imported hydrogen can be stored locally. However, Spain and North Africa cases have lower domestic pipeline requirements. This is explained by the synergies developed in the South of Germany between electrolytic production powered by ample solar resources and imports. Indeed, the domestic pipelines are then shared between both sources of hydrogen. This reduces the requirements for an extensive domestic network while maximizing the potential of electrolytic production from adequate solar resources. On the contrary, in the Norwegian case, little electrolytic capacity is deployed in the South of the country – deployment occurs northwards to also maximize synergies between production sources but taps into region with less adequate solar resources. Maps of flows in each case are provided in the Appendix. The very large pipeline requirements indicate that imports must be diversified to remain achievable.

Table 11: Technology capacities required in 2050 for the three sensitivity scenarios of imports from a single country, alongside the average levelized cost of hydrogen for the entire system.

	Capacities [GW]						
Connected Country	Electrolyzer	ATR	Solar PV	Salt Caverns [GWh]	Domestic Pipelines	International Pipeline	LCOH [€/kgH_2]
Norway	28.8	2.3	40.2	389	36.7	16.7	3.7
Spain	28.0	2.3	37.3	6.9	34.8	19.0	3.7
North Africa	28.1	2.3	37.2	17	34.2	18.6	4.0

3.4. Discussion

This study has highlighted the infrastructure requirements for a low-carbon hydrogen system. An increasingly important factor is the operation of electrolyzers and their relationship with decarbonized, renewable electricity production. This study, like many other hydrogen supply chain models, intends to decrease the overall costs in the system from a capital and operational perspective. This boils down to a macro-economic optimization that accounts for all system cost and models a centralized operation. In reality, electrolyzer developers may not necessarily co-deploy their own renewable production capacity, meaning that they will procure electricity by buying from the market. Shifting to a value perspective would likely lead to a different optimal utilization rate of electrolyzers. Furthermore, even if a developer owns adjacent renewable capacity, the potential to sell electricity during peak price hours would also change the optimal electrolyzer utilization. Nevertheless, a truly decarbonized operation of electrolyzers will require a flexible operation leading to capacity factors well below 100%.

The planned rapid ramp up of electrolytic production requires a large timely deployment of a large set of technologies. Since Germany plans to decarbonize its industrial demand first, the required constant hydrogen flows greatly incentivize the deployment of pipelines and large-scale storage to maximize the potential of regions with ample renewable resources and the synergies with storage as a buffer. While the cost of offshore wind is currently prohibitively high, future cost reductions can lead to systemic benefits in terms of electrolyzer utilization and decreased renewable capacity deployment.

Hydrogen transmission is preferred over electricity transmission in a least cost system. However, pipelines face the same issue of the right of way as transmission lines – their deployment can hardly be hastened. Particular care should be addressed to using existing pipelines with acquired right of ways to either retrofit or rebuild entirely. Overall, the cost of transportation is minimal on a levelized basis, but it unlocks important synergies in the system. Another important aspect of a system with increasing transport and storage of hydrogen is the consideration of its global warming potential. Greater scrutiny has recently been given to hydrogen, which is reported to negatively interact with molecules in the ozone layer, thus delaying the breakdown of methane and increasing its lifetime in the atmosphere [109]. Future pipelines and storage technologies must be appropriately tight to avoid leaks.

Salt caverns have large systemic benefits by providing buffer to several regions at once. A system in which collaboration between all stakeholders is weak may result in the lack of centralized infrastructure, leading to increased costs of hydrogen. In regions without salt caverns, there is no clear preferred option between compressed and liquid tanks – while liquid has a lower capital cost, the large compression requirements can sometimes be prohibitive. The choice depends on whether the system emphasizes renewable capacity deployment. If so, then compression requirements can offset potentially large curtailments and justify the installation of liquid tanks.

Reaching production independence in Germany is highly unlikely. Imports, notably via pipelines, can decrease the total cost and allow for a reasonable deployment of domestic capacities. However, to achieve carbon neutrality, this imported hydrogen is likely to come from electrolytic production powered by renewables in the long term. This will cause the same issue of variable flow rates and will require storage. Germany has the largest potential for onshore storage in Europe, while Norway has offshore potential and Spain and North Africa have limited resources [110]. Agreements to import hydrogen should include due consideration of storage requirements to ensure that low-carbon electrolytic hydrogen can be exported at a large scale.

Finally, this study delved into the cost implication of a system with increasing electrolytic production. Despite decreasing technology costs and even with optimistic electrolytic cost assumptions, the levelized cost of hydrogen remains high in the long term. This is caused by the large electricity requirements, unattainable maximal capacity factors, and associated technology requirements such as transport to demand sites and storage. The hourly operation of electrolyzers, which depends on local natural resources, cannot be overlooked when estimating the levelized cost. Increasing electrolyzer efficiency should be an important focus of research to reduce the renewable capacity requirements, ultimately driving down costs.

3.5. Conclusion

The present study investigated the supply chain requirements for a low-carbon hydrogen future increasingly dominated by electrolytic production in Germany. The analysis was supported by a novel hydrogen supply chain optimization model that considers a wide range of technologies for production, storage, and transport, solved at an hourly resolution over 12 regions and two offshore sites. It notably optimizes the capacity deployment of renewable generation throughout the country, which is addressed using granular hourly generation data and constrained by land eligibility. The objective of this study consists in assessing the scale of the required infrastructure needed to decarbonize hydrogen demand in Germany for three scenarios: 100% domestic electrolytic production, a system-wide carbon constraint, and a scenario aligned with current policies.

A scenario with 100% domestic electrolytic production brings to light the potential synergies between technologies from a systemic point of view. Salt caverns coupled with a large network of hydrogen pipelines are found to have large systemic benefits to provide buffer between variable electrolytic production and stable industrial demand. Pipelines are preferred over electricity transmission, notably over large distances. Electrolyzers thus tend to be located close to sites with ample natural resources for renewable electricity production. The base scenario determines the levelized cost of electrolytic production to sit between 4.9-6.1 €/kgH_2 in 2025 and 4.1-5.4 €/kgH_2 by 2050, which captures uncertainties in electrolyzer costs. This includes the levelized cost of storage and transmission, which accounts for 0.3-05 €/kgH_2 when salt caverns are available. Without salt caverns, the levelized cost increases by 1.0-2.2 €/kgH_2 due to the larger cost of compressed and liquid tanks and the greater addition of renewable capacity to reduce storage needs.

A system under a carbon constraint shows that ATR production with CCS is preferred over electrolytic production thanks to the cost benefits. This importantly relies on assumed reductions in the methane leakage rate and the grid carbon intensity. The cost of ATR production with CCS is found to total 2.8 €/kgH_2 in 2025, an important increase compared with unabated production due to the large cost of CCS installation. The cost of natural gas is an important determinant in the levelized cost, and its variability coupled with an increasing carbon price threatens the technology's position in the competitive landscape.

Finally, a scenario evaluates the system under which production constraints are set for electrolytic and ATR production domestically as well as imports from Norway, Spain, and North Africa through pipelines. This scenario uncovers significant benefits in terms of required capacity deployment throughout the country. By 2050, 28.5 GW of electrolyzers are installed alongside 39.3 GW of solar panels, 26.9 GW of domestic pipelines, and only 0.1 TWh of salt caverns. International pipelines are found to be very large, between 4.3 and 7.7 GW in capacity. A sensitivity analysis indicates that having multiple exporting countries is paramount to achieving large-scale decarbonization in Germany due to the scale of required demand.

3.6. Appendix

3.6.1. Technical Potential of Wind Turbines, Solar Panels, and Salt Caverns

Region	Wind – Onshore [MW]	Wind – Offshore [MW]	Solar [MW]	Salt Caverns [TWh]
Northwest Offshore	-	5000	0	0
Northeast Offshore	-	5000	0	0
Schleswig-Holstein	11159.38	-	33885	153

Mecklenburg-Western Pomerania	14115.7	-	23297.4	64.9
Lower Saxony	30539.22	-	70304.4	96.8
Brandenburg	10764.56	-	20349	0
Saxony-Anhalt	12059.8	-	14918.4	19.7
North Rhine-Westphalia	8969.22	-	10191.6	1.87
Saxony	6980.68	-	10744.2	0
Thuringia	8460.1	-	10234.8	0
Hesse	8870.98	-	17202.6	0
Rhineland-Palatinate	8529.58	-	21085.2	0
Baden-Württemberg	15517.72	-	28690.2	0
Bavaria	38531.82	-	82866.6	0

3.6.2. Constants

Name	Value	Unit	Source
Electrolyzer Efficiency - 2025	65	%	[107]
Electrolyzer Efficiency - 2030	65	%	[107]
Electrolyzer Efficiency - 2040	68	%	[107]
Electrolyzer Efficiency - 2050	70	%	[107]
ATR Capacity Factor	90	%	[15]
Battery Storage Duration	4	Hours	[75]
Compressor Req. – Salt Cavern	93	$kWhH_2/kWh_{el}$	
Compressor Req. – Comp. Tank	33	$kWhH_2/kWh_{el}$	
Compressor Req. – Liquid Tank	11	$kWhH_2/kWh_{el}$	
Transmission Losses %	6.25	%/1000km	[111]
Charging and Discharging Eff.	96	%	[75]
Detour Factor	1.4	-	[78]
Total Charge Time – Salt Cavern	608	Hours	[79]
Total Discharge Time – Salt Cavern	122	Hours	[79]
Total Charge Time – Compressed Tank	203	Hours	Assumption
Total Discharge Time – Compressed Tank	41	Hours	Assumption
Total Charge Time – Liquid Tank	203	Hours	Assumption
Total Discharge Time – Liquid Tank	41	Hours	Assumption
Electricity Req. – ATR	0.107	kWh/kWhH2	[15]
Natural Gas Req. – ATR	1.38	kWhNG/kWhH2	[15]
Natural Gas Pipeline Length	1,000	Km	Assumption
Spanish Pipeline Length	1,000	Km	Assumption
North African Pipeline Length	3,300	Km	[112]

3.6.3. System Characteristics

Name	Value	Unit	Source
Yearly Hydrogen Demand – 2025 (Low Demand)	50	TWh	[101]
Yearly Hydrogen Demand – 2030 (Low Demand)	105.5	TWh	[101]
Yearly Hydrogen Demand – 2040 (Low Demand)	142.9	TWh	[101]
Yearly Hydrogen Demand – 2050 (Low Demand)	187.5	TWh	[101]
Yearly Hydrogen Demand – 2025 (High Demand)	50	TWh	[101]
Yearly Hydrogen Demand – 2030 (High Demand)	105.5	TWh	[101]
Yearly Hydrogen Demand – 2040 (High Demand)	187.5	TWh	[101]
Yearly Hydrogen Demand – 2050 (High Demand)	331	TWh	[101]
Methane Leakage Rate – 2025	1.5	%	[40]
Methane Leakage Rate – 2030	1	%	Assumption
Methane Leakage Rate – 2040	0.5	%	Assumption
Methane Leakage Rate – 2050	0.3	%	Assumption
Grid Electricity Price – 2025	85	€/MWh	[105]
Grid Electricity Price – 2030	80	€/MWh	[105]
Grid Electricity Price – 2040	70	€/MWh	[105]
Grid Electricity Price – 2050	60	€/MWh	[105]
Grid Electricity Emissions – 2025	180	gCO_2/kWh	[105]
Grid Electricity Emissions – 2030	120	gCO_2/kWh	[105]
Grid Electricity Emissions – 2040	40	gCO_2/kWh	[105]
Grid Electricity Emissions – 2050	20	gCO_2/kWh	[105]
Maximum Carbon Intensity BAU - 2025	3.38	$kgCO_2/kgH_2$	[104]
Maximum Carbon Intensity BAU - 2030	3.38	$kgCO_2/kgH_2$	[104]
Maximum Carbon Intensity BAU - 2040	3.38	$kgCO_2/kgH_2$	[104]
Maximum Carbon Intensity BAU - 2050	3.38	$kgCO_2/kgH_2$	[104]
Maximum Carbon Intensity AD – 2025	3.38	$kgCO_2/kgH_2$	[104]
Maximum Carbon Intensity AD – 2030	2.40	$kgCO_2/kgH_2$	Assumption
Maximum Carbon Intensity AD – 2040	1.50	$kgCO_2/kgH_2$	Assumption
Maximum Carbon Intensity AD - 2050	1.00	$kgCO_2/kgH_2$	Assumption
Carbon Tax – 2025	50	€/tCO_2	[107]
Carbon Tax – 2030	100	€/tCO_2	[107]
Carbon Tax – 2040	150	€/tCO_2	[107]
Carbon Tax – 2050	225	€/tCO_2	[107]

3.6.4. Costs

Name		Value	Unit	Source
Weighted Average Cost of Capital		10	%	Assumption
Wind - Onshore	Lifetime	25	Years	[107]
	CapEx – 2025	1411	€/kW	[107]
	OpEx – 2025	3	% of CapEx/yr	[107]
	CapEx – 2030	1366	€/kW	[107]

	OpEx – 2030	3	% of CapEx/yr	[107]
	CapEx – 2040	1337	€/kW	[107]
	OpEx – 2040	3	% of CapEx/yr	[107]
	CapEx – 2050	1335	€/kW	[107]
	OpEx – 2050	3	% of CapEx/yr	[107]
Wind - Offshore	Lifetime	20	Years	[107]
	CapEx – 2025	3510	€/kW	[107]
	OpEx – 2025	3	% of CapEx/yr	[107]
	CapEx – 2030	2637	€/kW	[107]
	OpEx – 2030	3	% of CapEx/yr	[107]
	CapEx – 2040	2493	€/kW	[107]
	OpEx – 2040	3	% of CapEx/yr	[107]
	CapEx – 2050	2251	€/kW	[107]
	OpEx – 2050	3	% of CapEx/yr	[107]
Solar	Lifetime	30	Years	[107]
	CapEx – 2025	600	€/kW	[107]
	OpEx – 2025	2	% of CapEx/yr	[107]
	CapEx – 2030	550	€/kW	[107]
	OpEx – 2030	2	% of CapEx/yr	[107]
	CapEx – 2040	463	€/kW	[107]
	OpEx – 2040	2	% of CapEx/yr	[107]
	CapEx – 2050	390	€/kW	[107]
	OpEx – 2050	2	% of CapEx/yr	[107]
Transmission Lines - Onshore	Lifetime	40	Years	[113]
	CapEx	1.8088	€/kW-km	[111]
	OpEx	0.02	% of CapEx/yr	[113]
Transmission Lines - Offshore	Lifetime	40	Years	Assumption
	CapEx	7.67624	€/kW-km	[82]
	OpEx	2	% of CapEx/yr	Assumption
Electrical Storage	Lifetime	15	Years	[75]
	CapEx – Power	394.8	€/kW	[75]
	Capex - Energy	231.2	€/kWh	[75]
	OpEx	3.82	% of CapEx/yr	[75]
Electrolyzer	Lifetime	25	Years	[107]
	CapEx – 2025	676	€/kW	[107]
	OpEx – 2025	3.5	% of CapEx/yr	[107]
	CapEx – 2030	613	€/kW	[107]
	OpEx – 2030	3.4	% of CapEx/yr	[107]
	CapEx – 2040	554	€/kW	[107]
	OpEx – 2040	3.6	% of CapEx/yr	[107]
	CapEx – 2050	495	€/kW	[107]
	OpEx – 2050	3.9	% of CapEx/yr	[107]
	Lifetime	25	Years	[15]
	CapEx	1853.1	€/kW	[15]

ATR with 91% Carbon Capture - Greenfield	OpEx	5.9	% of CapEx/yr	[15]
Compressor - Storage	Lifetime	15	Years	[84]
	CapEx	1,303	€/kW$_{el}$	[84]
	OpEx	5	% of CapEx/yr	[84]
Cavern	Lifetime	30	Years	[76]
	CapEx	0.6874	€/kWhH_2	[76]
	OpEx	2	% of CapEx/yr	[76]
Compressed Tank	Lifetime	20	Years	Expert Elicitation
	CapEx	23	€/kgH_2	Expert Elicitation
	OpEx	2	% of CapEx/yr	Expert Elicitation
Liquid Tank	Lifetime	20	Years	Expert Elicitation
	CapEx	13.83	$/kg$H_2$	Expert Elicitation
	OpEx	2	% of CapEx/yr	Expert Elicitation
Onshore Pipeline (Includes North Africa & Spain)	Lifetime	40	Years	[84]
	CapEx	0.678	€/kW/km	[84]
	OpEx	2.4	% of CapEx/yr	[84]
Norwegian Pipeline	Lifetime	50	Years	[114]
	CapEx	317.8	€/kW	[114]
	OpEx	1	% of CapEx/yr	[114]
CO_2 Storage & Transport	Transport & Storage	3.67	€/kgCO_2	[115]
Natural Gas Cost	Cost – 2025	0.025	€/kWhNG	[107]9/1/23 9:55:00 AM
	Cost – 2030	0.016	€/kWhNG	[107]
	Cost – 2040	0.017	€/kWhNG	[107]
	Cost – 2050	0.017	€/kWhNG	[107]
North African Hydrogen Cost		3.3	€/kgH_2	[116]
Spanish Hydrogen Cost		3.1	€/kgH_2	[116]
Norwegian Hydrogen Cost		3.2	€/kgH_2	[117]

3.6.5. Emissions

Name	Value	Unit	Source

Methane Recovery & Processing	0.013446165	$kgCO_{2eq}/kWhNG$	[118]
Methane Leaks and Venting - Transport	0.007612532	$kgCO_{2eq}/kWhNG\text{-}1000km$	[118]
ATR – Captured	0.233123312	$kgCO_2/kWhH_2$	[15]
ATR – Released	0.01860186	$kgCO_2/kWhH_2$	[15]

3.6.6. Regional Split of Industrial Demand [TWh/year]

Region	2025 – Low	2025 – High	2030 – Low	2030 – High	2040 – Low	2040 – High	2050 – Low	2050 – High
Schleswig-Holstein	7	7	7.385	7.385	7.1	7.5	7.5	13.24
Mecklenburg-Western Pomerania	0	0	0	0	0	0	0	0
Lower Saxony	1	1	15.825	15.825	15.62	16.875	16.875	26.48
Brandenburg	2.5	2.5	7.385	7.385	7.1	7.5	7.5	13.24
Saxony-Anhalt	12.5	12.5	12.66	12.66	12.78	9.375	9.375	19.86
North Rhine-Westphalia	11	11	39.035	39.035	63.9	86.25	86.25	148.95
Saxony	0	0	0	0	7.1	13.125	13.125	16.55
Thuringia	0	0	0	0	0	0	0	3.31
Hesse	0	0	0	0	0	0	0	3.31
Rhineland-Palatinate	9	9	16.88	16.88	17.04	30	30	33.1
Baden-Württemberg	3.5	3.5	3.165	3.165	4.26	3.75	3.75	13.24
Bavaria	3.5	3.5	3.165	3.165	8.52	13.125	13.125	36.41
Total	**50**	**50**	**105.5**	**105.5**	**142.9**	**187.5**	**187.5**	**331**

3.6.7. Sensitivity on Imports

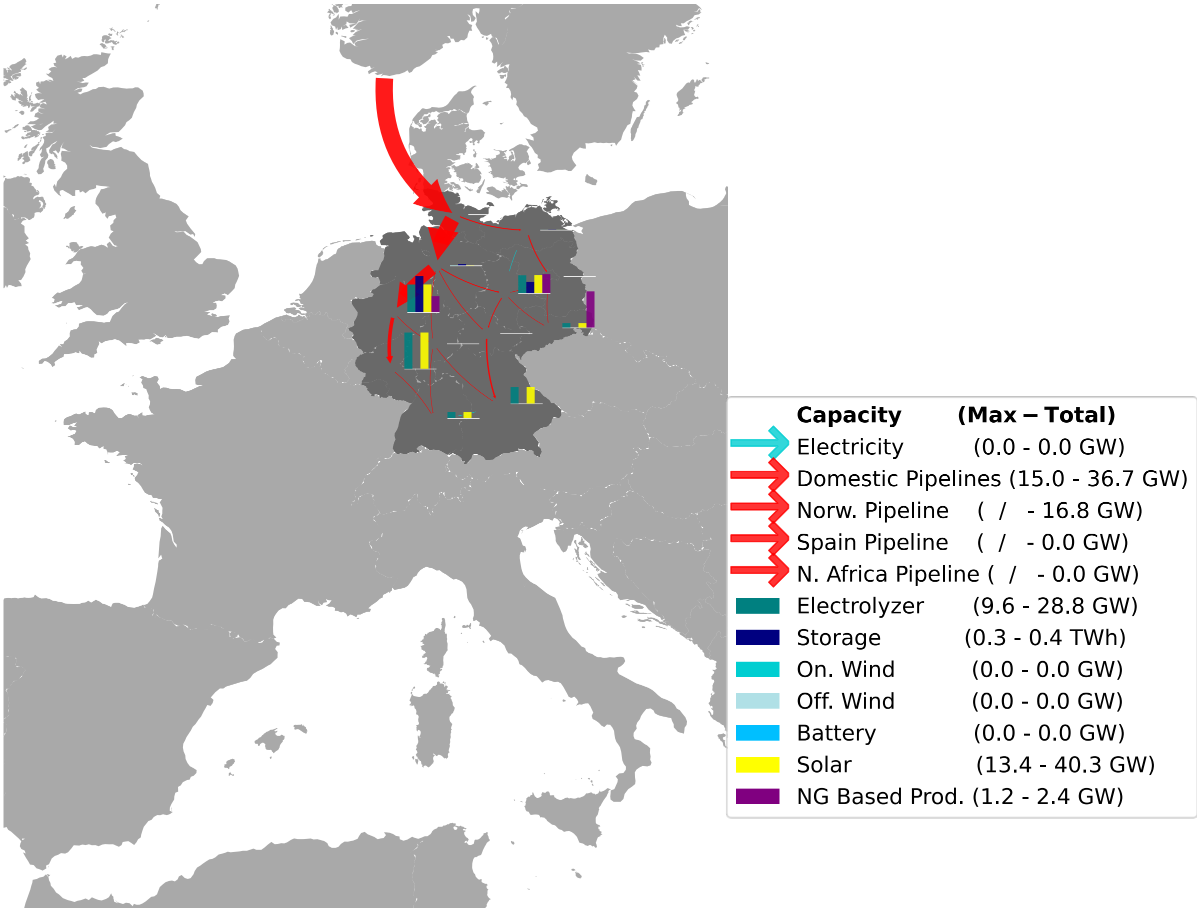


Figure 20: Illustration of the supply chain requirements for a system that allows imports from Norway only, in 2050, for the low demand scenario.

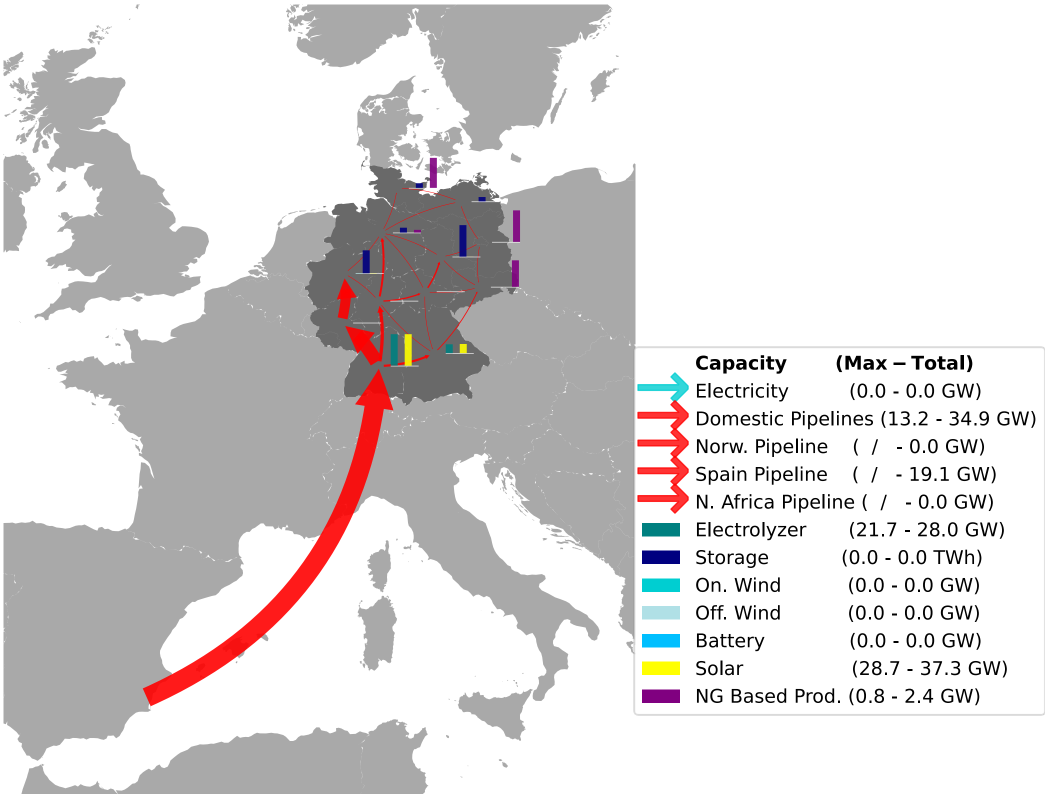


Figure 21: Illustration of the supply chain requirements for a system that allows imports from Spain only, in 2050, for the low demand scenario.

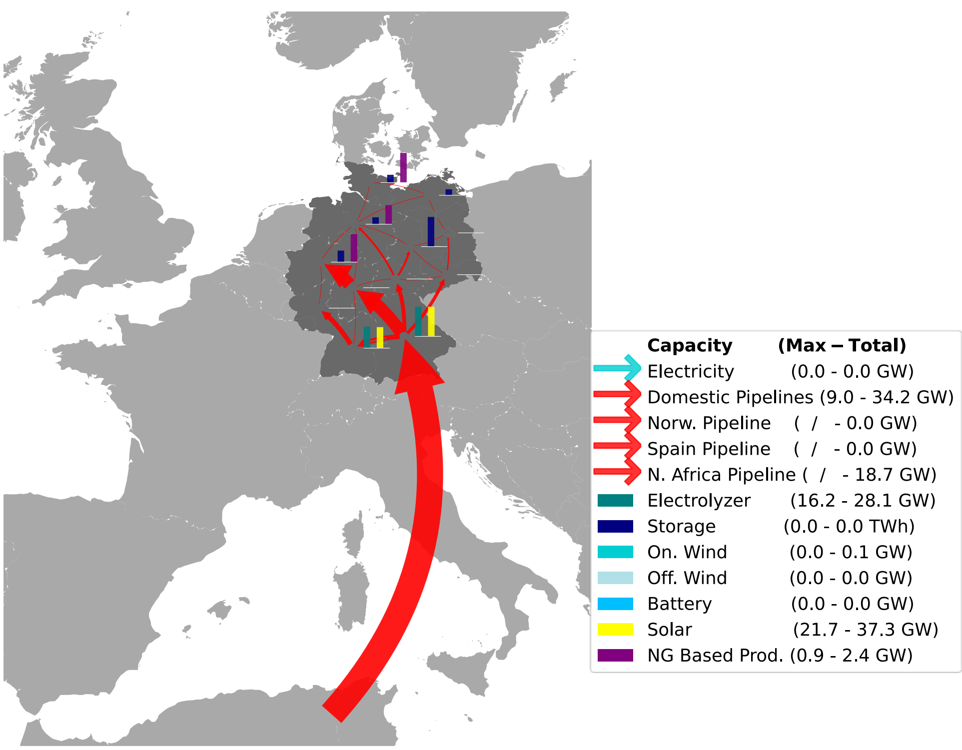


Figure 22: Illustration of the supply chain requirements for a system that allows imports from Norway only, in 2050, for the low demand scenario.

Chapter 4

Conclusion

This study presented a novel hydrogen supply chain optimization model. This model seeks to lower the overall cost of a system that encompasses renewable generation with solar PV and wind turbines, hydrogen production with electrolyzers, SMR and ATR, transmission with pipelines or transmission lines, and electricity and hydrogen storage. The variable production of renewable electricity requires a high granularity, which is captured at an hourly level using annual supply curves. This intends to faithfully represent the hourly operation of all technologies, shedding light on the synergies between electricity production, hydrogen production, transmission, and storage granularly. The considered hydrogen demand was assumed to stem from industrial applications, thus requiring constant hydrogen input. The model can also handle more variable demand in other case scenarios.

A case study considered the decarbonization of current hydrogen demand in Texas and Louisiana (217 TWh/yr in 2025) using electrolytic production only. The resulting levelized cost of hydrogen totaled 5.5 €/kgH_2 in 2025, decreasing to 4.9 €/kgH_2 in 2030 in an optimistic electrolytic cost outlook. This cost is mainly composed of the capacity costs of renewables and electrolyzers, and the cost in 2050 reflects added capacity in previous years, explaining the relatively low decrease. Inexpensive storage was found to be central to coping with the flexible operation of electrolyzers dictated by the power generation curve in order to fulfill constant demand. The absence of salt caverns in the system increases the renewable generation capacity to rely less on storage, leading to increased electricity curtailment. The benefit of large underground storage is greater in concurrence with pipeline transmission. It enables regions that do not have the required geological formation to benefit from this inexpensive form of storage, instead of producing hydrogen locally with either tanks or batteries, both of which importantly increase the levelized cost. Finally, the current cost of offshore wind seems unfavorable for its introduction in the system. Reducing the capital cost of offshore wind as well as that of undersea transmission lines may lead to benefits in certain regions of the US but did not show advantages in the Gulf Coast due to the larger capacity factors of onshore wind compared with offshore.

Another scenario considered the supply chain in the Gulf Coast under a carbon constraint, limiting the system-wide emissions allowed for hydrogen production. Two cases were analyzed – a business-as-usual case and an accelerated decarbonization case, with both decreasing thresholds through the years but with a more aggressive approach in the latter scenario. Results show that lax carbon constraints lead to continued reliance upon hydrogen produced from natural gas, especially if the upstream emissions can be decreased. With tighter constraints, the system primarily relies on electrolytic hydrogen. Sending an early signal to the industry of tight carbon constraints would thus accelerate the deployment of electrolytic hydrogen.

In the case of Germany, a scenario with 100% domestic electrolytic production also brings to light the potential synergies between technologies from a systemic point of view. Salt caverns coupled with a large network of hydrogen pipelines are found to have large systemic benefits to provide buffer between variable electrolytic production and stable industrial demand. Pipelines are preferred over electricity transmission, notably over large distances. Electrolyzers thus tend to be located close to sites with ample natural resources for renewable electricity production. The base scenario determines the levelized cost of electrolytic production to sit between 4.9-6.1 €/kgH_2 in 2025 and 4.1-5.4 €/kgH_2 by 2050, which captures uncertainties in electrolyzer costs. This includes the levelized cost of storage and transmission, which accounts for 0.3-05 €/kgH_2 when salt caverns are available. Without salt caverns, the levelized cost increases by 1.0-2.2 €/kgH_2 due to the larger cost of compressed and liquid tanks and the greater addition of renewable capacity to reduce storage needs.

A system under a carbon constraint shows that ATR production with CCS is preferred over electrolytic production thanks to the cost benefits. This importantly relies on assumed reductions in the methane leakage rate and the grid carbon intensity. The cost of ATR production with CCS is found to total 2.8 €/kgH_2 in 2025, an important increase compared with unabated production due to the large cost of CCS installation. The cost of natural gas is an important determinant in the levelized cost, and its variability coupled with an increasing carbon price threatens the technology's position in the competitive landscape.

Finally, a scenario evaluates the system under which production constraints are set for electrolytic and ATR production domestically as well as imports from Norway, Spain, and North Africa through pipelines. This scenario uncovers significant benefits in terms of required capacity deployment throughout the country. By 2050, 28.5 GW of electrolyzers are installed alongside 39.3 GW of solar panels, 26.9 GW of domestic pipelines, and only 0.1 TWh of salt caverns. International pipelines are found to be very large, between 4.3 and 7.7 GW in capacity. A sensitivity analysis indicates that having multiple exporting countries is paramount to achieving large-scale decarbonization in Germany due to the scale of required demand.

This study has highlighted the infrastructure requirements for a low-carbon hydrogen system. An increasingly important factor is the operation of electrolyzers and their relationship with decarbonized, renewable electricity production. This study, like many other hydrogen supply chain models, intends to decrease the overall costs in the system from a capital and operational perspective. This boils down to a macro-economic optimization that accounts for all system cost and models a centralized operation. In reality, electrolyzer developers may not necessarily co-deploy their own renewable production capacity, meaning that they will procure electricity by buying from the market. Shifting to a value perspective would likely lead to a different optimal utilization rate of electrolyzers. Furthermore, even if a developer owns adjacent renewable capacity, the potential to sell electricity during peak price hours would also change the optimal electrolyzer utilization. Nevertheless, a truly decarbonized operation of electrolyzers will require a flexible operation leading to capacity factors well below 100%.

Hydrogen transmission is preferred over electricity transmission in a least cost system. However, pipelines face the same issue of the right of way as transmission lines – their deployment can hardly be hastened. Particular care should be addressed to using existing pipelines with acquired right of ways to either retrofit or rebuild entirely. Overall, the cost transportation is minimal on a levelized basis, but it unlocks important synergies in the system. Another important aspect in a system with increasing transport and storage of hydrogen is the consideration of its global warming potential. Greater scrutiny has recently been given to hydrogen, which is reported to negatively interact with molecules in the ozone layer, thus delaying the breakdown of methane and increasing its lifetime in the atmosphere [109]. Future pipelines and storage technologies must be appropriately tight to avoid leaks.

Salt caverns have large systemic benefits by providing buffer to several regions at once. A system in which collaboration between all stakeholders is weak may result in the lack of centralized infrastructure, leading to the increased cost of hydrogen. In regions without salt caverns, there is no clear preferred option between compressed and liquid tanks – while liquid has a lower capital cost, the large compression requirements can sometimes be prohibitive. The choice depends on whether the system emphasizes renewable capacity deployment. If so, then compression requirements can offset potentially large curtailments and justify the installation of liquid tanks.

Finally, this study delved into the cost implication of a system with increasing electrolytic production. Despite decreasing technology costs and even with optimistic electrolytic cost assumptions, the levelized cost of hydrogen remains high in the long term. This is caused by the large electricity requirements, unattainable maximal capacity factors, and associated technology requirements such as transport to demand sites and storage. The hourly operation of electrolyzers, which depends on local natural resources, cannot be overlooked when estimating the levelized cost. Increasing electrolyzer efficiency should be an important focus of research to reduce the renewable capacity requirements, ultimately driving down costs.

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